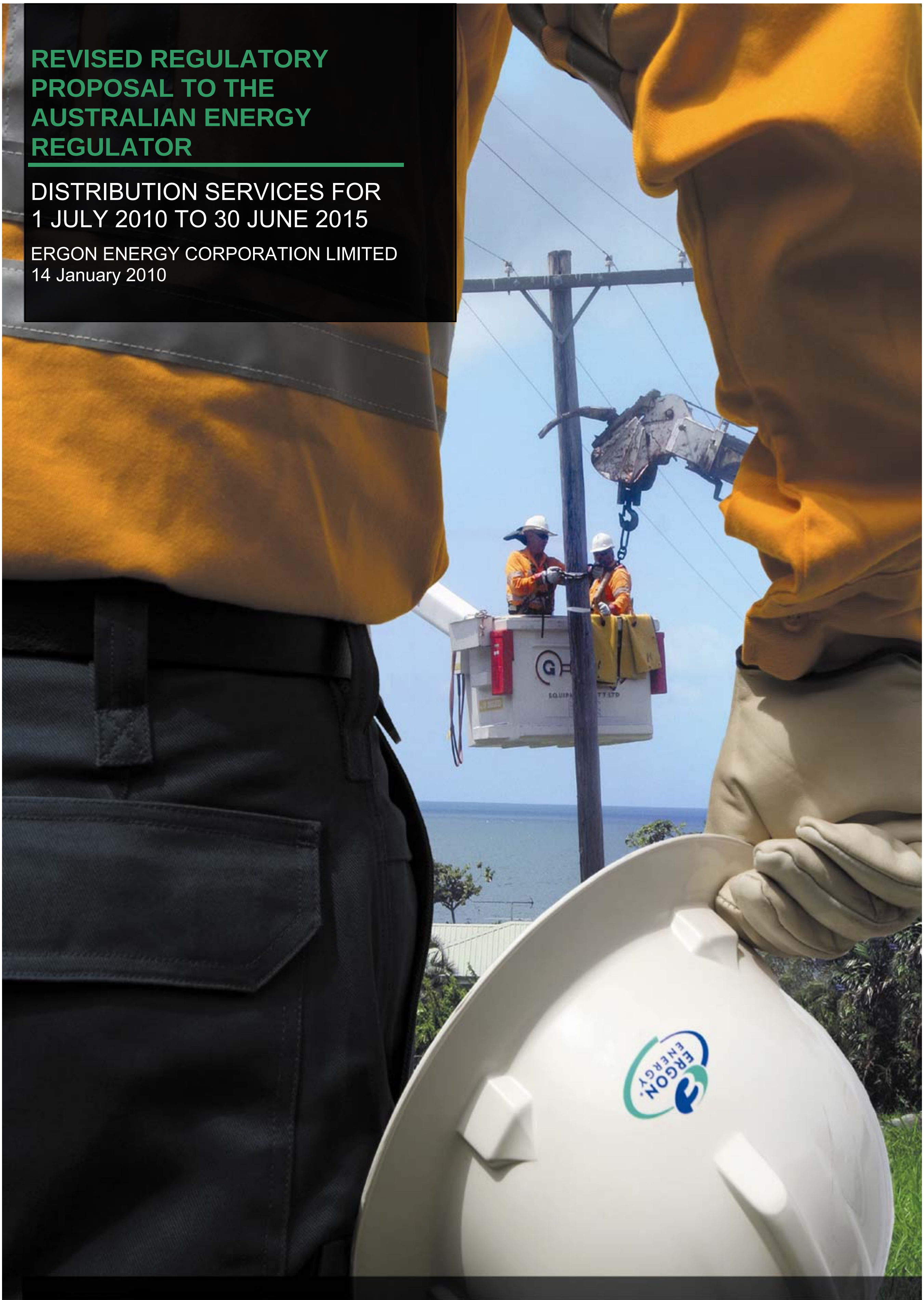
REVISED REGULATORY PROPOSAL TO THE AUSTRALIAN ENERGY REGULATOR

DISTRIBUTION SERVICES FOR 1 JULY 2010 TO 30 JUNE 2015

ERGON ENERGY CORPORATION LIMITED
14 January 2010



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GLOSSARY

AAWI	Average Annualised Wage Increase
ABARE	Australian Bureau of Agricultural and Resource Economics
ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AEP	Asset Equipment Plan
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
ANZSIC	Australian and New Zealand Standard Industrial Classification
ARR	Annual Revenue Requirement
CAC	Connection Asset Customer
Capex	Capital Expenditure
CBA	Commonwealth Bank of Australia
CBRC	Cabinet Budget Review Committee
CEG	Competition Economists Group
CFC	Construction Forecasting Council
CEPU	Communications, Electrical and Plumbing Union
CICW	Customer Initiated Capital Works
Code	Queensland Electricity Industry Code
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
CRT	Cathode Ray Tube
DC	Direct Current
DEE	Dangerous Electrical Events
DEEWR	Department of Education, Employment and Workplace Relations
DEWHA	Department of Environment Water Heritage and Arts
DM	Demand Management
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DMS	Demand Management System
DNAP	Distribution Network Augmentation Plan
DNSP	Distribution Network Service Provider
DUOS	Distribution Use of System

EBSS	Efficiency Benefit Sharing Scheme
EDSD Review	Electricity Distribution and Service Delivery Review
EE	Ergon Energy Corporation Limited
EECL	Ergon Energy Corporation Limited
EG	Embedded Generator
EGW	Electricity Gas Water
ENA	Energy Networks Association
Ergon Energy	Ergon Energy Corporation Limited
ESOO	Electricity Statement of Opportunities
EWP	Elevated Work Platform
Excel	Microsoft Excel
F&A	Framework and Approach
F&A Stage 1	Framework and Approach Stage 1
F&A Stage 2	Framework and Approach Stage 2
FFA	Field Force Automation
FIT	Feed-in-tariff
GDP	Gross Domestic Product
GRP	Gross Regional Product
GSL	Guaranteed Service Level
GSP	Gross State Product
GST	Goods and Services Tax
GW	Gigawatt
GWh	Gigawatt hour
HDBC	Hard Drawn Bare Copper
IAM	Identity and Access Management
IBNR	Incurred But Not Reported
ICC	Individually Calculated Customer
ICT	Information Communication and Telecommunications
IMF	International Monetary Fund
IT	Information Technology
KM	Kilometre
KPMG	Klynveld Peat Marwick Goerdeler (consultants)
kV	Kilovolt
kVA	Kilovolt-ampere
kW	Kilowatt
kWh	Kilowatt Hour

LCD	Liquid Crystal Display
LEO	Labour Economics Office
LME	London Metals Exchange
LNG	Liquefied Natural Gas
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MAR	Maximum Allowable Revenue
MED	Major Event Day
MEHRC	Minerals and Energy Human Resources Conference
MMA	McLennan Magasanik Associates
MRET	Mandatory Renewable Energy Target
MRP	Market Risk Premium
MSS	Minimum Service Standard
MVA	Megavolts-ampere
MVAR	Megavar reactive component of power
MW	Megawatt
MWh	Megawatt hour
NARMCOS (Data Model)	Network Assets Replacement Maintenance Capex Opex Summary Model
NDM	Network Demand Management
NEEI	National Energy Efficiency Initiative
NER	National Electricity Rules
NIEIR	National Institute of Economic and Industrial Research
NMI	National Metering Identifier
Nominal	With respect to dollars – means dollars-of-the-day. In this Revised Regulatory Proposal Nominal dollars are dollars as at 30 June of the financial year of which the dollars relate.
NPV	Net Present Value
Opex	Operating Expenditure
PB	Parsons Brinckerhoff
PCB	Polychlorinated Biphenyl
POE	Probability of Exceedance - means the likelihood that a forecast value will be exceeded by the actual value. For example, for an annual forecast a 50 per cent POE is likely to be exceeded once every second year, whereas a 10 per cent POE is likely to be exceeded once every 10 years.
PTRM	Post Tax Revenue Model
QCA	Queensland Competition Authority
RAB	Regulatory Asset Base

RBA	Reserve Bank of Australia
Real	With respect to dollars – means constant dollars at a specific date. In this Revised Regulatory Proposal where 'real' dollars are used, they are 2009-10 dollars unless otherwise stated.
RFM	Roll Forward Model
RIN	Regulatory Information Notice
Rules	National Electricity Rules
SAC	Standard Asset Customer
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCAMS	Substation Contingency and Management System
SEO	Seasoned Equity Offering
SERA	Survey of Employers who have Recently Advertised
SFG	Strategic Finance Group
SGSC	Smart Grid, Smart City
SKM	Sinclair Knight Mertz
SNAP	Sub-transmission Network Augmentation Plan
SPARQ	Sparq Solutions Pty Ltd
SORI	Statement of Regulatory Intent
STPIS	Service Target Performance Incentive Scheme
SWER	Single Wire Earth Return
Synergies	Synergies Economic Consulting
TaDS	Transmission and Distribution Services
TCP	Transmission Connection Point
TMED	Major Event Day Threshold
TWI	Trade Weighted Index
UbiNet	Ubiquitous Network
UCA	Union Collective Agreement
UMS	UMS Group Incorporated
URD	Urban Residential Development
VAr	Volt Ampere Reactive
VCR	Value of Customer Reliability
VT	Voltage Transformer
W	Watt
WACC	Weighted Average Cost of Capital

1 EXECUTIVE SUMMARY

1.1 Introduction

Ergon Energy has reviewed the Australian Energy Regulator's (AER) Draft Distribution Determination and welcomes the opportunity to submit this Revised Regulatory Proposal. Ergon Energy appreciates the open and constructive manner in which the AER has conducted its review of Ergon Energy's Regulatory Proposal.

Ergon Energy submits this Revised Regulatory Proposal to demonstrate the prudence and efficiency of its expenditure forecasts. It also seeks to describe the broader economic environment to which these forecasts relate.

This Revised Regulatory Proposal is essential to delivering the next stage of Ergon Energy's Strategic Plan for the 2010-15 regulatory control period. Ergon Energy's Strategic Plan is guided by its purpose to enhance the economic and lifestyle aspirations of its customers through sustainable energy solutions.

This purpose takes on added meaning in the context of Queensland's recovery from the Global Financial Crisis. Indeed, the AER's final Distribution Determination will reach beyond Ergon Energy and its customers, and have significant implications for the growth of the regional Queensland economy for many years to come. The Queensland resources sector is increasingly showing signs of a strong recovery – one which promises to generate thousands of jobs and inject billions in export dollars into the Australian economy.

Ergon Energy is the supplier of the critical electricity infrastructure that supports Queensland's burgeoning resources sector. It is through this Revised Regulatory Proposal that Ergon Energy seeks to secure the revenue required, based on prudent and efficient expenditure forecasts, to build a solid foundation upon which continued state development can occur. To secure anything less will position Ergon Energy as a roadblock to state and national economic recovery.

1.2 About Ergon Energy's Revised Regulatory Proposal

Ergon Energy's Revised Regulatory Proposal provides additional information to support and clarify its June 2009 Regulatory Proposal and addresses concerns or questions raised by the AER and its consultants in the Draft Distribution Determination. The Revised Regulatory Proposal:

- Highlights and addresses where Ergon Energy maintains a different position to the changes proposed by the AER in its Draft Distribution Determination;
- Acknowledges where Ergon Energy has accepted changes proposed by the AER in its Draft Distribution Determination; and
- Seeks additional information in order to clarify how aspects of the final Distribution Determination will be applied.

This Revised Regulatory Proposal generally does not address aspects of the June 2009 Regulatory Proposal that the AER has accepted.

1.2.1 Matters Where Ergon Energy Differs from the AER

Through this Revised Regulatory Proposal, Ergon Energy will outline matters on which it continues to maintain a different position to the AER. As detailed in Chapter 2, and subsequently throughout this Revised Regulatory Proposal, the following are the key areas of concern for Ergon Energy in delivering its Standard Control Services in the next regulatory control period:

Labour escalations

Ergon Energy has retained the labour escalations based on the current Ergon Energy Union Collective Agreement (UCA) as the labour cost escalators for the next regulatory control period as they are comparable with other recent relevant wage negotiation outcomes and reflect prudent and efficient wage increases.

Economic and demand forecasts

Ergon Energy has updated its demand forecast in the light of the most recent economic outlook data and Ergon Energy's 2008-09 summer peak. This new information indicates a far quicker economic recovery in regional Queensland than the AER has forecast in its Draft Distribution Determination.

Growth capital expenditure

Ergon Energy has retained its Corporation Initiated Augmentation capital expenditure from its June 2009 Regulatory Proposal and has increased its Customer Initiated Capital Works forecast as a result of basing its forecast on dwelling stock growth.

Non-System Property capital expenditure

Ergon Energy has slightly reduced its capital expenditure forecast for non-system property and has provided extensive additional documentation in support of its forecast, including business cases and condition reports.

1.2.2 Matters Where Ergon Energy Generally Agrees with the AER

The AER has proposed a number of changes in its Draft Distribution Determination that Ergon Energy has accepted. While some differences are detailed in the relevant chapters, Ergon Energy generally accepts the AER's position in relation to the following matters:

- Efficiency Benefit Sharing Scheme (EBSS);
- Demand Management Incentive Scheme (DMIS);
- Classification of services; and
- Control mechanisms.

1.2.3 Matters Where Ergon Energy Seeks Clarification from the AER

Ergon Energy is also seeking the AER's reconsideration or further clarification on a number of other matters. In particular:

- Ergon Energy seeks to clarify the nature and materiality threshold of pass through events, including emissions trading, feed-in tariffs and unfunded shared network events;
- Ergon Energy is seeking to have Service Target Performance Incentive Scheme (STPIS) targets based on the lower of the Minimum Service Standards (MSS) under the Queensland Electricity Industry Code (Code) or its historical reliability performance, rather than internal targets; and
- Ergon Energy is seeking to retain its proposed gamma of 0.2 rather than the AER's proposed gamma of 0.65.

In some instances, Ergon Energy believes the AER has not fully understood, and therefore has not given due consideration to in its Draft Distribution Determination, the information Ergon Energy supplied in its June 2009 Regulatory Proposal and accompanying documents. In other instances, Ergon Energy has identified additional information which is considered to be more up-to-date and relevant than that relied upon by the AER in its Draft Distribution Determination. Ergon Energy also seeks to address instances where the AER's position does not appear to reflect a correct application of the National Electricity Rules (Rules). Throughout this Revised Regulatory Proposal, Ergon Energy has endeavoured to provide further information to clarify and draw the AER's attention to these relevant matters.

1.3 Summary of Adjustments to Ergon Energy's June 2009 Regulatory Proposal

This section summarises the adjustments which account for key differences between Ergon Energy's capital and operating expenditure forecasts for Standard Control Services in its June 2009 Regulatory Proposal and this Revised Regulatory Proposal. This includes changes to direct costs, shared costs (overheads) and escalators.

1.3.1 General Adjustments

Changes to escalators and shared costs (overheads) have resulted in adjustments to all of Ergon Energy's capital and operating expenditure forecasts in this Revised Regulatory Proposal.

In its Draft Distribution Determination, the AER accepted that Ergon Energy's shared costs (overheads) were prudent and efficient with the exception of $39 million for capital expenditure and $6.4 million for operating expenditure. While these amounts have a minimal impact on shared costs (overheads), changes to direct costs have resulted in a reallocation of overheads.

In its Draft Distribution Determination, the AER proposed changes to both labour and material escalators. Ergon Energy has made no adjustment to labour escalators. It maintains its original position to apply the wage increases in the current UCA as the labour cost escalators for the next regulatory control period as they reflect prudent and efficient costs for the purposes of the operating and capital expenditure criteria in clauses 6.5.6(c) and 6.5.7(c) of the Rules. Ergon Energy has adjusted its material escalators, in particular to correct an error in its June 2009 Regulatory Proposal.

1.3.2 Capital Expenditure Adjustments

Ergon Energy believes the AER's proposed reduction of its capital expenditure from $6,033 million to $5,013 million cannot be justified under clause 6.5.7 of the Rules (see Chapter 10 for further details). Ergon Energy's revised capital expenditure program is shown in Table 1-1.

Table 1-1: Revised Forecast Capital Expenditure – by Category Driver – 2010-15 ($M Real $2009-10)

Category Driver	2010-11	2011-12	2012-13	2013-14	2014-15	Total	Average of 5 year Total
Asset Replacement	181.24	222.55	261.68	285.86	305.03	1,256.35	251.27
Corporation Initiated Augmentation	273.32	355.81	422.98	487.85	536.32	2,076.28	415.26
Customer Initiated Capital Works	363.68	394.72	341.83	357.27	389.01	1,846.51	369.30
Reliability and Quality Improvement	18.49	21.49	25.16	29.00	30.85	124.99	25.00
Other System	111.13	74.96	53.07	52.73	53.18	345.06	69.01
Non-System	175.37	152.57	127.29	80.75	88.98	624.95	124.99
Total	1,123.23	1,222.10	1,232.00	1,293.45	1,403.36	6,274.15	1,254.83

Source: Revised Submission Tables for Proposal 23.1

Changes in the direct costs between Ergon Energy's original and revised capital expenditure program are summarised below.

Ergon Energy has retained its original forecasts relating to the following programs:

- Corporation Initiated Augmentation capital expenditure;
- Asset Replacement capital expenditure; and
- Reliability and Quality Improvement capital expenditure.

Ergon Energy has adjusted its original forecasts relating to the following programs:

- Customer Initiated Capital Works (CICW) capital expenditure;
- Non-system ICT capital; and
- Non-system property capital expenditure.

Security of Supply

Amongst other things, Ergon Energy's capital expenditure forecast reflects its requirement to achieve the N-1 security of supply criteria arising from the Electricity Distribution Service Delivery (EDSD) Review, which are discussed in section 12.1.1.1 of the June 2009 Regulatory Proposal. The N-1 security of supply criteria are incorporated in Ergon Energy's annual Network Management Plan, which it prepares in accordance with the Code established by the portfolio Minister pursuant to section 120B of the Queensland *Electricity Act 1994*. The annual Network Management Plan is subject to scrutiny by the Queensland Competition Authority (QCA) and Ergon Energy must use its best endeavours to comply with the plan. Ergon Energy's planning, and demand forecasts, must therefore incorporate these N-1 security of supply criteria and it is required to report on a quarterly basis to the Queensland Government about its progress. Because the growth in network demand is not uniformly experienced across Ergon Energy's network, different parts of the network reach the security standard thresholds at different times. This means that Ergon Energy's capital works program will need to dynamically respond to changing requirements in order to meet the security criteria over the next regulatory control period. This capital works program is updated in the annual Network Management Plan.

1.3.3 Operating Expenditure Adjustments

Ergon Energy believes the AER's proposed reduction of its operating expenditure from $1,898 million to $1,514 million cannot be justified under clause 6.5.6 of the Rules (see Chapter 11 for further details). Of particular concern to Ergon Energy is the AER's proposed reduction to labour escalators, which accounts for $287 million of the $384 million reduction to Ergon Energy's operating expenditure. Ergon Energy maintains its original position to apply the wage increases in the current Ergon Energy UCA as they represent prudent and efficient labour cost escalators. Ergon Energy's revised operating expenditure program is shown in Table 1-2.

Changes in the direct costs between Ergon Energy's original and revised operating expenditure program are summarised below.

Ergon Energy has retained its original forecasts relating to the following programs:

- Forced Maintenance;
- Meter reading and customer service; and
- Self insurance.

Ergon Energy has adjusted its original forecasts relating to the following programs:

- Preventive Maintenance;
- Corrective Maintenance; and
- Vegetation management and access tracks.

Ergon Energy disagrees with the AER's rationale for its proposed changes to debt and equity raising costs and interest rate hedging costs, but for modelling purposes has applied the AER's forecasts.

Table 1-2: Forecast Operating Expenditure – by Category Driver – 2010-15 ($M Real $2009-10)

Category Driver	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Network Operating Costs	26.16	26.31	26.56	27.08	27.32	133.43	26.69
Network Maintenance Costs							
Preventive Maintenance	106.70	119.05	117.67	119.05	119.41	581.88	116.38
Corrective Maintenance	119.02	119.00	119.51	114.46	102.27	574.26	114.85
Forced Maintenance	41.35	41.61	41.74	41.55	40.92	207.17	41.43
Subtotal	267.07	279.66	278.92	275.06	262.60	1,363.31	272.66
Other Costs							
Meter Reading	11.69	11.84	12.03	12.30	12.44	60.30	12.06
Customer Services	19.92	20.15	20.33	20.65	20.74	101.79	20.36
Other Operating Costs	44.06	45.58	46.61	48.52	50.50	235.27	47.05
Subtotal	75.67	77.57	78.97	81.47	83.68	397.36	79.47
Total Operating Expenditure	368.90	383.54	384.45	383.61	373.60	1,894.10	378.82

Source: Revised Submission Tables for Proposal 26.1

1.4 Revised Regulatory Proposal Snapshot

Taking these adjustments to its capital and operating expenditure forecasts into account, the following tables provide a snapshot of Ergon Energy's Revised Regulatory Proposal for Standard Control Services.

1.4.1 Revised Regulatory Proposal Snapshot – Standard Control Services

Table 1-3 provides a snapshot of Ergon Energy's Revised Regulatory Proposal for its Standard Control Services.

Table 1-3 – Revised Regulatory Proposal Snapshot – Standard Control Services

	Explanations in this Revised Regulatory Proposal	Ergon Energy's Regulatory Proposal	AER's Draft Distribution Determination	Ergon Energy's Revised Regulatory Proposal
ARR (5 years) Smoothed ($M Nominal)	S. 19.3.1, Table 19-4	6,761.15	6,365.5	7,234.65
X factor (Yr 1 / Yrs 2 to 5) - % [1]	Section 19.3.2, Table 19-9	- 27.05 / - 7.69	- 26.63 / - 4.9	- 39.51% / - 6.42%
Opening RAB (1 July 2005) ($M Nominal)	Ch. 6, Table 6-1	4,146.17	4,146.2	4,146.17
Opening RAB (1 July 2010) ($M Nominal)	Ch. 6, Table 6-3	6,999.39	7,105.4	7,173.98
Closing RAB (30 June 2015) ($M Nominal)	Ch. 6, Table 6-4	13,097.89	11,911.0	13,403.78
Total Capital Expenditure (5 years) ($M Real $2009-10)	Ch. 6, Table 10-13, Table 19-6	6,032.94	5,012.8	6,274.13
Total Operating Expenditure (5 years) ($M Real $2009-10)	Ch. 11, Table 11-3, Table 19-5	1,898.46	$1,514.2	1,894.10
Cost of Capital - %	S. 14.4, Table 14-2	9.49%	10.06%	10.06%

Source: SCPTRM Submission Model and Revised Submission Tables for Proposal

1 A negative P^o and X factor mean an increase in prices

Table 1-4 compares the building blocks that make up Ergon Energy's total unsmoothed Annual Revenue Requirements (ARR) for its Standard Control Services for 2010-11 to 2014-15 as detailed in Ergon Energy's June 2009 Regulatory Proposal, the AER's Draft Distribution Determination and this Revised Regulatory Proposal.

Table 1-4 – Building Block Comparison – Standard Control Services ($M Nominal)

	Ergon Energy's June 2009 Regulatory Proposal	AER's Draft Distribution Determination	Ergon Energy's Revised Regulatory Proposal	Difference between Ergon Energy's Revised Regulatory Proposal and June 2009 Regulatory Proposal	Difference between Ergon Energy's Revised Regulatory Proposal and AER's Draft Distribution Determination
Regulatory Depreciation	598.60	790.80	782.11	183.51	-8.69
Return on Capital	4,397.18	4,430.40	4,766.50	369.32	336.10
Operating Expenditure	2,144.86	1,626.20	2,063.75	-81.11	437.55
Tax Allowance	235.15	116.50	376.12	140.97	259.62
Capital Contributions	-593.77	-593.80	-729.73	-135.96	-135.93
Revenue from Shared Assets	-16.87	-16.90	-16.82	0.05	0.08
Accelerated Depreciation	11.27	10.40	10.45	-0.82	0.05
Annual Revenue Requirements (Unsmoothed)	**6,776.42**	**6,363.70**	**7,252.39**	**475.97**	**888.69**
Expected Revenues (Smoothed)	**6,761.15**	**6,365.50**	**7,234.65**	**473.50**	**869.15**

Source: Revised Submission Tables for Proposal and Revised Proposal and SCPTRM Model

The key reasons for the $476 million increase in Ergon Energy's unsmoothed ARR between its June 2009 Regulatory Proposal and this Revised Regulatory Proposal are that Ergon Energy has:

- Made various adjustments to its capital and operating expenditure as detailed in section 1.3;
- Accepted the adjustments to the calculation of depreciation detailed in the AER's Draft Distribution Determination;
- Applied the AER's proposed weighted average cost of capital (WACC) parameters in this Revised Regulatory Proposal and incorporated Ergon Energy's actual 2008-09 capital expenditure, which have both increased the return on capital building block;
- Applied the AER's requested change to the application of inflation;
- Applied the AER's PTRM in order to recalculate a revised corporate income tax building block based on continuing to apply a gamma value of 0.2; and
- Reduced the allowances for capital contributions and accelerated depreciation in accordance with the AER's Draft Distribution Determination.

In accordance with the requirements of clause 6.5.9 of the Rules, Ergon Energy has applied the AER's PTRM to determine X factors of -39.51 per cent and -6.42 per cent that recover the smoothed expected revenues.

1.4.2 Demand Forecasts

Table 1-5 provides a high level summary of Ergon Energy's revised forecasts of coincident peak (maximum) demand, total energy consumption and customer numbers for the period 1 July 2010 to 30 June 2015. Ergon Energy has applied these forecasts in this Revised Regulatory Proposal.

Table 1-5 - Ergon Energy Maximum Demand, Energy and Customer Numbers Forecast for 2010-15, as at December 2009

December 2009 Forecasts	2010-11	2011-12	2012-13	2013-14	2014-15	Average of 5 Year Total
Ergon Energy Coincident peak (maximum) demand – December 2009 (MW)	2,807	3,052	3,181	3,282	3,365	3,137
Ergon Energy Total energy consumption (GWh)	15,870.51	16,450.40	16,874.17	17,432.66	17,887.16	n/a
Ergon Energy Customer numbers	684,469	695,242	706,204	717,356	728,706	n/a

1.4.3 Indicative Prices

Table 1-6 shows revised indicative prices for each Standard Control Service customer class in each year of the next regulatory control period. This is a simple expression of the prices forecast for the Standard Control Services for the next regulatory control period. It is not the basis on which Ergon Energy intends to charge for these services.

Table 1-6 - Indicative Prices Standard Control Services by Customer Grouping 2010-15 (c/kWh Real $2009-10)

Pricing Category	2010-11	2011-12	2012-13	2013-14	2014-15
ICC	1.136	1.194	1.258	1.326	1.397
CAC	4.774	5.035	5.306	5.592	5.894
SAC	11.701	12.166	12.648	13.148	13.668
EG	0.189	0.199	0.208	0.217	0.226

Source: RIN 2.2.5 Table 1 and RP917c AER Data_v1_Data_Room_7Jan10.xls

1.5 Conclusion

Ergon Energy submits this Revised Regulatory Proposal in response to the AER's Draft Distribution Determination. In general, it accepts the AER's adjustments to EBSS, DMIS, classification of services and control mechanisms and it seeks further clarification on STPIS, feed-in tariffs and gamma. Critically, it maintains a different position on labour cost escalations, demand forecasts, Growth capital expenditure and Non-System Property capital expenditure.

These four issues are essential to the successful delivery of Ergon Energy's Strategic Plan in 2010-15. This plan is aligned with the organisation's purpose to enhance the economic and lifestyle aspirations of its customers through sustainable energy solutions. As regional Queensland's burgeoning resources sector helps lead a national recovery following the Global Financial Crisis, this purpose takes on greater meaning. It is vital that Ergon Energy delivers critical electricity infrastructure to support the state's ongoing development. This Revised Regulatory Proposal seeks to ensure this happens.

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2 KEY ISSUES AND IMPACTS

In preparing this Revised Regulatory Proposal, Ergon Energy has strived to ensure that it will deliver acceptable network performance outcomes in a prudent and efficient manner, while meeting customers' expectations for affordability. Ergon Energy delivers its network operations in an environment of vast extremes in terms of weather, population density and industry. These factors can increase the average cost per customer of planning, building and operating a distribution network, and they pose a challenge unique to Ergon Energy among Australian distribution businesses. All elements of this Revised Regulatory Proposal are required to maintain the balance of performance and affordability, while supporting Queensland's ongoing economic recovery. However four issues are of particular concern to Ergon Energy. These are the AER's proposed reductions to:

- Labour escalations;
- Economic and demand forecasts;
- Growth capital expenditure; and
- Non-System Property capital expenditure.

If the AER's proposed reductions remain unchanged in its final Distribution Determination, Ergon Energy considers that this will have significant adverse impacts on Ergon Energy, its customers and the regional Queensland economy. These issues are summarised below and are also addressed in detail in the relevant chapters.

2.1 Key Issues

2.1.1 Labour Cost Escalations

The AER has rejected Ergon Energy's proposed labour cost escalators, which reflect its current UCA, on the grounds that it would eliminate incentive to negotiate efficient and competitive outcomes for future UCAs. It has also proposed separate escalation rates for contractors and internal labour and also different weightings for general and technical labour.

Ergon Energy believes its UCA, upon which its proposed labour costs escalators are based, reflects an efficient outcome, negotiated through a prudent process. This outcome is comparable with other recent wage negotiation outcomes. In addition, Ergon Energy must pay wages in accordance with the UCA regardless of the AER's decision.

Ergon Energy believes its labour cost escalators reflect the circumstances in which it operates. As the resources sector rapidly recovers from the Global Financial Crisis, industry experts are pointing to the return of skills shortages, which could reasonably be assumed to put upward pressure on wages when it is time to negotiate Ergon Energy's next UCA in 2011.

The AER's proposed different treatment of internal and contractor labour cost escalators has not been adopted by Ergon Energy as the actual difference is not material and therefore does not warrant separation. Similarly, Ergon Energy has not distinguished between different categories of employees. It notes that other DNSPs have negotiated UCA outcomes that do not make this distinction, and in practice, it is doubtful whether a DNSP would ever be able to discriminate between different categories of employees in relation to the underlying wage increases in an enterprise bargaining process.

In addition, Ergon Energy believes that under the Rules, the AER cannot reject proposed labour cost escalators on the basis of incentive for future enterprise bargaining outcomes, nor can it reject escalators that reasonably reflect the operating and capital expenditure criteria, even if lower labour cost escalators might better reflect the criteria.

As such, Ergon Energy maintains the labour costs escalators submitted in its June 2009 Regulatory Proposal.

2.1.2 Economic and demand forecasts

The AER has relied on economic forecasts produced by its consultants MMA to develop demand forecasts in its Draft Distribution Determination. Ergon Energy rejects both the economic and demand forecasts for the reasons explained below.

Ergon Energy asserts that that MMA's economic forecasts are now outdated as more recent economic data contradicts key elements of these forecasts. In a number of respects, they are also materially inaccurate. In particular, MMA relies on a forecast of -4.8 per cent GSP for 2008-09 when actual GSP was 0.8 per cent. The heavy reliance placed by MMA on the 2009 August KPMG Econtech economic forecast, dramatically weakens the appropriateness of the growth forecasts relied upon by the AER for the 2010-15 regulatory control period. As a consequence, less than three months after receiving Ergon Energy's Draft Distribution Determination, there is already approximately a 6 per cent difference in the GSP forecasts for the starting point for 2008-09 alone.

On the basis of the same KPMG Econtech forecast, MMA predicts Queensland's GSP growth will contract by an annual average 0.2 per cent from 2008-09 to 2010-11. This would make it the slowest growing state in Australia. Ergon Energy believes this is unreasonable given Queensland is also forecast to experience above national average population growth and strong growth in the mining and resources sector and has received advice and reports from various other sources that confirm this view.

Ergon Energy has also received informal advice from KPMG Econtech that its next forecast due for release in February 2010 confirms that the August 2009 forecast is out of date and that the outlook for Queensland GSP is far more positive than is implied by the result forecast by KPMG Econtech for 2008-09, due to Queensland's exposure to the minerals and resources sector, among other things. Ergon Energy has sought written confirmation from KPMG Econtech regarding the revisions planned to its forecasts, but this written confirmation was not available at the time of finalising this submission.

Further compounding the above issues, MMA appears to have relied on GSP as a proxy for growth in regional Queensland. This is inappropriate given the higher exposure of regional Queensland to the rapidly recovering Asian export markets.

With regard to demand the forecasting methodology, Ergon Energy accepts that a top-down forecast should be applied that is derived from appropriate economic and demographic variables. Ergon Energy has engaged the National Institute of Economic and Industrial Research (NIEIR) to prepare aggregate top-down demand forecasts. NIEIR has followed a prudent forecasting process to develop an appropriate top-down forecast. However, the AER has substituted the flawed MMA forecast. Ergon Energy believes that, in accordance with the Rules, the AER has not provided any material or reasonable justification for not adopting the NIEIR forecast.

Ergon Energy has completed an appropriate reconciliation of NIEIR's top-down and Ergon Energy's bottom-up forecasts. Furthermore, Ergon Energy asserts that it does effectively manage the risks associated with the use of spot loads and it does produce a weather-corrected historical aggregate demand, which is not materially different to that produced by MMA.

In summary, Ergon Energy believes the MMA economic forecasts are outdated and inconsistent with more recent forecasts by the Reserve Bank of Australia and Queensland Treasury, among others. Ergon Energy asserts the MMA demand forecasts therefore do not fall within a reasonable range of forecasts and the AER should instead accept those prepared recently for Ergon Energy by NIEIR.

2.1.3 Growth Capital Expenditure

2.1.3.1 Corporation Initiated Augmentation

The AER has proposed an 18 month delay to Ergon Energy's Corporation Initiated Augmentation capital expenditure as a result of deferring Ergon Energy's maximum demand forecast. As noted above, Ergon Energy believes the delay to demand forecasts is based on outdated economic forecasts and should not be relied upon by the AER. Hence it believes the subsequent delay to its proposed Corporation Initiated Augmentation capital expenditure cannot be justified.

In addition, the AER has accepted various assertions made by PB in relation to Ergon Energy's planning processes. Ergon Energy believes the AER has not given due consideration to the circumstances in which Ergon Energy operates. The AER has substituted Ergon Energy's planning processes with PB's model, which Ergon Energy believes to be less reliable. Ergon Energy has obtained independent reports validating its own planning processes. Details of these findings are contained in this Revised Regulatory Proposal and supporting information including the independent report prepared by Huegin [Document RP938c].

It appears to Ergon Energy that the AER has assumed that forecast Growth capital expenditure is directly proportional to aggregate maximum demand. Ergon Energy considers that this approach is inappropriate and should not be used in place of bottom-up forecasts that measure demand at specific points on the network. Ergon Energy's radial network structure results in the relationship between capital expenditure and aggregate maximum demand being much less correlated than for other DNSPs.

Accordingly, Ergon Energy submits that the AER should reinstate the proposed $526 million that it cut from Ergon Energy's Corporation Initiated Augmentation capital expenditure.

2.1.3.2 Customer Initiated Capital Works

With regard to CICW, the AER questioned Ergon Energy's planning methodology and provided a substitute forecast based on a model produced by its consultants, PB. Ergon Energy's planning methodology is robust and similar to that used by other DNSPs.

The AER questioned the reliability of using dwelling stock growth to forecast customer connections. Historical data shows a correlation does exist and the AER has previously accepted the NSW DNSPs' assumptions regarding this. Ergon Energy noted an error in the PB model. A corrected version of the PB substitute model provides a forecast within 5 per cent of the Ergon Energy forecast.

Ergon Energy has provided additional supporting data and analysis in the Revised Regulatory Proposal to support its original forecast. Ergon Energy believes the AER should reinstate the proposed $318 million that it cut from the CICW program.

2.1.4 Non-system Property Capital Expenditure

The AER has reduced Ergon Energy's property capital expenditure program for the next regulatory control period by $191 million to $196 million. This reduction was made on the basis that Ergon Energy's proposed property capital expenditure was not prudent and efficient. The AER has approved an amount that reflects a "business as usual approach"[1]. However, there has been significant and rapid growth in labour and associated resources over the current regulatory control period, and this will continue into the next regulatory control period. The property portfolio has undergone an extensive review which has identified the need to consolidate a growing number of employees into key locations and to acquire new properties to cater for continued growth in both employees and activities.

Ergon Energy has provided additional documentation to substantiate and justify its June 2009 Regulatory Proposed expenditure in order to demonstrate that it is prudent and efficient. Ergon Energy considers that its proposed capital expenditure on property is necessary in order to, among other things:

- Provide additional and or centralised accommodation;
- Comply with regulatory building requirements;
- Comply with safety and environmental requirements;
- Achieve the operational performance outcomes that underpin this Revised Regulatory Proposal; and
- Effectively manage potential post-disaster (cyclone) operational responses.

Of particular concern to Ergon Energy are the implications for its property strategy, which commenced implementation following Board approval in 2006. This strategy requires investment into the next regulatory control period for its completion and to honour existing contractual commitments and meet various legal compliance obligations applicable to each site. Ergon Energy has undertaken additional

[1] AER, "Queensland Draft Distribution Determination 2010–11 to 2014–15", page 508

work to address the concerns raised by PB and to further justify its revised non-system property capital expenditure of $388 million.

2.2 Key Impacts

Ergon Energy submits this Revised Regulatory Proposal to demonstrate the prudence and efficiency of its expenditure forecasts. This Revised Regulatory Proposal also seeks to describe the broader economic environment to which these forecasts relate. As such, this section describes direct impacts on Ergon Energy's capital and operating expenditure programs, as well as the potential economic impacts of the AER's Draft Distribution Determination.

Should the AER's final Distribution Determination remain unchanged from the Draft Distribution Determination, Ergon Energy will be placed at serious risk of being unable to deliver the capital and operating expenditure programs required to meet customer needs in 2010-15. These programs are designed to meet the objectives stated in clauses 6.5.6(c) and 6.5.7(c) of the Rules. Reductions to these programs will adversely impact on the capacity, safety, security and reliability of the network. Such consequences would reach beyond Ergon Energy and its customers and would impact on the regional Queensland economy.

In particular, the AER's proposed reductions to capital and operating expenditure, as well as reductions in proposed wage escalations will mean that:

- Ergon Energy will risk becoming a bottleneck for regional Queensland's economic recovery following the Global Financial Crisis;
- Ergon Energy's network maintenance strategy will be adversely impacted;
- Network security will decline, further exposing the network to the high risk summer peak period and storm season; and
- Minimum Service Standards of supply reliability for customers will be put at considerable risk.

These impacts are further detailed in the following sections.

2.2.1 Impacts for Regional Queensland's Economic Growth

The AER's proposed $844 million reduction to Ergon Energy's proposed Growth capital expenditure will adversely impact the organisation's ability to deliver its forecast Corporation Initiated Augmentation and CICW programs.

Based on recent economic reports, Ergon Energy is confident job creating industries and their communities will need additional electricity infrastructure sooner than the AER's consultants have forecast. As noted in Section 2.2, the Reserve Bank of Australia's November 2009 Statement noted that over the next two years, planned new rail and port infrastructure will enable a 30 per cent increase in coal production in Queensland and New South Wales. Most recently, in December 2009[2] Queensland Premier Anna Bligh announced the State Government had accepted an application from Hancock Prospecting to declare an infrastructure facility of significance for the coal rail corridor from Alpha and Kevin's Corner to Abbot Point.

Ergon Energy is a critical enabler of infrastructure to support regional Queensland's resources sector. The AER's proposed capital expenditure reductions will adversely impact the organisation's ability to build upstream shared network and will leave it exposed to unfunded customer connection demand. Ergon Energy understands the problem for job-creating industries when they are held back by lack of new electricity infrastructure and capacity. The Queensland economy cannot afford to stall for the lack of electricity infrastructure, particularly in the crucial mining, rail and water industries and Ergon Energy does not have the capacity to fund works over and above the Distribution Determination, should growth exceed the AER's expectation.

[2] Media release from Queensland Premier Anna Bligh, "Hundreds of jobs as Hancock proposal moves forward", 18 December 2009.

2.2.2 Impacts for Network Reliability, Security and Safety

Of all the things that are important to customers, they now consistently rate network performance as one of the top areas in which Ergon Energy delivers value. Ergon Energy's monthly customer research reflects this. An unacceptable level of reliability and security triggered the Queensland Government's EDSD Review in 2004. Investment in network performance in the current regulatory control period has delivered this significant improvement in the reliability and quality of electricity supply.

The AER's proposed $526 million reduction in Ergon Energy's Corporation Initiated Augmentation capital expenditure will adversely impact Ergon Energy's ability to deliver network reliability, security and safety. Specifically, the AER's proposed reductions will put at risk Ergon Energy's security of supply criteria, which are detailed in its annual Network Management Plan and its Statement of Corporate Intent with its shareholder. Both the Network Management Plan and the Statement of Corporate Intent are established pursuant to the legislative framework within which Ergon Energy operates.

Based on Ergon Energy's capital expenditure forecasts, by the end of the 2010-15 regulatory control period there will be 25 of 298 (8 per cent) substations outside the security criteria (reduced from 12 per cent in the current period). However, based on the AER's reduced capital expenditure, there will be another 10 to 12 substations that will not meet the security criteria. This will further expose the network during Ergon Energy's highest risk period of summer, when demand peaks and storms and cyclones occur.

Reductions in the Corporation Initiated Augmentation capital expenditure will also put the network at high risk of capacity constraints. Combined with the AER's proposed $35 million cut in Reliability and Quality Improvement capital expenditure, Ergon Energy will be at risk of not meeting the more stringent reliability targets under the Code. This would be a considerable blow to Ergon Energy's efforts to recover its reliability performance, which fell below the Code requirements in 2008-09 and is at risk for 2009-10.

Network safety will become increasingly difficult to maintain due to the AER's proposed $119 million cut to Asset Replacement capital expenditure and $100 million cut to Preventive and Corrective Maintenance. If these reductions are not revised, Ergon Energy will be unable to deliver two new programs aimed at safety and reliability improvements. These programs are pole top inspection and the proposed full service inspection program, which will contribute to compliance with the Queensland Electrical Safety Regulation 2002.

The AER's proposed increase from four years to 4.5 years for wooden pole inspection cycles will also expose these assets to significantly higher risk as Ergon Energy's operating environment includes Australia's most onerous timber decay and termite zones.[3] With parts of Ergon Energy's network inaccessible at certain times of the year due to extreme weather events, extending the pole inspection periodicity to 4.5 years would risk placing Ergon Energy in breach of its safety obligations under relevant state legislation as some poles will be inspected outside the five year mandatory timeframe.

2.2.3 Impacts on Labour Resources

Ergon Energy competes for labour with the resources sector. The outcomes that Ergon Energy negotiates under its UCAs, and therefore the wages that Ergon Energy pays, need to reflect labour market conditions.

Ergon Energy believes its proposed annual labour escalators of 4.5 per cent are prudent and efficient. This is particularly relevant given that many industry experts are citing the return of a skills shortage in the near future as, detailed in Chapter 9.

Ergon Energy is concerned that the AER's proposed reduction in labour escalations could make it more difficult to compete for resources in the near future where Ergon Energy expects to be in direct competition with the fast recovering resources sectors for specialist labour.

[3] Australian Timber Pole Resources for Energy Networks, A Review, October 2006

2.2.4 Implications for Customer Value

The combined impacts of the AER's proposed reductions will risk the safety and reliability of supply for customers due to inadequate maintenance and capacity constraints. Similar problems triggered the Queensland Government's Somerville enquiry in 2004 and since then Ergon Energy has invested heavily to bring the network up to an acceptable standard of performance that its customers value.

Ergon Energy's focus for 2010-15 is to prudently improve the safety and reliability of the network, while also investing in initiatives that seek to address the challenge of affordability for customers by expanding contestability and investing in non-network alternatives. These initiatives, detailed in Chapter 7, include trials and pilots focused on residential customers, large commercial and industrial customers, rural customers and customer education.

Through regular customer research, Ergon Energy is highly aware of the need to balance reliability with affordability. For this reason it has put forward this Revised Regulatory Proposal, which it believes contains only prudent and efficient investments that will deliver the optimal balance of service and price outcomes for customers. Through its retail arm, Ergon Energy also regularly engages its customers in how to use less electricity and how to manage bill payments.

Maintaining a "customer-driven" focus is one of four strategic priorities for Ergon Energy over the 2010-15 regulatory control period. This will also be a critical period of economic recovery and growth in regional Queensland, requiring appropriate investment in electricity infrastructure. With this in mind, Ergon Energy will continue to make prudent and efficient investment decisions, based on balancing network performance and affordability for customers.

3 QUEENSLAND ECONOMY

The AER has relied on economic forecasts produced by its consultants MMA in its Draft Distribution Determination. Ergon Energy asserts that these forecasts are now outdated as more recent economic data contradicts key elements of these forecasts. Furthermore, they are materially inaccurate in number of respects. In particular:

- MMA relied on an outlier forecast of -4.8 per cent GSP for 2008-09 when actual GSP was 0.8 per cent. This error in approach by the MMA in relying on the 2009 August KPMG Econtech economic forecast, dramatically weakens growth forecasts relied upon by the AER for the 2010-15 regulatory control period;
- On the basis of the same KPMG Econtech forecast, MMA predicts Queensland's GSP growth will contract by an annual average 0.2 per cent from 2008-09 to 2010-11. This would make it the slowest growing state in Australia. Ergon Energy believes this is unreasonable given Queensland is also forecast to experience above national average population growth and strong growth in the mining and resources sector; and
- MMA appears to have relied on GSP as a proxy for growth in regional Queensland, which is inappropriate given the higher exposure of regional Queensland to the rapidly recovering Asian export markets.

3.1 Chapter Overview

This Chapter examines the recent actual and forecast performance of the Queensland economy. In particular, it examines:

- The impact of the Global Financial Crisis on the Australian and Queensland economies;
- The Australian and Queensland economies' process of recovery from the Global Financial Crisis;
- The August 2009 KPMG Econtech economic forecasts that were relied on by MMA in their review of Ergon Energy's maximum demand forecasts;
- The differences between KPMG Econtech's August 2009 economic forecasts and other economic forecasts, including prepared by KPMG Econtech, that have recently been prepared; and
- Ergon Energy's view of the Queensland economy having regard for KPMG Econtech's and other independent forecasts and reports.

This provides important context for understanding Ergon Energy's actual and forecast demand and capital and operating expenditure in the current and next regulatory control periods, which are discussed in Chapters 8 and 10 of this Revised Regulatory Proposal.

3.2 The Impact of the Global Financial Crisis

The Queensland economy has grown more strongly than the rest of Australia and the Australian economy as a whole in all but three of the last 25 years. Indeed, 2008-09 was the first year since 1995-96 that the Queensland economy grew by a lesser amount than the rest of Australia and the Australian economy in total. Where the Queensland economy's growth was less than that of the Australian economy, history has shown that the Queensland economy strongly rebounded in the following years. This is illustrated in Table 3-1.

Table 3-1: Percentage Growth in Queensland GSP and Australian GDP: 1986-87 to 2007-08[4]

	Economic Growth			**Population Growth**		
	Queensland (GSP)	**Rest of Australia (GDP)**	**Australia (GDP)**	**Queensland (GSP)**	**Rest of Australia (GDP)**	**Australia (GDP)**
1986–87	4.20	2.10	2.40	1.92	1.46	1.53
1987–88	6.20	5.00	5.20	2.42	1.50	1.65
1988–89	7.70	3.00	3.70	3.20	1.41	1.71
1989–90	4.20	3.90	3.90	2.53	1.28	1.49
1990–91	–0.7	–0.6	–0.6	2.13	1.11	1.28
1991–92	3.00	–0.5	-	2.33	0.99	1.22
1992–93	6.60	3.10	3.70	2.63	0.64	0.99
1993–94	4.50	4.00	4.10	2.49	0.76	1.06
1994–95	5.30	4.10	4.30	2.45	0.95	1.22
1995–96	1.50	4.60	4.10	2.25	1.12	1.32
1996–97	5.30	3.60	3.90	1.68	1.01	1.13
1997–98	6.30	4.10	4.50	1.56	0.93	1.05
1998–99	6.70	4.90	5.20	1.56	1.05	1.15
1999–00	5.60	3.70	4.00	1.72	1.09	1.20
2000–01	2.40	1.80	1.90	1.89	1.23	1.36
2001–02	4.10	3.70	3.80	2.37	0.97	1.23
2002–03	5.60	2.70	3.20	2.54	0.94	1.24
2003–04	5.60	3.70	4.00	2.41	0.87	1.17
2004–05	6.10	2.10	2.80	2.41	1.07	1.33
2005–06	3.80	2.80	3.00	2.40	1.26	1.49
2006–07	5.20	2.90	3.30	2.57	1.62	1.81
2007–08	5.50	3.30	3.70	2.33	1.55	1.71
2008–09	0.80	1.10	1.00	2.63	1.93	2.07

The strength of the Queensland economy relative to the Rest of Australia over the past 25 years has been its ability to sustain high population growth in most economic conditions. This ability resulted from high economic and lifestyle interstate and overseas migration as well as large natural increases (i.e. births minus deaths). As illustrated in Table 3-1, Queensland has had higher population growth than the rest of Australia and Australia as a whole in every one of the last 25 years.

Other key factors that have contributed to the strong growth of the Queensland economy have been:

- Employment and wages growth, which reflected strong labour market conditions;
- Private consumption expenditure, which reflected sustained income and employment growth and strong consumer confidence;
- Dwelling investment, which reflected a boom in the housing sector;
- Private business investment, which was particularly driven by the mining and resources sector as commodity prices and international demand grew strongly; and
- Public sector investment, particularly in health, education, energy and transport infrastructure.

[4] Sourced from Australian Bureau of Statistics

Much more importantly for the regional Queensland economy, the very strong relative growth of the Queensland economy over the five years to 2007-08 is related to very buoyant and well reported private business investment, which was particularly driven by the mining and downstream primary processing, transport and shipping infrastructure as commodity prices and international demand particularly in Queensland's Asian markets continued to grow strongly. Unsurprisingly the Asian export oriented Queensland economy effectively withstood the weakening of the international economy during 2007-08, including the United States' economy falling into recession in November 2007. GSP in Queensland grew by 5.5 per cent in 2007-08, driven by:

- Household consumption growth of 4.9 per cent;
- Business investment growth of 16.3 per cent; and
- Public sector final demand growth of 7.4 per cent.[5]

However, by September 2008, with the bankruptcy of the investment bank Lehman Brothers, the nationalisation in the United States of Fannie Mae[6], Freddie Mac[7] and the American International Group[8], as well as the collapse of almost 30 other financial institutions around the world, it became clear that there would be a Global Financial Crisis that would significantly adversely impact the Australian and Queensland economies.

The global economy quickly ground to a halt in late 2008 as equity and commodity prices experienced large declines, banks stopped lending to one another and to the private sector, and international business and consumer confidence slumped.

The Reserve Bank of Australia noted in its November 2008 "Statement on Monetary Policy" that:

> *In addition to their effect on household and business confidence, the recent global developments are expected to feed through into the domestic economy through two main channels. First, the fall in the stock market has significantly reduced household wealth, which will dampen household spending.*
>
> *……..*
>
> *Second, as noted earlier, some unwinding of the boom in commodity prices, which significantly boosted incomes and demand over the past five years, appears to be occurring.*
>
> *The unwinding of much of the recent price increases is expected to result in a scaling-back of mining-related investment. A number of resource companies are reconsidering their capital expenditure intentions for 2009, and smaller mining firms in particular are likely to cut back their investment. Reduced spending in the resources sector would flow through into slower activity in other sectors of the economy.*[9]

The Reserve Bank of Australia went on to state in its November 2008 Statement that:

> *The latest capital expenditure (Capex) survey, conducted in July and August (2008), pointed to strong growth in 2008/09, in the mining sector and a range of other sectors. In contrast, private-sector surveys suggest the pace of investment growth could weaken materially, with the net balance of firms planning to increase investment over the coming period at below the long-run average in most surveys.*

[5] Queensland Treasury, "Annual Economic Report on the Queensland Economy – Year Ended June 2009", page 4

[6] Federal National Mortgage Association (Fannie Mae) purchased and securitized mortgages so that funds would be consistently available to the institutions that lend money to home buyers.

[7] Federal Home Loan Mortgage Association (Freddie Mac) bought mortgages on the secondary market, pooled them, and sold them as mortgage-backed securities to investors on the open market.

[8] American International Group is the United States' largest underwriter of commercial and industrial insurance.

[9] Ibid, page 66

The Bank's liaison suggests that many commercial building projects in the early stages of planning have been put on hold and, consistent with this, the value of non residential building approvals has weakened over recent months. The Bank's liaison suggests that some mining investments at the early stage of development may also be postponed.[10]

In its November 2008 "Mid Year Fiscal and Economic Outlook", the Australian Government revised its May 2008 forecast of real Gross Domestic Product (GDP) growth for 2008-09 from 2.75 per cent to 2 per cent on account of the downturn in the global economy adversely impacting the Australian economy. The Australian Government introduced a variety of measures to seek to stimulate the domestic economy, including:

- Guaranteeing bank deposits in an effort to stop the flow of funds out of banks and to re-encourage lending;
- Providing business with tax deductions for eligible investments;
- Seeking to accelerate public investment expenditure; and
- Providing cash handouts to households, including through the First Home Buyers Boost.

The Reserve Bank of Australia implemented complementary monetary policy measures by:

- Cutting the official cash rate five out of six months between August 2008 and April 2009 from 7.25 per cent to 3.0 per cent[11]; and
- Intervening to stabilise the Australian dollar during episodes of foreign exchange volatility.

The Global Financial Crisis quickly affected the Queensland economy in two key areas: commodity prices and the property market.

There was a sharp fall in commodity prices between August and November 2008:

- The price of iron ore on the spot market fell 60 per cent to about 30 per cent below the contract price;
- Thermal coal prices on the spot market fell about 25 per cent below the contract price;
- The Reserve Bank of Australia's index of base metals prices fell 30 per cent, as Nickel prices fell below the production costs of some producers;
- Oil prices fell 45 per cent; and
- Wheat prices fell 15 per cent and wool prices also fell significantly.[12]

There was also a sharp contraction in building activity. There were 2,706 dwelling units approved to be built in Queensland in November 2007 but this fell to 1,556 in November 2008 – a reduction of almost 45 per cent.

In February 2009, the Australian Government further revised downward the nation's GDP growth outlook for 2008-09 by forecasting that it would only reach 1 per cent, with growth in 2009-10 forecast to be 0.75 per cent before increasing to 3 per cent in each of the years 2010-11 and 2011-12.

However, by the time of its May 2009 "Statement on Monetary Policy", the Reserve Bank of Australia noted that:

While the recent GDP outcomes for most countries have been very weak, there are signs that the rate of contraction in output is abating. It is likely that the half year to the March quarter will prove to have been the period of greatest contraction, with the IMF's recently revised forecasts consistent with a modest increase in global GDP over the second half of 2009. Industrial production and exports have picked up in Asia, after earlier steep falls, and growth in the Chinese economy has sped up recently. There has

[10] Ibid, page 38

[11] The cash rate remained on hold at 3 per cent between April and September 2009, but was increased by 25 basis points in both October and November 2009 to be 3.5 per cent.

[12] Reserve Bank of Australia, Statement on Monetary Policy, November 2008, pages 31-32

also been some improvement in consumer and business confidence in a range of countries from the very low levels of late last year.[13]

In relation to the Australian economy, it noted that:

> *The downturn in the global economy has had a significant effect on output growth in Australia. Activity contracted in the latter part of 2008 and this has continued into 2009. The economy is, however, still expected to record better outcomes in 2009 and 2010 than those in most other advanced countries. This reflects, among other things, the stronger state of the Australian banking system, the significant policy stimulus to date and the depreciation of the currency that took place in the second half of 2008.*[14]

The Australian Government retained a cautious short term outlook for the domestic economy at the time of its May 2009 Budget. It forecast that, despite its significant stimulus measures and some signs of improvement in the international economy, Australia would have negative GDP growth of 0.5 per cent in 2009-10 before achieving positive growth of 2.25 per cent in 2010-11.

The effects of the Global Financial Crisis can be seen in the Queensland economy's key economic measures for 2008-09:

- GSP fell from 5.5 per cent in 2007-08 to 0.8 per cent in 2008-09 to be slightly below Australia's Gross Domestic Product of 1.0 per cent;
- Household consumption growth eased to 1.8 per cent in 2008-09, compared with 4.8 per cent in 2007-08;
- Dwelling investment growth was -6.9 per cent in 2008-09, following a fall to -1.3 per cent in 2007-08;
- Business investment growth remained strong at 10.1 per cent compared to 16.3 per cent in 2007-08;
- Private final demand grew by 2.1 per cent compared to 6.3 per cent in 2007-08; and
- Public sector final demand growth eased to 4.6 per cent compared to 7.4 per cent in 2007-08.[15]

Importantly for the future prospects of the Queensland economy:

- Business investment growth remained solid at 10.1 per cent not significantly down compared to the strong 16.3 per cent in 2007-08; and
- While dwelling investment growth was -6.9 per cent in 2008-09, following a fall to -1.3 per cent in 2007-08 this was mild relative to past building recessions and possibly unexpectedly so in Queensland against a backdrop of low vacancy rates.

The trends in these key economic measures of the Queensland economy between 1999-00 and 2008-09 can be seen in Table 3-2.

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[13] Ibid, page 1

[14] Ibid, page 2

[15] Queensland Treasury, "Annual Economic Report on the Queensland Economy – Year Ended June 2009", page 4

Table 3-2: Queensland's Key Economic Measures – 1997-98 to 2007-08 (Per Cent)[16]

Year	Gross State Product	Household consumption	Dwelling investment	Business investment	Private final demand	Public Final Demand
1999-00	5.7	4.4	15.1	1.0	4.9	7.1
2000-01	3.2	4.0	-13.5	-15.0	0.1	-2.4
2001-02	5.0	2.8	32.4	13.7	6.8	-0.3
2002-03	5.5	5.5	19.9	32.3	9.5	2.7
2003-04	4.7	9.3	8.9	11.9	9.2	5.3
2004-05	4.6	5.2	4.7	17.6	6.2	7.5
2005-06	4.5	4.6	1.6	22.2	6.9	7.4
2006-07	5.6	3.7	8.6	16.1	6.4	9.9
2007-08	5.5	4.9	-1.3	16.3	6.3	7.4
2008-09	0.8	1.8	-6.9	10.1	2.1	4.6

3.3 Recovering from the Global Financial Crisis

By the time of its August 2009 "Statement on Monetary Policy", the Reserve Bank of Australia began to provide a cautiously positive outlook for the global and Australian economies. It stated that:

> *The global economy is stabilising after contracting sharply in the December and March quarters. Over recent months, the value of international trade and global industrial production have both recorded modest gains after earlier large declines, and the extreme risk aversion seen earlier in the year has receded somewhat. Reflecting this, forecasts for world growth are being revised up for the first time in more than a year.*[17]

In relation to the Australian economy, it stated that:

> *Domestically, the economy continues to exhibit considerable resilience in the face of what has been a very difficult international environment. The December and March quarter GDP data, in conjunction with other information on the economy, suggest that output contracted only modestly around the turn of the year, compared with the very sharp contractions experienced in most other countries. More recently, the information that has become available suggests that demand and output have strengthened a little, with household consumption continuing to grow in the June quarter while investment has been weak.*[18]

The Reserve Bank of Australia gave the following explanation for the resilience of the Australian economy:

> *A number of factors have contributed to this comparatively good performance of the Australian economy. One is the strong state of Australia's financial system. Another is the significant monetary stimulus arising from the 4¼ percentage point reduction in the cash rate since September last year, with the lower rates largely passed through to end-borrowers. A third factor has been the fiscal stimulus which, in particular, has provided a considerable lift to household disposable incomes over the past nine months. The depreciation of the exchange rate last year also provided a stimulus to domestic activity, although much of this has been unwound by the appreciation over recent months. Finally, the strong recovery in China, which has boosted commodity prices and demand for Australia's exports, has also been important. While most countries have recorded declines in export volumes of at least 10 per cent since September last year,*

[16] Queensland Treasury, "Annual Economic Report on the Queensland Economy", various years

[17] Reserve Bank of Australia, "Statement on Monetary Policy", August 2009, page 1

[18] Ibid, page 1

> ***Australia's exports are estimated to have recorded a small rise over this period.*** [19] (Emphasis added.)

In its October 2009 "Queensland Economic Review", the Queensland Treasury also noted that there were strong early signs that the worst of the Global Financial Crisis was behind the Queensland economy and that it had begun to recover on a number of fronts:

- Labour market – the Queensland Treasury noted that:

> *Declines in trend employment in Queensland appear to have troughed. Trend employment in the State rose 600 persons (0.0%) in September 2009. However, employment remained 0.3% lower over the year and has fallen 0.6% from its peak in February 2009. The trend participation rate in Queensland rose to 67.5% in September 2009, only 0.2 percentage point lower than its historic high. Queensland was the only state to record a rise in participation in September.*
>
> *Stronger growth in the labour force than employment drove Queensland's trend unemployment rate 0.1 percentage point higher, to 6.0% in September 2009.* [20]

- Retail turnover – the Queensland Treasury noted that:

> *In seasonally adjusted (sa) terms, nominal retail turnover in Queensland rose by 1.4% in August 2009, following a revised fall of 1.1% in July 2009 and a decline of 2.4% in June 2009.* [21]

- Dwelling approvals – the Queensland Treasury noted that:

> *The total trend number of dwelling approvals in Queensland rose 0.7% in August 2009, but was 21.8% lower over the year. This was the sixth consecutive monthly increase, following 15 successive monthly declines. The trend number of dwelling approvals totalled 2,274 in July 2009, a 12.0% improvement from the recent trough reached in February 2009. This turnaround was driven by a 20.9% rise in private house approvals since February, which more than offset a 29.6% fall in private other residential approvals (units, townhouses, etc.) over the same period.* [22]

- Population – the Queensland Treasury noted that:

> *Queensland's estimated resident population rose 0.7% (or 30,854 persons) in March quarter 2009, to reach 4,380,383 persons. In comparison, the population in the rest of Australia rose 0.6% (or 104,276 persons) in the quarter. In annual terms, Queensland's population increased by a record 112,666 persons (or more than 2,100 persons per week) over the year to 31 March 2009.* ***This was the largest annual rise in population ever recorded by any Australian state or territory.*** [23] (Emphasis added.)

In its November 2009 "Statement on Monetary Policy", the Reserve Bank of Australia provided an even more positive assessment. It stated that:

> *The global economy is growing again after contracting sharply late last year and in the early part of 2009. There has been some recovery in world trade and most of the major economies now look to be expanding. The risk aversion that was so evident earlier in the year, particularly in financial markets, has abated and confidence is gradually returning.*
>
> *Asia is at the forefront of the global recovery. The region's financial systems have not experienced the same dislocation as elsewhere, and the economies are benefiting from a recovery in domestic demand, underpinned by stimulatory settings of both monetary and fiscal policy. Growth in China and India has been particularly strong.* [24]

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[19] Ibid, page 2

[20] Queensland Treasury, "Queensland Economic Review", October 2009, page 2

[21] Ibid, page 2

[22] Ibid, page 2

[23] Ibid, page 3

[24] Reserve Bank of Australia, "Statement on Monetary Policy", November 2009, page 1

It went on to add that:

> *These outcomes are better than those thought likely earlier in the year and forecasts for global growth have been revised up, with growth in Australia's trading partners expected to be close to trend in 2010. The large downside risks that were evident six months ago have also diminished.*[25]

It further noted that:

> *Economic conditions in Australia have also been stronger than expected. In contrast to other developed economies, the Australian economy is estimated to have expanded, albeit modestly, over the first half of the year and recent data suggest that this expansion has continued into the second half. Confidence has improved and spending has been supported by stimulatory settings for both monetary and fiscal policy. The Australian economy has also benefited from the strong bounce-back in Asia, particularly in China, with export volumes remaining broadly unchanged during a period in which global trade fell markedly.*
>
> *Investment in Australia has also held up reasonably well, underpinned by a strong expansion of the resources sector and various fiscal measures. While the latter have brought forward the timing of some spending on plant and equipment, investment over the coming year is likely to be stronger than earlier expected. Investment in the resources sector is at historically high levels and is expected to increase further, particularly as the LNG sector expands. This expected rise in investment – which is already at a high level relative to GDP and compared with other developed economies – should further boost the supply side of the Australian economy, **although as it takes place, short-term capacity constraints could again emerge in parts of the economy**.*[26] (Emphasis added.)

The Reserve Bank of Australia's November 2009 Statement also included an assessment of the outlook for investment in the resources sector. It stated that:

> *Information from the Bank's liaison with mining companies suggests that further significant increases in mining investment and output are likely over the years ahead. The outlook for iron ore and coal remains strong, with investment expected to remain at its current high level, or increase further, as a share of GDP. However, the industry that is likely to see the largest increase in investment is liquefied natural gas (LNG). In addition to the two LNG plants already in operation, two major new projects have been initiated: the $43 billion Gorgon project that received final investment approval from its three joint venture partners in September; and the $12 billion Pluto project that has been under construction since 2007 and is due to ship its first LNG in early 2011. In addition, there are several proposed large offshore LNG projects in Western Australia and the Northern Territory, as well as 'coal seam gas to LNG' projects in Queensland, that are aiming for final investment approval in the next 18 to 24 months. While any projections on future investment are subject to considerable uncertainty, it is plausible that investment in this sector could increase from around ½ per cent of GDP currently, to around 2½ per cent within the next four or five years.*
>
> *While the extent to which the large number of projects under consideration will translate into actual high levels of mining investment is uncertain – there are examples of previous episodes of optimism which quickly faded, leaving plans for expansion unfulfilled – the probability that many of these projects will be realised may be higher now than during past booms. This reflects three important considerations: the prospect of continued strong growth in China, India and other emerging economies in Asia; the fact that confirmed reserves of gas, iron ore and coal have already been discovered; and, for LNG, that projects generally lock in multi-decade contracts with buyers before construction commences.*

[25] Ibid, page 1

[26] Ibid, page 2

If the increases in investment discussed above were to occur, output of the mining sector would rise substantially in the medium term. Over the past five years, iron ore output increased by around 70 per cent. However, growth in coal capacity has been relatively slow, largely reflecting problems with shared rail and port infrastructure for coal in Queensland and New South Wales. ***Over the next two years, if capacity comes on-line as planned, production of these bulk commodities could increase by around one-third, with further significant increases possible over the remainder of the next decade.***[27] (Emphasis added.)

This view was supported by Australian Bureau of Agriculture and Resource Economics' (ABARE) "Minerals and Energy – Major development projects – October 2009 listing", which was issued in November 2009. ABARE noted that "At the end of October 2009, there were 74 projects at an advanced stage of development on ABARE's project list. Projects in this category are either committed or under construction"[28] and "The total capital expenditure of the 74 advanced projects at the end of October 2009 is $112.5 billion, an increase of 40 per cent from April 2009 and 67 per cent year on year"[29]. Nineteen of these 74 advanced projects are in Queensland. ABARE also identified a further 267 projects which are less advanced projects that "are either undergoing a feasibility (in some cases, prefeasibility) study, or have not yet been subject to a final investment decision since the completion of a feasibility study"[30]. Seventy six of these 267 less advanced projects are in Queensland. ABARE noted that "Despite the uncertainty inherent to projects at these earlier stages of consideration, the significant number of large scale projects at less advanced planning stages under consideration for development is expected to provide a firm platform for future growth in Australian minerals and energy production in the medium term and beyond"[31].

Similar comments regarding the future growth resources sector are contained in BIS Shrapnel's report released in September 2009, "Mining in Australia 2009-2024" [Document RP988c].

For example, the above-mentioned report indicates that expansion works "will continue to underwrite activity and maintain annual coal investment above $2.5 billion (in constant prices) until the expected market recovery in 2011/12" and that "coal prices are at sufficiently high levels (and are forecast to remain so) to justify continued investment."[32]

BIS Shrapnel also note that across the coal mining sector as a whole, mine expansions offer the advantage of economies of scale and will be a "key driver of investment", although there is "a fair share of Greenfield projects expected to take place."[33] This report noted that in 2008-09, the two largest coal projects to get underway were in Queensland with the $320 million Mount Arthur expansion and the $360 million Moolarben Underground thermal coal development and further notes that the $450 million Middlemount project in Queensland is the most "notable project of significance" to commence in 2009-10.[34]

Significantly, BIS Shrapnel observe in its report that "As certainty surrounding the global economic environment returns, larger investment projects [are set] to get underway from 2010-11. Leading the new contingent of sizeable projects will be the $760 million Goonyella Riverside Expansion and the $1.1 billion Eagle Downs mine (both within Queensland). From there, strengthening demand and upward movement in prices will encourage a raft of new developments to take place early next decade."[35] The report goes on to identify a further six major coal projects due to commence in 2011-

[27] Ibid, pages 46-47

[28] ABARE, "Minerals and Energy – Major development projects – October 2009 listing", November 2009, page 7

[29] Ibid, page 7

[30] Ibid, page 12

[31] Ibid, page 12

[32] BIS Shrapnel, "Mining in Australia 2009-2004' September 2009, page 25

[33] Ibid

[34] Ibid

[35] Ibid, page 27

12, with project costs totalling $4.358 billion[36] and in the latter part of the outlook period, BIS Shrapnel believe that the development of the Surat and Galilee Basin in Queensland will provide a further boost to activity in the resources sector[37].

Overall, based on the above-mentioned BIS Shrapnel report, it seems that growth in output for the resources sector is expected to remain positive, with mining output expected to "grow modestly in 2009-10, rising by 2.7 on the back of higher coal, iron ore and oil and gas production".[38] BIS Shrapnel forecast that "Output will then accelerate from 2010-11, as idled capacity for most mineral commodities begins to be restored back into production in addition to further expansions within the three main mining sectors".[39]

Table 3-3 shows the changes in employee numbers in Queensland's mining sector by quarter between September 2008 and September 2009. It shows that there has been only a relatively small decline in total numbers in this period and that the sector has effectively withstood the economic downturn.

Table 3-3: Employees in Queensland Mining Employees – September 2008 to September 2009[40]

	Sep-08	Dec-08	Mar-09	Jun-09	Sep-09
Open Cut/Exploration Mines (Total Employment Numbers)	20,429	22,785	22,440	21,010	21,085
Coal Underground Mines	4,695	5,165	5,126	4,951	5,818
Metalliferous Surface/Exploration Mines	6,145	5,645	4,966	4,453	4,338
Metalliferous "Other" Mines	1,842	1,890	1,729	1,989	1,858
Metalliferous Underground Mines	5,110	5,079	4,321	3,925	3,929
Quarries	1,575	1,603	1,518	1,454	1,480
Queensland Total	39,796	42,167	40,100	37,782	38,508

The Reserve Bank of Australia's November 2009 "Statement on Monetary Policy" revised up its forecast of Australia's GDP growth:

> *Given the resilience of the economy, GDP is now expected to increase by a little more than 2 per cent over the year to mid 2010, a considerably better outcome than thought likely earlier in the year. The central forecast is then for the economy to expand by 3¼ per cent over the year to mid 2011, with growth gradually increasing over the remainder of the forecast period.*[41]

When read together, the Reserve Bank of Australia's "Statements on Monetary Policy" between November 2008 and November 2009 highlight that:

- The Australian economy has been less adversely affected by the Global Financial Crisis than the Australian Government and the Reserve Bank of Australia initially predicted would be the case;
- The worst effects of the Global Financial Crisis are now likely to have past and the Australian economy is now likely to be on a recovery path as its key trading partners come out of recession;
- The Australian economy is now forecast to recover quicker from the Global Financial Crisis than the Australian Government and the Reserve Bank of Australia previously predicted would be the case; and

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[36] Ibid, section 2.8 Project lists, page 35

[37] Ibid, page 27

[38] Ibid, page xviii

[39] Ibid, page xviii

[40] Source - http://www.dme.qld.gov.au/mines/mines_safety_statistics.cfm

[41] Ibid, page 3

- There are strong prospects for significant growth in the resources sector.

These general points are highlighted in Table 3-4, which details the changes in the Reserve Bank of Australia's forecasts of GDP growth over the year to the quarters shown.

Table 3-4: Reserve Bank of Australia – Forecast Australian GDP over Year to Quarter Shown (Per Cent)

RBA Statement	Forecast Quarterly GDP Growth							
	March 2009	June 2009	Dec 2009	June 2010	Dec 2010	June 2011	Dec 2011	June 2012
November 2008		1.5	1.75	2.0	2.5	3.0		
February 2009		0.25	0.5	1.25	2.5	3.25		
May 2009		(1.25)	(1.0)	0.5	2.0	3.25	3.75	
August 2009	0.4 (a)	0.25	0.5	1.0	2.25	3.25	3.75	
November 2009		0.6 (a)	1.75	2.25	3.25	3.25	3.25	3.5

(a) Actual GDP data

Table 3-4 shows that whereas the Reserve Bank of Australia had predicted in its May 2009 Statement that Australia would experience negative growth in the years to June and December 2009, in fact the economy grew in the year to June 2009 by 0.6 per cent and was forecast in the November 2009 Statement to strengthen further in the year to December 2009 with growth of 1.75 per cent. Furthermore, whereas in the May 2009 Statement growth of 0.5 and 2.0 per cent were predicted for the years to June and December 2010, growth of 2.25 and 3.25 per cent are now predicted in the November 2009 Statement.

The strength of the economic recovery led the Governor of the Reserve Bank to comment in a speech on 5 November 2009 that "As it turns out, in April (2009) we were pretty much at the nadir of sentiment about the Australian economy. Six or seven months later, even most of the optimists are a little surprised, I suspect, at the economy's performance."[42] In a similar manner, on 1 December 2009, in his monetary policy statement announcing an increase in the cash rate of 25 basis points to 3.75 per cent, the Governor of the Reserve Bank stated that:

> *In Australia, the downturn was relatively mild, and measures of confidence and business conditions suggest that the economy is in a gradual recovery. The effects of the early stages of the fiscal stimulus on consumer demand are fading, but public infrastructure spending is starting to provide more impetus to demand. Prospects for ongoing expansion of private demand, including business investment, have been strengthening. There have been some early signs of an improvement in labour market conditions. The rate of unemployment is now likely to peak at a considerably lower level than earlier expected.*[43]

The Australian Government in its May 2009 Budget forecast that GDP growth for 2008-09 would be 0.0 per cent and for 2009-10 would be -0.5 per cent. In fact, GDP growth for 2008-09 was 1.0 per cent and, in its November 2009 "Mid Year Economic and Fiscal Outlook", the Australian Government revised its forecast of GDP growth for 2009-10 to 2.5 per cent. The Government's November 2009 medium term forecast of Australian GDP growth is detailed in Table 3-5.

Table 3-5: Australian Government – Forecast Australian GDP Growth November 2009 - Mid Year Economic and Fiscal Outlook (Per Cent)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Australian GDP Growth	1.0 (a)	1.5	2.75	4.0	4.0	4.0	4.0

(a) Actual GDP data

[42] Reserve Bank of Australia, "The Road To Prosperity", November 2009 http://www.rba.gov.au/Speeches/2009/sp-gov-051109.pdf , page 1

[43] Reserve Bank of Australia, "Statement by Glenn Stevens, Governor, Monetary Policy" 1 December 2009

The Queensland Government issued its "Mid Year Fiscal and Economic Review" in December 2009. In this review, the Government indicated that:

> *Economic conditions have improved since the 2009-10 Budget, leading to modest improvements in the majority of economic and fiscal forecasts. Despite this, further significant improvement will be needed before growth can return to trend.*[44]

It went on to state that:

> *The Queensland economy proved relatively resilient in 2008-09, expanding during a year when most major economies experienced deep recessions and global financial market conditions deteriorated. However, with economic growth easing to 0.8%, to be largely in line with growth nationally, 2008-09 represented the weakest year for the State economy since 1990-91. The financial crisis weighed on household confidence in particular, as well as on export demand from regions outside of emerging Asia and other parts of Australia.*
>
> *Reflecting an improvement in global economic and financial conditions, the outlook for the Queensland economy has strengthened since the Budget. The economy is now forecast to expand by 1% in 2009-10, compared with a ¼% contraction forecast at Budget time, while growth is forecast to strengthen to 3½% in 2010-11, above the 2¾% originally anticipated.*[45]

The strong prospects for the resources sector were supported by a report by the International Monetary Fund in December 2009. It stated that:

> *Looking ahead into 2010, prices of many commodities are likely to increase further. The demand side should generally be the main source of upward pressure, as global activity is widely expected to expand at a faster pace. With inventories remaining above average for many commodities and substantial spare capacity in many commodity sectors, the upward pressure is likely to remain moderate for some time, unless much stronger-than-expected global growth or other surprises lead to a rapid drawdown of these buffers.*
>
> *Commodity price prospects also depend on global macroeconomic conditions more broadly, including price developments for internationally traded goods and services more generally.*
>
> *Information about expected future spot prices derived from key commodity futures options confirms that investors anticipate higher prices in 2010, but the probability of another commodity price spike would seem remote over the near term.*[46]

The International Monetary Fund (IMF) went on to say that:

- *Looking at commodity price prospects from a longer-term perspective highlights how prices are* expected *to remain high by historical standards. The effects of the crisis have been to reduce prices somewhat below their 2008 peaks, but demand is expected to continue rising at a solid pace as industrialization continues in emerging and developing economies. Accommodating this demand will eventually require further capacity expansion in many commodity sectors, with some need to tap higher-cost sources.*[47]
- *Further into 2009; additional impetus came from buoyant recovery in emerging Asia and, as the year progressed, stronger-than-expected global activity more generally. The growing evidence of a relatively favourable economic performance in many emerging and developing economies had a strong impact on commodity prices, as commodity demand prospects increasingly depend on growth in these economies...*[48]

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[44] Queensland Government, "Mid Year Fiscal and Economic Review 2009-10: State Budget 2009–10", December 2009, page 1

[45] Ibid, page 3

[46] http://www.imf.org/external/pubs/ft/survey/so/2009/RES123009A.htm

[47] Ibid

[48] Ibid

3.4 Economic Forecasts Relied on by MMA

In its "Review of Ergon Energy's maximum demand forecasts for the 2011 to 2015 price review" that it prepared in October 2009 for the AER, MMA stated that:

> *The most recent (August 2009) KPMG Econtech report forecasts a very strong downturn, a contraction by 4.8%, for the Queensland economy in 2009. The three key components to this downturn were reduced consumer spending, the "demise" of the local property market and the decline in mining investment. Growth in 2010 is forecast to remain weak at 1.4%. Over the longer term from 2011 to 2015, stronger growth averaging over 3.5% pa is expected to resume with continued population growth and recoveries in the commodities and property markets. Even this is only some 70% of the growth rate experienced between 2002 and 2008. However, over the entire period of interest, 2008 to 2015, Queensland growth is expected by KPMG Econtech to average only 2% pa – less than half what it averaged over the earlier period. By comparison, the NIEIR April 2009 report for Energex forecast an annual growth rate of Queensland GSP of around 3% pa between 2008 and 2015.*[49]

Ergon Energy does not agree with the GSP values that MMA has relied on from the August 2009 KPMG Econtech report entitled "Australian National, State and Industry Outlook – Jun Qtr 2009 to Jun Qtr 2017". This is because:

- Queensland's GSP growth for 2008-09 was not -4.8 per cent as KPMG Econtech forecast in its August 2009 report. Rather, the actual Queensland GSP result was 0.8 per cent[50]. MMA states that "the very significant expected reduction in Queensland economic growth, from 5% pa over the period 2002 to 2008 to a forecast 2-3% pa over the period of 2008 to 2015 needs to be taken into account when forecasting maximum demand growth over the period of interest"[51]. However, this is based on an incorrect view of GSP growth in 2008-09 of -4.8 per cent;
- KPMG Econtech's August 2009 report presents dramatically different forecasts for the Queensland economy than those that it provided in its March 2009 report to the Australian Energy Market Operator (AEMO) that was prepared for the Electricity Statement of Opportunities (ESOO). In its March 2009 report for AEMO, KPMG Econtech projected that Queensland GSP would grow by 0.9 per cent in 2008-09 and 3.6 per cent over the period 2007-08 to 2014-15. This contrasts with the growth rate of -4.8 per cent in 2008-09 and 2 per cent for the period 2007-08 to 2014-15 presented in the August 2009 KPMG Econtech report;
- KPMG Econtech's August 2009 report contains conflicting GSP growth forecasts for 2008-09 to 2010-11. On page 39 of its August 2009 report, KPMG Econtech detailed forecast GSP growth for these three years of -4.8, 1.4 and 3.0 per cent, whereas in Table 3 of the "Detailed State Forecast Tables" in the appendices to the report it detailed forecasts for the same years of -6.2, 1.2 and 4.7 per cent; and
- KPMG Econtech's August 2009 report forecasts that:

  > *Queensland will be the slowest growing economy over the next three years. We expect GSP in Queensland to contract by an annual average of 0.2* [per cent] *over the medium term. This weak result reflects much lower business investment following high mining investment in recent years. A deflating property sector will also contribute to negative growth*[52]*.*

Ergon Energy disagrees that Queensland will be the slowest growing State or Territory in Australia over the next three years and that its economy will contract by 0.2 per cent per annum, which would make it the only Australian State with negative economic growth over this period. As evidenced in the

[49] MMA, "Review of Ergon Energy's maximum demand forecasts for the 2011 to 2015 price review", October 2009, page 15

[50] See the Queensland Government's "Annual Economic Report, 2008-09" at http://www.oesr.qld.gov.au/queensland-by-theme/economic-performance/regular-publications/annual-econ-report/index.shtml

[51] MMA, op cit, page 15

[52] KPMG Econtech, "Australian National, State and Industry Outlook – Jun Qtr 2009 to Jun Qtr 2017", August 2009, page 25

historical GSP information above, there has never been a three year period where the Queensland economy has underperformed the Rest of Australia when migration has been strong and the resources industry has had such potential for growth.

In addition to the material cited above, support for Ergon Energy's view regarding the resilience of the Queensland economy can also be found in the latest Commsec 'State of the States' report published on the Commsec website on 11 January 2010 [Document RP987c]. This report indicates that whilst economic activity in Queensland slowed in 2009 "actual activity levels are still well above levels considered 'normal' for the state over the past decade". In fact, Commsec's assessment of Queensland economic growth for the September 2009 quarter indicates growth is more than 20 per cent above the state's decade average level of output, ranking only behind Western Australia and the ACT.

The January 2010 Commsec report also makes the following observations about business investment outlook:

> *The resources-dependent states of Western Australia and Queensland continue to lead the business investment leader-board. While growth in investment has slowed over the past year in both states, the amount of work underway is still markedly above decade-average levels. In Western Australia, the amount of private capital expenditure in the September quarter was 107 per cent above the average levels of the past decade. In Queensland business investment is 68 per cent above 'normal' levels. Simply, there is a lot of work to be done.*

In terms of population growth, the Commsec report notes that:

> *Across the states and territories the current annual rate of population growth was compared with each economy's decade-average growth pace. Population growth is fastest in Western Australia (3.0 per cent) followed by Queensland (2.6 per cent). But both states have been consistently leading the rest of the nation, especially over the past three years.*

KPMG Econtech's assessment, which MMA has relied on, is based on an outlier view of Queensland's 2008-09 GSP growth and contains a number of other inconsistencies. Indeed, KPMG Econtech appears to contradict its own position elsewhere in its report by stating that "Going forward, Western Australia, Northern Territory and Queensland will lead Australia's economy recovery in 2010-11 on the back of strong export growth"[53]. This is at odds with its March 2009 report for AEMO, in which KPMG Econtech forecast that Queensland would be the fastest growing jurisdiction in the National Electricity Market for the three year period 2009-10 to 2011-12.[54]

Ergon Energy considers that KPMG Econtech's assessment is out of date and is inconsistent with the stronger and faster improvements in the Queensland economy that have been forecast more recently, by, amongst others, the Queensland Government. In particular, KPMG Econtech's growth forecast for the period 2008-2015 is heavily skewed by its 2008/09 growth forecast of -4.8%, compared to actual growth of 0.8% in this year. While economic forecasts are, by their very nature, inexact, an error of this magnitude casts doubt on the reliability of KPMG Econtech's forecast.

Ergon Energy believes that the apparent reliance on Queensland State product as a proxy for growth in the regional Queensland area serviced by Ergon Energy at a time of potential strong resources growth is not optimal.

Table 3-6 details historical and projected growth in Queensland GSP from various reports.

[53] Ibid, page 25

[54] Refer "KPMG Stage Two Electronic Report Appendix", March 2009

Table 3-6: Historical and Projected Growth in Queensland GSP from Various Reports (Per Cent)

Forecast Year	Publication					
	Actual	**KPMG Econtech Mar-09 for AEMO**	**KPMG Econtech Aug-09 used by MMA**	**NIEIR report to Ergon Energy Nov-07**	**NIEIR report to Ergon Energy Sep-08**	**NIEIR report to Ergon Energy Dec-09**
2002-03	4.2			5.3		
2003-04	3.9			5.3		
2004-05	4.6	5.1		4.8		
2005-06	4.5	3.7	5	4.9		
2006-07	5.6	4.7	3.6	4.2		
2007-08	5.5	5.6	5.3	4.9	5	5.3
2008-09	0.8	0.9	-4.8	4	4.3	1.5
2009-10		0.3	1.4	3.5	3.5	1.8
2010-11		4.7	3	3	2.6	2.3
2011-12		4.9	4.5	4.4	4.9	6.1
2012-13		4.8	4.2	3.3	5.5	4.8
2013-14		5.2	3.4	3.6	3.8	2.1
2014-15		4.6	2.7	4.4	4.6	1.8
2015-16		4.7		3.9	3.1	
2016-17		4.5		4.4	5	
2017-18		3.2			4.5	
2018-19		2.5				
Average annual change 2007-08 – 2014-15		3.9	2.5	3.9	4.2	3.2

Table 3-6 shows, in particular, that the greatest variations between the forecasts are in:

- 2008-09 where KPMG Econtech's forecast used by MMA (-4.8 per cent) is dramatically lower than KPMG Econtech's March 2009 forecast (0.9 per cent) and NIEIR's December 2009 forecast (1.5 per cent).

  Ergon Energy considers that it is a significant error for both the AER and MMA to rely on KPMG Econtech's forecast as the actual Queensland GSP growth outcome was 0.8 per cent; and

- 2009-10 where KPMG Econtech's forecast used by MMA (1.4 per cent) is higher than KPMG Econtech's March 2009 forecast (0.3 per cent) but lower than NIEIR's December 2009 forecast (1.8 per cent) and the Queensland Government's forecast of 3.5 per cent.

  Ergon Energy considers that KPMG Econtech's August 2009 is now out of date because, as discussed in sections 3.2 and 3.3, the Australian and Queensland economies have been less dramatically affected by, and have recovered more quickly from, the Global Financial Crisis than was generally predicted at the beginning of 2009, when the August 2009 forecast was released.

3.5 KPMG Econtech's next Quarterly Report

Ergon Energy sought to obtain KPMG Econtech's next quarterly report, which it understood had been due for release in November 2009, in order to see how KPMG Econtech had revised its forecast from its August 2009 report that was relied on by MMA based on analysis to the end of September 2009.

KPMG Econtech advised Ergon Energy[55] that they will be making model changes to account for "new industry classifications" provided by the AER and that their next quarterly report will not be available until February 2010. This means that Ergon Energy has not been able to have regard for this report in preparing this Revised Regulatory Proposal, which must be submitted to the AER by 14 January 2010.

Ergon Energy has discussed this issue with officers from KPMG Econtech and has received informal advice from the head of the forecasting division for KPMG Econtech in Canberra that confirms Ergon Energy's view that the August 2009 forecast is now out of date and that the forecast GSP for Queensland remains positive and likely to higher than most other states, due to the Queensland economy's exposure to the minerals and resources sector. Ergon Energy has requested written confirmation of this advice from KPMG Econtech, however, at the time of finalising this submission that written advice was not to hand.

3.6 Ergon Energy's Forecasts of the Queensland Economy

Ergon Energy considers that there is not a single value, or a single set of values, that will reasonably reflect the forecast performance of the Queensland economy over the next regulatory control period. Rather, there will be various values that are likely to reflect a reasonable range.

In deciding on this reasonable range, Ergon Energy recognises that it is appropriate for the AER, and its consultants MMA, to have regard for benchmarks from expert economic forecasters. Ergon Energy understands that KPMG Econtech could be included as one of these experts, however, it is unclear why no apparent reliance was placed by either MMA or the AER on the NIEIR forecasts supplied by Ergon Energy

However, Ergon Energy considers that KPMG Econtech's August 2009 forecast has been shown to be less reliable than other forecasts given the rapid changes in global and local economic developments such that it should not be included by MMA or the AER in developing the reasonable range of forecasts. This August 2009 forecast is any event, being revised and is considered to be out of date by KPMG Econtech, and Ergon Energy has received advice from KPMG Econtech that suggests Queensland GSP will experience positive growth.

In particular, Ergon Energy considers that:

- The effect of the Global Financial Crisis on the Queensland economy has been shallower and less severe than MMA suggests in its October 2009 report. This is because MMA has relied on an incorrect forecast by KPMG Econtech of Queensland's GSP growth of -4.8 per cent in 2008-

[55] KPMG Econtech email to Ergon Energy, 8 December 2009 [Document RP887c]

09. In fact, the actual GSP growth was 0.8 per cent. While Ergon Energy recognises that Queensland (and Australia more generally) experienced a significant economic downturn as a result of the Global Financial Crisis, it did not experience a contraction in its economy in 2008-09 as MMA and KPMG Econtech have suggested;

- The effect of the Global Financial Crisis on the Queensland economy will be shorter than MMA and KPMG Econtech suggest. Specifically, MMA and KPMG Econtech are overstating the severity of the impact of the Global Financial Crisis in Australia by forecasting that GSP growth will contract in Queensland by an annual average of 0.2 per cent over the period 2008-09 to 2010-11. Further, there is no economic basis for KPMG Econtech to suggest that, of all the Australian States and Territories, "Queensland will be the slowest growing economy over the next three years". Instead, Ergon Energy considers that the main impact for the Queensland economy of the Global Financial Crisis will be limited to 2008-09 and 2009-10, albeit that it will experience positive GSP growth in both years;
- The Queensland and Australian economies will return to growth stronger than MMA has forecast. Ergon Energy does not agree with MMA that Queensland's GSP growth will average about 2 per cent for the period 2007-08 to 2014-15. Again, KPMG Econtech's error in its 2008-09 forecast has a dramatic effect in understanding the growth forecast for this period. Rather, Ergon Energy shares the view that KPMG Econtech expressed elsewhere in its August 2009 report that Queensland will be one of the states that "lead(s) Australia's economic recovery in 2010-11 on the back of strong export growth"[56]. With the fastest population growth rate and a resources sector that is set to recover strongly back to the activity levels it experienced before the Global Financial Crisis, there is every reason to believe that Queensland will perform more strongly than Australian as a whole, as it did every year between 1999-00 and 2007-08;
- There is strong evidence to suggest that MMA is incorrect in saying that "the economic impacts of the Global Financial Crisis are unlikely to be 'recovered' over the period to 2015"[57] and that "the Global Financial Crisis would not just delay projects. It would also be expected to result in significantly fewer (or smaller) projects than would otherwise be the case."[58]

  Ergon Energy believes that there will be a significant increase in investment in projects in the Queensland resources sector in the current and next regulatory control periods. This view is supported by the Reserve Bank of Australia's views about the recovery of the resources sector in its November 2009 "Statement on Monetary Policy" and by ABARE's "Minerals and Energy – Major development projects – October 2009 listing", which identified 341 projects Australia-wide at either an "advanced" or "less advanced" stage of development on its project list. Further, the "Australian Financial Review" ran a front page article on 11 November 2009, which stated that "More than $16 billion of mining projects shelved during the Global Financial Crisis are back on the agenda as sentiment improves in the sector due to higher commodity prices and easier access to finance"; and
- There is strong evidence to suggest that the major resource projects that were forecast to occur in the next regulatory control period will still proceed and will contribute to Queensland's average GSP growth being at least 3.5 per cent per annum over 2010-11 to 2014-15, as suggested by the reports referred to in Table 3-6. This is consistent with the view, expressed in KPMG Econtech's August 2009 report, that "Queensland's long term economic prospects remain favourable" and that "State final demand is project(ed) to grow robustly from 2010/11 onwards"[59], albeit that Ergon Energy believes that Queensland will begin to recover quicker than KPMG Econtech has forecast.

Clause 6.5.7(c)(3) of the Rules require the AER to accept Ergon Energy's forecast of required capital expenditure if they reflect a realistic expectation of the demand forecast to achieve the capital expenditure forecasts. One of the matters that Ergon Energy considers the AER should have regard for in making this assessment is the economic forecasts that underpin the demand forecast.

[56] KPMG Econtech, "Australian National, State and Industry Outlook – Jun Qtr 2009 to Jun Qtr 2017", August 2009, page 25

[57] MMA, op cit, page 16

[58] Ibid, page 16

[59] KPMG Econtech, op cit, August 2009, page 39

KPMG Econtech's August 2009 report describes Queensland as follows:

> *Queensland is the 'rapid population growth State'. In the three years to 2010/11, Queensland's population is expected to increase at an average yearly rate of 2.8 per cent, well above forecast for national population growth of 2.0 per cent per annum. This is being largely driven by the migration of retirees from the southern states of NSW and Victoria. This population growth usually means that economic growth is also higher than at the national level. It also gives the construction industry a heightened role.*[60]

Ergon Energy considers that it is not credible to forecast, as KPMG Econtech has done on page 25 of its August 2009 report, that "Queensland will be the slowest growing economy over the next three years". There are several reasons for Ergon Energy's view.

Firstly, there has never been a period over the past 25 years when Queensland's population growth has been above the national average and its GSP growth rate has been below the Australian GDP growth rate (albeit that there have been three separate years during this period when this has been the case). This is evidenced by the data presented in Table 3-1.

Secondly, there has never been a sustained period over the last 25 years when there has been sustained growth in the resources and mining sector when Queensland's GSP growth has been below the national average.

The combination of forecasts of higher population growth than the national average and strong growth in the resources and mining sector mean that it is unreasonable to forecast that the Queensland economy will grow more slowly than the Australian average.

As detailed in Table 3-5, the Federal Government has forecast that the Australian GDP growth will be 2.75 per cent in 2010-11 and 4.0 per cent between 2011-12 and 2014-15. Ergon Energy therefore considers that these are well within the reasonable range of the growth rate that Queensland could expect to experience over the next regulatory control period.

Ergon Energy also considers that there is good reason to think that the economic growth in its service area will be stronger than in the rest of Queensland to the extent that growth in the resources and mining sector and its multiplier to the regional economy leads the state economic recovery. The demand for electricity in Ergon Energy's service area is also likely to grow more strongly than in the rest of Queensland, especially given that the resources and mining sector consume electricity relatively more intensively than the residential and commercial sectors, which dominate the rest of Queensland.

Ergon Energy has had regard for NIEIR's top-down maximum demand forecasts in preparing its own maximum demand forecasts in both its original Regulatory Proposal and this Revised Regulatory Proposal. NIEIR's forecasts are underpinned by its forecasts for the Queensland economy for the next regulatory control period. Ergon Energy is not suggesting that the values that NIEIR has prepared are the only "correct" forecasts of the Queensland economy, however, Ergon Energy remains unclear as to why little or no reliance has been placed upon them by MMA and the AER.

While NIEIR's GSP forecasts differ in several years from the Queensland Government's December 2009 "Mid Year Fiscal and Economic Review" and those of the Australian Government. Ergon Energy considers that NIEIR's forecasts do fall within the reasonable range of available forecasts and therefore provide an appropriate basis under the Rules for both Ergon Energy to rely on in preparing its maximum demand forecasts in this Revised Regulatory Proposal and also for the AER to consider in reviewing the proposals from Ergon Energy. NIEIR also take into account sectoral growth such as the resources sector which allows them to address differing impacts from the economic recovery within the two supply regions in Queensland.

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[60] KPMG Econtech, "Australian National, State and Industry Outlook – Jun Qtr 2009 to Jun Qtr 2017", August 2009, page 38

3.7 Relevant Documents Provided by Ergon Energy

The following documents are relevant to this Chapter but are new since, or were not provided to the AER with, Ergon Energy's June 2009 Regulatory Proposal:

RP886c	RP886c_EE Email to KPMG Econtech_18Nov09.rtf
RP887c	RP887c_KPMG Econtech email to EE_8Dec09.rtf
RP987c	RP987c_CommSec_State of the States Review_11Jan10.pdf
RP988c	RP988c_BIS Shrapnel_Mining in Aust 2009-2024.pdf

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4 CLASSIFICATION OF SERVICES AND NEGOTIATING ARRANGEMENTS

In response to the AER's Draft Distribution Determination Ergon Energy:

- Accepts the AER's classification of services but does not provide any comment on the proposed Negotiated Distribution Service Criteria. This is done on the basis that Ergon Energy will not have any Negotiated Distribution Services; and
- Does not accept the AER's proposed procedures for assigning or reassigning customers to tariff classes as these matters are adequately addressed in its Network Use of System Tariff Guide - Release 2 [Document RP934c] and by existing market systems and processes.

4.1 Ergon Energy's June 2009 Regulatory Proposal

4.1.1 Classification of Services

Chapter 14 of its June 2009 Regulatory Proposal detailed Ergon Energy's classification of services, which accepted the AER's likely classification that was detailed in the AER's "Final Decision - Framework and Approach Paper - Classification of Services and Control Mechanisms: Energex and Ergon Energy 2010–15" (F&A Stage 1) issued on 27 August 2008.

In particular, Ergon Energy accepted:

- That its Distribution Services should be classified into:
  - Standard Control Services, comprising Network Services, Connection Services and Metering Services; and
  - Alternative Control Services, comprising Street Lighting Services, Quoted Services and Fee Based Services.
- That none of its Distribution Services should be classified as a Negotiated Distribution Service; and
- The list of services detailed by the AER in Appendix B of its F&A Stage 1. Ergon Energy provided details of the services that it provides against each of the services listed by the AER.

4.1.2 Assigning Customers to Tariff Classes

In section 52.1 of its Regulatory Proposal, Ergon Energy confirmed that it assigns customers to tariffs on the basis of geographical location, usage and size.

Customers are first classified into the Eastern Zone, the Western Zone or Mount Isa, based on geographical location. In order to provide the appropriate economic and cost of supply signals, customers are then assigned into one of four classes of network users, namely:

- Individually Calculated Customers;
- Connection Asset Customers;
- Standard Asset Customers; and
- Embedded Generators.

The purpose of the four network user classes is to enable network prices to be developed that provide individual or direct cost of supply signals to network users where possible while recognising that it is not feasible to price every network user individually.

4.1.3 Negotiated Distribution Service Criteria

Ergon Energy did not propose in its classification proposal in Chapter 14 of its Regulatory Proposal that any if its Distribution Services be classified as Negotiated Distribution Services. As a result, Ergon Energy did not include a Negotiating Framework in its Regulatory Proposal and did not discuss the Negotiated Distribution Service Criteria that the AER released on 17 July 2009.

4.2 AER's November 2009 Draft Distribution Determination

In Chapters 2 and 3 of its Draft Distribution Determination, the AER:

- Applied the classification of services from its F&A Stage 1;
- Detailed the procedures for assigning customers to tariff classes in its Appendix B. These procedures include a requirement for Ergon Energy to inform customers of the availability of a dispute resolution mechanism under Part 10 of National Electricity Law; and
- Applied the same Negotiated Distribution Service Criteria that it published on 17 July 2009, although the AER did not classify any of Ergon Energy's Distribution Services as Negotiated Distribution Services.

4.3 Ergon Energy's Response to AER's Draft Distribution Determination

4.3.1 Classification of Services

Ergon Energy:

- Accepts the AER's classification of services; and
- Notes that the AER accepted the list of services that Ergon Energy identified for each category of Distribution Services. Ergon Energy does not propose any changes to its service listing.

4.3.2 Assigning Customers to Tariff Classes

Ergon Energy has some concerns with the AER's proposed procedures for assigning customers to tariff classes. These concerns are discussed in "Ergon Energy Response to Draft Distribution Determination: Assigning Customers to Tariff Classes" [Document RP935c]. Ergon Energy requests that the AER review its procedures and revise them to take into account the concerns raised by Ergon Energy.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- The AER's procedures for assigning customers to tariff classes set out in Appendix B include a requirement for Ergon Energy to inform customers of availability of dispute resolution mechanism under Part 10 of National Electricity Law [17-18, 441-443]	- Effective internal review system should clearly set out the process of escalation and be visible and transparent to users [17-18]	- Ergon Energy accepts the AER's decision that an effective internal review system should clearly set out the process of escalation and be visible and transparent to users. - Ergon Energy does not accept the AER's proposed procedures for assigning or reassigning customers to tariff classes as set out in Appendix B of the AER's Draft Distribution Determination. "Ergon Energy Response to Draft Distribution Determination: Assigning Customers to Tariff Classes" [Document RP935c] sets out Ergon Energy's issues with the procedures.
	- Ergon Energy's tariff guide / pricing principles statement does not explicitly recognise a customer's right to object nor that Ergon Energy will undertake a review of its decision in the event of an objection [17-18]	- As discussed in Ergon Energy's response to AER.ERG.12.01, Ergon Energy is currently not required to develop its prices in accordance with 6.18 of the Rules. Rather, Ergon Energy must comply with the QCA's 2005 Final Determination. Under these arrangements there is no requirement to publish details of its internal review system and processes in the event of a customer complaint or objection. - Ergon Energy's "Network Use of System Tariff Guide -

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
		release 2" [Document RP934c] provides details of the process for the review of a customer's network tariff code and the customer/retailer's right to object to Ergon Energy's decision. - Current jurisdictional obligations provide sufficient processes and mechanisms for rights to review. "Ergon Energy Response to Draft Distr bution Determination: Assigning Customers to Tariff Classes" [Document RP935c] provides further detail on these requirements. - As a result, Ergon Energy does not accept with the procedures in Appendix B of the AER's Draft Distribution Determination.

4.3.3 Negotiated Distribution Service Criteria

Ergon Energy notes that the AER is proposing to apply the same Negotiated Distribution Service Criteria that it published on 17 July 2009.

Ergon Energy does not have any comments on these criteria as they will not be used in the next regulatory control period as Ergon Energy is proposing not to have any services classified as Negotiated Distribution Services.

4.4 Ergon Energy's Revised Regulatory Proposal

Ergon Energy is not proposing any changes to the classification of services or treatment of Negotiated Distribution Service Criteria from its June 2009 Regulatory Proposal.

Ergon Energy does not accept the AER's proposed procedures for assigning or reassigning customers to tariff classes. Ergon Energy believes that its "Network Use of System Tariff Guide - release 2" [Document RP934c] provides appropriate details of the process for reviewing a customer's network tariff code and the customer/retailer's right to object to a decision by Ergon Energy. Further, existing jurisdictional obligations provide sufficient processes and mechanisms for the customer/retailer's right to review of its tariff class.

4.5 Rules' Requirements

In submitting this Revised Regulatory Proposal, Ergon Energy has had regard for the following relevant clauses of the Rules:

- Classification of services - clauses 6.2.1-6.2.3, 6.2.7, 6.7, 6.8.1(b)(1), 6.8.2(c)(1), 6.12.1(1), 6.12.3(b) and 11.16.6;
- Assigning Customers to Tariff Classes – clauses 6.12.1(17) and 6.18.4; and
- Negotiated Distribution Service Criteria – clauses 6.7.1, 6.7.2(a)(1)-(2), 6.7.3, 6.7.4, 6.7.5, 6.8.2(c)(5), 6.9.3, 6.12.1(15)-(16), 6.12.3(g) and (h) and 6.22.2.

4.6 Relevant Documents Provided by Ergon Energy

The following documents are relevant to this Chapter but are new since, or were not provided to the AER with, Ergon Energy's June 2009 Regulatory Proposal:

Email 11-09-09	EE response to AER.ERG.12.01
Email 11-09-09	EE response to AER.ERG.12.02
RP934c	RP934c_Ergon Network Tariff Guide 2009-10 Release 2.pdf
RP935c	RP935c_Ergon Energy Comments_AER DDD_Assigning Customers to Tariff Classes_13Dec09.pdf

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5 CONTROL MECHANISM FOR STANDARD CONTROL SERVICES

In response to the AER's Draft Distribution Determination, Ergon Energy:

- Accepts a revenue cap control mechanism being applied to its Standard Control Services for the next regulatory control period.

However, this chapter identifies various matters where Ergon Energy seeks clarification from the AER about the way in which the control mechanism is to be applied.

5.1 Ergon Energy's June 2009 Regulatory Proposal

Chapter 51 of its June 2009 Regulatory Proposal detailed Ergon Energy's proposal in relation to the control mechanism to apply to Standard Control Services in the next regulatory control period. Ergon Energy accepted the control mechanism set out by the AER in its F&A Stage 1, which provided that:

> *The AER will apply a fixed revenue cap control mechanism to those services classified by the AER as standard control services in the 2010–15 regulatory control period. Each fixed revenue cap will be of the CPI – X form and will be made in accordance with Part C of the NER—using the building block approach.*

The F&A Stage 1 also set out a number of adjustment mechanisms to be applied to the fixed revenue caps during the next regulatory control period. Ergon Energy, in its June 2009 Regulatory Proposal, supported these adjustments being applied to its revenue caps in the next regulatory control period. Ergon Energy also sought to clarify the following features of its revenue caps for Standard Control Services:

- The application of the unders and overs mechanism to capital contributions;
- Adjustments to the ARR for the use of Standard Control Services assets by other business entities within Ergon Energy;
- The application of side constraints on tariffs for Standard Control Services in relation to the above adjustments;
- Payments made under the Queensland Government's Solar Bonus Scheme, or any other equivalent Feed-In Tariff arrangement; and
- Unfunded Shared Network Events.

Chapter 6 of its June 2009 Regulatory Proposal detailed Ergon Energy's proposal in relation to Ring-Fencing. Ergon Energy proposed that the QCA's Ring-Fencing Guidelines continue in force until they are replaced by new Ring-Fencing Guidelines issued by the AER. Further, Ergon Energy proposed that the three Ring-Fencing waivers issued to Ergon Energy by the QCA continue to apply.

5.2 AER's November 2009 Draft Distribution Determination

In Chapters 4 and Appendix D and E of its Draft Distribution Determination, the AER:

- Applied the control mechanism from its F&A Stage 1;
- Detailed how the control mechanism is to be applied and how it will assess compliance with the control mechanism;
- Detailed the formula for calculation of side-constraints to apply to price movements of tariff classes; and
- Detailed the Ring-Fencing and compliance monitoring arrangements for the next regulatory control period.

5.3 Ergon Energy's Response to AER's Draft Distribution Determination

Ergon Energy accepts the AER's control mechanism for Standard Control Services. However, Ergon Energy seeks clarification from the AER on how the mechanism is to be applied. This is discussed in "Ergon Energy Response to Draft Distribution Determination: Comments on Chapter 4" [Document RP936c].

5.3.1 Distribution Use of System (DUOS) unders and overs

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- DUOS unders and overs term included in side constraint formula [31]	- Accepted Ergon Energy's request to continue the current QCA approach to recovering DUOS unders and overs [31]	- Ergon Energy accepts the AER's decision to continue with the current QCA approach to recovering DUOS unders and overs. - Ergon Energy supports this in principle, however, the methodology proposed by the AER does not align completely with the methodology currently applied by the QCA. This is discussed in Document RP936c. - Ergon Energy therefore proposes to adopt the methodology applied by the QCA as described in Document RP936c.

5.3.2 Changes in Inflation

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Maximum Allowable Revenue (MAR) to be adjusted for changes in the actual inflation rate [31]	- Changes in inflation not addressed by Ergon Energy in Regulatory Proposal [31]	- Ergon Energy did not address changes in inflation as in the current regulatory period as the QCA did not make annual adjustments for inflation.
	- Consistent with approach that the AER has applied to other revenue caps, such as for Transmission Network Service Provider [31]	- Subject to Ergon Energy's comments in Document RP936c, Ergon Energy accepts the AER's decision to adopt the approach to adjusting the MAR for changes in actual inflation. - Ergon Energy notes that the Australian Bureau of Statistics is intending to release March 2010 figures on 28 April 2010. It is expected that similar timing will apply in future years. As Ergon Energy's Pricing Proposal is due for submission to the AER by 30 April in each year (except 2010) this does not allow appropriate time to prepare a Pricing Proposal. - As discussed in Document RP936c and for the above reasons, Ergon Energy does not agree with using March to March CPI and instead requests December to December CPI be used so Ergon Energy is afforded sufficient time to prepare its Pricing Proposal.

5.3.3 STPIS

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- S_t term included in MAR and side constraint formula [33]	- Accept Ergon Energy's proposal to include annual adjustment for STPIS [33]	- Ergon Energy accepts the AER's decision to include an annual adjustment for STPIS. - Ergon Energy seeks clarification on the terminology contained in the MAR formula. This is discussed in Document RP936c.

5.3.4 Transitional Adjustments

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Transitional$_t$ term included in MAR and side constraint formula for adjustments to tax and use of shared assets by other business units [33-4]	- Adjustments required to account for actual tax (if any) in 2008-09 and 2009-10 and for current approach to treatment of shared assets [33-4]	- Ergon Energy accepts the AER's decision to include adjustments for actual tax and the treatment of shared assets. - Ergon Energy seeks clarification on the terminology contained in the MAR formula. This is discussed in Document RP936c.

5.3.5 Pass Throughs

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Pass through$_t$ term included in MAR and side constraint formula [34]	- Accept Ergon Energy's proposal to include annual adjustment for pass throughs [34]	- Ergon Energy accepts the AER's decision to include annual adjustments for pass throughs. - Ergon Energy seeks clarification on the terminology contained in the MAR formula. This is discussed in Document RP936c.

5.3.6 Maximum Allowable Revenue Formula

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- MAR for first year of next regulatory control period to be [35-6]: $MAR_t = AR_t$ - MAR for subsequent years of next regulatory control period to be [35]: $MAR_t = AR_t + S_t + C_t + transitional_t + pass\ through_t$	- Adjustments required to reflect allowances for STPIS, capital contributions unders and overs, transitional factors (i.e. tax and shared assets) and pass throughs [35-36]	- Subject to Ergon Energy's comments in Document RP936c, Ergon Energy accepts the AER's decision to adopt a formula for calculation of the MAR that includes adjustments for STPIS, capital contributions, transitional factors and pass throughs. - Ergon Energy seeks clarification on the terminology contained in the MAR formula. This is discussed in Document RP936c.

5.3.7 Side constraints

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- New side constraints formula [36-37]	- Adjustments required to reflect allowances for STPIS, capital contributions unders and overs, transitional factors (i.e. tax and shared assets) and pass throughs [36-37]	- Subject to Ergon Energy's comments in Document RP936c, Ergon Energy accepts the AER's decision to adopt a formula for calculation of side constraints that reflects STPIS, capital contributions, unders and overs, transitional factors and pass throughs. - Ergon Energy seeks clarification on the terminology contained in the formula. This is discussed in Document RP936c.

5.3.8 Ring Fencing and Compliance Monitoring

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- QCA ring fencing guidelines to apply as	- Consistent with clause 11.14.5(b)(3) [37-38]	- Ergon Energy accepts the AER's decision to adopt the QCA Ring-Fencing Guidelines.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
AER guidelines [37-38, 798-801]		- Ergon Energy seeks confirmation that, as proposed in Chapter 6 of its Regulatory Proposal, Ring-Fencing waivers granted by the QCA will continue to apply.
- AER to apply current QCA Regulatory Reporting Guidelines as transitional guidelines in the next regulatory control period. - AER to impose additional reporting requirements in Appendix Q which (if not already received as part of Ring Fencing or Regulatory Reporting) will be requested by way of Regulatory Information Instrument.	- Requirement of Ring-Fencing Guidelines - to give effect to new arrangements not covered by QCA [37-38]	- Ergon Energy is in general agreement with the AER's interpretation of the Ring-Fencing Guidelines requirement for the QCA's current Regulatory Reporting Guidelines to remain in force until such time as they are replaced by any new regulatory reporting guidelines or a Regulatory Information Instrument issued by the AER. - However, Ergon Energy notes that the current Guidelines were developed by the QCA to allow it to perform its functions as a jurisdictional regulator. Ergon Energy believes that the Reporting Guidelines should be amended to reflect the regulatory framework under the National Electricity Law and Rules and in reporting back to the AER against its Distribution Determination for the current regulatory control period. - Ergon Energy acknowledges the additional reporting requirements imposed in Appendix Q. Ergon Energy proposes that, consistent with requirements for Ring-Fencing compliance and regulatory reporting statements, the due dates for such reporting would be 31 October of each year. - Ergon Energy is concerned with the requirement to report figures for momentary average interruption frequency index, as discussed in section 15.3 of this Revised Regulatory Proposal. - Ergon Energy will seek to engage further with the AER on reporting requirements. It is proposed that this consultation would extend to include matters relating to Regulatory Reporting Statement templates associated with compliance under the Regulatory Reporting Guidelines.

5.3.9 Feed in Tariffs (FIT) and Unfunded Shared Network Events

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- AER has not included specific allowance in MAR and side constraint formula for FIT and unfunded shared network events [29, 36-7]	- FIT accepted as specific nominated cost pass through event [339-340]	- Ergon Energy continues to believe that Feed-In Tariff events should be treated as an unders-and-overs feature of the revenue cap Control Mechanism, and not as a cost pass through event. Furthermore, Ergon Energy notes that ETSA Utilities has lodged a Rule change request with the Australian Energy Market Commission (AEMC) on 7 October 2009 (released by the AEMC as the commencement of the consultation process on 16 December 2009) that essentially proposes that Feed-In Tariffs be treated as Ergon Energy proposed in its Regulatory Proposal. For the purpose of modelling this Revised Regulatory Proposal, Ergon Energy has included a Feed-In Tariff forecast. This is discussed further in section 18.3.3.
	- The AER has not made clear how it intends to treat unfunded shared network events]	- Ergon Energy proposes that the AER approve a specific nominated pass through provision for unfunded shared network events. This is discussed in section 18.3.3

5.4 Ergon Energy's Revised Regulatory Proposal

Ergon Energy accepts the AER's control mechanism for Standard Control Services but, as discussed in section 5.3, seeks clarification from the AER on:

- The application of the DUOS unders and overs arrangements;

- Changes in inflation being applied to Ergon Energy's revenue caps;
- The application of the STPIS in the control mechanism;
- The application of the transitional term included in the MAR and side constraint formula;
- The application of pass throughs in the control mechanism;
- The terminology in the MAR formula;
- The terminology in the side constraints formula;
- The nature and application of the ring fencing arrangements; and
- The treatment of FIT and unfunded shared network events.

5.5 Rules' Requirements

In submitting this Revised Regulatory Proposal in relation the control mechanism to apply to Standard Control Services, Ergon Energy has had regard for clauses 6.2.5, 6.2.6(a), 6.8.1(c), 6.8.2(c)(3), 6.12.1(11), 6.12.1(13), 6.12.3(c), S6.1.3(6), 6.17.1, 6.17.2, S6.1.3(6), 11.14.5 and 11.16.6(a) of the Rules.

5.6 Relevant Documents Provided by Ergon Energy

The following documents are relevant to this Chapter but are new since, or were not provided to the AER with, Ergon Energy's June 2009 Regulatory Proposal:

RP936c	RP936c_Ergon Energy Comments_Ch 4_AER DDD_14Dec09.pdf

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6 OPENING REGULATORY ASSET BASE

Ergon Energy has updated its RAB roll forward calculations for the current and next regulatory control periods in accordance with the requirements of the Rules, the Roll Forward Model (RFM), the Post Tax Revenue Model (PTRM) and specific instructions given by the AER to Ergon Energy.

6.1 Ergon Energy's June 2009 Regulatory Proposal

Chapter 40 of its June 2009 Regulatory Proposal explains how Ergon Energy calculated its RAB as at the end of the current regulatory control period, 30 June 2010, using the AER's RFM, to be $6,999 million. Table 6-1 reproduces an overview of this calculation.

Table 6-1 - Ergon Energy's Original Regulatory Asset Base for 2005-06 to 2009-10 ($M Nominal)

	2005-06	2006-07	2007-08	2008-09	2009-10
Opening Regulatory Asset Base	4,146.17	4,648.62	5,285.04	5,792.37	6,294.07
Capital Expenditure (net of additions and disposals)	621.19	724.10	648.46	684.33	833.92
Regulatory Depreciation	-118.74	-87.67	-141.13	-182.64	-128.60
Closing Regulatory Asset Base	4,648.62	5,285.04	5,792.37	6,294.07	6,999.39

Source: Revised Submission Tables for Proposal 40.2

Chapter 40 of its June 2009 Regulatory Proposal also explains how Ergon Energy calculated its RAB as at the commencement of the each regulatory year of the next regulatory control period. Table 6-2 reproduces an overview of this calculation.

Table 6-2 - Ergon Energy's Original Regulatory Asset Base for 2010-11 to 2014-15 ($M Nominal)

	2010-11	2011-12	2012-13	2013-14	2014-15
Opening Regulatory Asset Base	6,999.39	8,041.17	9,220.93	10,410.39	11,672.77
Capital Expenditure (net of additions and disposals)	1,145.14	1,296.53	1,303.17	1,392.84	1,559.42
Regulatory Depreciation	-103.36	-116.77	-113.71	-130.46	-134.30
Forecast Closing Regulatory Asset Base	8,041.17	9,220.93	10,410.39	11,672.77	13,097.89

Source: Revised Submission Tables for Proposal 40.2

In the case of both the current and next regulatory control period, in accordance with the Rules, the RFM and the PTRM, Ergon Energy has rolled forward the RAB for Standard Control Services between regulatory years by:

- Adding the actual, projected or forecast capital expenditure, inclusive of capital contributions, to the opening RAB for each respective year, as appropriate;
- Deducting the actual, projected or forecast depreciation for each year, as appropriate;
- Deducting the actual, projected or forecast disposals for each year, as appropriate; and
- Indexing the annual closing RAB for the actual, projected or forecast inflation for each year, as appropriate.

6.2 AER's November 2009 Draft Distribution Determination

In Chapter 5 of its Draft Distribution Determination, the AER set out its preference to:

- Use March to March CPI data to roll forward the RAB; and
- Apply actual depreciation to determine the opening RAB as at 1 July 2010.

Table 5.6 of the AER's Draft Distribution Determination details its proposed opening Regulatory Asset Base for Ergon Energy as at 1 July 2010 of $7,105.4 million (nominal).

6.3 Ergon Energy's Response to AER's Draft Distribution Determination

6.3.1 Escalation rate for RAB roll forward

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Use March to March CPI data to roll forward the RAB - not currently available but will be updated at the time of the AER's final Distribution Determination [47]	- Provides most up to date CPI data at time of making final Distribution Determination [47]	- Ergon Energy sought clarification from AER in relation to the CPI factor to be applied in its Regulatory Proposal. - The AER provided CPI data to Ergon Energy in its response in October 2008. Ergon Energy incorporated this CPI data into its Regulatory Proposal. - The AER's Draft Distribution Determination now requires the application of March to March CPI data. - Ergon Energy has incorporated the CPI data as detailed in the AER's Draft Distr bution Determination into this Revised Regulatory Proposal, on the basis that an update to this data will be made prior to the AER making its Distribution Determination.

6.3.2 Application of depreciation in RAB roll forward

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Apply actual depreciation to determine opening RAB for 1/7/2010 [49-52]	- Ergon Energy has misinterpreted clause 6.12.1(18) of Rules as applying to the next regulatory control period whereas it applies to determining the opening RAB in next regulatory control period only [49]	- Ergon Energy notes that the AER has decided to apply actual depreciation for determining the RAB for the regulatory control period commencing 1 July 2015. Ergon Energy accepts this approach.
	- Use of actual depreciation provides effective incentives for Ergon Energy to seek out efficiencies wherever possible in their capital expenditure programs [50]	- Ergon Energy notes that the AER has decided to apply actual depreciation for determining the Regulatory Asset Base for the regulatory control period commencing 1 July 2015. Ergon Energy accepts this approach.

6.4 Ergon Energy's Revised Regulatory Proposal

Ergon Energy's revised calculation of its RAB as at the end of the current regulatory control period, 30 June 2010, is detailed in Table 6-3.

Table 6-3 - Ergon Energy's Revised Regulatory Asset Base for 2005-06 to 2009-10 ($M Nominal)

	2005-06	2006-07	2007-08	2008-09	2009-10
Opening Regulatory Asset Base	4,146.17	4,661.74	5,241.95	5,855.99	6,449.77
Capital Expenditure (net disposals)	621.46	719.47	653.78	736.19	856.36
Regulatory Depreciation	-105.89	-139.27	-39.74	-142.41	-132.16
Closing Regulatory Asset Base	4,661.74	5,241.95	5,855.99	6,449.77	7,173.98

Source: Revised Submission Tables for Proposal 40.2

Ergon Energy's revised calculation of its RAB as at the commencement of the each regulatory year of the next regulatory control period is detailed in Table 6-4.

Table 6-4 - Ergon Energy's Revised Regulatory Asset Base for 2010-11 to 2014-15 ($M Nominal)

	2010-11	2011-12	2012-13	2013-14	2014-15
Opening Regulatory Asset Base	7,173.98	8,237.37	9,409.04	10,620.50	11,921.01
Capital Expenditure (net disposals)	1,213.17	1,324.08	1,367.58	1,471.25	1,635.83
Regulatory Depreciation	-149.78	-152.40	-156.12	-170.75	-153.06
Forecast Closing Regulatory Asset Base	8,237.37	9,409.04	10,620.50	11,921.01	13,403.78

Source: Revised Submission Tables for Proposal 40.2

6.5 Rules' Requirements

In submitting this Revised Regulatory Proposal in relation the Regulatory Asset Base to apply to Standard Control Services, Ergon Energy has had regard for clauses 6.3.2(a)(2), 6.4, 6.4.2(b)(1), 6.4.3(a)(1), 6.4.3(b)(1), 6.5.1, 6.12.1(6), S6.1.3(7), S6.1.3(10), S6.2.11, S6.2.3 and 11.16.3 of the Rules.

6.6 Relevant Documents Provided by Ergon Energy

There are no additional documents that are relevant to this Chapter that were not provided to the AER with Ergon Energy's June 2009 Regulatory Proposal.

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7 CONSIDERATION OF NON-NETWORK ALTERNATIVES

In response the AER's Draft Distribution Determination, and its comment that Ergon Energy made limited provision for efficient non-network alternatives as part of its capital expenditure program, Ergon Energy advises that it routinely considers non-network alternatives as part of its investment assessment process. However, the short-term nature of these non-network alternatives often means that they fail to meet pay back or other key financial criteria and accordingly are not considered viable.

However, Ergon Energy supports the implementation of demand management and/or network initiatives where these are economically more prudent or efficient than network augmentation and has developed a network planning process to identify and implement demand management alternatives where they are economically efficient and prudent. Ergon Energy is in the process of assessing the feasibility of various demand management and/or non-network alternatives during the current regulatory control period across representative sections of its customer base, with the prudence or efficiency of these various trials and pilot programmes yet to be fully demonstrated. Accordingly, Ergon Energy has not made any explicit provision for non-network alternatives in developing its forecast capital expenditure for the next regulatory control period.

Ergon Energy will assess the relative merits of non-network alternatives in the course of the next regulatory control period, in accordance with its planning processes and the requirements of the Regulatory Test. Unlike other DNSPs (such as ENERGEX and SP AusNet), Ergon Energy is not currently in a position to estimate or identify the potential capital expenditure that could be deferred as a result of implementing non-network solutions. The extent to which non-network and demand management options are considered and implemented will depend on the market's ability to deliver feasible and efficient solutions and advances in technology, which may lead to a greater number and range of viable and feasible non-network and demand management opportunities arising.

7.1 Ergon Energy's June 2009 Regulatory Proposal

Sections (N)6.1, (N)6.2 and 30.2 of Ergon Energy's June 2009 Regulatory Proposal discuss Ergon Energy's processes, procedures and policies for identifying prudent and efficient non-network alternatives. In particular, these sections note that:

- The focus of Ergon Energy's current non-network alternatives program is conducting trials and pilot projects in 2008-09 and 2009-10 to develop the necessary skills and expertise before the commencement of the next regulatory control period; and
- Ergon Energy has developed a three-stage process to support the requirements of clause 5.6.5A of the Rules to apply the Regulatory Test. This process will be undertaken in conjunction with existing capital planning and investment approval processes to assess whether a suitable non-network alternative is more prudent than a network augmentation. The three stages of this process involve undertaking a screening test, a feasibility investigation and a business case.

Ergon Energy has not yet proven the concept of non-network alternatives as being able to be substituted for more traditional poles-and-wires network solutions. In addition, there is currently uncertainty about the way in which the AER will treat investment in non-network alternatives in a Distribution Determination, given that the relatively new requirements of clause 6.5.6(e)(10) and 6.5.7(e)(10) and the lack of regulatory precedent for how assets beyond the connection point will be treated. This is particularly the case given that non-network expenditure may not result in assets that can be included in the RAB under the building block approach. As a result, Ergon Energy has forecast its capital expenditure based on projects and programs that are considered necessary to meet expected peak demand on its network.

Following the 'proof of concept' and firming of the demand deferment available from the non-network alternatives, Ergon Energy intends to substitute, where appropriate, this forecast capital expenditure for non-network alternative solutions in accordance with the methodology outlined in this chapter.

7.2 AER's November 2009 Draft Distribution Determination

The AER's Draft Distribution Determination includes various statements about the way in which Ergon Energy has regard for non-network alternatives in its investment decision making.

On page 94, the AER notes that PB concluded that:

> *in current practice, Ergon Energy rarely recognises efficient non-network alternatives as potential options when considering anticipated network constraints. However, Ergon Energy is currently developing its non-network alternative capability, and has pilot projects and trials in progress. These align broadly with good electricity industry practice.*

A similar statement is made on page 512.

The AER concluded on pages 108 to 109 that:

> *On the basis of its review, and advice from PB, the AER considers that the extent to which Ergon Energy has considered and made provision for efficient non-network alternatives as part of its capex proposal is limited. However, noting Ergon Energy's approach of including proposed demand management expenditure as part of its opex proposal, the AER is generally satisfied that Ergon Energy does consider, and make provision for, efficient non-network alternatives and demand management initiatives.*

7.3 Ergon Energy's Approach to Non-Network Alternatives

Ergon Energy utilises the processes outlined in the Rules and conducts the public Regulatory Test for augmentation projects that exceed an estimated $10 million. These processes require Ergon Energy to test the market for non-network solutions, among other things, and assists in determining whether a suitable non-network alternative is more prudent than network augmentation. To date, Ergon Energy has conducted fourteen of these public Regulatory Tests for projects exceeding $10 million and this process of public consultation has not identified any viable non-network solutions. Put another way, to date the market has failed to deliver any alternatives that are more prudent and efficient than network augmentation.[61]

As a consequence of the above-mentioned failure by the market, Ergon Energy is developing its own capacity to deliver non-network solutions even though it is not clear in the Rules that the AER will allow the costs of these solutions to be included in the ARRs and thus whether Ergon Energy will have the revenue to fund these solutions as an alternative to traditional network capacity solutions. Ergon Energy has secured alternative funding in excess of $50 million in the current regulatory control period to seed these programs by the Federal and State Government funding for Solar Cities and the States Energy Conservation and Demand Management programs.

The projects and pilots outlined in section 7.3.1 are still at the "proof of concept" stage and therefore it would not be prudent or efficient to include these options in business cases at this time as they are not sufficiently developed to include in business cases at this time. Once the concepts are sufficiently developed, and accurate costs, benefits and risks are understood it is anticipated they will be added to the options included in the business cases and will stand on their individual merits. In the mean time, the lack of inclusion does not diminish the fact that such options are already being developed and evaluated.

Ergon Energy is conscious of some major investment decisions that have been made where the business cases have been criticised after the event for not containing sufficient evidence of due diligence activities having been undertaken. A recent example of this is the Victorian Advanced Metering Infrastructure (AMI) program where the Victorian Auditor General has publicly criticised the economic merits of the business case:

> *The cost-benefit study behind the AMI decision was flawed and failed to offer a comprehensive view of the economic case for the project. There are significant unexplained discrepancies between the industry's economic estimates and the studies done in Victoria and at the national level. These discrepancies suggest a high degree of uncertainty about the economic case for the project.*[62]

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[61] See http://www.ergon.com.au/Network_Info/consultations/Default.asp?yf=true&platform=PC

[62] Victorian Auditor General's Report November 2009: 2009 - 10:3, page iX

Ergon Energy wishes to ensure that it manages its investments in a prudent and efficient manner at all stages of the investment lifecycle and as outlined in its existing processes will continue to prove the concepts it is testing through its pilots and trials and once the concepts are proven, then it will be able confidently to include non-network solutions into robust business cases going forward.

7.3.1 Existing Non-Network Alternatives Pilots and Trails

In Chapter 30 of its Regulatory Proposal, Ergon Energy outlined the non-network alternative initiatives that it has planned for the next regulatory control period. These initiatives cover the following segments:

- Residential customers;
- Large commercial and industrial customers (a carry-over of customer payments from the Townsville Commercial and Industrial Network Demand Management Pilot Project);
- Rural customers; and
- Customer education activities.

Ergon Energy is reasonably advanced in a number of the trials mentioned in Chapter 30 of its Regulatory Proposal and an update on each of these initiatives is provided below.

The forecast operating expenditure explicitly excluded generation and commercial and industrial customer demand management initiatives that could be funded by substituting forecast capital expenditure following investment analysis through the Regulatory Test process. The forecast operating expenditure will be targeted at broad based initiatives where the explicit deferral of capital expenditure cannot be identified. An example of this is direct load control of swimming pool pumps and filtration equipment where the removal of approximately 1 kW of customer load may not specifically defer or avoid capital works on a particular feeder but when rolled out over many customers in an area can result in the reduction of sufficient load to defer augmentation works. Similarly, Ergon Energy has significant hot water load under control through its audio frequency load control system. This is a broad based program that has over 200 MW of load that can be reduced and over 360,000 customers experience this system every day and take advantage of the tariff benefits.

7.3.1.1 Townsville Commercial and Industrial Network Demand Management (NDM) Pilot Project

The Townsville Commercial and Industrial NDM Pilot Project has contracted 11 MVA of customer load reduction with a further 6 MVA currently under negotiation. The project is targeting 20 MVA of contracted customer load by 30 June 2010.

A number of contracted customers have completed their capital works and have now commenced the measurement and verification phase that will confirm that the load reduction has occurred. Demand reductions range:

- From a 4.5 MVA reduction at James Cook University through the installation of an off-peak district chilled water scheme to replace individual building air conditioning chillers;
- To a 340 kVA reduction from the early replacement of inefficient chillers at Jupiter’s Casino and a 240 kVA reduction from power factor correction and lighting upgrades at the Willow’s Shopping Centre.

Although all customer works are not expected to be completed until mid 2011, work has commenced on the identification of capital augmentation works that could be deferred through the application of the approaches developed in this project to date. The trial projects have identified the importance of the time required to identify and develop the non-network alternatives. Once a potential non-network alternative opportunity is identified through screening test (refer to Section 30.2 of the June 2009 Regulatory Proposal) it can take as long as 12 to 18 months to identify and confirm suitable customers and to agree terms and conditions for the network support arrangement (e.g. load reduction, power factor improvement, use of a standby generator, etc). It can then take a further 12 to 18 months for the customer works to be implemented. All of this work needs to be in place before the date commencing the network alternative in order to provide sufficient certainty that the capital works can be deferred. Based on this timeframe, it is unlikely that non-network alternatives will be utilised until 2013 using the capability and expertise being developed through this trial.

7.3.1.2 Townsville: Queensland Solar City

The Townsville: Queensland Solar City (Solar City) project is a Federal Government initiative to trial a sustainable business model for the concentrated deployment of distributed generation (solar photovoltaic) and demand management through energy efficiency, load management, smart meters and innovative tariffs. The Australian Greenhouse Office announced the Solar City project in April 2007 and on the ground activities commenced in September 2007.

At this stage, the Solar City project has conducted energy assessments with over half the households and commercial businesses on Magnetic Island, installed over 1,200 smart meters and over 200 kW of solar photovoltaic distributed generation. The project is now at a point where analysis of the data gathered can commence in order to assess the success of a number of the initiatives. A number of qualitative lessons from the Solar City project have been used in other trials that Ergon Energy is undertaking.

7.3.1.3 Townsville and Magnetic Island Residential Direct Load Control Air Conditioning Pilot Project

The first round of a trial conducted during the 2008-09 summer of direct load control of residential air conditioning at Townsville and Magnetic Island proved to be encouraging and, as a result, a second round of trials is underway. The first trial found that an average load reduction of 0.9 kW could be achieved through cycling of the air conditioning unit compressor, with no customers' reports of adverse effects or discomfort.

The second trial is being undertaken in both Townsville and Cairns with an improved customer acquisition model being tested. Further, Cairns has been added to the trial to confirm that there are no Townsville specific issues with the customer acquisition channel or customer attitudes. If satisfactory results are achieved from this second trial, Ergon Energy will develop an air conditioning load control product offering for customers. Given the expected customer take up rate for such a product, it is unlikely that significant benefits will be obtained in the 2010 to 2015 regulatory control period.

7.3.1.4 Pool Pump and Filtration Trials

Ergon Energy has commenced a trial of direct load control of swimming pool pumps and filtration equipment. Customer acquisition for the trial has commenced and results are expected towards the end of the 2009-10 financial year. The trial is being undertaken in Cairns and results to date from customer focus groups, installers and pool maintenance service providers have been positive.

The trial involves the installation of a direct load control device that addresses key barriers to the uptake of this type of offer. These barriers include hardwiring of the appliance which makes maintenance and pump replacement costly and time consuming, and the need to sanitise the pool while in use. Tenders for this device are currently being assessed and once finalised the device will be fitted to customer's pools who have volunteered to take part in the trial.

If satisfactory results are achieved from this trial, Ergon Energy will begin development of a direct load control product offering for swimming pool pumps and filtration equipment in the 2010-11 financial year. As with the product offering for air conditioners it is unlikely that sufficient benefits will be obtained in the 2010 to 2015 regulatory control period.

7.3.1.5 Cloncurry North Single Wire Earth Return (SWER) NDM Trials

In late 2008, Ergon Energy completed a number of demand management initiatives with a small number of customers on the Cloncurry North SWER as part of a trial to examine the effectiveness of demand management on SWER lines. The results for this trial were pleasing as the initiatives resulted in a 20 per cent reduction in the demand recorded on the SWER isolation transformer over the projected demand for the 2008-09 summer. This demand reduction has resulted in an expected three year deferral of the capital augmentation for this SWER system.

Ergon Energy is now working on a second phase of SWER NDM trials in which four new SWER systems have been identified as potentially benefiting from demand management initiatives. The purpose of these trials will be to establish processes for undertaking these initiatives on a business as usual basis and to test a different commercial model that involves a contribution from the customer to the costs of undertaking the works.

7.3.1.6 Other Initiatives

Embedded Generation

Ergon Energy believes that the use of megawatt scale embedded generation can be used to defer capital augmentation works and is presently working on a number of projects in this regard.

One such project will be located at the towns of St George and Charleville. Ergon Energy has planned a duplication of the 66 kV sub-transmission lines to both these centres. A feasibility investigation has determined that the use of stand-by generation would be more cost effective and a Request for Information will be issued soon to seek options from the market.

Small scale embedded generation technologies are being investigated and trialled for use in remote rural SWER network support. These programs include Load Isolating Generators and battery storage technologies with photovoltaic support like the Redflow Battery Storage and the Grid Utility Support programs. These projects specifically aim to provide peak load and loss reduction in line with strategic objectives for future SWER improvement and operation. They will also provide VAr and short term supply quality or reliability improvements not previously available from the SWER network.

Energy Savers Project

The Energy Savers Project is a household demand and energy reduction trial being conducted in Mt Isa and the Mackay northern beach suburbs. The purpose of this trial is to understand the level of demand reduction that can be achieved by targeting residential customers with selected demand and energy reduction initiatives. The offer to customers consists of:

- The refund of the $50 cost of having a ClimateSmart Home Service conducted which involves the installation of energy efficient light globes, a water efficient shower head and an energy meter;
- A free Ergon Energy Home Efficiency Check to provide energy savings advice and information of Ergon Energy and other government rebates; and
- Rebates or incentives to install a solar or heat pump hot water service, ceiling insulation or the transfer of a pool pump or hot water service to a controlled load tariff.

Another aspect of this trial is to analyse the costs/benefits of the different approaches and the customer take-up rates for the various initiatives. The trial has progressed to the half way point and work is now starting on analysing the data that has been gather to date. Funding for this trial has been provided by the Queensland Government from the 2009-10 budget.

7.3.2 The Process for Assessing the Efficiency of Non-Network Alternatives

As discussed in section 7.1 of this chapter, sections (N)6.1, (N)6.2 and 30.2 of Ergon Energy's Regulatory Proposal discuss Ergon Energy's processes, procedures and policies for identifying efficient non-network alternatives. In addition, the diagrams in Chapter 23 of the June 2009 Regulatory Proposal detailed how Ergon Energy considers demand management initiatives in its capital planning decision making processes. This section 7.3.2 further outlines the work that Ergon Energy undertakes in this area.

Recently, Ergon Energy created a new role of Group Manager Alternative Energy Solutions within its Asset Management group. A principal accountability of this role is to ensure that non-network solutions continue to be given due consideration in the asset planning process, to manage the screening process to ensure identification of candidate projects and to ensure the timely implementation of non-network alternative solutions. In addition, Ergon Energy is an active participant in Industry Committees, working groups and forums that are looking to progress the implementation of non-network alternatives.

As part of a prudent and efficient method of identifying candidate projects, Ergon Energy annually reviews its various asset plans in order to identify capital projects that have the potential to be deferred or replaced with non-network alternatives. This approach is taken due to the lead times necessary to identify, develop and implement non-network alternatives that were mentioned in Section 7.3.1.1 of this chapter. It is intended that this screening test process will be conducted annually in parallel with the development of the asset plans. Projects identified as potential candidates for non-network solutions would then be subject to a more detailed investigation.

The screening test is an initial high level assessment using indicative costs and preliminary information to identify whether a non-network alternative opportunity could economically and efficiently solve a network constraint. An example of one of the current metrics that is used for screening the potential non-network alternatives is that the cost per unit of capacity (i.e. $/MVA) should be under $500 / kVA. The derivation of this metric is detailed in Document RP912c and Document RP913c and is currently being reviewed.

If the project passes the screening test then a three stage process is used to identify if the project should proceed. Firstly, it involves the estimation of the capital costs of a network solution to delivering the capacity to meet the constraint, and the annual operating and depreciation costs of that solution. Secondly, it involves assessing whether an alternative solution is available, whether by demand side or alternative supply options, to meet the constraint reliably. Thirdly, it involves assessing whether the cost, in present value terms, for the alternative option is lower than the network solution. If the alternative solution is a lower cost option, it would be selected.

Critical criteria in comparing network and non-network solutions to meet a network constraint are the timing of the non-network alternative – specifically whether it can be delivered in time to meet the capacity need – and the certainty that the alternative solution will deliver the required load reduction. Following identification of the potential non-network alternatives, feasibility investigations will be undertaken to scope the non-network alternative in terms of its cost, timing and risks. If this process determines that the non-network alternative is the preferred option, both from a cost and reliability sense, then work will commence on finalising the development of this option through a detailed business case. This may involve issuing a Request for Information to third parties to determine if the expected solutions are available.

If the business case is approved through Ergon Energy's internal investment governance processes, the non-network alternative will defer the capital works in the relevant asset plan for the period of time that the non-network solution resolves the constraint. Over time, as Ergon Energy proves the benefits of non-network alternatives, it is anticipated that the ratio of capital to operating expenditure will change to reflect the higher level of operating expenditure due to non-network alternatives.

The feasibility investigation and the subsequent business case include a full Net Present Value (NPV) analysis incorporating both the internal business value and a Community value analysis where there are non Ergon Energy benefits. The net present value of each option is factored into the Distribution determination of the preferred option. In addition, the impact on annual earnings is monitored. This is due to non-network alternatives typically having a different earnings impact due to their higher operating cost component relative to a capital intensive network solution.

In order to demonstrate this process, Ergon Energy has provided a copy of the business case for the augmentation of the 66 kV network supplying the town of Emerald in Document RP900c. In this example, demand management options were considered to provide either a one or two year deferral of the planned capital works. A simple screening test indicates that this represents an opportunity for the implementation of a non-network alternative on the basis that the unit cost of the network alternative exceeds $500/kVA. However, on further investigation of the nature of the load in the Emerald area, and the magnitude of the load reduction required, it is clear that the non-network solution is not the most efficient solution. This is because the peak load for this area occurs during the evening indicating that the peak is driven by residential consumers. In addition, a load reduction of 15 MVA to 16 MVA is necessary to satisfy Ergon Energy's security criteria. This would require between $19.5 million and $21.5 million of expenditure on non-network alternatives to achieve the necessary load reduction at this time of day. The resulting financial analysis demonstrates that the network option is the least cost alternative. In addition, the timeframes for delivery of the non-network alternatives add further risk to Options 2 and 3 (which involve deferring works to 2013-14 and 2014-15 respectively with demand management) in the business case.

This example illustrates the approach taken by Ergon Energy in this Regulatory Proposal to forecasting capital solutions for the forthcoming regulatory control period. While Ergon Energy is undertaking a number of non-network pilots and trials, its capability and processes to undertake non-network alternatives are in the early stages of development. Ergon Energy anticipates that over the next regulatory control period, as it further develops its capability and processes, forecast capital network solutions might well be substituted with operating costs associated with viable non-network solutions. However, as outlined in this Revised Regulatory Proposal, Ergon Energy has budgeted on known solutions and capital costs as this was seen as being the prudent approach rather than making assessments on unknown costs and benefits from non-network solutions under development. Any exclusion of future capital expenditure from Ergon Energy's forecast on the basis that non-network alternatives would be able to deliver the service outcomes would undermine Ergon Energy's ability to fund these non-network alternatives as it would not have sufficient regard for the manner and extent to which Ergon Energy has considered, and made provision for, efficient non-network alternatives pursuant to the Rules.

As discussed, Ergon is actively pursuing the assessment and potential introduction of non-network alternatives, currently there are numerous trial projects underway, some with promising interim results. In managing the potential introduction of non-network alternatives, Ergon Energy will continue to address network issues in the most prudent and efficient way possible; in some cases these issues may be addressed with non-network alternatives.

7.4 Relevant Documents Provided by Ergon Energy

The following documents are relevant to this Chapter but are new since, or were not provided to the AER with, Ergon Energy's June 2009 Regulatory Proposal:

RP900c	RP900c_EE_Capex Opex Substitution_Concept Example Emerald Business Case_21Dec09.doc
RP912c	RP912c_NAS_Benchmark Cost of Supply Discussion Paper_May09.pdf
RP913c	RP913c_EE_Revision to NAS Benchmark Cost of Supply_Dec09.doc

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8 DEMAND FORECASTS

In response to the AER's Draft Distribution Determination, Ergon Energy:

- Accepts that regulatory control period forecasts should be based on both a bottom-up spatial forecast and a top-down forecast that is derived from appropriate economic and demographic variables, and asserts that Ergon Energy has taken such an approach;
- Has engaged NIEIR to revise its top-down demand forecast;
- Asserts that no substantive material has been provided in accordance with the Rules to justify not using the NIEIR methodology or forecast as the top-down aggregate demand forecast;
- Asserts that it does reconcile the bottom-up forecast to the top-down econometric forecast;
- Asserts that it does effectively manage the risks associated with the use of spot loads; and
- Asserts that it does produce a weather-corrected historical top-down demand, which is not materially different to that produced by MMA.

8.1 Chapter Overview

Ergon Energy has revised its demand forecasts from its June 2009 Regulatory Proposal using the latest data available and has used this updated forecast as the basis for this Revised Regulatory Proposal.

In order to inform debate and discussion with the AER on this matter, Ergon Energy has reviewed its overall approach towards developing its revised demand forecasts. Ergon Energy has considered and had regard to the views expressed by the AER and MMA across their nominated six drivers of change in maximum demand in Queensland, which are detailed below:

- Economic growth;
- Population, dwelling and new customer growth;
- Growth in air-conditioning penetration and usage;
- Changes in climate;
- Energy efficiency and greenhouse gas reduction measures; and
- The CPRS and other price impacts.

Ergon Energy has reviewed its forecast inputs and methodology against each driver and the forecast methodology that Ergon Energy understands MMA has followed in its review. Further, Ergon Energy has also reviewed its forecast and methodology in a number of specific areas mentioned by MMA.

Based on this work, Ergon Energy remains of the view that its forecasting approach and methodology are consistent with sound electricity industry practice and it has not identified any reasons or evidence that suggest that it should adopt the approach outlined by the AER or the MMA over the approach it outlined in its June 2009 Regulatory Proposal.

In this Chapter, Ergon Energy presents its review as follows:

- Top-down forecasts
    - o Identification of relevant demographic and economic variables;
    - o Obtaining a prudent forecasts for these variables;
    - o Modelling the top-down forecast of peak demand; and
    - o Consideration of other relevant variables.
- Bottom-up forecasts
    - o Establishing the bottom-up forecast (including the management of spot loads); and
    - o Reconciliation of top-down and bottom-up forecasts.

These points are detailed in section 8.4.

Although economic conditions have been volatile throughout 2009, Ergon Energy has conducted this review mindful of its obligation to ensure that it produces a realistic forecast based on a robust and prudent methodology. This forecast is vital to the process of developing a prudent and efficient capital expenditure program for corporation initiated augmentation in accordance with acceptable criteria and is therefore a key element of this Revised Regulatory Proposal.

8.2 Ergon Energy's June 2009 Regulatory Proposal

Chapter 21 of its June 2009 Regulatory Proposal and RIN Pro Forma 2.3.8 detailed Ergon Energy's forecast coincident peak (maximum) demand, total energy consumption and customer numbers for the period 1 July 2010 to 30 June 2015. These demand forecasts are reproduced in Table 8-1.

Table 8-1 - Ergon Energy Demand Forecasts for 2010-15

	2010-11	2011-12	2012-13	2013-14	2014-15	Average of 5 year Total
Ergon Energy Coincident peak (maximum) demand (MW) – September 2007	2,967	3,063	3,153	3,243	3,330	3,151
Ergon Energy Total energy consumption (GWh)	15,870.51	16,450.40	16,874.17	17,432.66	17,887.16	16,902.98
Ergon Energy Customer numbers	684,469	695,242	706,204	717,356	728,706	706,395

Source: AR433c AER Data_v7_data room_28May09.xls

Section 21.3 of its Regulatory Proposal explains the methodology by which Ergon Energy prepared these forecasts. Ergon Energy:

- Uses its bulk supply, zone substation and distribution feeder maximum demand forecasts to prepare its Corporation Initiated Augmentation capital expenditure forecasts for Standard Control Services;
- Uses its customer dwelling stock forecast to prepare its Customer Initiated Capital Works forecast for Standard Control Services;
- Does not use energy forecasts to prepare either its capital or operating expenditure forecasts for Standard Control Services; and
- Will subsequently use forecasts of customer National Metering Identifiers (NMIs) and energy to prepare its Pricing Proposal.

8.3 AER's November 2009 Draft Distribution Determination

The AER engaged MMA to provide assistance in reviewing the demand forecasts used by Ergon Energy, with a particular focus on maximum demand and customer number forecasts and methodologies.

The AER's Draft Distribution Determination states that:

> *MMA considered the forecasts of Ergon Energy's maximum demand are up to 7.4 per cent lower[63] than those produced if the impacts of changes in key drivers are properly taken into account and spot load assessments are carried out more reliably. MMA stated that the difference could vary between 4.0 and 7.4 per cent depending on the amount of weather correction applied to the 2008-09 maximum demand, and input assumption used.*

[63] Ergon Energy queries whether the AER means "higher" rather than "lower".

MMA concluded that the difference between the Ergon Energy forecasts and its forecasts at the end of the next regulatory control period is approximately equivalent to one to two years of maximum demand growth.[64]

The AER's Draft Distribution Determination also states that:

The AER notes that, based on the evidence provided, there appears to be no systematic reconciliation between Ergon Energy's spatial maximum demand forecasts against NIEIR's independent system forecasts based on key drivers.

The AER considers that it is not appropriate to rely on only a bottom-up approach in forecasting maximum demand, particularly in the current environment when changes in key drivers of demand are expected, for example as a result of GFC and the proposed introduction of CPRS. The AER therefore considers that Ergon Energy's bottom-up maximum demand forecasting methodology is unlikely to accurately account for the impact of changes in key drivers during the next regulatory control period.[65]

The AER then went on to state that:

The AER considers that MMA's detailed analysis of historical spot load forecasts provides some indication that Ergon Energy is over optimistic in forecasting the timing and the size of spot loads. The AER also has concerns about Ergon Energy's ability to produce accurate spatial demand forecasts without detailed records of historical load switching activities.

The AER considers that reducing Ergon Energy's forecast maximum demand to the levels shown in table 6.10 provides a more realistic basis for determining capex and opex forecasts that would comply with the NER.

Based on these points, the AER made reductions as shown in the Table 8-2 below. The average demand over the five year regulatory control period has been reduced from 3,151 MW to 2,917 MW or 7.4% over the five years.

Table 8-2 – AER conclusion on Ergon Energy maximum demand forecast (MW)[66]

	2011	2012	2013	2014	2015
50 per cent PoE maximum demand	2,693	2,811	2,928	3,031	3,121

8.4 Ergon Energy's Response to AER's Draft Distribution Determination

In this section, Ergon Energy will demonstrate the alignment of its forecasting process with the top-down elements based on the work carried out by NIEIR for Ergon Energy. Ergon Energy will comment on the other variables considered by the AER and MMA in the Draft Distribution Determination and address the issues raised in the Draft Distribution Determination around processes used in the bottom-up forecast and reconciliation to the econometric forecast used to drive Ergon Energy's medium term forecast.

At a high level, the difference between the approaches articulated by MMA and that used by Ergon Energy does not appear to be significant. In substance, the chief difference in approach appears to be that Ergon Energy has, in MMA's view, failed to adequately reconcile the bottom-up forecast with the top-down forecast produced by NIEIR. MMA appears to be concerned that, as a result of this failure, Ergon Energy has failed to take into account the effect of the key economic, demographic, air-conditioning and weather drivers on future demand.

Based on Ergon Energy's current economic forecasts and load projections using both top-down and bottom-up methodologies, Ergon Energy rejects the conclusion that it has not adequately reconciled its bottom-up forecasts with the econometric forecasts produced by NIEIR. The reconciliation process used by Ergon Energy is described below and is supported by the source material supplied to the

[64] AER, "Ergon Energy - Draft Distribution Determination", 25 November 2009, Section 6.5.1.2, page 69

[65] Ibid, section 6.6.1, page 73

[66] Ibid, section 6.6.1, page 74 and 75

AER. Further, as explained in Chapter 3, Ergon Energy considers that MMA has overstated the impact of the Global Financial Crisis.

While it appears that MMA prefers a different approach to the conversion of a demand forecast into a capital program of works and associated financial forecast, this difference of opinion does not provide a proper basis pursuant to the Rules for rejecting the approach to demand forecasting used by Ergon Energy.

The bottom-up approach is used for forecasting the capability and performance of individual assets in Ergon Energy's economic environment and electricity network that is quite different in nature to geographically smaller networks. Also, this bottom-up forecast is used as an input to the planning process and therefore into project initiation for network development and capital expenditure forecasts.

Ergon Energy clearly does have regard for economic indicators as a critical tool for reconciling its bottom-up forecasts. Having regard for the size and diversity of Ergon Energy's network, and the one to five year timing of projects, this is a prudent and efficient approach for converting the economic driven forecast into a prudent tool for developing a capital works program for Corporation Initiated Augmentation capital expenditure. Powerlink also requires, and is provided with, regional bottom-up forecasts by Ergon Energy in order to undertake the joint planning required under Chapter 5 of the Rules. MMA's review does not recognise the benefits and technical necessity of the approach used by Ergon Energy and other network service providers.

While reasonable minds can be expected to disagree on the *optimal* approach to forecasting maximum demand and the spatial tools to derive capital works forecasts, the issue for the AER under the Rules is not whether its consultant disagrees with NIEIR or Ergon Energy, but whether it or its consultant's opinion provides a credible basis for concluding that Ergon Energy's maximum demand forecasts do not produce outcomes within a range that reasonably reflects the operating and capital expenditure criteria.

Ergon Energy also believes that the balanced approach it has used is not inconsistent with an approach that would be adopted by a prudent and efficient DNSP. Further, Ergon Energy has been unable to identify any reasons or evidence supplied by the AER or MMA that provides a basis for the AER to conclude that demand forecasts produced using Ergon Energy's approach do not reasonably reflect the operating and capital expenditure criteria.

For the reasons set out in this chapter, Ergon Energy submits that its reconciled top-down/bottom-up approach produces outcomes that reasonably reflect the operating and capital expenditure criteria. Ergon Energy notes that no material is presented by the AER to demonstrate any justification for not relying on the NIEIR forecast and methodology.

Nevertheless, if in acting in accordance with the Rules, the AER remains of the view that a top-down approach should instead be used, Ergon Energy submits that, in the alternative, the proper decision under the Rules is then to use the top-down demand forecasts produced for Ergon Energy by NIEIR and provided to the AER. This is discussed further in this Chapter.

8.4.1 Top-down Forecasts

MMA states that:

> *MMA also recommends that in future, Ergon Energy adopt a top-down methodology which changes according to key economic, demographic, air-conditioning and weather drivers, as well as the bottom-up approach currently used, and reconcile the two forecasts.*[67]

This section will confirm that Ergon Energy's approach is in fact consistent with that adopted by MMA and Ergon Energy is submitting a revised forecast that meets the requirements of prudence and efficiency.

MMA also identified two methodology issues that it considered were material in relation to the assessment of the adequacy of Ergon Energy's approach. These issues related to the forecasting process adopted by Ergon Energy around weather correction and the use of spot loads in the forecasting process. This section will address these concerns raised by the AER's consultant.

[67] Ibid, page 9

8.4.1.1 Identification of relevant demographic variables

Ergon Energy, through NIEIR, and the AER, through MMA, have both attempted to identify demographic drivers for their models. The test that needs to be undertaken is an assessment of the relevance of these variables to the regional Queensland economy.

In relation to demographic drivers, both forecasters have identified some residential drivers such as population and customer number growth. MMA has based its forecast of customer growth on a series reconciled with the ABS Queensland population projections. NIEIR has derived its forecast inherently by including regional analysis within their model. While the econometric logic of the NIEIR approach is more robust for a regional Queensland forecast of customer growth, the differences in the forecast outcomes are not material.

Neither MMA nor NIEIR's forecast models have internalised demographic information on the two other material customer segments, being farming and commercial. Growth in relation to these matters is either assumed to be correlated to population growth or included in economic variables.

MMA has also included in its commentary some analysis of air-conditioning penetration rates across regional Queensland to draw a conclusion that the growth impact of air-conditioning on the summer peak will slow in the forecast period. Ergon Energy notes that the MMA analysis on this aspect did not consider whether deepening of penetration in terms of additional air-conditioners per household was complementing the increase in penetration.

As shown in Figure 8-1 and Figure 8-2 below, unsurprisingly given the relatively lower disposable incomes in regional Queensland, customers have not opted for full house ducted air-conditioning but instead have incrementally increased the proportion of their household air-conditioned to address both affordability and extreme weather conditions. As established in MMA's discussion of weather correction, there have not been extreme summer weather conditions in regional Queensland for two years, which in Ergon Energy's experience will result in a build up in latent demand.

It should be noted that the number of households in Queensland with more than one air-conditioner ('coolers') increased substantially between the 2005 and 2008. According to the Australian Bureau of Statistics (ABS) survey data referenced by MMA, the proportion of dwellings with more than one 'cooler' increased from around 20 per cent in 2005 to approximately 30 per cent in 2008. The two charts below are reproduced from the 2005 and 2008 ABS Survey Reports (catalogue no's 4602.0 and 4602.0.55.001, respectively).

Figure 8-1 - ABS Survey Report – Catalogue 4602.0 – Coolers in Dwellings 2005

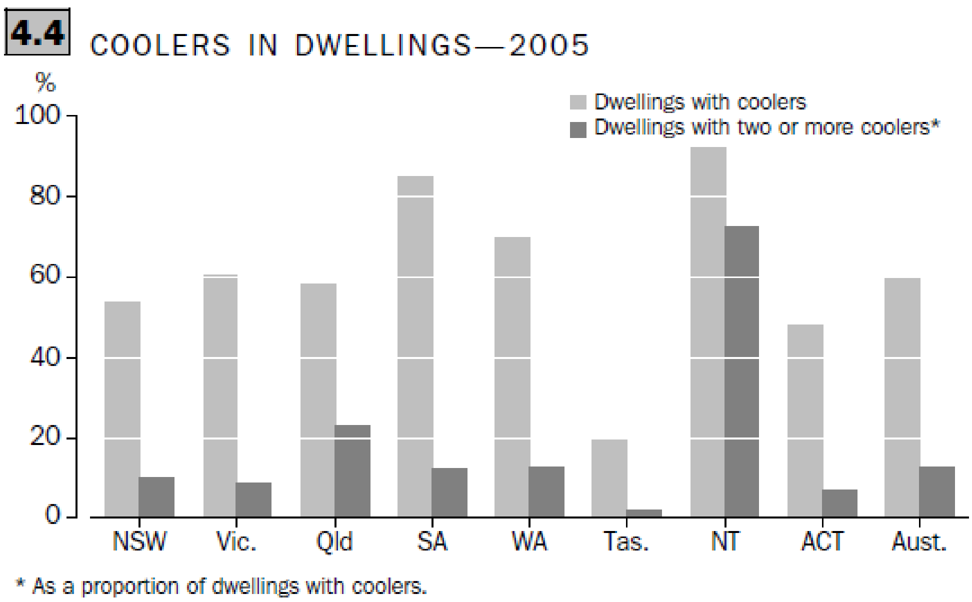
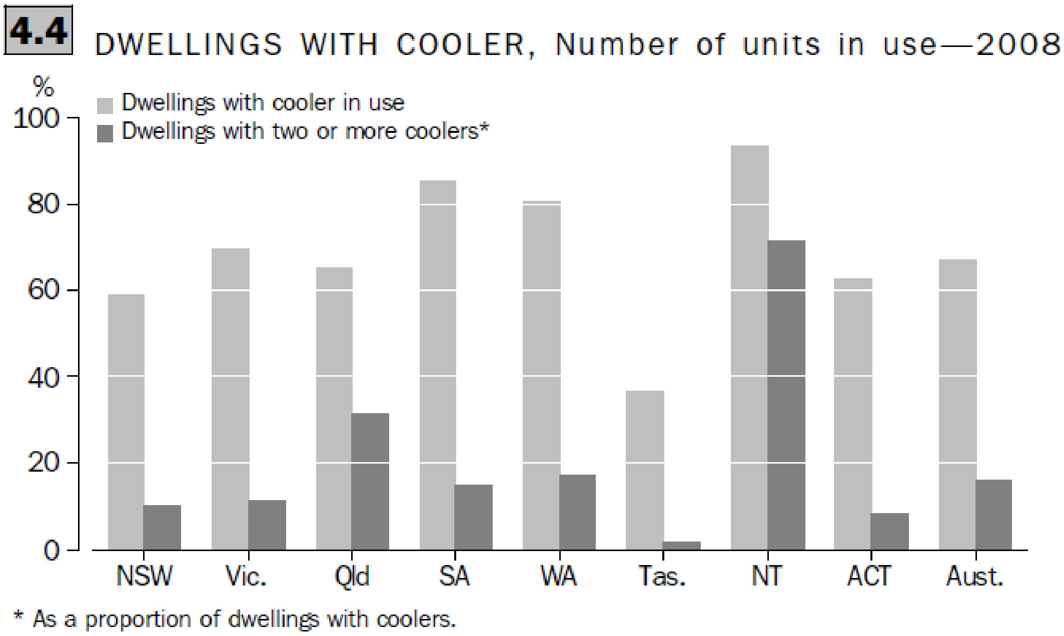


Figure 8-2: ABS Survey Report – Catalogue 4602.0.55.001 –Dwellings with Cooler 2008



The survey data suggests that there is significant scope for growth in the stock of installed air-conditioners across regional Queensland with the northern and western Queensland profile expected to move towards the Northern Territory levels. Like flat screen televisions, computers and refrigerators, in the tropics air-conditioners are no longer seen by households as a luxury good and the ownership of more than one unit per household is expected to become normal.

In summary, Ergon Energy's conclusion is that MMA has not provided any sound reasons to dismiss the NIEIR variables. In fact, Ergon Energy considers that the introduction of a flawed air-conditioning analysis will introduce a systemic downward bias on peak demand.

8.4.1.2 Identification of Relevant Economic Variables

MMA states that:

> *MMA consider that the use of only a bottom-up approach against the background of the recent economic and minerals boom is likely to result in an unrealistic outcome.* [68]

Ergon Energy considers that correctly specified models particularly around turning points in economic growth are critical to demand forecasting. In Ergon Energy's view, the critical issue in determining whether the selected independent variables are value adding to a model lies in their relevance to the regional Queensland economy, particularly in the current economic circumstances.

From the information available to Ergon Energy, the AER's consultant seems to have only relied on one economic variable – GSP. In Chapter 3, Ergon Energy has provided significant commentary on why the use of a single variable not adequately related to the regional economy is flawed.

To summarise the position outlined in Chapter 3:

- The Queensland economy is dominated by the larger south east Queensland economy, which is driven by population growth and by small to medium commercial and industrial growth, which is largely focused on drivers internal to the Queensland and Australian economy;
- Like Western Australia, some sectors of regional Queensland's economy are significantly weighted towards resources (gas, coal and metals and to some extent downstream processing)

[68] MMA's "Report to Australian Energy Regulator – Review of Ergon Energy's Maximum Demand Forecasts for the 2011 to 2015 price review", 20 October 2009, page 6

and the rural sector. Both of these sectors are predominantly exposed to export markets and have material multiplier influences into the local economy; and

- The export markets, that the regional Queensland economy is predominantly influenced by, are the developed and developing economies of Asia. The IMF has recently confirmed that the current rise in resources prices has been led globally by expectations of a stronger recovery in the Asian economies, rather than the recovery in the European and American economies.

Ergon Energy believes that a model that does not include variables that differentiate the south east Queensland dominated State product from regional Queensland product is not prudent for forecasting in regional Queensland, just as a forecaster would not consider it prudent to forecast Western Australian growth by using national GDP.

Ergon Energy has chosen NIEIR for the specific reason that its model does include sectoral forecasts that allow it to treat the different weightings of the economic sectors inherently within their model. This is further supported by the fact that the two sectors of concern are predominantly based in regional Queensland and that, while the driver of these export sectors is not based on the rest of the Queensland economy but rather on the growth of our trading partners in Asia, NIEIR has internalised this export growth into its model.

In summary, Ergon Energy considers that the economic variable selected by MMA is not prudent for forecasting the regional economy. Also, the AER has not established any material or reasonable justification for not relying on this component of the NIEIR forecast.

8.4.1.3 Obtaining Prudent Forecasts of the Independent Variables

There is significant commentary in Chapter 3 of this Revised Regulatory Proposal around the forecast, and assumptions of the depth, of the Global Financial Crisis that the AER included in its Draft Distribution Determination. Ergon Energy has included in Chapter 3 references from Queensland State Treasury, the Reserve Bank and the IMF which all raise serious questions regarding the validity and reasonableness of the AER’s assumptions.

Ergon Energy is very concerned about the consequence of MMA selecting a forecast based on the most pessimistic period of the downturn in the Australian economy in their projections for the next regulatory control period. Furthermore, it is worth noting that less than three months after receiving the Draft Distribution Determination, there is already approximately a 6 per cent difference in the GSP forecasts for 2008-09 alone.

Ergon Energy concedes that forecasting economic variables in these economic circumstances is difficult. Accordingly, Ergon Energy relies on NIEIR to maintain currency with its top-down forecast variables and engages NIEIR at least annually to update its maximum demand forecast.

Further, as an experienced forecaster, dealing with turning points in local, State and national economies over many years, Ergon Energy has established a position that reliance on a single forecast methodology is neither efficient nor prudent. This is why Ergon Energy maintains a balance between top-down and bottom-up forecasting. These forecasts are supplemented by detailed discussions on expectations with large customers on their plans for their connection points. These detailed customer discussions are very relevant to an economy that, like Western Australia, is dominated by a large resources sector.

Ergon Energy does not consider that the bottom-up approach as a forecast tool is better than the econometric approach provided by NIEIR in forecasting maximum demands. Ergon Energy, as demonstrated in section 8.4.3.1, below that it does not simply passively accept the NIEIR forecast outputs, but actively debates and discusses issues based on areas where there is potential strength in that more micro level of detail.

This approach in not unique to Ergon Energy in applied forecasting and is widely used in financial market forecasting, where value forecasters use detailed company discussions to supplement and improve their short term forecasts of corporate and sector prospects. The approach adopted by Ergon Energy appears broadly consistent with the approach adopted by a number of DNSPs across Australia. Further, Ergon Energy believes that the apparent substantial error that MMA now has in its starting point economic forecast assumption, validates the prudence of this approach.

Finally, in the discussions that Ergon Energy has had with NIEIR around its most recent forecast, Ergon Energy has questioned its assumptions underpinning the slow recovery in Queensland GSP and the low levels in the outer years of the forecast. In these discussions, Ergon Energy has satisfied itself that in the sectoral forecasts the regional Queensland forecast is adequately reflective of the resources recovery that the IMF addressed and that this growth has been reflected in the NIEIR forecast methodology through multipliers into the local regional economic growth.

In summary, Ergon Energy considers that its top-down forecast methodology is balanced and prudent and is vindicated by the substantial starting point failure of the singular approach applied by MMA. Further, Ergon Energy believes that the AER in its Draft Distribution Determination has not provided sufficient or reasonable grounds for rejecting the NIEIR economic forecasts in Ergon Energy's June 2009 Regulatory Proposal and believes that the most recent forecasts are prudent and efficient.

8.4.1.4 Modelling of the Top-down Forecast of Peak Demand

In terms of the above-mentioned aspect of the MMA forecasting approach, the comments by MMA around the weather correction of the historical system demands will be addressed first followed by commentary on the other variables that MMA identified.

Weather Correction of Historical System Demands

In terms of taking account of weather correction in relation to its forecasts, Ergon Energy supports MMA in that it considers weather correction of historical data is an important element of building a prudent demand model. Ergon Energy does conduct a weather correction process at the micro level on its zone substations and bulk supply points forecasts as a validation process for its bottom-up forecast. This is converted by coincidence factors into a State maximum demand forecast.

Following MMA's commentary on the Ergon Energy weather correction, Ergon Energy engaged Evans & Peck[69] to review its historical data and to determine an amount of weather correction and this has been compared to MMA's estimates of weather correction in Table 8-3.

Table 8-3 – Comparison of Ergon Energy, MMA and Evans & Peck Weather Corrected Historical Coincident Maximum Demands

	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09
System actual MD	2,213	2,268	2,380	2,584	2,332	2,418
Ergon Energy's 50 per cent POE MD	**2,155**	**2,256**	**2,368**	**2,484**	**2,448**	**2,558**
MMA System 50 per cent POE MD[70]	**2,127**	**2,242**	**2,357**	**2,502**	**2,422**	**N/A**
Evans & Peck Diversified Total		**2,248**	**2,360**	**2,527**	**2,417**	**2,532**

Ergon Energy notes that while there was commentary around the methodology, there is no material difference in forecast output between the MMA approach, the Evans & Peck approach and the Ergon Energy approach. Ergon Energy notes that in Table 5.1 of MMA's report, MMA has reported non-coincident weather corrected maximum demand rather than Ergon Energy's coincident weather corrected maximum demand.

MMA asserts (e.g. at Figure 4-1 on page 47 and in other sections of its report) that weather patterns are not considered in an appropriate manner by Ergon Energy as a driver or input in relation to demand forecasting. The MMA report at page 65 notes that the weather correction data for the system maximum demands used by Powerlink between 2003-04 to 2007-08 "corroborates the Ergon Energy data over this period", and then goes on to state that while there "remains some uncertainty as to the exact weather correction to apply in 2008/09" due to differences between Ergon Energy's and Powerlink's data, a correction of 177 MW was nevertheless considered appropriate. Ergon Energy has reviewed the current season and, based on partial information, accepts that it would be prudent to reduce the MMA starting point weather corrected peak by 37 MW to 2,558 MW.

[69] Evans & Peck's report will be provided to the AER when it is received.

[70] MMA's "Report to Australian Energy Regulator – Review of Ergon Energy's Maximum Demand Forecasts for the 2011 to 2015 price review", 20 October 2009, page 66, Table 5.1

Ergon Energy considers that the approach it described in relation to this aspect in Table 42 of the June 2009 Regulatory Proposal remains sound and appropriate given the diversity of weather patterns and micro-climates experienced across its regional network and not materially different to the alternative macro methodologies.

Issues regarding other variables considered by MMA

The second input to assessing the translation of the economic model to a top-down peak load forecast is to consider MMA's commentary around variables that it considered may be of some impact on final demand. However, Ergon Energy could not see evidence that MMA had directly linked these to its model. The two most significant of these are the impacts of price movements for electricity and any CPRS.

While Ergon Energy and other businesses across Australia continue to seek certainty on the terms and methodology to be applied in any future CPRS arrangements, Ergon Energy notes that on pages 73 and 74 of NIEIR's report [Document RP970c] that NIEIR has in fact attempted to include impacts of this yet to be finalised scheme as an inherent input to its model.

In relation to the impacts of electricity pricing, Ergon Energy notes that there is a correlation between price and demand but that the electricity commodity particularly at peak conditions when human comfort indices are at strained levels, has normally been modelled as relatively inelastic. Therefore Ergon Energy would expect this correlation to be stronger for energy than for demand. Ergon Energy also notes that on page 73 of NIEIR's report [Document RP970c] that has included price as an inherent component of its forecast model.

Finally, Ergon Energy notes that while the main other variables that MMA identified for their modelling are in fact included in the NIEIR model, there was a potential systemic downward bias in the options that MMA looked at.

Ergon Energy also considers that there are other potential variables that could tend to increase the electrical intensity of system peak to regional product, such as the trend towards a stronger system summer peak relative to other seasons, transfer of loads between the transmission and distribution systems and new electrically intensive loads. Ergon Energy's preference has been to work with NIEIR to ensure the robustness of the explanatory power of the inherent variables in their model and to minimise reliance on issues that cannot be prudently incorporated effectively into the model.

In summary:

- The comments by the AER and MMA on Ergon Energy's weather-coincident maximum demand appear to reflect a difference in methodology rather than substance, in terms of outcomes. This has been confirmed by an independent assessment by Evans & Peck;
- Ergon Energy, in reviewing its loads data for this summer, believes that it would be prudent to reduce the MMA starting point 2008-09 estimate of coincident maximum demand by 37 MW; and
- MMA does not appear to have properly recognised and acknowledged that the additional other variables of price impacts and CPRS that it considered worth adjusting the Ergon Energy forecast for, were actually included as inherent variables in the NIEIR forecast.

Ergon Energy does not consider that MMA has established any material issues with the NIEIR model's econometrics nor have they established any material gaps that have not been included in that modelling.

8.4.2 Which Top-down Model should be Used?

In its Draft Distribution Determination, the AER stated (at page 74):

> *The AER considers that in the absence of a system maximum demand model, it is reasonable to address Ergon Energy's methodological deficiencies at the spatial level using a top-down approach*.

Ergon Energy believes that it has complied with all the basic elements of conventional forecast methodology and that each element has been developed in a sound and prudent manner. Furthermore, Ergon Energy believes that the AER and MMA have not provided a sufficient or material basis to substitute an alternative forecast of either economic, demographic or load forecasts.

For the reasons set out later in this Chapter, Ergon Energy submits that its balanced top-down and bottom-up forecasting approach produces outcomes that reasonably reflect the operating and capital expenditure criteria, and that the bottom up forecast is reconciled to a valid top-down forecast.

Ergon Energy notes that pursuant to the Rules it will not have a further opportunity prior to the release of the final Distribution Determination to submit a further demand forecast to the AER for its consideration. Based on the Draft Determination, Ergon Energy notes that it is possible that the AER may not accept the approach outlined above by Ergon Energy or the forecast contained in Table 8-7 of this Revised Regulatory Proposal.

Given the above, if the AER, acting properly in accordance with the Rules does not approve the forecast maximum demand set out Table 8-7, Ergon Energy submits, in the alternative, that the proper approach under the Rules is to instead substitute the following maximum demand forecast, based on the top-down forecast produced for Ergon Energy by NIEIR and provided to the AER with this revised regulatory proposal.

At page 100 of its Draft Distribution Determination, the AER states that the estimate of maximum demand substituted by the AER:

> *is the minimum adjustment necessary for demand forecasts to comply with the NER*.

If the AER remains of the view that a top-down approach to demand forecasts should be preferred to the combined and reconciled top-down/bottom-up approach used by Ergon Energy, then in adjusting Ergon Energy's forecasts to the minimum extent necessary would suggest the AER should instead use the top-down demand forecast prepared for Ergon Energy by NIEIR in 2009 in Table 8.4 [Document AR970c].

Table 8-4 – NIEIR December 2009 Maximum Demand Forecast

December 2009 Forecasts	2010-11	2011-12	2012-13	2013-14	2014-15	Average of 5 Year Total
Co-incident maximum demand	2,799	3,052	3,181	3,282	3,365	3,136

8.4.3 Bottom-up Forecasts

In this section, Ergon Energy will address two issues that the AER in its Draft Distribution Determination considered material. They are the need to undertake a robust reconciliation between the bottom-up spatial forecast and the top-down econometric based forecast and the use of spot loads as a component of that forecast process.

8.4.3.1 Reconciliation between Top-Down and Bottom-Up Forecasts

As stated by Ergon Energy in its June 2009 Regulatory Proposal, the demand forecast used to develop the capital expenditure forecast was the 2007 spatial (bottom-up) demand forecast. This demand forecast was reconciled with the 2007 top-down forecast prepared by NIEIR and no significant discrepancies were encountered.

Ergon Energy has now also reconciled the December 2009 NIEIR system demand forecast (Document RP908c) with its most recent bottom-up demand forecast, and apart from the need to adjust the timing of some spot loads in the early years, the bottom-up forecasts are materially compatible.

MMA has stated that:

> *We understand that the forecasts are checked (at an aggregated and diversified level) against those of NIEIR (which are econometrically derived) and the in-house strategic forecasts. However, Ergon Energy has stressed that this is a check only at a very gross level. This review appears to capture changes in significant block loads. However, it is not clear how this review translates to the ZSS level trends. As a result, any prospective changes to key drivers are not taken into account in forecasting.* [71]

[71] Ibid, section 4.1, page 46

Ergon Energy has now provided to the AER examples of correspondence between Ergon Energy and NIEIR. These are provided in Document RP894c showing that a number of discrepancies have been identified and resolved with NIEIR.

In addition, the spreadsheet in Document RP909c shows the result of this with all current and past forecasts shown both graphically and in supporting worksheets.

The purpose of Ergon Energy's reconciliation with the independently developed NIEIR forecast is to ensure that the Ergon Energy system level forecast and connection point forecasts are aligned with a forecast based on econometric and demographic forecasts and therefore, properly take account of changes in key drivers.

This complements the Ergon Energy bottom-up forecast, which is based on internally derived demand and customer information and a reliable process for assessing spot loads.

Ergon Energy has an established annual process which examines the above issues systematically both at the Transmission Connection Point (TCP) and distribution system level. The forecasts are compared to ensure that the forecasts are aligned or to highlight any significant differences. An example of this reconciliation is in Document PL570c, which was provided to MMA during its examination of Ergon Energy's demand forecast. This documents the considerable effort undertaken in comparing the top-down and bottom-up forecasting approaches. Graphs are provided to summarise the reconciliation of all TCP, regional and the system forecasts.

If there are discrepancies between the forecasts then these are re-examined by Ergon Energy to ensure differences are understood, acknowledged and corrected if necessary. This process is undertaken with NIEIR in order that both NIEIR and Ergon Energy understand any differences in the two forecasts.

The reconciliation is performed in Stage 13 of the forecasting process as described in Ergon Energy's June 2009 Regulatory Proposal[72]:

> *In Stage 13, Network Forecasting & Development compares Draft 1 of Ergon Energy's annual coincident maximum demand forecasts with the forecasts produced by NIEIR in order to understand and reconcile any significant differences in outputs that have been produced between the two modelling approaches. The reconciliation is made against NIEIR's MW forecast under a base economic scenario at 50 per cent POE. Appendix G of NIEIR's September 2008 "Maximum demand forecasts for Ergon Energy connection points to 2018" compares NIEIR's and Network Forecasting & Development's approach to preparing their maximum demand forecasts.*

The mechanism by which this reconciliation is achieved is:

- Ergon Energy produces its initial forecasts at zone substations and bulk supply points;
- Coincidence factors and diversity factors are developed based on actual system demands to derive forecasts at the regional and system wide level. It should be noted that additional diversity in regional peak demands can, and has, resulted in lower overall growth at the system level. Lower growth at the system level for this reason has no impact at all on the required distribution network augmentation program or capital works forecasts;
- NIEIR produces an independent econometric forecast based on world, Australian, Queensland and most importantly regional economic and demographic indicators and provides its forecast to Ergon Energy; and
- Areas of significant difference between the two forecasts are identified by use of the Ergon Energy-generated spreadsheet (e.g. Document PL570c). One graph from this spreadsheet, depicting one of the 104 supply point forecasts which are compared, was published in Ergon Energy's June 2009 Regulatory Proposal as an example. This spreadsheet is used to plot the Ergon Energy forecasts and the NIEIR forecasts. Differences between the two can be clearly identified. Where the differences are significant, an investigation is undertaken into the reasons for the differences. Typical significant differences are those which affect networks security as defined in the Network Management Plan [Document AR402 and Document AR445], timing of capital works, or major load changes (typically > 5MVA);

[72] Ergon Energy's Regulatory Proposal, page 170.

- NIEIR prepares a table of comparisons of growth rates at substations in its reports. These are set out in NIEIR's annual reports, viz:
  - Page 342 (of 345) in Appendix H of "Maximum demand forecasts for Ergon Energy connection points to 2017", November 2007 [Document AR065c]; and
  - Page 272 (of 275) in Appendix G "Maximum demand forecasts for Ergon Energy connection points to 2018", September 2008 [Document AR128c].
- Ergon Energy utilises these tables from the NIEIR reports to highlight potential differences in forecasting outcomes and then concentrates on the absolute MW differences in the forecast in areas where differences have been observed; and
- Any significant differences that have been identified are discussed between NIEIR and Ergon Energy to determine what may be the cause of the difference and whether adjustments need to be made to the forecast by either NIEIR or Ergon Energy. Comments are made within the workbook, telephone conversations take place and emails summarising the conversations are exchanged for forecasts which vary significantly. As NIEIR has a top-down approach, the differences between the forecasts appear on the lower level Bulk Supply Point forecasts. Any identified discrepancies with the NIEIR forecast are expected to be rectified for the following year's forecasts.

  For example, in the most recent December 2009 forecast [Document RP970c], NIEIR has predicted higher loads in the Surat Basin area than what Ergon Energy has forecast. Ergon Energy's forecast is based on very recent joint planning discussions with Powerlink about where these loads are likely to connect – i.e. into the transmission network or alternatively into the distribution network. NIEIR forecasts are higher because it has not accounted for the expected connection points at this point in time and has allocated most of the loads to the distribution network. NIEIR will make appropriate connection point adjustments in their model for the following year's forecast.

In summary, Ergon Energy has demonstrated:

- An active and prudent process between NIEIR and Ergon Energy that enables reconciling loads at a spatial level;
- An appropriate level of reconciliation between the aggregate bottom-up and top-down forecasts prepared for this Revised Regulatory Proposal (see Table 8-5); and
- Apart from the first year where NIEIR's most recent forecast partially supports one of the assumptions that MMA drew about a delay in the regional economies return to growth, the 2007 forecast used for the detailed calculation of capital works is also appropriately reconciled to the current NIEIR load forecast. Further supporting information on the timing of capital works subject to the year one delay is provided in Chapter 10.

8.4.3.2 Spot Loads

MMA formed the view, which the AER accepted, that Ergon Energy's bottom-up forecast was "over optimistic in forecasting the timing and the size of spot loads"[73]. The AER stated that it "also has concerns about Ergon Energy's ability to produce accurate spatial demand forecasts without detailed records of historical load switching activities"[74].

As stated earlier in this chapter, Ergon Energy believes that the use of detailed customer conversations to assist it to manage major new loads, particularly on radial networks that have small base customer load, is a valuable component of the forecast methodology, which supports the attributes of Ergon Energy's network and customer mix.

Ergon Energy has considered the comments from the AER and confirms that Ergon Energy is aware of, and effectively mitigates, the two potential risks from the use of customer insight driven spot loads. The first risk the AER comments on is the potential for overstating the short-term component of the

[73] AER's Draft Distribution Determination Section 6.6.1, page 74

[74] Ibid.

forecast with the second and usually the more material risk being the underforecasting of these loads in the medium to long term.

Ergon Energy adopts the forecast approach described in this section because it has proven to be an important tool to strengthen the robustness of starting point forecast through the reconciliation process and discussions between NIEIR and Ergon Energy. With a large portion of its load exposed to export markets rather than the traditional drivers on internal State and gross national product growth, Ergon Energy, through its relationship with NIEIR, has developed a prudent and robust two dimensional approach to testing and confirming the starting point forecasts for the regulatory control period.

Double-Counting Spot Loads

Future spot loads are identified by the Ergon Energy customer connection process from information provided directly by existing or future customers communicating with Ergon Energy's Major Customer Connection Managers. Spot loads are then tracked within the Ergon Energy's forecasting section. The process used to collect and collate information from customers is provided in Document RP895c and Document RP896c. Evidence is also provided of the interaction between the Major Customer Connection Managers and the forecasting team to ensure the forecast accurately reflects customers' intentions. It should be noted that the documented process shows that the forecasters are diligent in ensuring that loads are not double-counted. The forecasting process itself removes the block loads from any trending associated with the organic growth of load at a substation and then adds the block loads after this trending is performed.

Future spot loads are included in the spatial bottom-up forecast after existing load trends have been added. Past spot loads are excluded from the trending process. This process is encompassed in the spreadsheets that are used for forecasting – the block loads and their probabilities of connection are separated from the main trending analysis and added back into the total load of a substation on a separate line.

MMA stated that[75]:

> *MMA has not been able to accurately quantify the impacts of these across all the ZSS but provides an indicative assessment of 2.6% based on double-counting alone. In addition MMA considers it reasonable to assume that many spot loads will be delayed by at least a year.*

Ergon Energy maintains its view that its manual process to manage spot loads in the forecast is reliable, and that there are processes in place to identify and manage any risks of double-counting. Ergon Energy considers that it is unreasonable to conclude based on MMA's approach that Ergon Energy's current process produces double-counting that overstates growth by 2.6 per cent.

MMA measured the extent of possible double-counting of block loads in Ergon Energy's zone substation forecasts by applying a 5 per cent minimum threshold to block loads for a sample of eight zone substations in the Ergon Energy network[76]. The analysis showed that by applying a minimum threshold of 5 per cent of the load on each individual zone substation, there was an unweighted average percentage reduction of 2.6 per cent in the forecasts in 2015. MMA also noted that the distribution of changes was quite uneven, with five of the zone substations having unchanged forecasts and two having a reduction exceeding 10 per cent.

MMA has taken a very small sample of zone substations to analyse this issue, and consequently very little statistical weight can be attributed to their estimate that the (unweighted) average reduction in forecasts was 2.6 per cent in 2015. Using the MMA process, a sample of eight zone substations was chosen for analysis from a population of 359. Three substations show a load reduction and five show no change in load based on the application of a spot load threshold. MMA themselves state that this test was "not intended to be a statistical analysis"[77].

Ergon Energy considers that it has demonstrated its process to manage spot loads in the forecast is reliable and prudent. Ergon Energy also considers that not only is there no material historical basis

[75] MMA's "Report to Australian Energy Regulator – Review of Ergon Energy's Maximum Demand Forecasts for the 2011 to 2015 price review", 20 October 2009, page 63, section 4.5.2

[76] Ibid, page 51, section 4.3.2

[77] Ibid, page 51, footnote

across the whole forecast for the conclusions drawn by MMA but that the reconciliation process against the aggregate demand ensures that any residual bias if it existed would be dealt with.

Timing of Spot Loads

MMA states that[78]:

> *In addition, many spot loads are likely to be delayed by at least a year.*

As set out in section 8.4.1.3 above, MMA has based its spot load conclusions on its starting point economic forecast assumption that now seems at least partially flawed. The MMA analysis is based on a small sample of the overall forecast, and MMA do not provide a sufficiently detailed analysis that is statistically relevant to support the statement and/or any other factual information to support its analysis.

The information from customers relied upon by Ergon Energy is based on what they communicate to Ergon Energy's Major Customer Connection Managers – no major augmentation is implemented until customers provide guarantees of connection either through a signed connection contract or a bank guarantee for the cost of augmentation (or both). Ergon Energy believes that it would be exposed to a high risk should it significantly change or ignore what customers communicate to Ergon Energy about their requirements.

MMA also has not accounted for the fact that customers approach Ergon Energy seeking connection in a short time frame without providing information about their needs well in advance. The probabilistic approach to the block loads will allow for a small number of these "unknown" customers to obtain a network connection should the connection of other loads be deferred.

MMA appears to have sought to justify its spot load calculations on the basis of an unsupported assumption that "many spot loads are likely to be delayed by at least a year". As set out in section 8.4.3.2 above, Ergon Energy has been informed by customers of only two project delays and only for a relatively short period of some six months.

New loads are being identified continually, in particular large mining related loads in the Surat and Bowen basin. Since the start of the Regulatory Proposal process, information about the nature and timing of these loads has been gained from customers and from Powerlink.

While some of the largest loads will be supplied by connection to Powerlink, a number of new customers inquiries have been received from customers in the Surat Basin and these have not appeared in the current forecast year.

Ergon Energy has processes to monitor future spot loads, both with customers directly and with Powerlink through the joint planning process. Ergon Energy is therefore in a very solid position to make valid decisions about the timing of future spot loads and maintains that there is no significant skewing of the forecast due to the timing of spot loads.

[78] Ibid, page 7, Executive Summary

8.4.4 Summary of Ergon Energy's Response to the AER

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
Reject Ergon Energy maximum demand forecast as not reflecting realistic expectation of demand and accept forecast by MMA [74, 81, 99-100]	Ergon Energy does not systematically reconcile its bottom-up forecasts to NIEIR forecasts and does not document the differences between the two forecasts [64, 73, 98]. Not appropriate for Ergon Energy to rely only on bottom-up forecasts [73]	- Ergon Energy accepts that it should not rely primarily on its bottom-up forecast. - NIEIR has followed prudent forecasting practices to develop an appropriate top-down forecast. - The AER has not provided any material or reasonable justification for not adopting the NIEIR forecast. - Ergon Energy believes the MMA model and independent variable forecasts are flawed. - Ergon Energy has completed an appropriate reconciliation of NIEIR's top-down and Ergon Energy bottom-up forecasts. - Refer to sections 8.4.1 to 8.4.3.
	Ergon Energy has overstated the size and timing of large spot loads, and may double count spot loads [67, 74, 98]	- MMA based this assumption on a significant decline in 2008-09 GSP. This has proven, through recent revised official GSP forecast, to be a flaw in the MMA forecast and not in Ergon Energy's spot load process. - Ergon Energy believes from its experience that detailed discussions with its large customers is a strength when applied appropriately to top-down forecasting and that recent events have confirmed this position. - Refer to sections 8.4.1 to 8.4.3.
	Ergon Energy's spatial demand forecast methodology is flawed and l kely to produce over optimistic forecasts by not appropriately taking into account key drivers, including the Global Financial Crisis and CPRS [68, 73, 98]	- Ergon Energy accepts that it should not rely primarily on a bottom-up forecast. - NIEIR has followed prudent forecasting practice to develop an appropriate top-down forecast. For example, on page 73 of RP970c, NIEIR has confirmed that both price and CPRS were considered inherently within its model. - The AER has not provided any material or reasonable justification for not adopting the NIEIR forecast. - Ergon Energy believes the MMA model and independent variable forecasts are flawed. - Ergon Energy has completed an appropriate reconciliation of NIEIR's top-down and Ergon Energy bottom-up forecasts. - Refer to sections 8.4.1 to 8.4.3.
	The AER accepts MMA's weather normalised 50 per cent maximum demand forecasts for Ergon Energy being 4.0 to 7.4 per cent lower than Ergon Energy's forecasts. This is equivalent to one to two years of maximum demand growth [69, 74, 98]	- MMA has a 6 per cent error in its starting point GSP forecast. - Ergon Energy believes the MMA model and independent variable forecasts are flawed. - NIEIR has followed prudent forecasting practice to develop an appropriate top-down forecast. - The AER has not provided any material or reasonable justification for not adopting the NIEIR forecast. - Refer to sections 8.4.1 to 8.4.3.
	Ergon Energy's maximum demand forecasts are not realistic [68, 74]	- Ergon Energy accepts that it should not rely primarily on its bottom-up forecast. - NIEIR has followed prudent forecasting practice to develop an appropriate top-down forecast. - The AER has not provided any material or reasonable justification for not adopting the NIEIR forecast. - Refer to sections 8.4.1 to 8.4.3.

8.4.5 Ergon Energy's Revised Regulatory Proposal Maximum Demand Forecast

8.4.5.1 Load Forecast

As shown in Table 8-5, Ergon Energy has updated its 2009 maximum demand forecast using a robust methodology, using current economic forecasts and providing the basic input to Ergon Energy's assessment of the future growth on its distribution network.

Based on its reconciliation process with NIEIR's top-down forecast, and in consideration of its detailed large customer discussions, Ergon Energy has made minor adjustments to the starting point year (2009-10) and the first year of the next regulatory control period (2010-11). Ergon Energy does not consider that this demonstrates any systemic short-term over forecasting as suggested by MMA, nor that the changes are material to the regulatory control period forecast.

Ergon Energy's Revised Regulatory Proposal bases its capital expenditure forecasts on the 2007 bottom-up maximum demand forecast. Apart from the first year of the regulatory control period forecast, the differences between each year's forecasts are not material, being 1 per cent or less. The differences in the first year and the impacts on capital expenditure forecasts are explained in Chapter 10.

Ergon Energy notes the MMA forecast. It believes the MMA model and independent variable forecasts are flawed. Ergon Energy considers the AER has not provided any material or reasonable justification for not adopting the NIEIR forecast.

Table 8-5 - 50 per cent POE Maximum Demand Forecast Comparisons (MW) - Ergon Energy 2007 and 2009 Forecasts

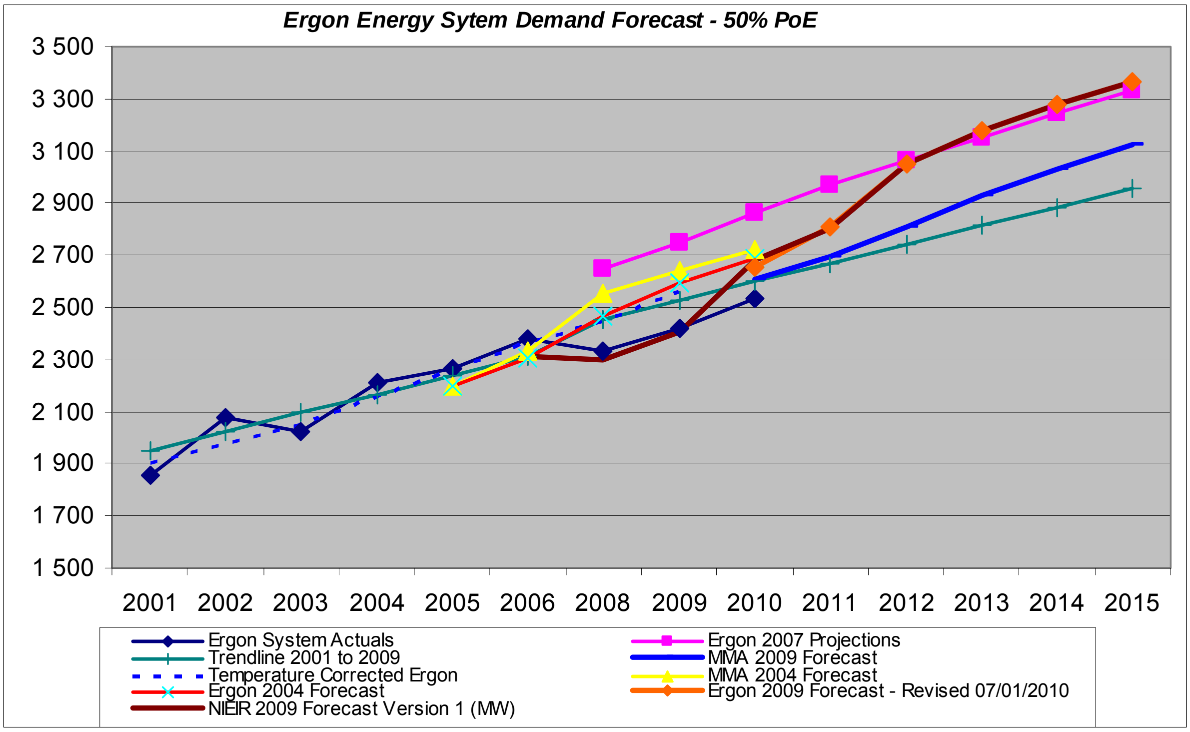
	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
NIEIR 2009 Forecast	**2,681**	**2,799**	**3,052**	**3,181**	**3,282**	**3,365**
Ergon Energy 2009 Forecast (Updated 7 January 2010)	**2,654**	**2,807**	**3,052**	**3,181**	**3,282**	**3,365**
Ergon Energy 2007 Forecast – June 2009 Regulatory Proposal Table 40 page 160		2,967	3,063	3,153	3,243	3,330
MMA 2009 Forecast	2,607	2,693	2,811	2,928	3,031	3,121
NIEIR 2009 Forecast MW Growth	4.9%	4.4%	9.1%	4.2%	3.2%	2.5%
Ergon Energy 2009 Forecast MW Growth	3.9%	5.8%	8.7%	4.2%	3.2%	2.5%
MMA 2009 Forecast MW Growth	2.0%	3.3%	4.4%	4.2%	3.5%	3.0%
NIEIR GSP Growth	1.8%	2.3%	6.1%	4.8%	2.1%	1.8%
MMA GSP Growth	1.4%	3.0%	4.5%	4.2%	3.4%	2.7%

Source: Coincident peak (maximum demand) – Ergon Energy's Network Planning 2007 and 2009 forecasts (refer also NIEIR November 2007 [Document AR065c] and December 2009 [Document RP908c])

In Table 8-5, the Ergon Energy forecast has been reconciled with the NIEIR forecast at the system level. Hence, the NIEIR forecast can be compared with the MMA forecast directly. NIEIR has used its own GSP figures, which are also included in the table.

Figure 8-3 illustrates these forecasts graphically. It shows modest GSP and load growth in 2008-09, 2009-10 and 2010-11 and increased growth in 2011-12 followed by a lesser growth rate in subsequent years.

Figure 8-3 Demand Forecast Comparison



In particular the following points should be noted:

- The process detailed in Document RP895c has been followed to confirm that the timing and probability of large customer connections are in line with information communicated by customers to the Major Customer Connection Managers and to ensure that there is no double-counting of block loads in the forecasting process;
- Ergon Energy has conducted Joint Planning with Powerlink to review the connection point forecasts and to discuss the likely connection points for large gas compression and mining loads being developed at present in the Surat Basin over an area from the east of Kogan to Wandoan as well as the development of other significant loads in the Bowen Basin;
- Ergon Energy received NIEIR's most recent econometric forecast in December 2009 [Document RP970c]. The Ergon Energy forecast was reconciled with the NIEIR forecast using the process described in section 8.4.3.1. The NIEIR forecast has predicted a strong recovery from the Global Financial Crisis. This aligns with information provided by customers to Ergon Energy's Major Customer Connection Managers;
- Recent peak demands during November and December 2009 have been 5.4 per cent and 4.8 per cent higher respectively than the demands from 2008 (the previous records for those months) for similar temperature conditions. This data provides a useful indicator of the amount of increase in demand that has been experienced during the year. The underlying zone substation and connection point forecasts continue to show load growth in line with the measured results and this growth is driving the distribution network capital expenditure augmentation work program; and
- The top-down aggregated average system-wide maximum demand forecast has reduced from the previous year as a result of recalculation of coincidence, and diversity factors from the previous two years where the weather, in particular temperature, patterns have provided much more diversity, and hence lower coincidence, in the timing of the peak loads across individual network segments throughout the Ergon Energy supply area. As discussed in section 8.4.1.4, this diversity in load patterns does not result in any requirement to reduce Corporation Initiated Augmentation capital expenditure within the sections of the network where the peak is being experienced.

The AER should therefore accept Ergon Energy's 2009 forecast as the demand forecast for Ergon Energy for the next regulatory control period.

8.4.5.2 Comparison with 2007 forecast

Ergon Energy's capital expenditure forecast in its June 2009 Regulatory Proposal was prepared on the basis of the September 2007 Ergon Energy Maximum Demand forecasts at the regional level (i.e. not the top down aggregated average system-wide maximum demand as depicted in Figure 8-3).

Ergon Energy's '2009 forecast' is not materially different from the '2007 forecast' and hence the only impact on the Ergon Energy capital works program may be one of timing.

In addition, the aggregated average top-down system-wide maximum demand forecast is not used to prepare the capital expenditure forecasts.

Ergon Energy reiterates the factual reasoning set out in this Chapter 8 that it is the spatial regional (bottom-up) forecasts that dictate the capital expenditure augmentation program of capital works that is required. Ergon Energy does not believe that it is prudent to depart from the program of capital works that it proposed in its June 2009 Regulatory Proposal. This is discussed in more detail in Chapter 10.

8.4.6 Energy Consumption Forecast

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Ergon Energy must review its energy consumption forecasts before submitting its Pricing Proposal [79]	- Ergon Energy's forecast is too high given current economic environment [79]	- MMA has a 6 per cent error in its starting point GSP forecast. - Ergon Energy believes the MMA model and independent variable forecasts are flawed. - As set out in section 21.3.4.2 of Ergon Energy's Regulatory Proposal, energy forecasts are determined for one year only and are only used for pricing purposes (not for preparing expenditure forecasts). - The forecast provided in Table 39 of Ergon Energy's June 2009 Regulatory Proposal was based on its energy forecast for 2009-10 which was used to prepare Ergon Energy's 2009-10 pricing submission to the QCA. - The QCA approved Ergon Energy's 2009-10 pricing submission which was based on this energy forecast. - As stated above, Ergon Energy prepares its energy forecasts on an annual basis. This is done in two phases as explained in Ergon Energy's response to the AER modelling request for street lighting services [Document RP898c]. - Ergon Energy's current, revised energy forecasts, which are based on Phase 2 of its forecasts for the 2010-11 Pricing Proposal, are set out in Table 8-6 below. - Ergon Energy will refine its forecasts in Phase 2 of its process in February/March 2010 so that the most current information is incorporated. The resulting forecast will be used in the preparation of Ergon Energy's 2010-11 Pricing Proposal. - In any event, as set out in Chapter 3, the effect of the economy in Queensland is not expected to have a material impact on either of customer numbers nor energy.

As discussed in sections 21.3.3.2 and 21.3.4 of Ergon Energy's Regulatory Proposal, Ergon Energy annually prepares a one year forecast of customer numbers and energy consumption for preparation of its Pricing Proposal. These forecasts are prepared in two phases, as discussed in Ergon Energy's response to the AER modelling request for street lighting services [Document RP898c]. The first phase is prepared in November/December of each year. This is an initial forecast. Phase two is conducted in February/March of each year to refine the forecasts based on the most up to date information available prior to preparation of the annual Pricing Proposal.

Ergon Energy has completed Phase One of its forecasts for the 2010-11 Pricing Proposal and these are set out in the table below. Phase Two will be completed in February/March 2010 and these final forecasts will be used to prepare Ergon Energy's Pricing Proposal.

Table 8-6 - Ergon Energy and Customer Numbers Forecast, as at December 2009

December 2009	2010-11	2011-12	2012-13	2013-14	2014-15
Ergon Energy Total energy consumption (GWh)	15,870.51	16,450.40	16,874.17	17,432.66	17,887.16
Ergon Energy Customer numbers	684,469	695,242	706,204	717,356	728,706

8.5 Ergon Energy's Revised Regulatory Proposal

Having regard for the demand forecast basis set out in section 8.4, Ergon Energy's Revised Regulatory Proposal forecasts are as set out in Table 8-7.

Table 8-7 - Ergon Energy Maximum Demand, Energy and Customer Numbers Forecast, as at December 2009

December 2009 Forecasts	2010-11	2011-12	2012-13	2013-14	2014-15	Average of 5 Year Total
Ergon Energy Coincident peak (maximum) demand – December 2009 (MW)	2,807	3,052	3,181	3,282	3,365	3,137
Ergon Energy Total energy consumption (GWh)	15,870.51	16,450.40	16,874.17	17,432.66	17,887.16	n/a
Ergon Energy Customer numbers	684,469	695,242	706,204	717,356	728,706	n/a

Ergon Energy notes that pursuant to the Rules, it will not have a further opportunity prior to the release of the final Distribution Determination to submit a further demand forecast to the AER for its consideration. Based on the Draft Distribution Determination, Ergon Energy notes that it is possible that the AER may not accept the approach outlined above by Ergon Energy or the forecast contained in Table 8-7.

Given the above, if the AER, acting properly in accordance with the Rules, does not approve the forecast maximum demand set out above, Ergon Energy submits, in the alternative, that the proper approach under the Rules is to instead substitute the following maximum demand forecast, based on the top-down forecast produced for Ergon Energy by NIEIR and provided to the AER with this Revised Regulatory Proposal in Table 8.4.

8.6 Rules' Requirements

In submitting this Revised Regulatory Proposal in relation the demand forecast to apply to Standard Control Services, Ergon Energy has had regard for clauses 6.5.6(a)(1), 6.5.6(c)(3), 6.5.7(a)(1), 6.5.7(c)(3) and S6.1.1(3) of the Rules.

8.7 Relevant Documents Provided by Ergon Energy

The following documents are relevant to this Chapter, some of which have been previously provided to the AER, while others are new since, or were not provided to the AER with, Ergon Energy's June 2009 Regulatory Proposal:

AR065c	NIEIR Report_Nov07.pdf
AR128c	NIEIR Report_Sep08.pdf
AR374c	NIEIR Report_Economic Outlook Aust & Qld Dec08 Qtr_Apr09.pdf
AR402	EE_Network Management Plan_Part A 2008-09 to 2012-13.pdf
AR433c	AER Data_v7_data room_28May09.xls
AR445	EE_Network Management Plan_Part B 2008-09 to 2012-13_V2.pdf

PL549	PL549_Powerlink 2009 Annual Planning Report.pdf
PL570c	PL570c_ERGON_NIEIR_Reconcile_2007.xls
PL655c	PL655c_EE_Ergon Forecast 2008 Final_Rev2_Mar09_GSM final.xls
PL801c	PL801c_NIEIR_Report for NEMMCO_Economic Outlook 2017-18_Jun08.pdf
RP886c	RP886c_EE Email to KPMG Econtech_18Nov09.rtf
RP887c	RP887c_KPMG Econtech Email to EE_8Dec09.rtf
RP894c	RP894c_EE-NIEIR Reconciliations 2005 & 2008 Demand Forecasts_15Dec09.doc
RP895c	RP895c_EE_Customer Connection Block Loads_20Dec09.doc
RP896c	RP896c_EE_Customer Connection Block Loads_SUPPORTING INFO (181 files, 85 folders)_20Dec09.doc
RP898c	RP898c_EE Email to AER_Street Lighting Services Modelling_24Nov09.rtf
RP908c	RP908c_NIEIR_Summer Max Demand Forecasts for EE to 2020_rcd 22Dec09
RP909c	RP909c_NIEIR EE Reconciliation 2009_20Dec09.doc
RP917c	RP917c RRP AER Data_V1_Data Room_07Jan10
RP929c	RP929c_EE_Region BSP & CP 2009 Forecast_23Dec09.zip
RP970c	RP970c_NIEIR_2009 Demand Forecast_Dec09.doc
RP981c	RP981c_Evans & Peck Demand Review
RP986c	RP986c_EE Email to AER_Street Lighting Modelling Request_24 Nov 09.rft

9 LABOUR COST ESCALATORS

The AER has rejected Ergon Energy's proposed labour cost escalators, which reflect its current UCA, on the grounds that it would eliminate incentives for Ergon Energy to negotiate efficient and competitive outcomes for future UCAs. It has also proposed separate escalation rates for contractors and internal labour and different weightings for general and technical labour.

Ergon Energy asserts:

- Its UCA, upon which its proposed labour costs escalators are based, reflects an efficient outcome, negotiated through a prudent process, and is comparable with other recent wage negotiation outcomes. Ergon Energy must pay wages in accordance with the UCA regardless of the AER's decision;
- Its labour cost escalators reflect the circumstances in which it operates, as it expects a skills' shortage, forecast to return with the recovery from the Global Financial Crisis, will put upward pressure on wages when it is time to negotiate its next UCA in 2011;
- The difference between internal and contractor and labour cost escalators is not material so does not warrant separation;
- Other DNSPs have negotiated UCA outcomes that do not distinguish between different categories of employees; and
- Under the Rules, the AER cannot reject proposed labour cost escalators on the basis of incentive for future enterprise bargaining outcomes, nor can it reject escalators that reasonably reflect the operating and capital expenditure criteria.

9.1 Chapter Overview

This Chapter provides further information to support Ergon Energy' use of the wage increases in its current UCA, as the labour cost escalators for the next regulatory control period as they reflect prudent and efficient costs for the purposes of the operating and capital expenditure criteria in clauses 6.5.6(c) and 6.5.7(c) of the Rules. The contents of this Chapter are drawn on in Chapters 10 and 11 in responding to the AER's specific criticisms of the labour escalation rates that Ergon Energy has applied in developing the operating and capital expenditure forecasts that it included in its June 2009 Regulatory Proposal.

9.2 Ergon Energy's June 2009 Regulatory Proposal

Ergon Energy detailed its proposed nominal labour cost escalation rates in Table 91 of its June 2009 Regulatory Proposal. These values are replicated in Table 9-1.

Table 9-1 - Ergon Energy's nominal labour escalation rates from June 2009 Regulatory Proposal (Per cent)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Contractors	5.1	5.1	4.4	4.5	4.5	4.5	4.5
Internal labour	5.1	5.1	4.4	4.5	4.5	4.5	4.5

Ergon Energy proposed that its labour escalation rates for the next regulatory control period should be the same for internal labour and contractors and should be based on its current UCA escalation rates, which took effect in 2008 and apply until 2011.

Ergon Energy believes that the current UCA is within the range of reasonable labour cost escalation rates for both internal labour and contractors. This is because the rates:

- Reflect the circumstances in which Ergon Energy operates and are necessary to attract and retain internal labour and contractors in order to meet the operating expenditure objectives;
- Have been determined in accordance with a prudent process; and

- Are efficient as they are comparable with other recent relevant wage negotiation outcomes.

Each of these matters is discussed below in the context of the requirements of Chapter 6 of the Rules and the labour cost escalation rates that have subsequently been included in the AER's Draft Distribution Determination.

[redacted]

[redacted]

[79] See http://www.ergon.com.au/about_us/corporate_intent.asp?yf=true&platform=PC

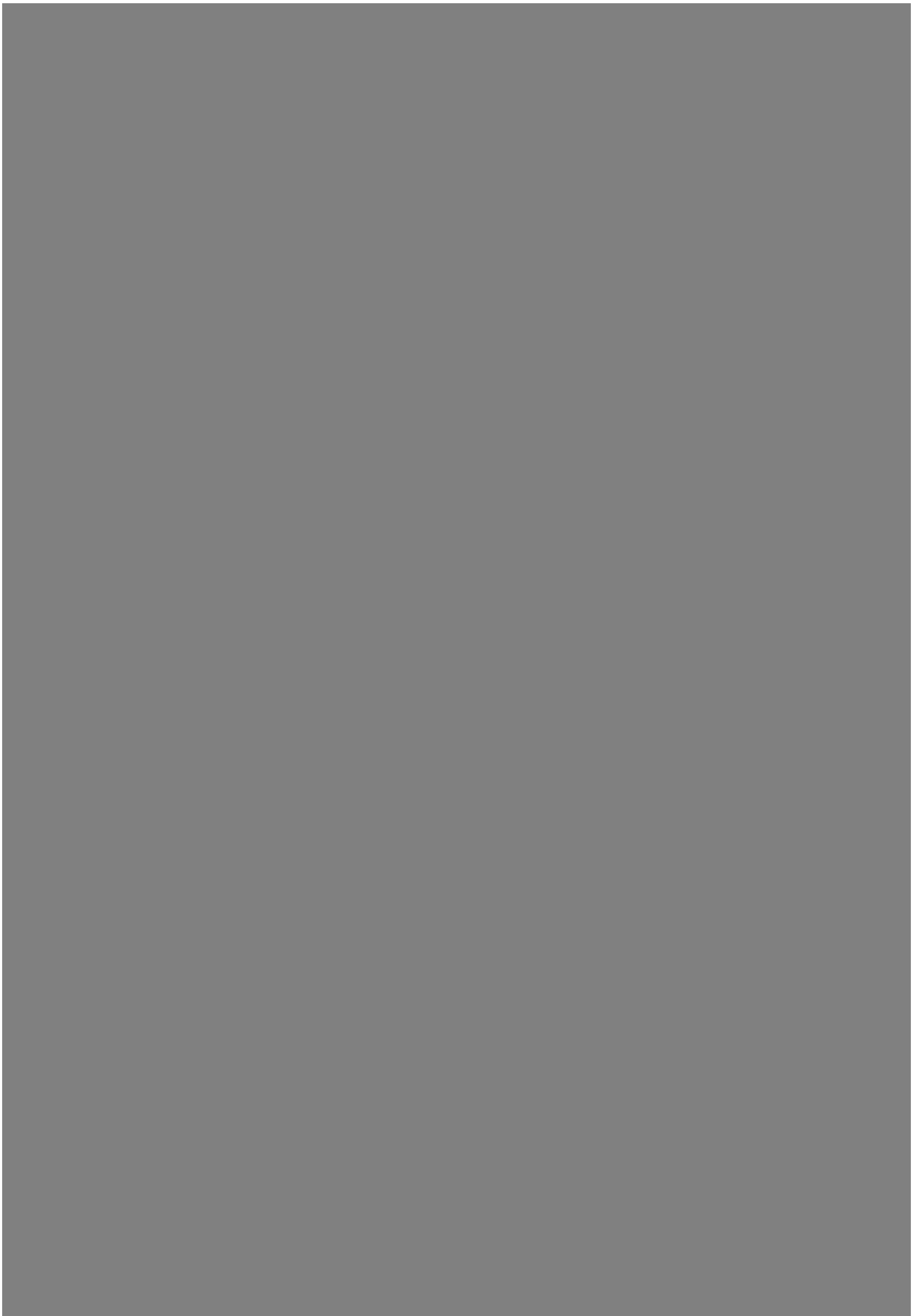
[redacted]

80 Refer to Ergon Energy's discussion about the economy in Chapter 1.

81 Ibid.

[redacted]

[82] Mercer (Australia) Pty Ltd, “Forum: Remuneration Trends and Human Capital Insights March/April 2008” and Mercer (Australia) Pty Ltd, “Forum: Remuneration Trends and Human Capital Insights March/April 2009”. These are proprietary documents to Mercer.



9.11 Ergon Energy's Revised Regulatory Proposal

After genuine consideration of the AER's Draft Distribution Determination reasons for its proposed substitute labour escalation rates, and on the basis of the additional information Ergon Energy has set out in this Revised Regulatory Proposal, Ergon Energy submits that its original labour escalators are within a reasonable range that the AER should accept, based on the information provided in this chapter. Furthermore, Ergon Energy considers that having the same labour escalator for both internal labour and contractors is appropriate. Ergon Energy's Revised Regulatory Proposal nominal labour escalation rates are set out in Table 9-10.

Table 9-10 – Ergon Energy's Nominal Labour Escalation Rates (Per cent)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Contractors	5.1	5.1	4.4	4.5	4.5	4.5	4.5
Internal labour	5.1	5.1	4.4	4.5	4.5	4.5	4.5

9.12 Rules' Requirements

In submitting this Revised Regulatory Proposal in relation the labour escalation rate, Ergon Energy has had regard for clauses 6.5.6(c) and 6.5.7(c) of the Rules.

9.13 Relevant Documents Provided by Ergon Energy

The following documents are relevant to this Chapter, some of which have been previously provided to the AER, while others are new since, or were not provided to the AER with, Ergon Energy's June 2009 Regulatory Proposal:

AR268c	AR268c_EE_Strategic Workforce Plan 2008-18_May08.pdf
RP888c	RP888c_AER_Access Economics Calculation Labour Escalation_from AER 11Dec09.xls
RP889c	RP889c_#1_AWE Data Aug 2007.pdf
RP890c	RP890c_#2_AWE Data Aug 09.pdf
RP891c	RP891c_#4_LPI Data Sep 09.pdf
RP892c	RP892c_#5_DEEWR Trends in Federal Enterprise Bargaining June 2009.pdf
RP893c	RP893c_#6_QLD Overview of Demand for Trades.pdf
RP914c	RP914c_#3_ABS 2008 Labour Force Australia Report_Cat 6202.0.pdf

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10 FORECAST CAPITAL EXPENDITURE

In its Draft Distribution Determination, the AER reduced Ergon Energy's capital expenditure program of $6,033 million by $1,020 million.

Ergon Energy has reviewed its capital expenditure forecasts and has proposed revised capital expenditure of $6,274 million. Ergon Energy asserts that the AER's reduction is unacceptable on the following grounds:

- Economic growth will be stronger than MMA has forecast for the next regulatory control period;
- Spatial demand (bottom-up) forecasts that drive the capital program are higher than the aggregate forecast which underestimates capital expenditure required for the environment in which Ergon Energy operates;
- The AER's proposed allowance will not fund anticipated new customer connections;
- Expenditure is required to provide additional and centralised property facilities in order to cater for growth in Ergon Energy's employees and operations; and
- It will put at risk Ergon Energy's ability to deliver against its regulatory obligations for reliability and security of supply.

10.1 Chapter Overview

In this Chapter, Ergon Energy details its revised capital expenditure forecasts for the next regulatory control period. In particular, Ergon Energy has:

- Retained its forecasts for the following categories of capital expenditure from its June 2009 Regulatory Proposal (while recognising that the value of these forecasts has changed on account of changes to cost escalations and reallocation of shared costs (overheads)):
  - Corporation Initiated Augmentation capital expenditure;
  - Asset Replacement capital expenditure; and
  - Reliability and Quality Improvement capital expenditure.
- Varied its forecasts for the following categories of capital expenditure from its June 2009 Regulatory Proposal (while recognising that the value of these forecasts has also been affected by changes to cost escalations and the reallocation of shared costs (overheads)):
  - CICW;
  - Non-System ICT capital expenditure; and
  - Non-System Property capital expenditure.

10.2 Ergon Energy's June 2009 Regulatory Proposal

Chapter 23 of its June 2009 Regulatory Proposal detailed Ergon Energy's capital expenditure forecasts for Standard Control Services for the period 1 July 2010 to 30 June 2015. These capital expenditure forecasts are reproduced in Table 10-1.

Table 10-1: Original Forecast Capital Expenditure – by Category Driver – 2010-15 ($M Real $2009-10)

Category Driver	2010-11	2011-12	2012-13	2013-14	2014-15	Total	Average of 5 year Total
Asset Replacement	177.44	212.68	250.03	274.81	299.18	1,214.14	242.83
Corporation Initiated Augmentation	267.84	339.38	401.26	463.58	518.89	1,990.95	398.19
Customer Initiated Capital Works	336.11	354.99	315.56	328.70	359.63	1,694.99	339.00
Reliability and Quality Improvement	18.29	20.89	24.50	28.28	30.43	122.39	24.48
Other System	105.62	72.94	50.78	50.39	51.65	331.38	66.28
Non-System	180.90	199.03	135.19	82.27	81.70	679.10	135.82
Total	1,086.20	1,199.90	1,177.32	1,228.03	1,341.49	6,032.94	1,206.59

Source: Tables for Proposal 23.1

Chapter 23 of its Regulatory Proposal explained the methodology by which Ergon Energy prepared its capital expenditure forecasts. Chapter 24 of its Regulatory Proposal demonstrated how Ergon Energy's capital expenditure forecasts for the next regulatory control period achieve the capital expenditure objectives, having regard for the capital expenditure criteria and capital expenditure factors for the purposes of clause 6.5.6 of the Rules.

In addition, Ergon Energy provided the following other information in its Regulatory Proposal relevant to its capital expenditure forecasts:

- Section 32.1 detailed Ergon Energy's unit rates for key items of plant and equipment for Standard Control Services for the period 1 July 2010 to 30 June 2015;
- Chapter 33 detailed Ergon Energy's cost escalation factors to be applied to its capital expenditure for materials, contractors, labour and all other cost inputs for the period 2008-09 to 2014-15;
- Chapter 34 detailed and justified Ergon Energy's shared costs (overheads) and explained the process for the attribution of direct costs and for the allocation of shared costs (overheads) using causal allocations;
- Chapter 35 detailed how Ergon Energy will deliver its additional capability requirement. In particular, Ergon Energy articulated multiple strategies already established within the business to maintain and develop the internal workforce, ensure access to key materials and increase the amount of work to be undertaken by external providers and through contestability. The increased use of outsourcing and contestability will help build market competition and drive efficient delivery outcomes ; and
- Chapter 47 detailed Ergon Energy's forecast of small customer capital contributions for the period 1 July 2010 to 30 June 2015 totalling $110.31 million, comprising $43.2 million in cash contributions and $67.11 million in gifted assets.

10.3 AER's November 2009 Draft Distribution Determination

Following its review of Ergon Energy's capital expenditure proposal the AER has made the following adjustments:

- $844 million reduction to Growth capital expenditure to reflect the AER's view of a realistic expectation of demand and a revised approach to forecasting CICW expenditure;
- $119 million reduction to asset replacement capital expenditure to reflect a business as usual approach to forecasting expenditure in this category;

- $35 million reduction to Reliability and Quality Improvement capital expenditure to exclude expenditure associated with the feeder improvement program and reflect a revised level of expenditure based on outcomes in the current regulatory control period plus additional expenditure for the Supervisory Control and Data Acquisition (SCADA) acceleration program;
- $39 million reduction in shared costs (overheads) associated with the ICT services, sponsorship and community engagement that do not reasonably reflect the capital expenditure criteria and the capital expenditure objectives;
- $253 million reduction to non–system capital expenditure to exclude ICT systems expenditure associated with the change program and expenditure on major building projects; and
- $82 million increase to total capital expenditure, applied across all components of forecast capital expenditure, to account for errors in the application of input cost escalators.

Table 10-2: AER conclusion on Ergon Energy's capital expenditure allowance ($M Real 2009-10)[92]

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposed capital expenditure	1,086.2	1,199.9	1,177.3	1,228.0	1,341.5	6,032.9
1. Adjustment to Growth capital expenditure	-155.1	-179.5	-140.9	-168.2	-200.5	-844.2
2. Adjustment to Asset Replacement capital expenditure	-9.9	-19.4	-30.9	-30.0	-28.6	-118.8
3. Adjustment to Reliability and Quality Improvement capital expenditure	-2.6	-4.5	-7.1	-9.8	-11.4	-35.3
4. Adjustment to Non–System capital expenditure	-95.6	-115.7	-50.6	1.7	6.6	-253.5
Adjustment to shared costs (overheads)	-2.2	-5.9	-9.2	-9.8	-11.5	-38.6
Re-inclusion of shared costs (overheads) that were included in Growth, Asset Replacement, Reliability and Non–System capital expenditure deductions	40.6	48.3	36.0	30.6	32.6	188.1
Adjustment to cost escalators	-16.2	2.0	22.2	37.6	36.5	82.1
AER capital expenditure allowance	845.4	925.2	996.8	1,080.0	1,165.3	5,012.8

Notes: Totals may not add due to rounding

The shared costs (overheads) included in deductions one to four above are not to be removed from Ergon Energy's capital expenditure allowance. This is because, with the exception of an adjustment for ICT services, the AER has not proposed any adjustments to Ergon Energy's shared costs (overheads).

[92] AER, "Draft Decision, Queensland Draft distribution determination 2010-11 to 2014-15", 25 November 2009, page xxiv

10.4 Ergon Energy's Response to AER's Draft Distribution Determination

10.4.1 Policies and Procedures

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Concerned that capital expenditure planning and governance policies and procedures not consistently applied, which may have implications for effective and efficient identification of investment priorities [95-6]	- Quality, completeness and robustness of options analysis varied considerably [94, 106, 512]	- Ergon Energy has established a robust investment analysis process which applies to all business cases. - PB's assertion that the options analysis is inconsistent and incomplete does not take into account that the management of the distribution network will have a range of business cases which have few options e.g. supply to a new customer from the existing network, while augmentation projects may have several options including demand management and alternative energy solutions. - Ergon Energy's process requires all projects of significance (i.e. over $500,000) to have the same business case template completed in line with good governance processes.
	- Business case documentation lacks robustness, generally does not consider non-network alternatives and includes limited NPV analysis [106]	- Ergon Energy disagrees with PB that the business case documentation lacks robustness. PB has not given proper consideration to the business case templates which include a detailed NPV analysis and is a mandatory requirement for project/investment approval for significant projects. - Ergon Energy can only assume this comment applies to the program funding request which uses a subset of the project business case documentation to identify budget provision information for future years funding analysis and prioritisation. - Any significant expenditure approval requires the full business case documentation, including NPV analysis to be completed. - As indicated to PB, Ergon Energy's business case documentation is being further supported in future releases (January 2010) with additional value and benefit documentation to provide more consistent evaluation of non-network solutions.
	- Prudent application of demand forecasts in development of capital expenditure only partially demonstrated and evidenced by business documentation [94, 512]	- As indicated in documentation provided to PB, the demand management forecasts are included at a project level and therefore demonstration of the business documentation is dependent on the projects in progress at any particular time. - PB and the AER have not properly considered the range of project scopes in a DNSP. When the program is dominated by responses to customer supply requests or refurbishment projects the opportunity for demand management and the use of demand forecasts is greatly restricted.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
	- Rarely recognise efficient non-network alternatives as potential options to address network constraints [94, 512]	- Ergon Energy advised PB that Ergon Energy is currently developing solutions which the network planners can utilise expediently to implement demand management or non-network alternatives. - The AER has not given consideration to the difficulty in utilising these non-network options through the lead time that is required to provide the demand reduction. This lead time is generally driven by the time to obtain customer acceptance in sufficient levels to obtain the demand reduction. This lead time is, in many instances, greater than the customer driven supply requirement and therefore non-network options are not viable as demand will have increased above the capacity of the system before any alternative can be implemented. - Ergon Energy clearly demonstrated that it is pursuing alternatives with its projects in Townsville and Magnetic Island as well as other sites. It is further developing viable packaged non-network alternatives that system planners can implement in the timeframes available.

10.4.2 Growth Capex – Corporation Initiated Augmentation

10.4.2.1 Ergon Energy's June 2009 Regulatory Proposal

In its June 2009 Regulatory Proposal, Ergon Energy proposed a total Corporation Initiated Augmentation capital expenditure requirement for the upcoming regulatory control period of $1,990.95 million (Real $2009-10).

The forecast amount was based on detailed bottom-up spatial demand forecasts and used in conjunction with Ergon Energy's planning criteria to forecast the capital expenditure requirement.

10.4.2.2 The AER's Draft Distribution Determination

In the Draft Distribution Determination the AER raised a number of concerns regarding the expenditure forecast and proposed an alternative forecast. Specifically, the AER:

- Did not accept the Ergon forecast as efficient on the basis of their stated concerns regarding business case documentation, planning documentation and forecast demand;
- Provided a substitute forecast on the basis of a revised global demand forecast provided by MMA and a capital expenditure model constructed by PB; and
- Estimated Ergon Energy's required capital expenditure for the next regulatory period to be $1,383 million (reflecting a reduction $526 million).

10.4.2.3 Ergon Energy's response to the Draft Distribution Determination

Given the feedback provided in the Draft Distribution Determination, Ergon Energy has undertaken a detailed review of the methodology and magnitude of the proposed capital expenditure forecast with specific regard to each of the concerns raised by the AER.

As part of its Revised Regulatory Proposal, Ergon Energy has taken the opportunity to provide:

- Clarification and explanation of information previously submitted;
- Additional information where previously submitted supporting documentation was found by the AER to be insufficient; and
- The views of an independent report examining the adjustments proposed by the AER.

Ergon Energy does not support the reduction proposed by the AER and as such is reinstating its original Corporation Initiated Augmentation capital expenditure forecast. Based on a detailed review of the available information, and new information made available since the June 2009 Regulatory

Proposal was submitted, Ergon Energy considers that the forecast proposed in its June 2009 Regulatory Proposal most reasonably reflects the costs of meeting its regulatory obligations.

Ergon Energy further considers that the alternative forecast proposed by the AER cannot be utilised as it:

- Incorrectly assumes that Ergon Energy's planning documentation cannot be aligned with its forecast capital expenditure;
- Relies wholly upon MMA's top-down global demand forecast, which is flawed in its approach, utilises incorrect data, and is inherently less accurate than the combined top-down and bottom-up approach employed by Ergon Energy;
- Relies on "sensitivity analysis" conducted by PB, which significantly overstates the proportion of Ergon Energy's Corporation Initiated Augmentation capital expenditure which is sensitive to deferral of forecast demand; and
- Is inconsistent with previous regulatory determinations in assuming that there is a linear and proportional relationship between growth related capital expenditure and global maximum demand.

The findings of Ergon Energy's review of the Corporation Initiated Augmentation capital expenditure forecast and the specific concerns raised by the AER in the Draft Distribution Determination are detailed in the sections below.

10.4.2.3.1 Business case documentation does not ensure efficiency

Ergon Energy agrees with PB that business cases, or similar documentation, combined with options analysis and NPV calculations provide a clear and transparent basis for decision making and external review. However, with a proposed Corporation Initiated Augmentation capital expenditure program of more than 1,100 projects over the next regulatory control period, it is not feasible or practical to think that Ergon Energy should have business cases completed for all of its projects, particularly given that many of these projects will not be undertaken for five or more years after Ergon Energy's Regulatory Proposal has been prepared. As such, there is therefore a need for the AER to consider projects that do not have business cases completed.

Ergon Energy notes that practices of DNSPs in relation to business case documentation may vary across Australia. PB, for example, has reported elsewhere without any apparent major issue that one DNSP that it reviewed in 2009 documents their options analysis in the business case formally presented for approval, which typically occurred only in the year immediately before the project starts and that as a result limited formal business case documentation prior to the start of that DNSP's next regulatory control period was available for review. PB found this was in accordance with the processes adopted by that DNSP and, as a result, PB considered other high level material available to it in examining augmentation projects for that DNSP.[93]

Accordingly, Ergon Energy engaged Huegin to review this concern raised by PB. The details of Huegin's review can be found in Document RP938c. As noted by Huegin, the consideration of options alone does not ensure efficiency, and any finding of relative efficiency based on the existence or otherwise of business case (or similar) documentation should only be considered if there is direct evidence that the capital expenditure is not efficient.

Ergon Energy maintains that it has considered the available options in accordance with its planning documentation and that preferred options have been selected based on advice of subject matter experts, and / or local managers with detailed local asset knowledge.

10.4.2.3.2 Reconciliation between planning documentation and capital expenditure forecast

On page 528 of the Draft Distribution Determination, the AER noted PB's finding that "a clear relationship between the relevant planning documentation and the CIA capex proposal was not evident".

[93] PB, "Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015", 2009, page 28

Huegin's report (Document RP938c) investigates the validity of this concern. Using the information requested by (and provided to) PB during their review, Huegin conducted a representative study of the asset categories found within Ergon Energy's Sub-Transmission Network Augmentation Plan (SNAP) planning documentation. Huegin was able to reconcile the source and exact quantities between the capital expenditure model and the planning documentation for 100 per cent of the projects investigated.

Huegin expanded the scope of investigated projects to include a representative sample from the Distribution Network Augmentation Plan (DNAP) planning documentation as well (which it appears PB did not attempt, as no request was made by PB for Ergon Energy to provide this information). After investigating 303 of the 1,100+ projects contained in the DNAPs and SNAPs (representing more than 50 per cent of the total value of Corporation Initiated Augmentation capital expenditure), Huegin found that 99.7 per cent of projects (302 of 303) were able to be reconciled between the planning documentation and the capital expenditure forecast.

Based on the findings of this review, Ergon Energy considers that a sufficiently detailed review shows that there is no valid reason to suggest that the two sets of figures cannot be reconciled.

10.4.2.3.3 Sensitivity analysis is flawed

In determining the magnitude of the proposed reduction, the AER have relied on the sensitivity analysis undertaken by PB to determine the proportion of Ergon Energy's Corporation Initiated Augmentation capital expenditure forecast that is sensitive to changes in forecast demand. As discussed in detail by Huegin in Document RP938c, the sensitivity analysis conducted by PB fails to account for the elements described as "specific issues" which relate to non-forecast demand driven expenditure.

Huegin's analysis indicates that in addition to the 7.7 per cent identified by PB as being independent of changes in forecast demand, there is a minimum of 6.0 per cent and a maximum of 37.3 per cent of the Corporation Initiated Augmentation capital expenditure forecast amount which should also be excluded from any adjustment based on changes to forecast demand.

Ergon Energy further considers that the approach used by PB is overly simplistic, does not account for variation across different feeders and incorrectly assumes that changes to system maximum demand can be applied in a homogenous manner proportionally across the network.

10.4.2.3.4 Corporation Initiated Augmentation capital expenditure and change in system maximum demand are not proportional

As discussed by Huegin the assumption that a reduction in demand growth can be used to model a proportional reduction in Growth capital expenditure has previously been shown to be flawed and should not be accepted as a reliable alternative to a detailed bottom-up capital expenditure forecast.

In the recent (2009) NSW Distribution Determination, the AER advised that global (top-down) methodologies such as that applied by PB were only appropriate as a "high level assessment of reasonableness", and further found that "spatial forecasts are required to assess necessary expenditure on the network"[94].

It is not valid to assume that a proportional reduction should apply by using the difference between the average annual growth rates of two maximum demand scenarios. As discussed by Huegin such an approach is likely to result in a significantly higher reduction in expenditure than would be established if the demand forecast were applied appropriately on a bottom-up basis, as is done by Ergon Energy in their planning documentation.

The assumptions relied upon by PB in applying their reduction mechanism to Customer Initiated Augmentation capital expenditure are fundamentally flawed and their methodology contradicts previous findings published by the AER and the QCA.

[94] AER, "Final decision New South Wales Distribution Determination 2009–10 to 2013–14", 28 April 2009, page 93

10.4.2.3.5 Ergon Energy's demand forecast: an appropriate basis for the capital expenditure forecast

Ergon Energy considers that the spatial (bottom-up) demand forecast used to develop the proposed Corporation Initiated Augmentation capital expenditure forecast is an accurate and reliable methodology of sufficient detail to allow the evaluation of capital expenditure requirements.

As stated by Ergon Energy in its June 2009 Regulatory Proposal, the demand forecast used to develop the capital expenditure proposal was the 2007 spatial demand forecast. This demand forecast was reconciled with the 2007 top-down forecast prepared by NIEIR and no significant discrepancies were encountered.

Ergon Energy undertook an additional bottom-up spatial demand forecast in 2008, which was considerably higher than it forecast in 2007. At the time of its June 2009 Regulatory Proposal Ergon Energy considered that the 2008 demand forecast did not accurately represent forecast demand as it did not account for recent changes in the macroeconomic environment (such as the Global Financial Crisis), and the 2007 forecast was a more appropriate basis for determining the forecast capital expenditure requirement.

Since it submitted its June 2009 Regulatory Proposal, Ergon Energy has conducted its 2009 bottom-up spatial demand forecast and has reconciled this with the December 2009 top-down maximum demand forecast prepared by NIEIR. The 2009 spatial forecast shows a marginal decrease on that forecast in 2007; however it is still significantly higher than that proposed by the AER and MMA.

This is to be expected as the forecast prepared by MMA (as highlighted by MMA) is heavily reliant on the incorrect assumption of GSP being negative 4.8 per cent in 2008-09. Actual GSP for 2008-09 was positive 0.8 per cent. Ergon Energy considers that on this basis alone, the system demand forecast provided by MMA cannot be relied upon as a basis for making adjustments to growth capital expenditure.

Ergon Energy considers that given the marginal difference between the 2007 and 2009 spatial bottom-up forecasts and the inherent inaccuracy and unreliable nature of applying top-down demand forecasts to determine capital expenditure requirements (as noted by the AER during the 2009 NSW Distribution Determination), the AER should accept the Corporation Initiated Augmentation capital expenditure detailed in Ergon Energy's June 2009 Regulatory Proposal (adjusted for escalations and shared costs (overheads)). This is detailed in Table 10-3.

Table 10-3: Revised Forecast Corporation Initiated Augmentation capital expenditure – 2010-15 ($M Real $2009-10)

Category Driver	2010-11	2011-12	2012-13	2013-14	2014-15	Total	Average of 5 year Total
Corporation Initiated Augmentation	273.32	355.81	422.98	487.85	536.32	2,076.28	415.26

Source: Revised Submission Tables for Proposal 23.1

10.4.2.4 Summary of concerns and responses regarding Corporation Initiated Augmentation capital expenditure

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reduction of $526 million as a result of deferring expenditure by 18 months [106, 109, 129, 526, 529]	- "The AER considers that … the lack of business case or other supporting documents and inconsistent or incomplete options analysis processes, support a view that the need, timing and efficiency of the proposed capex has not been established by Ergon Energy." [528]	- Addressed above: o It is impractical to expect all of Ergon Energy's projects to be accompanied by a business case o In each case, SMEs choose the most appropriate option, although this is not always documented o Huegin has reconciled the planning documentation and capital expenditure forecast as detailed in Document RP938c.
	- "…the AER notes the advice from MMA that Ergon Energy's peak demand forecasts are not realistic and are likely to be overstated to the extent of one to two years of peak demand growth." [528]	- Addressed above: o Ergon Energy's demand forecast is an appropriate basis for the capital expenditure forecast.
	- "The approach recommended by PB for determining this reduction is to reduce the total forecast MVA growth in peak demand over the next regulatory control period by the average of one to two years (18 months) average MVA growth, and apply these revised forecasts to the demand related component of forecast CIA capex." [528]	- Addressed above: o Corporation Initiated Augmentation capital expenditure and change in system maximum demand are not proportional.

10.4.3 Growth Capital expenditure – Customer Initiated Capital Works

10.4.3.1 Ergon Energy's June 2009 Regulatory Proposal

Ergon Energy proposed a total CICW forecast of $1,694.99 million (FY10 real dollars) in the June 2009 regulatory proposal. The CICW forecast is based on:

- The actual 2007-08 CICW as a known starting point;
- An adjustment for updates to the CICW price book to reflect current costs;
- Applying forecast changes in dwelling stock and Gross Regional Product to the baseline expenditure as escalators for small CICW (domestic and rural, subdivision and small commercial and industrial connections) and large CICW (large commercial and industrial connections) respectively. These forecast changes were prepared by an expert economic forecasting consultant, NIEIR; and

- Applying scope changes to reflect the expected increase in contestability arising from an uptake of the alternative provider option for Urban Residential Developments (URDs) and extension of the alternate provider option to commercial and industrial connections.

10.4.3.2 The AER's Draft Distribution Determination

The AER did not accept the forecast CICW in Ergon Energy's June 2009 Regulatory Proposal. Rather, the AER considered that Ergon Energy's forecast CICW should be based on average historical connection numbers and costs and forecast customer growth rate, as recommended by PB. The impact of the AER's substitute CICW forecast is a reduction of $318 million (Real $2009-10). In proposing this reduction, the AER:

- Noted that "PB identified a number of concerns regarding the applicability of various growth forecasts used by Ergon Energy as part of its CICW forecasting methodology" [529];
- Noted PB's view that "insufficient supporting information was available to justify the CICW forecasts, and that it was therefore unable to conclude that the proposed CICW capex was efficient" [529];
- Considered that "the robustness of Ergon Energy's forecast CICW capex is not supported by Ergon Energy's forecasting methodology" [529];
- Considered that "the application of dwelling stock growth forecasts in order to forecast growth in commercial and industrial connections is not appropriate" [529];
- Considered that the approach recommended by PB "provides a reasonable approach to determining a substitute forecast CICW capex allowance, noting that PB's recommended CICW allowance is consistent with CICW expenditure in the current regulatory control period" [529]; and
- Considered that reducing Ergon Energy's proposed growth capex for CICW by $318m "results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for this capex component to comply with the NER." [529]

10.4.3.3 Ergon Energy's response to the Draft Distribution Determination

Ergon Energy has considered each of the AER's concerns and does not accept the AER's decision to reduce Ergon Energy's CICW forecast.

The specific reasons for Ergon Energy's Revised Regulatory Proposal are addressed in the following sections:

- Section 10.3.3.1 details Ergon Energy's consideration of the AER and PB's concerns as stated in the Draft Distribution Determination and the PB report;
- Section 10.3.3.2 details the reasons for Ergon Energy's decision not to accept that the AER's substitute CICW forecast reasonably reflects the capital expenditure criteria or Ergon Energy's regulatory obligations regarding customer connections; and
- Section 10.3.3.3 details the Ergon Energy revised proposal for CICW and details the factors that Ergon Energy has considered in determining that this revised forecast reasonably reflects the capital expenditure criteria and regulatory obligations regarding customer connections.

In addition:

- Document RP937c prepared by Ergon Energy provides detailed analysis and supporting information to support the Revised Regulatory Proposal.
- Document RP938c prepared by Huegin provides independent external analysis to support the Revised Regulatory Proposal.

10.4.3.3.1 Analytical Support for the Ergon Energy Assumptions

Ergon Energy has generally forecast CICW on the basis of:

- A known starting point - the 2007-08 actual expenditure;
- Separately forecasting individual customer categories; and

- Assumed drivers of the individual customer categories identified above.

Ergon Energy considers that the forecast represents not only a reasonable reflection of the capital required for CICW connections, but is also the most prudent method of ensuring that:

- Ergon Energy meets its regulatory obligation to connect customers to the network – an external driver that Ergon Energy has no control over; and
- The anticipated customer connection activities are funded.

Ergon Energy considers that the forecast of individual customer category requirements complies with the Cost Allocation Method approved by the AER and is also prudent in terms of matching supply to demand for activities that are influenced by particular external drivers.

The AER identified concerns regarding Ergon Energy's input assumptions to its CICW forecast model as a factor for not accepting Ergon Energy's CICW proposal, namely that the use of dwelling stock growth and Gross Regional Product (GRP) are inappropriate forecast assumptions for small and large CICW respectively. Ergon Energy does not agree with the AER and considers that both dwelling stock growth and GRP are appropriate growth forecast assumptions for small and large CICW respectively. Document RP937c provides the rationale for these assumptions:

> *Dwelling stock growth has been chosen because Ergon Energy considers that there would be a strong positive correlation between:*
>
> - *new dwellings and new SAC connections, given that new dwellings need to be connected to the distribution system in order to take electricity supply; and*
> - *new dwellings and general economic activity which in turn impacts on the probability of new large CICW projects.*

The AER have specifically referenced the PB concern that dwelling stock growth is not well correlated to commercial and industrial connection expenditure. PB also raised a concern that GRP is not well correlated to large CICW.

PB raised a further concern regarding the applicability of dwelling stock growth as a forecast for rural connections due to the historical concentration of growth in specific, coastal areas. Ergon Energy does not consider this concern relevant to the CICW forecast or methodology as:

- A connection classified as rural does not preclude that connection being in a coastal area;
- Rural connections constitute only two per cent (by quantity) of total domestic and rural connections and hence any potential differences would have little material impact on the overall forecasts;
- The dwelling stock forecasts are constructed from regional forecasts, and therefore account for the differences in growth across regions; and
- Ergon Energy's historical growth profile by network area has no bearing on the NIEIR forecast of dwelling stock for the entire network area or regions of it. Further, forecast growth is not expected to alter in terms of distribution of growth rates across the state.

Notwithstanding the above points, Ergon Energy accepts the concerns raised by PB on the basis of the Draft Distribution Determination and PB's view that insufficient information was presented by Ergon Energy to support the assumptions. In this Revised Regulatory Proposal, Ergon Energy provides additional information below to support the relationships assumed between the inputs and CICW expenditure, thereby discounting the AER's primary reasons for not accepting the original Ergon Energy CICW forecast.

10.4.3.3.2 Dwelling Stock Growth and Domestic and Rural Connections

Ergon Energy tested the assumption of dwelling stock changes as a driver of commercial and industrial connection expenditure. This testing used historical data to demonstrate that the assumption of a strong relationship between dwelling stock growth and domestic and rural connection expenditure is valid, and that use of dwelling stock as the forecast driver for domestic and rural CICW expenditure is appropriate.

Ergon Energy also engaged Huegin to provide an independent test of the assumption. In section 3.5 of its report [Document RP938c], Huegin found that a strong statistical relationship exists between dwelling stock and domestic and rural connection expenditure.

Huegin also tested the reasonableness of the NIEIR dwelling stock forecasts. Huegin found that the NIEIR forecast is reasonable using a simple test employing population growth and average household size estimates as a proxy for dwelling stock growth for Ergon Energy's network area.

10.4.3.3.3 Dwelling Stock Growth and Small Commercial and Industrial Connections

Historical data shows a strong correlation between dwelling stock growth and small commercial and industrial connection expenditure. The changes in reporting of commercial and industrial connection expenditure by size, however, limit the availability of historical data. Given the small data sets, Ergon also engaged Huegin to provide an independent test of the forecasts for small commercial and industrial connection expenditure. Huegin's report [Document RP938c] found:

- A correlation between historical dwelling stock and small commercial and industrial connection expenditure exists;
- Non-residential construction value in Queensland is also correlated to Ergon Energy's small commercial and industrial connection expenditure; and
- A substitute forecast for this category using forecast non-residential construction value validates the overall magnitude of the small commercial and industrial forecast, albeit with a different profile.

10.4.3.3.4 Gross Regional Product and Large Commercial and Industrial Connections

Ergon Energy tested the assumption that GRP influences large commercial and industrial connections. Ergon Energy could not demonstrate a strong correlation between large CICW and GRP. Investigation revealed that changes in the realisation and the spread of connection projects over several years render the correlation weak.

Ergon Energy have revised their forecast methodology for large CICW and have recalculated large CICW based on dwelling stock growth due to the correlation between overall commercial and industrial expenditure and dwelling stock.

Ergon Energy notes that Huegin's report [Document RP938c] recommended an alternative manner in which to address the time lag issue with large CICW and have incorporated the $19 million dollar shift in this category of expenditure.

10.4.3.3.5 Substitute Forecast Not Prudent

The AER states in its decision that the substitute CICW represents "business as usual" [526] and that the reduction of $318 million is the minimum required to satisfy the capital expenditure criteria [529]. The AER further notes in making its decision that it considered during the review of reasonableness of the PB approach that "PB's recommended CICW allowance is consistent with CICW expenditure in the current regulatory control period". [529]

Substitute Forecast Not Business As Usual

Business as usual in terms of CICW for Ergon Energy is a regulatory obligation to connect customers to the network. As the network grows, the number of connections each year grows and therefore expenditure increases. Scope changes, labour and material cost increases and other variables outside the control of Ergon Energy further contribute to expenditure growth. CICW is an output of these factors and with a growing network, increasing expenditure is the business as usual condition for Ergon Energy, given the constraint of the regulatory obligation to connect customers.

Ergon Energy does not accept that expenditure consistent with the current regulatory period reflects the capital expenditure objectives and criteria in the Rules. In fact, Ergon Energy considers that the AER forecast, which is $16 million lower than the total for the current regulatory control period, increases the risk that Ergon Energy will be exposed to unfunded connection obligations.

Substitute Forecast Basis Not Reasonable

The strongest driver of the PB forecast is the assumption of historical average connection costs, however the data used by PB in calculating the historical cost of a connection is incorrect. PB has used the connection numbers reported by Ergon Energy in its June 2009 Regulatory Proposal despite Ergon Energy having advised PB that these numbers were out of date. Document RP937c provides updated values, which have been reflected into this Revised Regulatory Proposal. This discrepancy is irrelevant to Ergon Energy's forecast, however the PB substitute model relies directly upon historical connection numbers to determine an average historical connection cost.

Apart from the calculation error, the rationale for estimating an average historical connection cost is flawed. Average connection costs are poorly correlated to CICW, as demonstrated in the Huegin report [Document RP938c]. There are several reasons for the poor correlation between average cost of connection and total connection expenditure, including:

- Variations in the contribution of the different customer categories to overall expenditure;
- Variations in the scope of connection projects; and
- Changes in material and labour costs.

Further to the above points, the average cost of a connection for any given year is already the average of thousands of connections – averaging across multiple years further diminishes the applicability of a single historical average cost as an escalator of CICW.

Ergon Energy engaged Huegin to review the PB forecast model and methodology. The results of that review are included in document [Document RP938c] and summarised below:

- The connection numbers used by PB are incorrect, representing an $80 million error in their forecast;
- The accuracy that PB claim for their average connection cost is reliant upon comparison against the first two years of Ergon Energy's forecast that PB have recommended that the AER not accept;
- A more appropriate average connection cost input in the PB model results in a forecast significantly closer to Ergon Energy's forecast; and
- The PB forecast is at the very low end of the range of forecasts assessed by Huegin.

10.4.3.4 Ergon Energy Revised Regulatory Proposal for CICW

Ergon Energy believes that the AER's decision to reduce the CICW allowance exposes Ergon Energy to considerable risk of unfunded connection requirements. Ergon Energy's obligations regarding customer connections are outlined at clause 5.3.1(c) of the Rules, the Queensland Electricity Act 1994 and clause 5.1 of the Standard Connection Contract annexed to the Electricity Industry Code.

The substitute forecast represents an unrealistic estimate of connection expenditure. The profile indicates a reduction in expenditure, despite the increasing size of the network.

Numerous other references and forecasting methods (as detailed by Huegin in Document RP938c) provide further support that Ergon Energy's forecast CICW is prudent and efficient and the AER substitute forecast is not a reasonable reflection of the requirements of a DNSP under the circumstances of Ergon Energy.

Further, the actual expenditure related to CICW for 2008-09 validates the first year of the Ergon Energy CICW forecast and demonstrates the error in PB's substitute forecast.

For the reasons stated above, and with regard to the other considerations detailed in this chapter, Ergon Energy submits the revised CICW forecast for the next regulatory control period detailed in Table 10-4.

Table 10-4: Revised Forecast CICW – 2010-15 ($M Real $2009-10)

Category Driver	2010-11	2011-12	2012-13	2013-14	2014-15	Total	Average of 5 year Total
Customer Initiated Capital Works	363.68	394.72	341.83	357.27	389.01	1,846.51	369.30

Source: Revised Submission Tables for Proposal 23.1

10.4.3.5 Summary of Concerns and Responses Regarding CICW

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reduction of $318 million as forecast has not been sufficiently substantiated [106, 109, 129, 529]	- The AER considers that the robustness of Ergon Energy's forecast CICW is not supported by Ergon Energy's forecasting methodology. For example, the AER considers that the application of dwelling stock growth forecasts in order to forecast growth in commercial and industrial connections is not appropriate. [109, 529]	- Ergon Energy has provided evidence that dwelling stock growth forecasts are appropriate to forecast growth in commercial and industrial connection expenditure [Document RP937c], as outlined in section 10.3.3 of this Revised Regulatory Proposal and in Huegin's report [Document RP938c]. - Ergon Energy has also addressed each of the other concerns regarding growth forecasts raised by PB and referenced by the AER, as outlined in section 10.3.3 of this Revised Regulatory Proposal and in Huegin's report [Document RP938c].
	- PB's proposed approach to determining a prudent and efficient level of CICW is to apply a business as usual approach. PB constructed a model to produce a business as usual CICW forecast based on Ergon Energy's average historical connection numbers and costs, and forecast customer growth rate [109, 526]	- The PB approach is not 'business as usual', as explained in section 10.3.3.2 of this revised proposal and in Huegin's report [Document RP938c] - Section 10.3.3.2 of this Revised Regulatory Proposal and Huegin's report [Document RP938c] also demonstrate: o The data error in PB's model inputs that results in a $80 million output error; o The unsuitability of historical connection numbers and costs for a business as usual model; and o The anomaly inherent in PB's forecasting method.
	- The AER has reviewed this approach and considers it provides a reasonable approach to determining a substitute forecast CICW allowance, noting that PB's recommended CICW allowance is consistent with CICW in the current regulatory control period.	- Section 10.3.3.2 and 10.3.3.3 of this Revised Regulatory Proposal and Huegin's report [Document RP938c] demonstrate that the Ergon Energy model results are a more reasonable reflection of CICW costs than the AER's substitute forecast. - That the PB recommended CICW allowance is consistent with CICW in the current regulatory period is an indication of its unsuitability, rather than validation of its reasonableness. The underlying driver of connection growth is population growth – a compounding escalator.

10.4.4 Asset Replacement

10.4.4.1 Ergon Energy's June 2009 Regulatory Proposal

In its June 2009 Regulatory Proposal, Ergon Energy forecast Asset Replacement capital expenditure of $1,214.1 million over the coming regulatory control period. This forecast covered replacement programs for 26 classes of assets.

10.4.4.2 The AER's Draft Distribution Determination

In the Draft Distribution Determination the AER has proposed a reduction in replacement capital expenditure of $118.8 million over the five years of the next regulatory control period.

The reduction proposed by the AER is based on sustaining the level of replacement capital expenditure at a business as usual level of expenditure over the next regulatory control period.

In coming to this conclusion, the AER examined four of the 26 asset categories (pole tops, underground cables and joints, connectors and conductors, and zone substation transformers). In all but one case, the AER (as a result of PB's investigation) was concerned with the level of information that Ergon Energy was able to provide in support of its forecast levels of Asset Replacement expenditure.

The underground cables and joints proposal was not adjusted, as the level of expenditure proposed by Ergon Energy is at the business as usual level. The other three categories (and as a consequence all untested categories) were allocated business as usual levels of expenditure.

In making its Draft Distribution Determination, the AER relied on the following main points:

1. *"Ergon Energy, despite claiming to use a condition based approach to asset replacement also applies an age based approach"* [95];
2. *"The application of both a condition based and aged based asset replacement approach is unlikely to result in a prudent and efficient capex"*[96]; and
3. *"Ergon Energy was unable to provide sufficient information to satisfy PB as to the basis for its forecast replacement volumes (with the exception of underground cables and joints replacement capex)………Ergon Energy has not demonstrated that its forecast replacement capex is prudent and efficient"*[97].

10.4.4.3 Ergon Energy's Response to AER's Draft Distribution Determination

One of the key reasons stated by the AER for not accepting the proposed forecasts was the lack of supporting information provided.

Based upon the feedback from the AER regarding the lack of information justifying its forecasts. Ergon Energy has undertaken additional work to support the existing forecasts in the three areas where the AER and PB were dissatisfied.

Another key concern of the AER was that Ergon Energy replaces assets based on age rather than condition. Ergon Energy does not use an age based approach to asset replacement.

The business as usual level of expenditure for asset replacement as proposed in the Draft Distribution Determination will have unacceptable consequences for the network in terms of both performance (customer service) and safety (employee and public).

Ergon Energy maintains that its forecast in its June 2009 Regulatory Proposal is prudent and efficient.

In support of this reinstatement, Ergon Energy has provided in this Revised Regulatory Proposal, as appropriate:

- Clarification of information already provided;
- Additional information developed in response to the shortcomings identified by the AER and PB; and
- Reference to two independent reports that collectively examine the three asset classes for which a reduction was applied by the AER.

In putting forward a revised proposal for Asset Replacement capital expenditure, Ergon Energy has addressed the following four main points:

[95] AER, "Draft decision Queensland Draft Distribution Determination 2010–11 to 2014–15", 25 November 2009, page 110

[96] Ibid, page 111

[97] Ibid, page 111

- Ergon Energy replaces assets based on age;
- The initial proposal from Ergon Energy contained insufficient information to allow PB to make a determination of prudence and efficiency;
- Assessing four categories of expenditure and using the results to adjust an entire category can, in this case, not be supported; and
- A level of expenditure equivalent to business as usual is appropriate for application to all asset classes.

This section of the Revised Regulatory Proposal is structured in three parts:

- Part 1 – Addresses the issue of age versus condition based replacement;
- Part 2 – Addresses the test applied by the AER and PB to assess the prudence and efficiency of the forecast as provided in the June 2009 Regulatory Proposal; and
- Part 3 – Addresses each of the asset categories in turn, providing additional information in support of the proposed replacement forecasts.

10.4.4.3.1 Part 1 – Replacement based on condition

Ergon Energy agrees with the AER that a condition based approach to replacement is appropriate. Ergon Energy replaces assets based upon condition based inspections and assessments. Ergon Energy disagrees with the assessment by the AER that asset replacements are undertaken based on age.

The two main programs under which Ergon Energy replaces assets are the defect and condition based programs. These are addressed in the following paragraphs.

The defect program accounts for approximately 41 per cent of the total Asset Replacement and renewal capital expenditure in Ergon Energy's Regulatory Proposal. Ergon Energy's defect remediation program flows out of the asset inspection program and also includes repair or replacement following the failure of major items of plant such as underground cables or transformers. Defects are classified as P1, P2 or PM. P1 and P2 defects are those that are likely to fail imminently or within the next inspection interval and must be remediated within the Defect Policy timeframes. PM defects are those that are non-compliant with regulatory requirements (e.g. clearances and earth resistance) or do not meet specified condition requirements and can be programmed for remediation on a planned basis after further assessment of their condition and as funding permits. The forecasts in NARMCOS for this program are based on the asset population and known historical defect rates from the asset inspection program.

Condition based programs make up the remainder of the Asset Replacement and renewal capital expenditure program being approximately 59 per cent of total Asset Replacement capital expenditure. Replacement or refurbishment under these programs is based on asset condition determined from various maintenance and testing programs, an analysis of network performance and also of dangerous electrical events (DEEs). Where condition information is not known, asset age is used as a proxy for condition for the purposes of prioritising areas of the network for analysis and also for financial forecasting purposes. While asset age is used in this manner, age is not used as the basis for asset replacement. Contrary to the conclusion drawn by PB in their report, replacement is only undertaken following analysis of the performance and condition of assets.

In order to obtain an additional perspective on its Asset Replacement expenditure forecasts and policies, Ergon Energy engaged Huegin to examine its Asset Replacement capital expenditure. Huegin's report [Document RP938c] found that:

- Ergon Energy uses the most appropriate maintenance method given the assets and circumstances, whereby its Preventive Maintenance is based upon predictive inspections;
- Age is used to forecast replacement volumes, rather than for identifying assets that are to be replaced; and
- Replacement of assets is based on asset condition.

Ergon Energy reiterates that it replaces assets based upon condition and performance rather than age. Further to this issue, for the three asset types for which a reduction in replacement capital expenditure has been proposed, the particular condition attributes used to assess condition are shown in Table 10-5.

Table 10-5 - Condition indicators used by Ergon Energy

Asset Type	Condition indicators used
Pole tops	Visual inspection
Zone substation transformers	Oil condition, Moisture content, Degree of polymerisation, Dissolved gas analysis
Conductors and connectors	Material type, diameter, recorded failures

It is important to note that in tailoring programs for condition assessments, age can be used as a factor in identifying high-risk assets, as can climate, the knowledge of local depot personnel and the number of failures being experienced.

10.4.4.3.2 Part 2 - Justification of a reduction based on the test applied

In order to assess the prudence and efficiency of the Asset Replacement capital expenditure for the 26 asset classes, the AER has used an assessment of four categories making up 48 per cent of the Asset Replacement capital expenditure.

A statistical test applied by the AER and PB requires that a hypothesis be framed. However, there has been no hypothesis stated.

The entire category has been allocated a spend equivalent to a business as usual level. The only asset class that met this condition of the four examined was underground cables and joints. Based on one in four assets satisfying the criteria, the rest of the categories were allocated a business as usual level of expenditure; this is flawed both logically and statistically.

The logical flaw is that no hypothesis was stated and the test result was still applied. The statistical flaw is that a result of one from a sample of four taken from a population of 26 could be expected to return results accurate to 25 per cent +/- 39.8 per cent. That is, the margin of error of the results is greater than the result of the test.

Based upon both statistical and logical flaws, the reduction in replacement capital expenditure cannot be justified by the results of the test applied.

10.4.4.3.3 Part 3 - Review of Specific Asset Categories

As the AER adjusted the proposed level of expenditure on the adjustment made to three of the four asset types examined, the following sections of the revised proposal address each of these three categories.

Pole Top Replacement Program

The proposed Pole Top Replacement Program includes the remediation of defects identified through current Elevated Work Platform (EWP) inspection program in the Far North region, defects that are forecast to require remediation from the introduction of new detailed (mast mounted camera and aerial inspection) programs and also some provision for condition based sub-transmission line pole top replacement. This program constitutes 10 per cent of the total Asset Replacement capital expenditure.

Based on the views of the AER and PB, Ergon Energy has provided additional clarification of the justifications of the original forecasts. Additionally, Ergon Energy engaged Huegin to review the appropriateness of the volume forecasts.

The proposed forecast for pole tops replacement is based upon a program that has been implemented because of the failure of the current (business as usual) approach to deliver the required level of reliability in areas deemed to be high risk. The traditional inspection process is critically flawed, and as such, a revised program has been designed, tested and implemented.

The revised program has been assessed during two separate studies. The first study (Noonan and Brooks) investigated the effectiveness of the initial program and recommended the EWP inspection program. The second study (the limited EWP program) further verified the need for a revised inspection regime for high risk poles. The current pole top replacement forecast is (as stated by the AER) based upon the results of this limited study.

Based on the prudence and efficiency of the revised program, the operating expenditure to conduct the program has been approved by the AER. The number of defects detected per inspection for this approved, targeted program will be higher than that traditionally experienced. There are two fundamental reasons for this:

- Only high risk pole tops are being targeted; and
- The inspection program has been shown to uncover a higher rate of defects (that is a higher number of defects per inspection) than the traditional program.

As such, the business as usual level of expenditure on this asset class is inappropriate. The number of defects will be higher than previously encountered.

Ergon Energy engaged Huegin to examine the replacement forecasts for pole tops and the appropriateness of the substitute business as usual forecast for this category. Huegin examined the replacement forecasts for pole tops, tracing the provenance of this program (and associated forecasts) back to the original study that prompted the EWP program. Huegin found that:

- The maintenance method employed by Ergon Energy for pole tops is appropriate;
- The study by Noonan and Brooks:
  - Highlighted that the traditional pole top replacement approach was inadequate;
  - Proposed a different method for pole top replacement; and
  - Highlighted the areas of risk to be assessed (high rainfall, aged poles).
- The targeted EWP program has shown an increased pole top defect rate;
- The operating expenditure for the EWP inspection program has been approved; and
- The revised program will result in increased pole top defects being identified – and these defects will need to be remediated.

Huegin assessed the statistical significance of the two limited studies and determined that they were of sufficient statistical significance to represent the populations from which the samples were drawn. Huegin located independent research detailing the drivers behind pole top degradation, of which environmental factors were the key. Based upon this finding, Huegin compared the environmental characteristics of the area used for the EWP program and the rest of the network. Huegin found that based on environmental parameters, the results of the limited studies can be scaled and used beyond the Far North region.

Based upon the information in the June 2009 Regulatory Proposal, the additional work undertaken and the findings of Huegin's report [Document RP938c], Ergon Energy has retained the initial asset replacement capital expenditure forecast for pole tops. In doing so, Ergon Energy emphasizes that:

- The traditional (business as usual) approach has been shown to be inadequate in two separate studies;
- The two separate studies have produced significantly elevated failure rates compared to the business as usual levels;
- Operating expenditure for an expanded program of EWP inspections, which has generated the increased defect ratios has been approved; and
- The results of the targeted programs are applicable beyond the limited area in which they were undertaken.

Conductor and Connector Replacement Program

The conductor and connector replacement program constitutes 24 per cent of total forecast asset replacement expenditure. Whilst Ergon Energy intends to reinstate the original forecast for conductors and connectors, it has particularly noted the following statements in the AER's Draft Distribution Determination:

> *The AER notes that Ergon Energy was unable to provide sufficient information to satisfy PB as to the basis for its forecast replacement volumes.*[98]
>
> *Given Ergon Energy's inability to substantiate replacement volume forecasts and its use of an age based asset replacement approach rather than a condition based approach, the AER considers that Ergon Energy has not demonstrated that its forecast replacement capex is prudent and efficient.*[99]

To clarify its position in respect of these matters, Ergon Energy has updated its "Conductor and Connector Maintenance and Refurbishment Strategy" [Document RP941c]. This document now provides specific information regarding the replacement volumes forecast and clarifies the use of a condition as opposed to age based replacement regime for conductors and connectors. The salient points from this document are:

- Ergon Energy currently replaces conductors and connectors under various investment programs, including condition based maintenance and augmentation. The main reasons for this work to be done are: voltage complaints; network performance-network reliability; augment an existing line to cater for load growth; conversion of overhead high voltage conductors to underground for key infrastructure in cyclone prone areas; mechanical (broken strand) and condition (rust, height) defects;
- Having regard to resource and other constraints, Ergon Energy has historically targeted its investment programs for those categories that have been identified as high risk and is expanding the replacement program as the risk changes. A condition based maintenance solution was implemented in 2002 to identify and remediate high risk conductor and other defects. This approach and the company's policy were reviewed again over 2007 and 2008 and the policy was updated to take account of the changing risks in some areas. Following the review additional funds were allocated in 2008-09 to replace copper conductors (including 7/064 copper conductors), particularly focusing on condition, risk and performance;
- Age, material, diameter, location, climate and performance are all factors that are used to identify high risk conductors;
- 5.7 per cent of the total conductor assets are over the recognised maximum age of 50 years. Without any replacement, 10.57 per cent of the current population will exceed the 50 year life by 2015;
- Hard Drawn Bare Copper (HDBC), especially the aged (over 50 years old), small diameter conductor, is universally recognized as having a high probability of failure:
    - 3.11 per cent (60 per cent of 5.12 per cent) of the high voltage distribution network conductor is HDBC - all of which is aged; and
    - 12.7 per cent of the sub-transmission conductor population is HDBC - much of which is aged.
- The dangerous electrical events register supports this approach of addressing HDBC – aligning poor performance with high risk assets;
- A number of external and independent reviews have also recommended increased conductor replacements, including:
    - The July 2004 EDSD Review recommended strategies be formulated to replace all of Ergon Energy's aged 7/.064 copper conductors; and
    - In 2008 the Queensland Department of Mines and Energy recommended that Ergon Energy finalise a program of work for conductor replacements.
- Ergon Energy has forecast (and therefore proposed) to replace 1.3 per cent of the installed conductor length over the next regulatory control period;
- There is more aged, small diameter, high risk HDBC to be replaced than Ergon Energy has asked for in the June 2009 Regulatory Proposal; and

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[98] AER, "Draft decision Queensland Draft distribution determination 2010–11 to 2014–15", 25 November 2009, page 111

[99] Ibid, page 111

- Ergon Energy will continue to use a risk analysis process (probability and consequence) to determine the replacement program ensuring the optimum result is achieved within resource and other constraints.

In addition to updating the “Conductor and Connector Maintenance and Refurbishment Strategy” [Document RP941c] in order to clarify the company’s position in respect of the matters raised by the AER, Ergon Energy engaged Huegin to review the approach to forecasting replacement volumes and identifying the actual assts to be replaced. Huegin found that the approach to maintenance and the method of forecasting replacement volumes was appropriate. Further, Huegin found there to be no justification for the proposed business as usual level of expenditure detailed in the Draft Distribution Determination.

Ergon Energy recognizes that there are still enhancements to be made in the management of the conductor and connector asset population. This was a key motivation for Ergon Energy developing and implementing the maintenance and refurbishment strategy mentioned earlier in 2002, and progressively reviewing and improving its focus again in 2007, and again since then. Ergon Energy continues to improve the management of conductors and connectors and reinstates the original forecast replacement volumes noting the following key points:

- Ergon Energy replaces conductors and connectors based on condition, risk and performance – exercising prudence;
- Ergon Energy has proposed a realistic program, recognizing resource and other limitations; and
- Ergon Energy will use a risk based approach to optimize the actual replacements – adopting an efficient approach.

Zone Substation Transformer Replacement

Ergon Energy has proposed a budget of 7 per cent of its total Asset Replacement capital expenditure on zone substation transformer replacement. Of this, 31 per cent of the zone substation transformer capital expenditure is for the purchase of strategic spares, which is essentially for the replacement of failed in service transformers. The other 69 per cent relates to a transformer dry-out program and planned replacement prior to failure of transformers at the end of their life.

The costs associated with the failure of a transformer in service can be significant. In a recent case of the failure of a 2.5MVA transformer in a single transformer substation, the direct costs associated with the failure were approximately $400,000. This covered the cost of generation, staff time and customer claims. However, an estimated additional $1.5 million customer loss of supply cost, not to mention the loss of reputation and discomfort for customers was also incurred. Because of the distributed nature of the Ergon Energy network, there are more than 100 substations that are single transformer substations with no or limited back-up capability. Therefore, it is not economically viable for Ergon Energy to install N-1 supply capability at these substations.

Ergon Energy has already provided the AER with a transformer failure rate for the last few years. Approximately 26 failures were identified over the past two years, of which 12 have had winding failures – refer Document PL587c and Document PL835c. Ergon Energy is moving to a more proactive program for transformer management, including transformer dry-outs and replacement prior to failure, as the cost of transformer failures in service can be significant as discussed above.

As indicated in Ergon Energy’s response to PB’s question PB.ERG.VP.30:

> *Ergon Energy also has a comprehensive routine oil sampling program for oil filled equipment. The Powerlink Oil Testing Laboratory under a formal Service Level Agreement performs dissolved gas analysis of these samples. The results of each oil sample are colour coded (Red, Amber, Yellow and Green) by Powerlink to indicate the urgency of the response required and emailed to nominated Ergon Energy staff. The results are reviewed and future action plans developed for the equipment to ensure the ongoing equipment integrity and the safety of staff.*
>
> *The detailed test results from Powerlink are also loaded into the Ergon Substation Contingency and Management System (SCAMS) where further analysis and trending of results is carried out. Reports from SCAMS are then used to review equipment maintenance, refurbishment and replacement actions.*

Record sheets are completed when performing routine maintenance on substation equipment. Examples of these include battery testing, circuit breaker testing, and DLA measurements on bushings. Measurements and testing results are recorded on these forms and assessed against acceptance criteria as specified on these sheets. Plans are in place to also load this information into Ellipse/SCAMS to enable trending and analysis over time.

At the present point of time, maintenance of substation equipment is only scheduled on time intervals. In the future it is intended that maintenance of tap changers and circuit breakers will be scheduled on a combination of operation counts as well as time. However further project work is required to enable capture of this operational data from the field and storage in Ellipse and SCAMS to enable analysis and triggering and scheduling of future routine maintenance work in accordance with pre-determined criteria.

The Individual Transformer Condition Reports for Transformer Dry-Out Program document [Document PL599c] highlights some of the transformers in the network that are in need of dry-out. The 18 transformers in the report each have detailed information in relation to:

- Expected life;
- The actual transformer insulation age;
- The PCB level;
- Water Content;
- Dissolved gas analysis;
- Degree of Polymerisation;
- Other information such as:
    - Location;
    - Make;
    - Voltage Primary & Secondary;
    - Serial Number;
    - Rating;
    - Year of Manufacture; and
    - Equipment Status.

Document PL783c details condition assessments on 445 power transformers that require some intervention to address their condition. In its Draft Distribution Determination, the AER noted that "PB concluded that there was no information provided to substantiate the volume forecast for the general replacement of transformers" [537]. This statement is incorrect as the above document clearly indicated those transformers for which the most appropriate action is planned replacement or dry-out.

On page 537 of its Draft Distribution Determination, the AER also noted:

PB noted that the purchase of strategic spares is based on historical failure rates and these rates are much higher that general industry trends which most likely indicates an underlying asset management problem. PB was also concerned that the proposed transformer dry-out program volumes may be too low given the apparent state of the transformer population and its high failure rate.

This reflects that Ergon Energy does have a significant management issue to address the condition of its transformer fleet. Ergon Energy has proposed a number of interventions as shown in Document PL783c for the management of its transformers based on their condition, being the provision of:

- Strategic spares for the replacement of failed in service transformers. It is noted that only 25 such replacements have been provided for over the next five year period. This is much lower than the current failure rate, which has been 26 failures in the last two years alone. This lower forecast failure rate takes into consideration the other intervention measures below;

- General replacements prior to failure of 35 transformers of various sizes at the end of their lives. The total of these general replacements plus the failed in service replacements mentioned above is less than the expected number of transformer failures given the current failure rate;
- A dry-out program either in the workshop or onsite to dry-out transformers with high moisture content but still with significant remaining insulation life. The high moisture content in these transformers presents a high risk of transformer failure and also necessitates de-rating of the transformers until moisture levels are reduced. This program requires re-clamping of windings due to their shrinkage after the dry-out. Due to the number of transformers requiring this treatment, it is planned to perform dry-outs in both the workshop and on-site. Various factors, including the availability of spares, workshop capacity, transport considerations and site access constraints will determine the appropriate action for each transformer. A dry-out program is currently in development; and
- A dry-out program under the operating expenditure program using Trojan dry-out units and molecular sieves to dry-out transformers with high moisture levels but at a level that does not require treatment in accordance with the dot point above.

The dry-out programs proposed by Ergon Energy will help reduce the probability of failure of these transformers as the water content in oil reduces the insulation level of the transformer. Ergon Energy believes that the intervention measures being adopted to address the condition of its transformer fleet are appropriate and that the proposed programs are prudent and efficient.

Ergon Energy has reviewed its forecast for zone substation transformers replacement and has prepared Document RP939c. In this document, Ergon Energy modelled the transformer fleet to ascertain the likely rates of failure and the required levels of intervention and replacement. Ergon Energy's approach was to use the current condition of the fleet, coupled with known failure rates to model the degradation of the fleet over time. Using this approach, Ergon Energy then modelled the likely levels of failure and also the levels of intervention required. Ergon Energy's model applies the current business rules in terms of intervening based on transformer condition (insulation or oil condition). It should be noted that prior to using the actual failure rates from the last two years, Ergon Energy attempted to use the same failure rate curves as used in various research papers addressing transformer failure. Unfortunately, the Ergon Energy fleet is aged past the point where meaningful results can be achieved using the available research data on failure probability with age.

Table 10-6 compares the results of Ergon Energy's model and the forecasts it derived. In summary, Ergon Energy's model predicts a greater number of events (and as such expenditure) than were forecast in its June 2009 Regulatory Proposal.

Table 10-6 - Comparison between revised modelling and forecast for June 2009 Regulatory Proposal

Item	June 2009 Regulatory Proposal	Revised modelling	Notes
Dry-outs required	76	90	
Treatment with Trojan or molecular sieve	100	142	- Without additional capital expenditure to buy further equipment Ergon Energy will be unl kely to be able to undertake more than they have allocated. That is, Ergon Energy will be able to accomplish in the order of 100 dry-outs
Strategic spares required (driven by forecast failures)	25	44	- The 44 failures
Replacements required	25	53	- Capital expenditure forecast assumes only 45 replacements. This is because it is assumed that the final 10 replacements will actually take place in the following regulatory period, as they are modelled to reach replacement point at the end of the 2010-2014 regulatory period
Forecast capital expenditure	$57.8m	$89.0m	- Figures exclude overheads

Ergon Energy's modelling indicates that its proposed zone substation transformer replacement capital expenditure is likely to be insufficient for the next regulatory control period. The modelling clearly shows that, based on condition, Ergon Energy's forecast zone substation transformer replacement is required in order for it to operate prudently and efficiently. Ergon Energy agrees with PB's concern that the proposed volumes for the dry out program may be too low given the condition of the transformer fleet.

Ergon Energy notes, however, that it faces equipment and resource constraints, which are likely to affect its ability to undertake more dry outs than it allowed for in the regulatory forecast. Ergon Energy concludes that business as usual expenditure for zone substation replacement is insufficient for the next regulatory control period. Business as usual levels of expenditure will restrict Ergon Energy to undertaking only a certain proportion of the required transformer replacements. This will pose a significant risk to Ergon Energy due to the higher probability of transformer failure that will result.

Based on the initial work completed, as well as the modelling undertaken, Ergon Energy considers that the forecast replacement capital expenditure associated with transformers is the absolute minimum that a prudent and efficient operator would require in the same circumstances. The AER and PB have indicated that there was insufficient information to support the volume forecasts. In addition to the complete condition assessment of the 445 degraded transformers that clearly supports the original forecast, Document RP939c also highlights the need for increased expenditure.

Based on the original information and additional supporting information, Ergon Energy maintains its view that its initial forecast for zone substation transformers is required in the next regulatory control period.

10.4.4.4 Conclusion

In its June 2009 Regulatory Proposal, Ergon Energy forecast Asset Replacement capital expenditure of $1,214.1 million for the next regulatory control period. This forecast covered replacement programs for 26 classes of assets.

The AER has proposed a reduction of $118.8 million by applying a business as usual level of expenditure to Ergon Energy's Asset Replacement capital expenditure.

The AER and PB reviewed the forecasts for four of the 26 asset classes and found that three of the forecasts were not prudent and efficient. Based on the findings of the review, the AER has proposed that all 26 asset classes be subject to business as usual levels of Asset Replacement capital expenditure over the coming regulatory control period.

The AER and PB believe that Ergon Energy replaces assets based on age as well as condition. Ergon Energy does not agree with this assessment, as its assets are replaced based on condition.

The AER and PB have used a test to assess prudence and efficiency that has been shown to be logically and statistically flawed. The test is inappropriate for applying a reduction in capital expenditure across the asset categories as proposed.

The AER found that in each of the three asset classes reviewed there was insufficient information to show that the forecast replacement volumes were prudent and efficient. Ergon Energy have undertaken (and commissioned) additional work to examine the forecast replacement volumes for the three asset classes which the AER and PB examined in detail.

In each of the three asset classes examined by the AER, Ergon Energy maintains that the original forecasts are appropriate, as they reflect prudent expenditure that may even be lower than is actually necessary. Ergon Energy will ensure prudence through a risk based approach to replacement. As such, Ergon Energy maintains its original forecast of Asset Replacement capital expenditure across all 26 asset types.

Ergon Energy's revised Asset Replacement capital expenditure forecast is detailed in Table 10-7.

Table 10-7: Revised Forecast Asset Replacement Capital Expenditure – 2010-15 ($M Real $2009-10)

Category Driver	2010-11	2011-12	2012-13	2013-14	2014-15	Total	Average of 5 year Total
Asset Replacement	181.24	222.55	261.68	285.86	305.03	1,256.35	251.27

Source: Revised Submission Tables for Proposal 23.1

10.4.4.5 Summary of Concerns and Responses Regarding Asset Replacement Capital expenditure

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reduction of $119 million as the volume forecasts not demonstrated to be prudent [106, 111, 129]	- PB identified that despite claiming to use a condition based approach to asset replacement, Ergon Energy utilises an age based approach as well	- Addressed above. Ergon Energy use a condition based assessment to identify assets to be replaced.
	- The AER considers that a condition based approach that takes into account a range of factors (one being asset age) is more likely to result in an efficient outcome.	- Addressed above. Ergon Energy agrees with the AER and confirms that it employs a condition based approach.
	- The AER notes that Ergon Energy was unable to provide sufficient information to satisfy PB as to the basis for its forecast replacement volumes (with the exception of underground cables and joints Asset Replacement capital expenditure).	- Addressed above. In each of the three cases where concerns were raised, Ergon Energy has undertaken additional work (or commissioned additional work) to further examine the initially proposed replacement forecasts. In each case, the initial forecasts were found to be either prudent or lower than may actually be necessary. Ergon Energy uses a risk based approach to ensure prudence.
	- The AER considers forecast replacement volumes are a key driver of overall replacement capital expenditure and therefore must be accurate and reliable to develop a prudent and efficient forecast capital expenditure program.	- Addressed above. In the three cases examined by the AER, Ergon Energy has shown the forecasts to be either prudent or lower than may actually be necessary. Prudence is assured through a risk based approach.
	- Given Ergon Energy's inability to substantiate replacement volume forecasts and its use of an age based asset replacement approach rather than a condition based approach, the AER considers that Ergon Energy has not demonstrated that its forecast replacement	- Addressed above. Ergon Energy has in all three cases examined by the AER completed additional work (or had additional work completed) to examine the replacement volumes. In each case the volumes forecast by Ergon Energy have been substantiated. As discussed by both Ergon Energy and Huegin, Ergon Energy does not use an age based approach to asset replacement.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
	capital expenditure is prudent and efficient	

10.4.5 Reliability and Quality Improvement

10.4.5.1 Ergon Energy's June 2009 Regulatory Proposal

Ergon Energy proposed Reliability and Quality Improvement capital expenditure of $122.4 million for the next regulatory control period.

10.4.5.2 The AER's Draft Distribution Determination

The AER did not accept Ergon Energy's forecast for Reliability and Quality Improvement capital expenditure. Specifically, the AER:

- Stated that Ergon Energy has established prudent strategies to identify the worst performing parts of its network and targeted expenditure on those areas [113];
- Reviewed the feeder improvement program (which constitutes 33 per cent of the forecast) documentation and accepted "PB's advice that there is insufficient information to support the program." [113];
- Accepted PB's advice that "forecast reliability and quality capex be maintained at current period levels with an allowance for the SCADA acceleration program added to it" [113]; and
- Considered that "reducing Ergon Energy's proposed reliability and quality capex by $35 million results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for this capex component to comply with the NER." [113].

10.4.5.3 Ergon Energy's response to the Draft Distribution Determination

Ergon Energy has considered each of the AER's concerns and, on the basis of reviewing the original assumptions and methodology employed, does not accept the AER's decision to reduce the forecast Reliability and Quality Improvement capital expenditure.

10.4.5.3.1 Concerns raised by AER regarding Ergon Energy process

Particular concerns raised by PB and referenced by the AER in relation to Ergon Energy's Reliability and Quality Improvement capital expenditure planning process are:

- Ergon Energy's feeder improvement program documentation demonstrates a targeted approach, yet the documentation "fails to demonstrate why the top 50 worst performing feeders is the prudent number to target" [543];
- There is no detailed analysis of the cause of poor performance of the worst performing feeders [543];
- The individual benefits of each feeder improvement are not recognised or the timeframe over which they should be addressed is not listed [543]; and
- It does not address the potential overlap in the proposed expenditures [543].

Ergon Energy does not consider the above criticisms accurately represent the processes adopted by the company. Each of these issues is addressed in turn in the following sections.

10.4.5.3.2 Fifty worst performing feeders a reporting figure, not the targeted works

The reporting of the 50 worst performing feeders is a legacy of the QCA requirement to report the 10 worst performing feeders in each category (urban, short rural and long rural) and Ergon Energy's decision to include an extra 20 short rural feeders due to the significant proportion of customers connected to the short rural network. It does not affect the prudence or efficiency of Ergon Energy's Reliability and Quality Improvement expenditure forecast. To be clear, Ergon Energy:

- Identifies all “red” feeders – of which there are currently 145 in the distribution network;
- Reports on, and conducts deeper investigations into, its 50 worst feeders; and
- Targets 8.5 feeders per year based on deliverability considerations.

The number of feeders actually targeted by the Feeder Improvement Program is therefore based on balancing the identified need with resource constraints.

The AER states that Ergon Energy has established prudent strategies to identify the worst performing parts of its network and target expenditure on those areas. Ergon Energy considers that the inclusion in the Draft Distribution Determination of PB’s concerns regarding the top 50 worst performing feeders being the “prudent number to target” is not a valid reason to reduce Ergon Energy’s Reliability and Quality Improvement capital expenditure as:

- The number of worst performing feeders reported by Ergon Energy does not represent the number of feeders targeted; and
- There is no requirement in the Rules to report or target a specific number of feeders when planning Reliability and Quality Improvement capital expenditure.

10.4.5.3.3 Causes of poor performance are investigated

Ergon Energy, contrary to the statement in the Draft Distribution Determination, conducts causal analysis of feeder performance issues. The outcome of this analysis is documented in the annual network performance reports [Document AR049, Document AR151, Document AR217, Document AR218, Document PL704c, Document RP906c and Document RP907c] and Network Management Plan [Document AR402 and Document AR445]. The Feeder Improvement Program Strategy [Document AR341] includes reference to these documents.

In terms of reliability, causes of poor performance are instances that result in network outages. The appendices of the Network Management Plan [Document AR402 and Document AR445] include summary tables of the 20 categories of event triggers and the relative contribution to the feeder customer minutes lost. This data informs both the requirement to address the performance issue and the most appropriate improvement or remediation action. The reporting of feeder performance over three years when identifying red feeders further assists in the determination of appropriate improvement initiatives.

Huegin’s report [Document RP938c] provides further evidence of the inclusion of causal analysis in the development of the Feeder Improvement Program.

10.4.5.3.4 Benefits and timing are addressed

Individual feeder improvement initiative benefits identification and timing considerations are inherent in the Feeder Improvement Program [Document AR341]. Benefits of improvement options are identified and discussed in the Network Management Plan [Document AR402 and Document AR445]. Determination of the most appropriate timing is a dynamic decision-making process that is based on the prioritisation of need and resource and the capacity planning process of Ergon Energy.

10.4.5.3.5 Overlap potential is mitigated

In its Draft Distribution Determination, the AER references PB’s statement that Ergon Energy’s Feeder Improvement Program is “not specifically targeted expenditure but appears to be a provision to address feeder performance”. The AER further references PB’s acknowledgement that this is “strictly not an issue of efficiency”, but a consideration for “concern due to the potential for the proposed capex to duplicate other capex and opex that are identified to target the same performance problems”.

Ergon Energy agrees that, to degree, the forecast is a “provision to address feeder performance”, but only as far as:

- Any forecast based on assumptions of future requirements is a provision; and

- Reliability improvement options are based on the identification of actual worst performing feeders and causes of reliability problems, which will change over time and hence cannot be definitively scoped ex-ante.

Ergon Energy does not consider that the above points provide potential for duplication of operating expenditure or other capital expenditure. The Feeder Improvement Program planning process includes the identification of projects in the near, medium and long-term that either address feeder performance issue through alternative expenditure programs and/or are programmed on the same location as the poorly performing feeder. Therefore, where a red feeder's performance is likely to be improved by a planned refurbishment or replacement project, that feeder will eventually 'drop out' of the worst performing feeder list and those outside the top 50 will be included in its place.

Further, Ergon Energy's Network Management Plan [Document AR402 and Document AR445] includes the requirement to consider maintenance and operation solutions concurrently with reliability improvement initiatives when determining the most appropriate strategy for improving reliability of poorly performing feeders.

Huegin's report [Document RP938c] provides further evidence of the inclusion of causal analysis in the development of the Feeder Improvement Program.

10.4.5.3.6 Historical expenditure not reflective of need

PB recommended that forecast Reliability and Quality Improvement capital expenditure be maintained at current period levels, with the exception of an allowance for the SCADA acceleration program. The AER considered that "PB's recommended approach to calculation of a substitute reliability and quality capex allowance is reasonable" and, noting that current regulatory control period Reliability and Quality Improvement capital expenditure averages $11 million per annum, adjusted the Ergon Energy forecast by $35 million. Ergon Energy does not consider that this approach meets the capital expenditure criteria as:

- PB acknowledge that they have not assessed the prudence and efficiency of current period Reliability and Quality Improvement capital expenditure;
- Actual current period Reliability and Quality Improvement capital expenditure is much lower than planned due to a reallocation of resources to meet regulatory obligations to connect customers, which grew faster than anticipated; and
- The approach does not consider the likely requirement for reliability improvement expenditure in the next regulatory control period nor the reduction of Minimum Service Standard targets.

Ergon Energy considers that the AER's reliance on PB's recommendation for a reduction in the forecast without due consideration of the reasons for the historically lower than allowed capital expenditure reflects a failure to consider the circumstances of the DNSP in accordance with clause 6.5.7(c)(2).

Historic underspend

Ergon Energy has underspent on Reliability and Quality Improvement capital improvement due to the significant increase in growth above that anticipated in the current regulatory control period. It also compounds a legacy of such trade-offs being made - with the regulatory obligation to connect customers taking resources away from planned reliability improvement expenditure.

The 2004 EDSD Review found that both ENERGEX and Ergon Energy re-allocated capital expenditure from reliability and replacement works to customer connection works over the previous regulatory period (2001-05) in order to accommodate unexpected growth rates. The QCA noted in its Final Determination that:

> *The EDSD Review (2004) found that both Energex and Ergon re-allocated capex from reliability and replacement works to customer connection works over the current regulatory period in order to accommodate a higher number of customers than was originally forecast.*[100]

[100] Queensland Competition Authority, Final Determination – Regulation of Electricity Distribution, April 2005

A greater allowance was subsequently made for Reliability and Quality Improvement capital expenditure, however further growth above that anticipated in the current regulatory period (2006-10) also constrained the proportion of the allowance that could be expensed.

This legacy has resulted in Ergon Energy achieving a relative level of Reliability and Quality Improvement capital expenditure that is among the lowest in Australia, as shown in Huegin's report [Document RP938c].

Forecasts based on need

Ergon Energy considers the current and historical expenditure for Reliability and Quality Improvement capital expenditure to be less than prudent as well as less than planned. Ergon Energy also has MSS targets that are becoming more stringent, particularly this year and next.

The pressures of the historic underspend on reliability improvement initiatives and the significant progressive lowering of MSS targets require Ergon Energy to respond with Reliability and Quality Improvement capital expenditure programs that will meet increasing expectations of customers. The Feeder Improvement Program developed by Ergon Energy is:

- Based on the gap analysis of feeder performance and MSS targets;
- Prioritised for worst performing feeders and the number of customers affected; and
- Informed by the benefits and expected average cost of the initiatives available to Ergon Energy.

Ergon Energy therefore considers that its Reliability and Quality Improvement forecast for the next regulatory period is reasonable for a DNSP in the circumstances of Ergon Energy.

10.4.5.4 Ergon Energy revised regulatory proposal for Reliability and Quality Improvement

For the reasons outlined in this section, Ergon Energy has retained its original forecast for Reliability and Quality Improvement capital expenditure from its June 2009 Regulatory Proposal.

The AER states that their review found Ergon Energy's policy and procedure to be in general accordance with good electricity practice. Further, the AER states that Ergon Energy has established prudent strategies to identify the worst performing parts of its network and target expenditure on those areas. The AER's main concern therefore appears to be related to PB's concerns regarding the potential for overlap with other capital expenditure programs and the reported lack of supporting information for specific programs.

Ergon Energy has demonstrated that the potential to duplicate other capital and operating expenditure is mitigated through the planning process. Ergon Energy has further demonstrated that:

- The need for the Reliability and Quality Improvement capital expenditure is clear and that the forecast provided by Ergon Energy represents the amount possible with resources constraints which is lower than the optimum amount if resources were not constrained;
- Costs and benefits are considered in the planning process;
- Integration with other network strategies is considered; and
- Using historical Reliability and Quality Improvement capital expenditure without reviewing the prudence of that expenditure places Ergon Energy customers at risk of increasing reliability and quality of supply issues.

With the adjustment for the treatment of escalations and overheads, Ergon Energy's revised proposal for Reliability and Quality Improvement capital expenditure is detailed in Table 10-8.

Table 10-8: Revised Forecast Reliability and Quality Improvement Capital Expenditure – 2010-15 ($M Real $2009-10)

Category Driver	2010-11	2011-12	2012-13	2013-14	2014-15	Total	Average of 5 year Total
Reliability and Quality Improvement	18.49	21.49	25.16	29.00	30.85	124.99	25.00

Source: Revised Submission Tables for Proposal 23.1

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reduction of $35 million as feeder improvement program has not been demonstrated to be efficient [106, 129]	- Not clear to PB why 50 worst performing feeders is the right number [543]	- There is no explicit regulatory justification for 50 worst performing feeders. Ergon Energy was required to report annually on the 10 worst performing feeders in each category via the QCA's annual regulatory report. Ergon Energy further chose to include the next 20 worst short rural feeders as this is the category of Ergon Energy's biggest customer base. - As detailed in section 10.4.5.3, the number of worst performing feeders reported has no relevance to the expenditure forecast and no bearing on the prudence and efficiency. The exact number of feeders chosen to target is calculated based on the available resources and Ergon Energy's capacity to deliver the forecast program.
	- Benefits of feeder improvement program not recognised or the timeframe over which they should be addressed is not listed [543, 546]	- Estimated benefits and costs are included in the Feeder Improvement Program. Benefits are measured in customer minutes and valued against hurdle rates derived from industry values such as Value of Customer Reliability (VCR) and the STPIS regime. - The timeframe is inherent in the ranking and prioritisation process – the best value projects will be addressed first, unless resources dictate otherwise.
	- the causes of poor performance are not recognised, and it is therefore unclear how the proposed expenditure will address the performance issues and how the proposed cost has been determined [543, 546]	- As discussed in section 10.4.5.3, cause analysis is available in the annual network performance reports and Network Management Plans. - The proposed costs are determined based on an average cost per feeder, which is calculated on the basis of unit rates for reliability improvement product building blocks.
	- other capital and operating expenditures are identified that will also target the same performance problem, and this has not been taken into account in the development of the feeder improvement program capital expenditure proposal [543, 546]	- Ergon Energy's Feeder Improvement Program [Document AR341] provides a description of the process by which Ergon Energy assesses and identifies works for inclusion on the Feeder Improvement Program. - Through this process, Ergon Energy considers other capital and operating expenditure that has, or will, impact a feeder's performance in order to ensure that there is no overlap with other expenditure outside of the feeder improvement program. - Ergon Energy notes that, if it is determined that the proposed expenditure is not required for the targeted feeders due to performance improvements resulting from other expenditure programs, then there are a significant number of alternative poor performing feeders on the worst performing feeder list that Ergon Energy can target in order to improve the SAIDI performance.
	- The AER has reviewed the feeder improvement program documentation	- Section 10.3.5 of this Revised Regulatory Proposal clearly identifies the need for Reliability and Quality Improvement capital expenditure. Ergon Energy considers that the

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
	and considers that there is insufficient information to support the program. [546]	program documentation, encompassing the feeder improvement strategy and program, the annual network management plan and performance reports, is sufficient to support the program.
	- PB recommended expenditure be maintained at current levels plus allowance for SCADA acceleration strategy [544-6]	- Ergon Energy considers that the results of PB's analysis neither proves nor supports their assumption about the efficiency of the current expenditure and that it is inappropriate to extend any conclusions that PB may have drawn on the basis of their limited review. There is, however, sufficient information to demonstrate that current expenditure is not a reasonable basis for a substitute forecast. - As discussed in the Huegin report [Document RP938c], in comparison with other Australian DNSPs, Ergon Energy has historically had relatively low levels of Reliability and Quality Improvement capital expenditure. - Ergon Energy considers that its historic Reliability and Quality Improvement capital expenditure is inadequate to improve the reliability and quality performance of its network through the generic feeder improvement program and the Feeder Improvement Program for Worst Performing Feeders - Ergon Energy considers that its original forecasts were within a range of acceptable values and rejects the basis on which the AER has proposed its alternative values. This is because the AER has provided no proof or support for the retention of business as usual expenditure.

10.4.6 Non-System - Information Communication and Telecommunications

Ergon Energy's Regulatory Proposal requested an amount of $10 million per annum for its change program (see Table 5.7 in PB report). This request was categorised as part of the "End Use Computing Assets", however, the change program is not directly related to ICT.

This funding has been revised to $2 million per annum which comprises non-ICT change projects and Cultural transformation supporting ICT change projects.

10.4.6.1 Cultural Transformation

Ergon Energy is embarking on a transformation program designed to transform the way its people operate in order to deliver on its strategic objectives. Ergon Energy's Strategic Plan [Document AR099] highlights that it will be delivering power to its customers in fundamentally different ways in the future and whilst this has a substantial impact on its network assets and IT capability, effectively transforming to these new ways of working is not possible without a fundamental shift in employees' skill and mind sets. Thus the transformation of its culture is the underpinning success factor to being able to develop, implement and embed a sustainable and different way of doing business that is efficient and prudent.

This transformation will be built around the traditional ICT program and non ICT change projects (described below). ICT projects have changes associated with the project incorporated into the project costs, however they do not address the greater cultural transformation effort that is required.

10.4.6.2 Non-ICT change projects

Non-ICT projects also make up the change program. Over the last three years, these projects have addressed change in the following areas: Complaints Management; Control Centre Transition; the customer driven capital works process (Nexus); Ellipse Training Material Development; Field Switching Authorisation Training; Operating Schematics; Outage Management; and Materials Forecasting.

Non-ICT changed projects averaged around $1.3 million per year for the years 2008-09 and 2009-10. It is expected that, with the level of transformation required, the expenditure in 2007-08 ($2.25 million) will be the benchmark going forward. Ergon Energy's submission allows for an incremental amount of $2 million per year in non-ICT change.

Ergon Energy has separately identified this expenditure as it is a crucial and fundamental part of transforming the business over the next regulatory period. While it could be argued that transformation activities are part of a normal business cycle and thus form part of the normal operating costs, Ergon Energy has classified this separately and should not be penalised for making this expenditure transparent.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reduction of $65 million to remove costs associated with change program [106, 117, 129]	- Costs associated with change program should be removed because Ergon Energy is unable to provide business case documents – not demonstrated to be prudent and efficient [117, 563, 572]	- Change program costs have been revised down from $10 million per year to $2 million per year based on historical incremental spend in the non-ICT change program.

10.4.7 Non-System - Property

In its Draft Distribution Determination, the AER cut Ergon Energy's property capital expenditure program for the next regulatory control period by $191 million to $196 million on the basis of advice from PB that Ergon Energy's proposed property capital expenditure was not prudent and efficient and that the AER should only approve an amount that reflects a "business as usual approach"[101].

Ergon Energy disagrees with the AER's Draft Distribution Determination and has provided additional documentation to substantiate and justify its proposed expenditure in order to demonstrate that it is both prudent and efficient. Ergon Energy considers that its proposed capital expenditure on property is necessary in order to, amongst other things:

- Comply with regulatory building requirements;
- Comply with safety and environmental requirements;
- Achieve the operational performance outcomes that underpin this Revised Regulatory Proposal; and
- Effectively manage potential post-disaster (cyclone) operational responses.

10.4.7.1 "Business As Usual" Consequences for Ergon Energy

The AER has not recognised the following matters in accepting PB's recommendation to maintain "business as usual" investment levels in the next regulatory control period:

- The historical *ad hoc* development of Ergon Energy's major depots and under-investment in its property assets over the last 10 to 12 years has resulted in many dysfunctional site layouts, less than desirable safety outcomes, less than optimal workplace productivity performance and building compliance issues with certain property assets;
- Over the last 10 to 12 years, growth in industry demand, particularly from the mining sector, has driven increased growth of the electricity network which has led to growth in the order of 30 per cent in overall employee numbers and business facilities' requirements across Ergon Energy's network. This growth, combined with a non-strategic approach to property management, has resulted in fragmented property assets resulting in inappropriate accommodation capacity solutions and low workplace efficiencies at many major regional locations. For example, Ergon Energy operates in Townsville out of eight separate properties with a number of employees currently accommodated in temporary demountable buildings, resulting in inefficient property utilisation and ineffective work practices;

[101] AER, "Queensland Draft Distribution Determination 2010–11 to 2014–15", page 508

- Many of Ergon Energy's property assets are either approaching, or at, the end of their economic lives, where fitness for purpose and/or compliance with current standards has resulted in a need to fundamentally replace or upgrade them; and
- PB's retrospective rejection of the 2006 Board approval of the Property Strategy has serious implications for Ergon Energy. For example, existing contractual commitments, involving expenditure over the 2008-09 to 2010-11 period, are already in place yet have been disregarded by PB. Pre-existing contracts that require investment expenditure in 2010-11 will need to be honoured by Ergon Energy and yet are not acknowledged in the PB advice. Ergon Energy considers this an unreasonable outcome.

Ergon Energy is facing a period of change in the approach to property asset management and believes that PB's recommendation for "business as usual" investment levels will result in unacceptable asset performance; operational inefficiencies and suppressed productivity rates; and increased safety and environmental risks resulting from these legacy issues. This situation cannot generally be addressed incrementally.

10.4.7.2 Ergon Energy's Revised Regulatory Proposal for Property Capital Expenditure

Ergon Energy's revised property expenditure for the next regulatory control period is detailed in Table 10-9.

Table 10-9: Revised Property Capital Expenditure – Direct Costs ($M Real 2007-08)

	2010-11	2011-12	2012-13	2013-14	2014-15	Average of 5 year Total
Investment Major Works	59.00	42.00	37.00	15.00	22.00	175.00
Investment Routine Works	28.00	31.00	17.20	8.10	4.50	88.80
Total	87.00	73.00	54.20	23.10	26.50	263.80

The Revised Regulatory Proposal forecast of $263.8 million is $3 million lower than the $266 million included in Ergon Energy's June 2009 Regulatory Proposal.

Table 10-10: Changes to Property Capital Expenditure Forecast ($M Real 2007-08)

	Change ($)	Details
Swallow Road Cairns	7.1	Amended scope reflecting further design development
Stage 1 Glenmore Rd Rockhampton	4.8	Represents completion of pre-existing commitment.
Stage 2 Glenmore Rd Rockhampton	2.8	Amended scope reflecting further design development
Ness Street, Mackay	15.9	Represents completion of pre-existing commitments
Searle St Maryborough	8.8	Amended scope representing further design development
Data centre building	(20.0)	Removed from submission
Ingham Rd Townsville	(3.3)	Refined estimate of works[102]
South Street Toowoomba	(11.0)	Reprioritised
Hervey Bay	(5.3)	Represents completion of pre-existing commitments
Purchase of Land	(2.8)	Removed from submission
Total Variance	**(3.0)**	

Ergon Energy has prepared a series of documents to support its revised property capital expenditure, including detailed business cases for each of its high value property projects proposed for Townsville, Cairns, Rockhampton, Toowoomba and the data centre.

[102] Ingham Rd (Townsville) development has been deferred by 2 years so that site enabling civil/services works will commence in 2012/13 with site development commencing later in the 2010-15 regulatory period and spread over two regulatory periods; noting that pre-commitment will be made in the 2010-15 regulatory period for the total project.

Ergon Energy's responses to the AER's specific criticisms of Ergon Energy's June 2009 Regulatory Proposal are provided below.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reduction of $191 million to reflect a business as usual approach [107, 129]	- Ergon Energy is unable to provide business cases or other supporting documentation for high value property projects proposed for Townsville, Cairns, Rockhampton, Toowoomba, Maryborough and the data centre [118, 561]	- Ergon Energy has had regard for the AER's assessment and in order to support its view that its forecast property capital expenditure is prudent and efficient has: o Developed additional investment justification for the proposed six high value property projects: Townsville, Cairns, Rockhampton, Toowoomba, Maryborough/Hervey Bay and Mackay over the regulatory period, including independent field asset condition audit reports; independent site assessment reports; project business cases; and recommendation documents – refer to Document RP942c to Document PR961c and Document RP973c to Document RP980c; o Refined project definitions through updated user requirement specifications; refined design development details; and updated cost plans as a result of the work that has continued since the PB report was prepared; o Reviewed the proposed investment program to reflect any shifts in priorities, resulting from additional project justification work; o Prepared a revised property investment submission to reflect the refined project definitions; program priorities; and overall investment to maintain sustainable levels of investment; and o Reviewed forecast escalation rates for building construction and anticipated delivery contracts to ensure that the rates adopted for the proposed works reflect current market conditions and reasonable estimates of anticipated shifts over the duration of the regulatory period.
	- Other criticisms made by PB [560-1]:	
	o Building strategy out of date	- The PB report prepared for the AER refers[103] to the Ergon Corporate Property Strategy as "out of date" on the basis of: o Changes in estimated surplus asset values without changing the strategy; o Differences between the building works' estimates provided in the Regulatory Proposal and those in the strategy; o Prioritisation of works in the Regulatory Proposal differs from the indicative prioritisation in the strategy; and o Shifts in the market values of property assets in the time between the Corporate Property Strategy (2006) [Document AR319c] and the Regulatory Proposal. - It is true that the development work for the corporate property major works program has been progressing in the period between when the Corporate Property Strategy [Document AR319c] was approved in 2006 and the Regulatory Proposal was prepared in 2009. This has resulted in progressive refinement in works scopes and cost estimates, however the over-arching Corporate Property Strategy is unchanged; - Since receiving PB's report to the AER, Ergon Energy has commissioned independent objective site and building asset condition assessment reports and has prepared business

[103] PB Report (October 2009) P 87/192

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
		cases for each of the major works locations. On the basis of this additional work, there has been some re-prioritisation and re-sequencing of the works constituting the property major works program. This is reflected in this Revised Regulatory Proposal however the over-arching Corporate Property Strategy [Document AR319c] is unchanged; - Ergon Energy considers that the inevitable project changes that occur over time due to refined works scopes, cost estimates, asset market values, and implementation sequencing affect the detail of the capital works program but do not affect the over-arching Corporate Property Strategy [Document AR319c]. As a result, the capital works program is reviewed annually whereas the Corporate Property Strategy is reviewed every three to five years. The varying factors referred to by PB are included in the business cases' considerations that now underpin the revised property regulatory submission; and - Consequently, Ergon Energy rejects the notion that the Corporate Property Strategy [Document AR319c] is 'out of date'.
	o Lack of detail for ranking projects	- The determination of the preferred investment option for a specific regional location is undertaken as a part of the business case process; - Business cases have been completed for the proposed six high value property projects. They incorporate consideration of alternative development scenarios to address the local Ergon Energy business needs as an integral part of the process of identifying the preferred option for that location. - These business cases have been provided to the AER in Document RP942c to Document RP947c. - The overall major works program sequencing is based on: the considered level of business risk exposure and tolerance; the urgency of the business requirements for respective specific locations; pragmatic delivery and implementation considerations; and the overall level of available capital funding regarded as sustainable; - Following completion of the business cases for the six major project works locations, the relative priority of the proposed works was reviewed and summarised in Document RP962c. This reprioritisation underpins the Revised Regulatory Proposal forecasts and is based on data sourced from the individual business cases justifying the preferred development option for each of the regional locations.
	- Insufficient information re deliverability	- The delivery program for the refined major works has been appropriately scheduled to reflect realistic and reasonable time allowances for documentation; tendering; procurement; approvals; construction durations; fit-out; commissioning; and occupancy stages of the delivery process; - Ergon Energy's Corporate Property group also reviews alternative procurement strategies to establish the most appropriate balance of risk allocation; value for money; market competition; and delivery certainty for specific projects. As a consequence of awarding the first of the construction contracts for the property major works program, market confirmation has now been received for the respective planned scheduling timelines; budget estimates; procurement assumptions; and risk transfer assumptions; - In addition, throughout the ongoing delivery process for the major works program, Ergon Energy Corporate Property

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
		engages specialist external expertise for the provision of project management; quantity surveying and cost control; contractor procurement documentation; probity; and property planning and advisory services to complement the internal resources and capabilities. These services have significantly increased the overall level of confidence in delivery capability; and - Consequently, Ergon Energy believes that confidence in delivery of the major property works program is justifiably well founded.

Ergon Energy's revised total Non-System capital expenditure forecast is detailed in Table 10-11.

Table 10-11: Revised Forecast Non-System Capital Expenditure – 2010-15 ($M Real $2009-10)

Category Driver	2010-11	2011-12	2012-13	2013-14	2014-15	Total	Average of 5 year Total
Non-System	175.37	152.57	127.29	80.75	88.98	624.95	124.99

Source: Revised Submission Tables for Proposal 23.1

10.4.8 Shared Costs (Overheads)

Ergon Energy's submitted SPARQ charges based on four new areas of capability for Ergon Energy over the next regulatory period:

- Distribution Management System at a cost of $26 million;
- Field Force Automation at a cost of $18 million;
- Data centres at a cost of $5.4 million; and
- ICT infrastructure at a cost of $6 million.

The AER concluded that the majority of ICT projects were not supported by analysis that demonstrated prudence or efficiency, with the exception of the reconfiguration of the data centres [120, 571-2].

Ergon Energy acknowledges that the business cases for this expenditure were not advanced at the time of submission of the Regulatory Proposal. However, Ergon Energy has now submitted high level business cases for each of its major projects, which lead to the next steps in its internal governance process.

10.4.8.1 Distribution Management System (DMS)

DMS is the foundation information and decision support system for the deployment of intelligence in a distribution network.

Customers in the future will expect from DNSPs the ability to connect embedded renewable generation as they respond to climate change. Customers will require Ergon Energy to move from a centralised, producer-controlled network to one that is less centralised and more customer-interactive.

DMS is key to providing this capability as it allows the coordination of real time information and power flows that allows embedded generation to be connected to the system.

The DMS will provide significant other benefits as it automates many of the manual processes in operating a distribution network and supports new technologies in the network. The DMS provides benefits through enhanced operating efficiency; improved business continuity; operating the network smarter (not fatter); improved quality of supply; improved safety outcomes; enhanced customer interaction. The DMS is the foundation information and decision support system for the deployment of intelligence in a distribution network.

Ergon Energy acknowledges that the timing and nature of a DMS for Ergon Energy is still uncertain and therefore it is still building its final business case. However, Ergon Energy will continue to develop its DMS systems requirements, working through the request for tender results and the next steps on developing a detailed project planning and a business case for approval through the Ergon Energy governance processes. A high level business case for DMS is supplied at Document RP904c with supporting information is provided at Document RP902c and Document RP903c.

Based on all the above, funding to support the implementation of a DMS has been retained in Ergon Energy's (and SPARQ's) capital expenditure profile in this Revised Regulatory Proposal.

10.4.8.2 Field Force Automation (FFA)

Ergon Energy recognises the benefits that can flow from deployment of an enabling technology to its field workforce, not just in the field, but also from the changes to workflow that are possible by having mobile technology.

A FFA solution will deliver benefits that contribute to the overall three per cent annual productivity improvement included in Ergon Energy's Regulatory Proposal. These benefits include:

- A reduction in travel costs through the efficient and effective flow of information to support the remote delivery of work in the field. Field staff do not need to drive to collect daily work schedules and return forms – they are automated and available on site;
- Increases in completeness and accuracy of data. Field staff capture all the data required to finalise a job on site and timesheets, safety and risk management data are largely automated;
- Improved customer service. Ergon Energy's National Contact Centre accesses job status in near real time to provide customers and other key stakeholders with the latest information.
- Increased safety: Reduced travelling time reduces road safety incidents.

FFA is a key part of Ergon Energy's strategy for the future and so it has been retained as part of its capital expenditure forecast.

A high level business case [Document RP905c] and supporting documentation [Document PL712c, Document RP963c, Document RP964c, Document RP965c] is submitted as part of this Revised Regulatory Proposal. Ergon Energy notes that the business case is for all aspects of FFA, not just Ergon Energy's rollout and upgrade projects.

The business case includes:

- An NPV analysis based on a seven year asset lifecycle;
- Deferral of the start date for the pilot and therefore of the rollout and upgrade by 18 months;
- Inclusion of all SPARQ costs for the seven year life cycle of the asset which adds $6.1 million to the total IT Cost; and
- Inclusion of Ergon Energy costs of $7.23 million.

The business case shows that the total costs over the implementation and seven year life post implementation of the asset are $60.8 million while the benefits are $105.68 million.

This initial project outlays are $34.73 million, compared with the original estimate of $21.4 million. The original estimate was based on two of the four FFA projects included in the roadmap. The revised costs based on changes in project start dates and asset life of $34.73 million includes the SPARQ costs for the pilot project, project and schedule upgrade as well as Ergon Energy's costs for all FFA projects from 2010 to 2015. The $34.73 million represents the capital expenditure funding requirement during the five year regulatory period is broken down between project costs (pilot, rollout, upgrade, plan/schedule capital work) of $32.98 million and continuous improvements costs of $1.75 million.

Ergon Energy is not requesting these additional funds, rather it is assumed that the business will offset the additional cost through project benefits realised during the regulatory period.

10.4.8.3 New ICT Infrastructure

Technology and ICT standards are not static but rather they evolve over time. Ergon Energy considers it important to take advantage of new ICT products and capabilities as they are released, provided that expenditure on these products and capabilities can be shown to be prudent and efficient. This results in a variety of benefits, ranging from efficiency improvements and competitive advantages through to solutions that facilitate a new aspect of business capability. As new technologies mature, they often set the standards that become mainstream capabilities that are adopted and expected throughout the industry.

Examples of technologies that are currently being considered are:

- Unified communications; and
- Identity and Access Management (IAM).

The purpose of unified communications is to integrate the various forms of electronic communications such as voice telephony, email, voice mail, and instant messaging with collaboration solutions (voice – video – web conferencing) and electronic presence information to increase the total value and efficiency of communications.

The business benefits of unified communications include:

- Reduced call costs; and
- Improved staff efficiency through accuracy and efficiency of communications.

Unified communications can result in up to two hours of more productive work from individuals each day. Research firm Chadwick Martin Bailey (formerly Sage Research) calls this "The Collaboration Effect".

IAM incorporates a central database that maintains the association between user accounts and actual staff identities. This becomes a key audit and control point to manage user authentication (i.e. who are you) and authorisation (i.e. what are you authorised to do). The primary reasons to implement IAM solutions are business facilitation, cost containment, operational efficiency, IT risk management and regulatory compliance. IAM also ensures a secure access control infrastructure.

These two initiatives are forecast to cost approximately $3 million over the three year period 2010-11 to 2012-13. Business cases for both these projects are attached in Document RP901c.

As ICT technologies evolve relatively quickly, it is not yet clear which other technologies will emerge in the later years of the next regulatory control period. However, Ergon Energy has retained $1 million per year in its forecast capital expenditure in order to facilitate the investigation and implementation of new strategic ICT technologies where significant business benefit can be demonstrated.

10.4.8.4 Summary of ICT Projects

In summary, the costs for the four ICT projects remain in accordance with the ICT plan detailed in Table 10-12. It is noted that these values differ to those shown above and on page 346 of the Regulatory Proposal as the values that were previously provided were not correctly escalated.

Table 10-12: Revised ICT capital expenditure

	Capital expenditure $M 2009-10
FFA	19.1
DMS	22.8
Data Centres	4.9
ICT Strategic Technologies	5.1

Ergon Energy's responses to the AER's specific criticisms of Ergon Energy's June 2009 Regulatory Proposal are provided below.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reduction of $39 million in shared costs (overheads) allocated to capital expenditure [121]	- Majority of ICT projects not supported by analysis that demonstrated prudence or efficiency, with exception of reconfiguration of data room [120-1, 572]	- Ergon Energy has provided further information justifying expenditure for DMS, FFA and new ICT infrastructure in section 10.4.8.3.
	- PB developed revised forecasts by taking 2008-09 service charges and assumed that increases in ICT indirect costs predominantly driven by SPARQ Capital expenditure. PB applied reductions in service charges in proportion to recommended reductions in SPARQ ICT capital expenditure [120]	- As above.
	- Reduction of $1.5 million for sponsorship and other community engagement activities [121]	- Ergon Energy accepts the AER's reduction and has reflected it into its modelling for this Revised Regulatory Proposal however Ergon Energy believes that it is a legitimate business expense.
	- 77 per cent of reductions in shared costs (overheads) allocated to capital expenditure 690]	- See above for ICT component.

10.4.8.5 Sponsorship and Community Engagement

Ergon Energy accepts the AER's reduction of $1.5 million for sponsorship and other community engagement activities and has reflected it into its modelling for this Revised Regulatory Proposal.

10.4.9 Cost Escalations – Materials

Ergon Energy's responses to the AER's specific criticisms of Ergon Energy's June 2009 Regulatory Proposal in relation to material cost escalations are provided below.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Increase of $82 million in capital expenditure due to revisions in (materials and labour) cost escalations [124, 129] - Revised material cost escalators	- AER noted two errors identified by PB in materials cost escalation model [124, 522]: o Calculation of cumulative nominal escalators in step 2 includes cumulative effect of CPI but not of the escalators themselves o Set of CPI values used to inflate 2007-08 real values to nominal in step 2 is different from the set used to deflate back to 2009-10 real	- Ergon Energy applied escalation rates in accordance with indices provided by SKM. However, SKM have subsequently confirmed they provided annual escalators to Ergon Energy in a year-on-year format (as opposed to the cumulative format required for the Ergon Model) in error. - SKM subsequently provided updated escalation rates to Ergon Energy, which Ergon Energy has applied in this Revised Regulatory Proposal. - If Ergon Energy used the PTRM inflation rate to inflate the 2007-08 real values then this would understate the nominal values as the CPI used in the PTRM is the 10 year average of RBA midpoint inflation of between 2 and 3 per cent (i.e. 2.45). - Instead, Ergon Energy has applied the annual CPI in order to covert 2007-08 real values into nominal values and then has applied the PTRM's inflation rate in the model.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
	values in step 5	
- Revised aluminium and copper cost escalator [586-8]	- Cost escalators based on futures contracts alone provide more accurate indicator of future materials costs than based on future contracts and economic forecasts [586-8]	- Ergon Energy notes that, whether cost escalators based on futures contracts alone provide a more accurate indicator of future materials costs than futures contracts and economic forecasts depends on the liquidity of the market producing the forward pricing. Ergon Energy understands that the AER has already accepted this premise in relation to steel cost escalation, with the London Metals Exchange (LME) steel market considered at present to have low liquidity levels. - Ergon Energy is concerned about the AER's recommendation to use the 63 and 127 month LME figures, due to the limited liquidity at present in these long range markets. - Ergon Energy considers that the AER is technically incorrect in stating that, since previous decisions, the LME forward contracts have become available to cover the entire revenue control period. The LME 123 month has been available since September 2008, and the 63 month figures since the mid 1980's. - Ergon Energy understands that the 63 month and 123 month "prices" do not represent official LME prices based on bids and offers, which is why they are not to be found as official published prices on the LME website. Rather, these prices are determined by a LME Quotations Committee using a fair value method that is based on a consideration of the volumes transacted, and spreads found within the three month LME pricing data. - Ergon Energy considers that the AER has not presented a valid reason to change from the methodology that it applied in its NSW decision, which was made at a time when both the 63 month and 123 month LME prices were available for inclusion in modelling. - Ergon Energy has therefore applied updated escalators in this Revised Regulatory Proposal using the original methodology of 3, 15 and 27 month LME values out to the Consensus Economics long-term average.
	- AER disagrees with SKM approaches to treatment of exchange rates and inflation [586-8]	- Ergon Energy has applied updated escalation rates using the exchange rates that the AER published from KPMG Econtech's August 2009 "Australian National, State and Industry Outlook". - These updated escalators have been developed whilst including the AER's suggested methodology of converting real US$ prices to their nominal equivalence using US Congressional Budget Office forecast US Inflation rates.
- Revised steel cost escalator [588-90]	- AER has proposed an alternative approach for calculating steel price escalator [588-90]	- Ergon Energy agrees with the requirement to convert the US$ price of short tons (via a multiplier of 1.1023) to their equivalent tonnes price prior to taking the average of the US and European HRC steel prices. - Ergon Energy has applied updated escalators based on the most recent data using this calculation.
	- Must update for most recent data [590]	- Ergon Energy has provided updated escalators based on the most recent data.
- Revised crude oil escalator [590-2]	- Cost escalators based on futures contracts alone provide more accurate indicator of future materials costs than based on future contracts	- Ergon Energy notes that, whether cost escalators based on futures' contracts alone provide a more accurate indicator of future materials costs than futures contracts and economic forecasts depends on the liquidity of the market producing the forward pricing. Ergon Energy understands that the AER has already accepted this premise in relation to steel cost

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
	and economic forecasts [590-2]	escalation, with the LME steel market considered at present to have low liquidity levels.
	- Should base on month data not single trading day [590-2]	- The methodology applied in developing Ergon Energy's escalators use monthly averages.
- Revised exchange rate [593-4]	- Should base forecasts on the most recent data [593-4]	- Ergon Energy has provided updated escalators based on the most recent data.
- Remove any weighting of trade weighted components [593-5]	- Not clear to AER how SKM has applied and weighted the trade weighted index in developing asset class escalators [593-5]	- It is noted that the AER has not requested, nor apparently assessed the weightings that have been assigned to any of the several other cost drivers within the SKM model, (e.g. copper, steel, aluminium, oil, etc.) which have nevertheless been accepted. - The AER's treatment of the trade weighted index (TWI) within the SKM model is therefore inconsistent with the AER's acceptance of other components of the SKM model. SKM's report [Document PL651c] explains how the TWI component within the SKM model [Document PL652c] has been applied – this is explained in a similar manner to other elements of the model. Ergon Energy therefore rejects the view that the AER had no knowledge of how the TWI is applied within the model, as this would be inconsistent with the AER's acceptance of the use of other components within the SKM model. - SKM has advised that it would be pleased to provide further clarification of its application of the TWI component to the AER, should the need arise. - In discussing an apparent correlation with the movement of the TWI and the "real decreases in raw materials costs" [page 594], it appears that the AER has misunderstood the application of the TWI component within the model. SKM do not apply the TWI to commodity prices during modelling. The TWI factor forms one of the components of final equipment pricing. - TWI is only applied to a limited number of items of plant and equipment, specifically those typically sourced from overseas manufacturers. In Ergon Energy's case, this is protection and control, switchgear and isolators. - SKM has also indicated that it would be pleased to provide the AER with further supporting evidence, based on a backcast of the model compared with actual annual contract pricing details that have been submitted by a wide range of Australian DNSPs. This supportive evidence identifies that the use of the SKM model including the TWI component is a far better match to actual equipment prices paid by Australian DNSPs than the model with its TWI component assigned to CPI as has been suggested by the AER.
- Revised inflation rate [595-6]	- Inflation rate has changed since CEG's April 2008 report [595-6]	- Ergon Energy agrees and considers that the most recent credible forecasts should be used.
	- Calculate 10 year inflation forecast using a geometric average of the RBA short term forecasts for the first two years and the mid-point of the RBA's target inflation range for the remaining years [278-281,	- Ergon Energy has used the RBA forecasts as per the AER's Draft Distr bution Determination.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
	595-6]	
- Construction costs [598-9]	- More appropriate to apply updated engineering construction cost forecasts from the Construction Forecasting Council's (CFC) website	- Ergon Energy agrees and has provided updated escalation rates based on the latest engineering construction cost forecasts from CFC's website.

10.4.10 Cost Escalations – Labour

Ergon Energy's responses to the AER's specific criticisms of Ergon Energy's June 2009 Regulatory Proposal in relation to labour cost escalations are provided below.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Increase of $82 million in capital expenditure due to revisions in (materials and labour) cost escalations [124, 129] - Revised cost escalators based on advice from Access Economics [607, 614, 616] - Escalators to be updated closer to final decision to account for latest data [614]	- Not appropriate to apply single escalation rate to internal and contract labour [124, 615]	- Ergon Energy considers that it is appropriate to apply a single escalation rate to internal and contract labour for the reasons detailed in section 9.8 of this Revised Regulatory Proposal.
	- Not appropriate to apply UCA rate for labour cost escalations because [521-2, 613]: o Compensating for UCA wage increases eliminates incentives to pursue efficient and competitive wage outcomes o Doesn't recognise that skills shortage will recede	- Ergon Energy does not think it is open to the AER under the Rules, when assessing the potential impact of using the UCA rate as the labour cost escalator, to consider Ergon Energy's incentives to actively pursue efficient and competitive wage outcomes during future UCA negotiations with its staff and representative unions. - This is discussed in detail in Chapter 9, in particular in section 9.10.
	- Access Economics considers that [607]: o Under performance of Queensland economy not yet reflected in wages o Demand for Electricity Gas and Water (EGW) labour slowing o Future supply side developments will increase demand for EGW labour	- As discussed in Chapter 3 of this Revised Regulatory Proposal, Ergon Energy believes that the effect of the Global Financial Crisis on the Queensland economy has been shallower and less severe, and that it is l kely to recover quicker, than has been widely forecast. - Ergon Energy entered into its current UCA in 2008 – it therefore took effect before the Global Financial Crisis commenced in October 2008. Ergon Energy therefore needs to pay the actual increases agreed under the UCA, rather than any more general labour cost escalations that may have been assessed for the Australian or Queensland economies, or indeed for the electricity industry. - Current labour market information suggests that, as the Queensland and Australian economies strengthen after the global economic crisis, there will again be labour shortages in key skill areas when Ergon Energy begins to negotiate its new UCA in 2010 to apply from 2011. It can be expected that these shortages will put upward pressure on the wage increases that Ergon Energy will negotiate. - Ergon Energy considers that, because the Global Financial Crisis arose, and will be largely over, during the period of the current UCA, it will have very little impact on the wage increases that Ergon Energy will actually need to pay. Rather, Ergon Energy negotiated its current UCA during a tight labour market, and expects to be doing so again when it comes time to negotiate its next UCA.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
	- AER calculated weighted average labour cost escalators based on 73 per cent internal labour and 27 per cent general contract labour [613-4]	- Internal labour, regardless of whether it is specialist or general, is paid the same wage increases based on the UCA. - Ergon Energy therefore sees no reasons to apply a weighting to specialist and general labour resources for the purposes of determining the labour escalation rate to apply in the next regulatory control period. - Instead, the UCA wage increases should be applied uniformly to both specialist and general labour.

10.4.11 Deliverability

Ergon Energy's responses to the AER's specific criticisms of Ergon Energy's June 2009 Regulatory Proposal in relation to the deliverability of the capital program are provided below.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
AER concerned about PB's finding that Ergon Energy had only undertaken a high-level and cursory review of its capability to deliver the forecast program of works and that this introduced a level of risk to the delivery of the program [125-127, 568-571]	- AER relied on PB assessment [125-127, 568-571] - "In PB's view, the general approach adopted by Ergon Energy to support its capability to deliver the next regulatory period PoW represents some degree of risk in that the business' capability to source its future labour needs has been quantified in a simple manner and not rigorously tested." [PB Report 153]	- Ergon Energy notes that both PB and the AER have indicated that overall they are satisfied that the proposed program of work is deliverable. In particular, the AER states in its Draft Distr bution Determination (refer p127) "…the AER is satisfied that the deliverability of the forecast capex program will not be constrained by resource availability." - Ergon Energy notes that it has explained to PB and the AER a multifaceted approach to support delivery of its program of works. This includes initiatives in relation to establishing (pre-qualified) preferred suppliers for outsourcing, automation of materials forecasting and ordering (including for long lead time materials), development, retention and growth of the internal workforce and expansion.
	- "However more recently Ergon Energy has advised in the June 2009 capex report that it delivered only 79 per cent of its annual budget, although PB notes that the capex delivered was $818m compared with its regulatory estimate for 2008/09 of $732m." [PB Report 153]	- The underspend against budget related to a small number of specific issues which are unrelated to Ergon Energy's overall ability to deliver its work. Ergon Energy spent $818 million on regulated capital expenditure against a budget of $1,035 million with the majority of the shortfall due to: o $65 million related to deferral by one year of the UbiNet project and Smart Meter trials. Delivery of these two projects is now successfully under way in 2009-10. o $50 million related to the rapid and unexpected reduction in CICW due to the onset of the Global Financial Crisis. This was related to a sudden change in demand rather than a shortage of supply. Capacity to deliver this type of work is expected to increase further as the use of alternative providers for CICW grows. o $100 million related to Non-System capital expenditure, and primarily resulting from deliberate initiatives by Ergon Energy to reduce or defer costs in fleet and buildings expenditure. An external benchmarking study identified opportunities for fleet savings which are being implemented. Buildings expenditure was deferred to divert the money to system augmentation in the final stages of the economic boom, however the sudden downturn resulted in the committed funds not being spent. Efficiency gains rather than an inability to deliver work were the key driver of the underspend and these one-off issues are not expected to recur; o Ergon Energy is otherwise within 0.5 per cent of its

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
		capital expenditure budget target supporting its view that it is able to manage and deliver its capital expenditure work programs.
	- "Two of the three internal business documents provided by Ergon Energy were in draft form and had not been finalised to support Ergon Energy's delivery capability for the proposed PoW". [PB Report 153] • Ergon Energy, Draft, PL730c_EE_Energy Services Workforce Capability Plan_2007-09.pdf; • Ergon Energy, March 09, PL733c_EE-People Strategy Framework_Mar09.pdf – marked as draft in the footer; • Ergon Energy, AR268c_EE_Strategic Workforce Plan 208-18.pdf – final version provided	- PB and the AER requested copies of working documents as evidence that Ergon Energy maintained and used processes to manage delivery of its works. Ergon Energy provided various samples, including but not limited to the following, with a specific advice that they were provided on this basis (refer response to question PB.ERG.VP.76). It is not appropriate that PB has subsequently claimed Ergon Energy has not completed such processes. In particular: o Document PL730c was provided in response to PB.ERG.VP.76 as evidence that detailed capability planning processes had been in place at Ergon Energy for some years. This plan was from the 2007-08 year in which the work program was delivered in full. The fact that the supplied document had 'draft' written on it does not automatically lead to the conclusion that the document was either not approved, not used, or invalid, or that Ergon Energy did not have formal planning processes in place; and o Document PL733c was provided in response to PB.ERG.VP.76 as evidence that Ergon Energy prepared documents relating to resourcing strategies that were submitted to the Ergon Energy Board for approval. Ergon Energy provided this document in good faith as a contemporary example of workforce planning approvals and clearly noted "…it is provided as an example of business as usual processes as requested by the AER". The fact that it was still in draft does not diminish the fact that Ergon Energy has undertaken a process of Board approval for its latest workforce strategies.
	- "Ergon Energy is relying on its demonstrated ability to deliver the 2006/07 PoW to support deliverability in future years". [PB Report 153]	- As documented by PB in its report, Ergon Energy has implemented a broad range of initiatives to underpin its ability to attract, retain, and develop its internal and contractor workforce (refer p154 of PB report pp350-351 of the Ergon Energy regulatory proposal, and responses to AER questions PB.ERG.VP.61, PB.ERG.VP.62, PB.ERG.VP.76, and PB.ERG.VP.77). These initiatives included automated materials management, period contracts for materials including long lead items, strategic workforce planning, substantial apprentice, technical trainee and graduate programs, Employer of Choice, Diversity strategies, and others.
	- "Specifically, it has been identified that even after allowing for a 3 per cent productivity improvement from the existing workforce, the demand will materially increase whilst supply will also materially decrease". [PB Report 153]	- Ergon Energy assumes the statement about supply materially decreasing is based on Ergon Energy's Strategic Workforce Plan 2008-2018 [Document AR268c] that was supplied to the AER as in response to question PB.ERG.VP.76. This document indicated that normal workforce attrition will continue to cause staff to leave the business and that Ergon Energy's workforce this will continue to need replenishing through recruitment and other means. As PB noted, Ergon Energy provided details of a number of workforce-related initiatives already in place to provide this replenishment. - It is incorrect to state that Ergon Energy's workforce supply will decrease. It was highlighted in response to PB.ERG.VP.76 that the report was drafted in late 2007 – prior to the financial downturn – and that contemporary views about many workforce issues had improved since that time.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
	- "Of particular note is the business' significant increase in Asset Replacement capital expenditure, which tends to include a high degree of brown field type work that tends to lead to more complicated and demanding projects less suited to outsourcing". [PB Report 153]	- Ergon Energy notes that it can readily manage the increasing brownfield works by redirecting a larger portion of internal staff to the more complicated projects and outsourcing less complex (e.g. Greenfield) projects if required. It is noted that Greenfield works (e.g. augmentation) are also continuing to increase, meaning the resultant percentage of brownfield work may not change much. In addition, contractors are continually developing their abilities in relation to the delivery of more complex (including brownfield) projects and are expected to continue to do this to meet contemporary customer demands.
	- "PB considers the material procurement practices historically employed by Ergon Energy provide some confidence that it will be able to deliver the necessary plant, equipment and materials to deliver its PoW, however long lead time zone substation transformers and poles for feeder developments are key components that are missing from the existing contracts outlined". [PB Report 153]	- Ergon Energy provided an example list of period contracts [Document PL728c] for *inventory* items in response to question PB.ERG.VP.77. This list included current contracts for supply of wooden poles (2006/0124/T) and distribution transformers (2004/037/T), however, *non-inventory* items need to be obtained from a separate source. Period contracts for *non-inventory* items include contracts for concrete poles (2009/0090/T) and substation transformers (2006/0132/T), hence the concerns raised by PB about not having arrangements in place for long lead time items are unfounded.
	- "PB considers that Ergon Energy should escalate the application of its short term and longer term strategies and actions arising from its strategic workforce planning, in order to ensure it can increase its internal labour workforce and deliver the necessary 3 per cent productivity improvements required over the next regulatory period". [PB Report 154]	- Ergon Energy has already embedded many of the key workforce strategies into its business over the past few years and is now reaping the rewards (e.g. substantial internal apprentice and trainee programs, Employer of Choice and Diversity strategies, Workforce Planning, Depot 3PR, ET2010, etc). Ergon Energy will continue to develop its workforce strategies as part of our ongoing continuous improvement, further underpinning deliverability of the proposed expenditure forecast.

10.5 Ergon Energy's Revised Regulatory Proposal

Ergon Energy's revised calculation of capital expenditure forecasts for Standard Control Services for the period 1 July 2010 to 30 June 2015 is detailed in Table 10-13.

Table 10-13: Revised Forecast Capital Expenditure – by Category Driver – 2010-15 ($M Real $2009-10)

Category Driver	2010-11	2011-12	2012-13	2013-14	2014-15	Total	Average of 5 year Total
Asset Replacement	181.24	222.55	261.68	285.86	305.03	1,256.35	251.27
Corporation Initiated Augmentation	273.32	355.81	422.98	487.85	536.32	2,076.28	415.26
Customer Initiated Capital Works	363.68	394.72	341.83	357.27	389.01	1,846.51	369.30
Reliability and Quality Improvement	18.49	21.49	25.16	29.00	30.85	124.99	25.00
Other System	111.13	74.96	53.07	52.73	53.18	345.06	69.01
Non-System	175.37	152.57	127.29	80.75	88.98	624.95	124.99
Total	1,123.23	1,222.10	1,232.00	1,293.45	1,403.36	6,274.15	1,254.83

Source: Revised Submission Tables for Proposal 23.1

10.6 Rules' requirements

In submitting this Revised Regulatory Proposal in relation the capital expenditure for Standard Control Services, Ergon Energy has had regard for clauses 6.5.7, 6.12.1(3), and S6.1.1 of the Rules.

10.7 Relevant documents provided by Ergon Energy

The following documents are relevant to this Chapter, some of which have been previously provided to the AER, while others are new since, or were not provided to the AER with, Ergon Energy's June 2009 Regulatory Proposal:

Email 29-07-09	EE response to PB.ERG.VP.30
Email 19-08-09	EE response to PB.ERG.VP.61
Email 19-08-09	EE response to PB.ERG.VP.62
Email 20-08-09	EE response to PB.ERG.VP.76
Email 19-08-09	EE response to PB.ERG.VP.77
AR049	EE_Annual Network Reliability Performance Report 2006-07_5Dec07
AR099	Ergon Energy's Strategic Plan_What's on the Horizon
AR151	EE_Annual Network Performance Report_Power Quality 2006-07_26Oct07
AR217	EE_Annual Network Reliability Performance Report 2007-08_5Nov08
AR218	EE_Annual Network Reliability Performance Report 2007-08_APPENDICIES E-K_31Oct08
AR268c	EE_Strategic Workforce Plan 2008-18_May08
AR319c	EE_Corporate Property Strategic Plan_V23_28Aug06
AR341	EE_Feeder Improvement Program_V1.2_1Apr09

AR401	EE_Network Management Plan_Summary 2008-09 to 2012-13
AR402	EE_Network Management Plan_Part A 2008-09 to 2012-13
AR445	EE_Network Management Plan_Part B 2008-09 to 2012-13_V2
PL587c	PL587c_EE_Historical Failure Nos Zone SStn Assets_28Jul09.xls
PL599c	PL599c_EE_Tx Condition Reports for Tx Dry Out Program_Draft_22Jan08.pdf
PL651c	PL651c_SKM_Escalators Capex_Jan09 Update_rcd 4Feb09.pdf
PL652c	PL652c_SKM_Escalators Capex_Jan09 Update_rcd 4Feb09.xls
PL704c	PL704c_EE_Annual Network Reliability Performance Report_2007-08.pdf
PL712c	PL712c_EE_ET2010 SC 0906 B Discussion Paper FFA Strategy V0_4.doc
PL728c	PL728c_EE_Contracts Anniversary-Standards 0904_19Aug09.xls
PL730c	PL730c_EE_Energy Services Workforce Capability Plan_2007-08.pdf
PL733c	PL733c_EE_People Strategy Framework_Mar09.pdf
PL783c	PL783c_EE_Power Transformer Condition Assessments_25Aug09.xls
PL835c	PL835c_EE_Statistics Sub Assets Investigations 2008 Rev 1.xls
RP882c	RP882c_EE_FN Pole Top Field Trial Results_Apr04.pdf
RP883c	RP883c_Evans & Peck_EGX & EE Feeder Improvement Program Review_23Jan09_EGX Removed.pdf
RP884c	RP884c_KPMG_Review of Ergon OH Line Asset Defect Reduction Program.ppt
RP901c	RP901c_EE_New Strategic ICT_Business Case_21Dec09.doc
RP902c	RP902c_EE_DMS_Business Case Spreadsheet_21Dec09.xls
RP903c	RP903c_EE_DMS_Business Case Gate 1 Summary_21Dec09.pdf
RP904c	RP904c_EE_DMS_Business Case High Level_21Dec09.doc
RP905c	RP905c_FFA_Business Case Spreadsheet_21Dec09.xls
RP906c	RP906c ANPR 2008_09 Final_221209.pdf
RP907c	RP907c_ANPR 2008_09_Appendices E_to_K_ 221209.pdf
RP937c	RP937c_EE_CICW SCS Forecasts_061209.doc
RP938c	RP938c_Huegin Report for EE_V1.0_12Jan10.pdf
RP939c	RP939c_Modelling of Zone Substation replacement capex.pdf

RP940c	RP940c_CICW Model revised 061209
RP941c	RP941c_Conductor Maintenance and Refurbishment Strategy V1-0B.doc
RP942c	RP942c_Cairns Business Case V1-15 Dec 09.pdf
RP943c	RP943c_Hervey Bay Business Case V1-15 Dec 09.pdf
RP944c	RP944c_Mackay Business Case V1 - 15 Dec 09.pdf
RP945c	RP945c_Maryborough Business Case V1-15 Dec 09.pdf
RP946c	RP946c_Rockhampton Business Case V1-15 Dec 09.pdf
RP947c	RP947c_Townsville Business Case V1-15 Dec 09.pdf
RP948c	RP948c_Cairns_Site Assessment Report.pdf
RP949c	RP949c_Hervey Bay_Site Assessment Report.pdf
RP950c	RP950c_Mackay_Site Assessment Report.pdf
RP951c	RP951c_Maryborough_Site Assessment Report.pdf
RP952c	RP952c_Rockhampton_Site Assessment Report.pdf
RP953c	RP953c_Townsville_Site Assessment Report.pdf
RP954c	RP954c_091207 Cairns Lake Street Building Condition Report.pdf
RP955c	RP955c_091207 Cairns McLeod St Building Condition Report.pdf
RP956c	RP956c_091207 Mackay Ness St Building Condition Report.pdf
RP957c	RP957c_091207 Rockhampton Glenmore Rd Building Condition Report.pdf
RP958c	RP958c_091207 Townsville Dalrymple Rd Building Condition Report.pdf
RP959c	RP959c_091208 Hervey Bay Building Condition Report.pdf
RP960c	RP960c_091208 Maryborough Searle St Building Condition Report.pdf
RP961c	RP961c_Rockhampton Richardson Rd Condition Report.pdf
RP962c	RP962c_Draft Determination Response 17 dec 09 v4.doc
RP963c	RP963c_Appendix 1 Benefits Summary AER response V0.1.xls
RP964c	RP964c_FFA Business Case AER response V0.1_16Dec09.xls
RP965c	RP965c_FFA Position Paper AER response v0.4_16Dec09.doc
RP971c	RP971c_AER_EE_FIP.doc
RP972c	RP972c_Ergon Energy STPIS ModelRevisedRegProposal_11012010.xls
RP973c	RP973c_091203 Ergon Cairns Lake St Capex Recommendations.pdf

RP974c	RP974c_091203 Ergon Cairns McLeod St Capex Recommendations.pdf
RP975c	RP975c_091203 Ergon Townsville Dalrymple rd Capex Recommendations.pdf
RP976c	RP976c_Ergon Hervey Bay Old MB Rd Capex Recommendations.pdf
RP977c	RP977c_Ergon Mackay Ness St Capex Recommendations.pdf
RP978c	RP978c_Ergon Maryborough Searle St Capex Recommendations.pdf
RP979c	RP979c_Ergon Rockhampton Glenmore Rd CapexRecommendations.pdf
RP980c	RP980c_Ergon Rockhampton Richardson Rd Capex Recommendations.pdf

11 FORECAST OPERATING EXPENDITURE

In its Draft Distribution Determination, the AER significantly reduced Ergon Energy's proposed $1,898 million operating expenditure program by $384 million.

Ergon Energy believes this reduction is not justified because it:

- Fails to properly account for Ergon Energy's prudent and efficient labour cost escalations;
- Effectively increases pole maintenance cycle times to over five years, which will result in Ergon Energy breaching State legislative obligations and cause increased failure rates;
- Doesn't give due consideration to the level of vegetation management required in Ergon Energy's tropical fast growth areas;
- Provides insufficient funds to maintain access tracks within legislative parameters, given Ergon Energy's exposure to extreme weather events; and
- Fails to compensate Ergon Energy for the costs of insurance and debt raising.

11.1 Chapter overview

In this Chapter, Ergon Energy details its revised operating expenditure forecasts for the next regulatory control period. In particular, Ergon Energy has:

- Maintained its forecasts for the following categories of operating expenditure from its June 2009 Regulatory Proposal (while recognising that the value of these forecasts has changed on account of changes to cost escalations and reallocation of shared costs (overheads)):
  - Customer Service and Meter Reading;
  - Forced Maintenance; and
  - Self insurance.
- Varied its forecasts for the following categories of operating expenditure from its June 2009 Regulatory Proposal (while recognising that the value of these forecasts has also been affected by changes to cost escalations and the reallocation of shared costs (overheads)):
  - Preventive Maintenance;
  - Corrective Maintenance; and
  - Vegetation management and access tracks.
- Not accepted the AER's decision to cut Ergon Energy's operating expenditure in relation to the following expenditure categories, but has nevertheless reflected the AER's revisions into its modelling for the purposes of this Revised Regulatory Proposal:
  - Debt raising costs;
  - Equity raising costs; and
  - Interest rate hedging costs.

11.2 Ergon Energy's June 2009 Regulatory Proposal

Chapter 26 of its June 2009 Regulatory Proposal and RIN Pro Forma 2.2.2 detailed Ergon Energy's operating expenditure forecasts for Standard Control Services for the period 1 July 2010 to 30 June 2015, based on expenditure type. These operating expenditure forecasts are reproduced in Table 11-1.

Table 11-1: Original Forecast Operating Expenditure – by Expenditure Type – 2010-15 ($M Real $2009-10)

Expenditure Category	2010-11	2011-12	2012-13	2013-14	2014-15	Total	Average of 5 year Total
Network Operating Costs	26.36	26.33	26.67	27.21	27.51	134.08	26.82
Network Maintenance Costs							
Preventive Maintenance	108.82	119.56	120.15	123.36	121.68	593.57	118.71
Corrective Maintenance	121.88	121.48	122.82	117.94	105.66	589.78	117.96
Forced Maintenance	41.00	40.85	41.34	41.42	41.08	205.69	41.14
Subtotal	271.70	281.89	284.31	282.72	268.42	1,389.04	277.81
Other Costs							
Meter Reading	11.75	11.81	12.03	12.31	12.48	60.38	12.08
Customer Services	19.82	19.86	20.19	20.60	20.81	101.28	20.26
Other Operating Costs (includes DMIA and Self Insurance)	40.47	41.59	42.29	43.85	45.48	213.68	42.74
Subtotal	72.04	73.26	74.51	76.76	78.77	375.34	75.07
Total	**370.10**	**381.48**	**385.49**	**386.69**	**374.70**	**1,898.46**	**379.70**

Source: Tables for Proposal 26.1

Chapter 26 of its Regulatory Proposal explained the methodology by which Ergon Energy prepared its operating expenditure forecasts. Chapter 27 of its Regulatory Proposal demonstrated how Ergon Energy's operating expenditure forecasts for the next regulatory control period achieve the operating expenditure objectives, having regard for the operating expenditure criteria and operating expenditure factors for the purposes of clause 6.5.6 of the Rules.

In addition, Ergon Energy provided the following other information in its Regulatory Proposal relevant to its operating expenditure forecasts:

- Section 28.1 detailed Ergon Energy's self insurance forecasts for Standard Control Services for the period 1 July 2010 to 30 June 2015 totalling $20.1 million;
- Section 28.2 detailed Ergon Energy's debt raising cost forecasts for Standard Control Services for the period 1 July 2010 to 30 June 2015 of $94.08 million;
- Section 28.2.1.1 detailed Ergon Energy's view that it considered that it would be prudent to manage a portion of its interest rate risks through hedging, it did not propose a specific allowance in its expenditure forecasts, although it indicated that it may later do so;
- Chapter 30 detailed Ergon Energy's Non-Network Alternatives program for Standard Control Services for the period 1 July 2010 to 30 June 2015 totalling $61.2 million.
- Section 32.2 detailed Ergon Energy's unit rates, relating to its operating expenditure, for key items of plant and equipment for Standard Control Services for the period 1 July 2010 to 30 June 2015 relating to its operating expenditure;
- Chapter 33 detailed Ergon Energy's cost escalation factors to be applied to its operating expenditure for materials, contractors, labour and all other cost inputs for the period 2008-09 to 2014-15; and
- Chapter 34 detailed and justified Ergon Energy's shared costs (overheads) and explained the process for the attribution of direct costs and for the allocation of shared costs (overheads) using causal allocations.

Following a specific request from the AER after it submitted its Regulatory Proposal, Ergon Energy also proposed benchmark equity raising costs of $93.2 million over the period 1 July 2010 to 30 June 2015.

11.3 AER's November 2009 Draft Distribution Determination

The AER assessed Ergon Energy's forecast operating expenditure and was not satisfied that Ergon Energy's operating expenditure forecast reasonably reflects the operating expenditure criteria, including the operating expenditure objectives, in the Rules In coming to this view, the AER has had regard to the operating expenditure factors.

In establishing its operating expenditure allowance the AER has made the following adjustments:

- $33 million reduction to Preventive Maintenance;
- $14 million reduction to Corrective Maintenance;
- $7 million reduction to Forced Maintenance;
- $53 million reduction to vegetation management;
- $84 million reduction to other operating expenditure;
- $6.4 million reduction to ICT overheads;
- $21 million reduction to self insurance;
- $72 million reduction to debt raising and equity raising costs; and
- $264 million reduction to operating expenditure to reflect the impact of revised input cost escalators.

Table 11-2: AER conclusion on Ergon Energy's total operating expenditure ($M Real 2009-10)[104]

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy controllable operating expenditure forecast	365.9	377.3	381.2	382.3	370.2	1,876.9
Self insurance costs	4.2	4.2	4.3	4.4	4.5	21.5
Debt and equity raising costs	11.9	16.3	22.0	22.8	21.1	94.1
Ergon Energy total operating expenditure	382.0	397.8	407.5	409.5	395.8	1,992.6
AER controllable operating expenditure (including input cost escalation and reinstated shared costs (overheads))[a]	316.7	315.2	300.4	288.9	271.0	1,492.1
Self insurance costs	0.0	0.0	0.0	0.0	0.0	0.0
Equity raising costs[b]	-	-	-	-	-	-
Debt raising costs	3.8	4.0	4.4	4.7	5.1	22.0
AER total operating expenditure	**320.5**	**319.2**	**304.8**	**293.6**	**276.1**	**1,514.2**

Note Totals may not add due to rounding.

a. The shared costs (overheads) included in the AER's deductions to operating expenditure are not to be removed from Ergon Energy's operating expenditure allowance. This is because, with the exception of an adjustment for ICT services and sponsorship costs, the AER has not proposed any adjustments to Ergon Energy's shared costs (overheads).

b. The AER will allow Ergon Energy to amortise a total of $11.9 million ($2009-10) for benchmark equity raising costs for the next regulatory control period.

[104] AER, "Draft Decision Queensland Draft distribution determination 2010-11 to 2014-15", 25 November 2009, page xxvii

11.4 Ergon Energy's Response to AER's Draft Distribution Determination

11.4.1 Inter-business Benchmarking

Ergon Energy notes that "as required under clause 6.5.6(e)(4) of the Rules, the AER has had regard to benchmark efficient expenditures in assessing Ergon Energy's base year opex and proposed forecast allowances" [661].

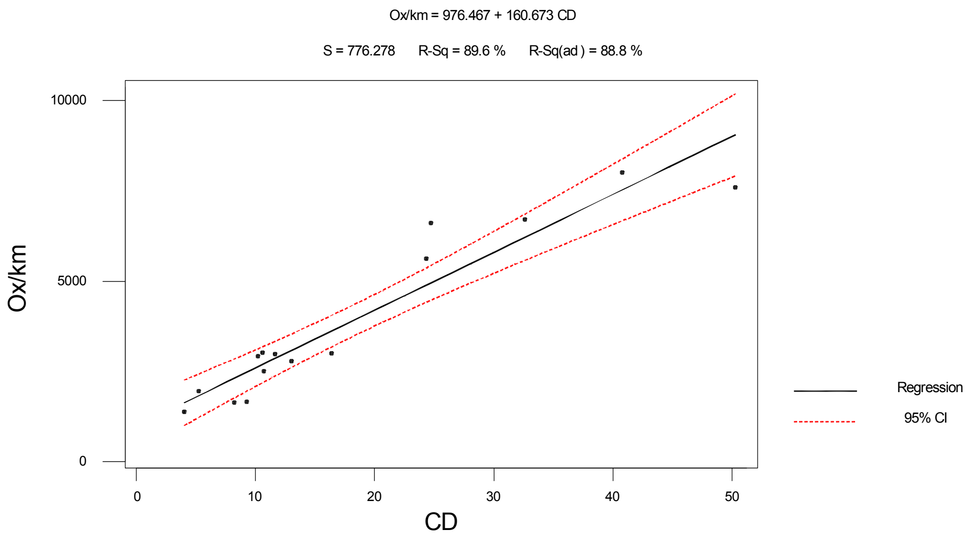
Ergon Energy further notes that as a result of benchmarking studies, completed by both the AER and PB, the AER has formed the view that "Ergon Energy's opex appears relatively high in 2007–08 compared to the sample" [661].

As is discussed in the reports of both Huegin [Document RP938c] and Benchmark Economics [Document RP966c], the limitations of using benchmarking in the way prescribed by the Rules are so severe as to cast serious doubt upon the conclusions drawn from such an exercise. As such, Ergon Energy does not consider the results of the benchmarking exercises to be useful in informing an assessment of the efficiency and prudence of Ergon Energy's base year operating expenditure or forecast operating expenditure for the next regulatory control period.

In any event, a proper statistical analysis based on the Chapter 6 requirements would show that Ergon Energy is (within normal confidence levels) operating near a best fit trend line for the correlations used by PB and therefore should be considered prudent and efficient in its operational expenditure. Ergon Energy commissioned Benchmark Economics to provide a sound statistical analysis consistent with the AER's data and other available data, consistent with the requirements of Chapter 6 of the Rules.

As the best fit regression line represents only an estimate of the 'efficient' level, it would be appropriate to include confidence intervals within which the true value of the slope could be expected to fall (Figure 11-1). The "CI" in Figure 11-1 shows that, with a 95 per cent confidence level, the true value of the slope (i.e. the change in opex/km for a given change in customers/km) lies somewhere between the intervals. Given this additional information, it is not statistically appropriate to assume the regression represents the 'efficient' level, we can only say that it lies somewhere between the top and bottom interval. Ergon Energy (the observation around four connections per kilometre) lies well within the 95 per cent confidence interval.

Figure 11-1: Regression plot: Opex/km and Customers/km - CD[105]



105 Refer Benchmark Economics' report, Document RP966c.

Ergon Energy believes that proper consideration of the benchmarking data constructed in accordance with the Chapter 6 criteria and with a suitable group of peer organisations supports that its operational expenditure is prudent and efficient and further that the conclusions drawn in the draft by PB do not consider the facts appropriately and do not support their conclusions.

11.4.2 Forecasting Methodology – Capex / Opex Trade Offs

As highlighted in its June 2009 Regulatory Proposal, Ergon Energy recognises the interactions between various categories of capital and operating expenditure. Ergon Energy accepts the recommendation by the AER to explicitly model the impact of the interaction between the capital and operating expenditure programs by replicating the model provided by PB.

Applying PB's methodology results in a reduction of $9.9 million to the original forecast amount for Preventive and Corrective Maintenance ($5.0 million for Preventive and $4.9 million for Corrective Maintenance) and this reduction has been reflected into Ergon Energy's Revised Regulatory Proposal.

11.4.3 Preventive Maintenance (excluding Vegetation Management and Access Tracks)

11.4.3.1 Ergon Energy's June 2009 Regulatory Proposal

In its June 2009 Regulatory Proposal, Ergon Energy proposed a total Preventive Maintenance expenditure forecast (excluding vegetation management and access tracks and sites) of $594 million for the next regulatory control period.

11.4.3.2 The AER Draft Distribution Determination

In considering the proposed Preventive Maintenance expenditure forecast, the AER has recommended adjustments in areas that it considered were not prudent and efficient. The AER proposed adjustments of:

- $17 million to account for the longer inspection cycles for ground based poles;
- $8.7 million as a result of Growth capital expenditure programs being reduced;
- $1.7 million reduction in coincident visual inspection program; and
- $5.0 million to account for the capex/opex trade off (see discussion in section J.3.1 of the AER's Draft Distribution Determination).

The key points that will be addressed in this part of the Revised Regulatory Proposal relate to the inspection periodicity for wooden poles and coincident inspections. When addressing the wooden pole inspection periodicity, the AER relied upon two points:

First:

> *The AER considers that Ergon Energy has been overly conservative in its approach to risk regarding the possible failure of its wooden poles.*

Secondly:

> *The AER considers that given the current reliability of the poles, and Ergon Energy's comprehensive knowledge of the assets arising from the previous inspection cycle, increasing the inspection cycle to 4.5 years will result in opex forecasts that better reflect the costs of a prudent operator.*

With regard to inspection of overhead services (visual and full inspection), the AER stated that:

> *The AER considers such a preventive maintenance program is appropriate but notes PB has identified an overlap in the program with a similar program: coincident visual inspections. As the two programs achieve similar outcomes, the AER considers Ergon Energy should take into account a reduction in the number of coincident visual inspections, to offset the increase in full inspections, after the pilot program is completed in 2009–10.*

11.4.3.3 Ergon Energy's Response to the Draft Distribution Determination

Ergon Energy has retained its Preventive Maintenance forecast from its June 2009 Regulatory Proposal, excepting an allowance made by the AER for the opex/capex trade-off discussed in section 11.4.2. This section does not discuss the proposed reduction in operating expenditure linked to the capital expenditure program as Ergon Energy has argued in Chapter 10 for a reinstatement of its capital expenditure forecast.

This section of the Revised Regulatory Proposal is structured in two parts. The first addresses the issue of wooden pole inspection periodicity and the second addresses the coincident inspection issue.

11.4.3.3.1 Proposed increase in pole inspection periodicity

In the Draft Distribution Determination, the AER has proposed an increase in Ergon Energy's pole inspection periodicity. The AER's reasons for the proposed increase are that:

- Ergon Energy is overly conservative in inspecting poles every 4 years; and
- Given Ergon Energy's comprehensive knowledge of the assets an inspection periodicity of 4.5 years is more appropriate.

PB reached the same conclusion as the AER. The reasons that the AER gave in its Draft Distribution Determination for increasing the pole inspection periodicity were:

- Ergon Energy, having completed two full inspection cycles, will have a detailed and comprehensive understanding of the pole assets;
- Pole failure rates are only half the rate of the required standard; and
- Extending the pole inspection periodicity to 4.5 years:
  - Will not detrimentally impact business risk or the pole failure rate;
  - Will allow for a suitable operational margin to ensure that all poles are inspected within the regulatory timeframe of 5 years;
  - Will bring Ergon Energy closer in line with similar distribution businesses such as ENERGEX; and
  - Will reduce preventive inspection operating expenditure by $15.35 million.

The current four year inspection period adopted by Ergon Energy is an extension to the prior inspection period of three years. The four year inspection cycle is prudent and there exists insufficient information for Ergon Energy, PB or the AER to safely recommend an extension beyond this period. Each of the concerns raised by the AER and PB are addressed in turn in this section of the Revised Regulatory Proposal.

In responding to each of the concerns, Ergon Energy has clarified the position put forward in its June 2009 Regulatory Proposal. Additionally, Ergon Energy engaged Huegin to review the key issues associated with pole inspection periodicity for the Ergon Energy wooden pole population and the extension proposed by the AER.

Insufficient information to justify an extension to the pole inspection periodicity to 4.5 years

This issue is addressed in detail in Huegin's report [Document RP938c]. Huegin examined the information needed to justify an extension to the current pole inspection periodicity. Huegin found that the key piece of information required to extend the pole inspection periodicity is the P-F[106] curve, which requires information on age, failures and defects.

Whilst Ergon Energy has gone part way to understanding failure modes, there is scant information on functional failures. Further, Ergon Energy does not fully understand the age of all of the individual poles in its network.

The main points as summarised by Huegin are:

- Ergon Energy has adopted an appropriate approach to pole maintenance;

[106] This refers to potential for failure.

- Ergon Energy does not know the P-F interval for the installed pole population. This is essential if an extension is to be sufficiently justified;
- Ergon Energy does not possess sufficient appropriate information to understand the pole P-F interval; and
- Neither Ergon Energy, nor PB, can justify the proposed extension to the pole inspection periodicity using the information currently available.

There is therefore insufficient information to safely justify an extension of the pole inspection periodicity beyond four years.

Standards are not intended to justify lesser performance

In their report, PB has noted that the performance of Ergon Energy's poles in terms of failure rates is better than the minimum mandated performance.

It should be noted that:

- The minimum acceptable standard is not a target to be met but rather a standard not to be breached;
- Ergon Energy's is not in breach of the standard; and
- Ergon Energy does not believe it to be the practice of a prudent network operator to reduce maintenance standards to increase the failure rate so as to be closer to a minimum acceptable standard. Ergon Energy also considers that adoption of such an approach would also be out of alignment with application legislative safety standards, having regard to the manner in which its network operates.

Ergon Energy does not believe that the current performance against the standard justifies an extension to the pole inspection periodicity.

4.5 year pole inspection periodicity will adversely impact pole failure rate

Ergon Energy accepts that the probability of wooden pole failures within a given population increases with age. While neither Ergon Energy nor PB understands the P-F curve with respect to Ergon Energy's pole population, Ergon Energy accepts that there is a P-F curve. A P-F curve indicates that the longer a given potential failure (a defect) is left without detection and rectification (inspection and subsequent Corrective Maintenance) the further the failure will progress. As such, an increased inspection periodicity will allow defects to progress further, resulting in increased failure rates.

Huegin also addressed this issue in their report [Document RP938c] and found that for Queensland power poles the hazard rate increases exponentially with age - this is exacerbated by environmental factors and inspection accuracy. Furthermore, Huegin found that the historical accuracy of Ergon Energy pole inspectors might be less than assumed in research models - further increasing the growth in realised hazard rate.

The underlying hazard rate for Ergon Energy's pole population increases exponentially with age and that increasing the pole inspection periodicity will ensure an increase in the pole failure rate.

Due to the nature of Ergon Energy's network, a pole inspection periodicity of 4.5 years will not allow all poles to be inspected within the regulatory timeframe

Ergon Energy operations cover an extremely large geographic area, some 1,698,100 square kilometres. This presents significant field force mobilisation issues, especially during times of flood, cyclones and the annual wet/storm season. Having a 4 year pole inspection cycle, which builds in a buffer of one full year, ensures that poles that cannot be inspected in accordance with the planned schedule can be rescheduled for inspection within the regulatory requirement of five years.

Moving to a pole inspection periodicity of 4.5 years will ensure that some poles are inspected outside the mandated 5 year period. As has been discussed by Huegin in their report [Document RP938c], and as explained in the next section, the climate is the most significant driver of wood pole degradation rate. As such, adopting the suggested 4.5 year inspection regime will result in those poles most at risk of failure being inspected outside the mandated timeframe.

The drivers of pole degradation for Ergon Energy and ENERGEX are not similar

In its report [Document RP938c], Huegin specifically examined the issue of similarity between the Ergon Energy and ENERGEX networks for the purpose of comparing pole maintenance periodicities. As a starting point, Huegin used published academic research to identify the key factors impacting pole degradation rate - the main factor was shown to be climate. The academic research referenced by Huegin relates pole hazard rates to climate and inspection effectiveness. The academic research referenced by Huegin was based on a population of poles within the Brisbane urban area.

Huegin then conducted analysis to determine the degree to which the environments for the test population and the Ergon Energy pole populations are similar. Huegin examined nine different environmental factors and found that Ergon Energy's environment is:

- More severe for all but one factor; and
- More variable for all factors.

Huegin concluded that, in terms of the drivers of pole degradation, the environments for Ergon Energy and ENERGEX are not similar.

Beyond the work completed by Huegin, the "Australian Timber Pole Resources for Energy Networks, A Review, October 2006" [Document RP967c] indicates that Ergon Energy has the most severe timber decay hazard zones in Australia and much of Ergon Energy's distribution network is also shown as having the most severe termite activity.

A comparison with ENERGEX for the purposes of justifying an extension in the pole inspection periodicity is inappropriate.

A reduction in Preventive Maintenance expenditure cannot be considered in isolation

Ergon Energy does not believe that a change in inspection periodicity will result in the operating expenditure savings as identified by PB. Regardless of this, there will be an increase in the number and severity of failures and the prevalence and severity of defects. This is because of the exponential nature of degradation. As such, if Ergon Energy adopts an increased pole maintenance period, there will be an increase in both Corrective and Forced Maintenance. This inevitable increase has not been accounted for in the AER's Draft Distribution Determination.

11.4.3.3.2 Inspection of overhead services

In assessing the inspection program for overhead services, the AER noted that "…PB has identified an overlap in the program with a similar program: coincident visual inspections."

Based on the assumed overlap between these two programs the AER considers that "Ergon Energy should take into account a reduction in the number of coincident visual inspections in order to offset the increase in full inspections, after the pilot program is completed in 2009–10"

Dissimilar programs with no overlap

Ergon Energy does not agree with the AER and PB that the overhead services inspection should be merged with the visual inspection program. These two programs have no overlap and are different in the failure modes they address, the activities completed and the frequency at which they are undertaken. The full service inspection program does not include visual inspection along the full length of the service wire or at the point of mains supply. Rather, it is restricted to a visual inspection and electrical testing at the customer's connection.

The full service inspection program in conjunction with the current visual inspection program will actively reduce dangerous electrical events and improve data quality.

The cost of excluding services inspected through the new full service inspection and testing program from the current asset inspection program will exceed the savings identified by PB due to the required enterprise resource planning solution changes and ongoing administrative costs.

The full service inspection will incur higher costs than those estimated by Ergon Energy if the visual inspection of services is incorporated into the full service inspection. This will offset the reduction in allowance proposed by the AER for the visual inspection program.

11.4.3.4 Conclusion

In considering Preventive Maintenance expenditure for the next regulatory control period, Ergon Energy forecast expenditure of $594 million. The AER has proposed the following reductions to this expenditure:

- $17 million to account for the longer inspection cycles for ground based poles;
- $8.7 million as a result of Growth capital expenditure programs being reduced;
- $1.7 million reduction in coincident visual inspection program; and
- $5.0 million to account for the capex/opex trade off.

This section of Ergon Energy's Revised Regulatory Proposal has addressed the $17 million proposed reduction to account for a proposed extension to the pole inspection periodicity and the $1.7 million proposed reduction related to the coincident visual inspection program.

In addressing the pole inspection periodicity, Ergon Energy engaged Huegin to provide an assessment of the proposed extension. The main points from the Huegin report [Document RP938c] are:

- Ergon Energy, PB and the AER do not have sufficient information to justify extending the current pole inspection periodicity beyond four years;
- An extension to the pole inspection periodicity will adversely impact the pole failure rate;
- An extension to the pole inspection periodicity will result in the most vulnerable poles being inspected outside the five year regulatory timeframe;
- An extension to the pole inspection periodicity cannot be justified on the basis of adopting a similar regime to ENERGEX as the environment for ENERGEX poles is more benign than for Ergon Energy; and
- An extension to the pole inspection periodicity will result in increased Forced and Corrective Maintenance being required.

Ergon Energy therefore maintains its Preventive Maintenance forecast associated with the pole inspection program from its June 2009 Regulatory Proposal as it considers that it continues to be prudent and efficient.

With regard to the proposed reduction for the coincident visual inspection program, Ergon Energy notes that:

- The two programs have no overlap;
- The two programs address different failure modes;
- The two programs consist of different activities; and
- The full service inspection will incur higher costs than those estimated by Ergon Energy if the visual inspection of services is incorporated into the full service inspection.

Ergon Energy therefore proposes that its original Preventive Maintenance forecast associated with its visual inspection program be retained.

11.4.3.5 Summary of Concerns and Responses Regarding Preventive Maintenance

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reduction of $33 million in Preventive Maintenance expenditure (excluding Vegetation Management and Access Tracks) [161, 668]	- The AER considers that Ergon Energy has been overly conservative in its approach to risk regarding the poss ble failure of its wooden poles. The AER considers that given the current reliability of the poles, and Ergon Energy's	- Addressed above: o Ergon Energy, PB and the AER have insufficient knowledge to extend the inspection periodicity for wooden poles; and o Extending the pole inspection periodicity beyond four years is not prudent for Ergon Energy's distribution network.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
	comprehensive knowledge of the assets arising from the previous inspection cycle, increasing the inspection cycle to 4.5 years will result in operating expenditure forecasts that better reflect the costs of a prudent operator	
	- Overhead services - the AER considers such a Preventive Maintenance program is appropriate but notes PB has identified an overlap in the program with a similar program: coincident visual inspections. As the two programs achieve similar outcomes, the AER considers Ergon Energy should take into account a reduction in the number of coincident visual inspections, to offset the increase in full inspections, after the pilot program is completed in 2009–10.	- Addressed above. Ergon Energy considers that: o There is no overlap between the subject programs; and o The two programs do not achieve similar outcomes.
	- Need to account in operating expenditure program for the reduction in network growth resulting from the reduced capital expenditure program – reduction of $8.7 million [160, 668]	- This is discussed in section 11.4 of this Revised Regulatory Proposal.
	- Need to account for increased asset replacement in Preventive Maintenance program – reduction of $5 million [160, 657, 668]	- Ergon Energy accepts this reduction and has reflected it into this Revised Regulatory Proposal.

11.4.4 Corrective Maintenance (excluding Vegetation Management and Access Tracks)

11.4.4.1 Ergon Energy's June 2009 Regulatory Proposal

In its June 2009 Regulatory Proposal, Ergon Energy proposed a total Corrective Maintenance expenditure forecast (excluding vegetation management and access tracks and sites) of $160 million (excluding vegetation and access track costs) for the next regulatory control period.

11.4.4.2 The AER Draft Distribution Determination

In considering the proposed Corrective Maintenance operating expenditure forecast, the AER has proposed adjustments of:

- $9.5 million to account for the exclusion of a scope change to remove old lines; and
- $4.9 million to account for the capex/opex trade-off.

11.4.4.3 Ergon Energy's Response to the Draft Distribution Determination

Ergon Energy accepts the adjustment related to the opex/capex trade-off but does not accept the AER's proposed reduction relating to the dismantling of old lines. The Corrective Maintenance that Ergon Energy allowed for the dismantling of old lines is targeted at lines where no current line rebuild or decommissioning capital project has been forecast.

Ergon Energy's financial policies require assets to be written off in order for them to be expensed. Where there are asset replacements, the dismantling of old assets replaced is included as part of the capital project costs. Ergon Energy's proposed allocation in this regard covers situations where the asset is no longer required or where the asset continued in service for some time after a capital project was completed and is now no longer required.

Ergon Energy therefore disagrees with the AER and PB's views that this Corrective Maintenance is not required. Rather, it is necessary because there is no other basis by which these old lines will be removed from service.

11.4.4.4 Conclusion

Ergon Energy accepts the proposed reduction related to the opex/capex trade-off. However, Ergon Energy does not agree with the proposed reduction relating to the removal of old lines. Ergon Energy considers that it is inappropriate for the removal of old lines to be considered part of a capital project. Corrective maintenance is the most appropriate (and only) means to facilitate the removal of these old lines.

For Corrective Maintenance, Ergon Energy maintains the original forecast, with the exception of the adjustment made for the opex/capex trade-off.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reduction of $14.4 million in Corrective Maintenance operating expenditure (excluding Vegetation Management and Access Tracks) [161, 672]	- Not appropriate to include scope change for removal of old lines [161, 672]	- Ergon Energy does not accept this reduction for the reasons given above.
	- Need to account for increased asset replacement in Corrective Maintenance program – reduction of $4.9 million [657, 672]	- Ergon Energy accepts this reduction and has reflected it into this Revised Regulatory Proposal.

11.4.5 Forced Maintenance

11.4.5.1 Ergon Energy's June 2009 Regulatory Proposal

In its June 2009 Regulatory Proposal, Ergon Energy proposed a total Forced Maintenance expenditure forecast of $206 million for the next regulatory control period. This represents an average (real) decrease of 2 per cent compared with the current regulatory control period.

11.4.5.2 The AER Draft Distribution Determination

The AER has proposed a reduction in the forecast Forced Maintenance expenditure allowance. The specific reasons for the reduction were stated in the AER's Draft Distribution Determination as being as a result of an improvement in the condition of assets due to:

- Increased spending on replacement capital expenditure projects; and
- Increased spending on Preventive and Corrective Maintenance activities.

These programs are relevant as the AER stated the "…some forced maintenance is necessary where assets fail due to poor condition". In justifying the amount of the reduction, the AER noted "PB's review of Ergon Energy's forced maintenance activities found that 40 per cent of forced maintenance faults arose from poor plant condition or performance".

11.4.5.3 Ergon Energy's response to the Draft Distribution Determination

Before assessing the logic used by PB, and relied upon by the AER, it is worth assessing the claim that Ergon Energy has not accounted for the proposed increases in Preventive Maintenance expenditure and capital expenditure. The AER has proposed reducing the forecast level of Asset Replacement capital expenditure and Preventive Maintenance expenditure. For both of these expenditure categories it has been shown that the AER's proposed level of expenditure will result in less than the amounts required to undertake prudent network management. Should these reductions be formalised, there will not be the stated positive effect on Forced Maintenance through improved asset condition – rather the opposite will be the case. That is, a contributor to the flat forecast level of Forced Maintenance is the anticipated replacement of vulnerable assets.

Ergon Energy does not agree with the logic used by the AER and PB to justify the proposed reduction in Forced Maintenance operating expenditure. In support of this, Ergon Energy refers the AER to Huegin's report [Document RP938c], which found that:

- PB did not find that 40 per cent of Forced Maintenance faults arose from poor plant condition or performance;
- PB assumed that 40 per cent of Forced Maintenance faults arose from poor plant condition or performance;
- PB's assumption is not supported by independent academic research;
- PB's assumption is not supported by Ergon Energy data; and
- Independent research, as well as Ergon Energy's own data, indicates that external factors (including weather and animals) are the most significant contributor to Forced Maintenance.

In addition to these points, Ergon Energy notes that Forced Maintenance has not been forecast to grow, despite an increasing network size. Ergon Energy maintains the original forecast for Forced Maintenance.

11.4.5.4 Summary of concerns and Responses Regarding Forced Maintenance

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reduction of $6.7 million in Forced Maintenance expenditure [162, 674]	- 40 per cent of Forced Maintenance arises from faults from poor plant condition or performance [673]	- Addressed above. Ergon Energy considers that the contention that a significant proportion of Forced Maintenance is related to underlying asset condition is not supportable. To the contrary, academic research (published), texts and Ergon Energy's own data points to external influences being the major factor, with asset condition having a small impact.
	- Asset replacement capital expenditure and Preventive and Corrective Maintenance should result in reduction in Forced Maintenance [162, 674]	- Addressed above.

11.4.6 Vegetation Management, Access Tracks and Sites

11.4.6.1 Ergon Energy's June 2009 Regulatory Proposal

As part of its June 2009 Regulatory Proposal Ergon Energy developed Preventive and Corrective Maintenance expenditure forecasts related to Vegetation Management and Access Tracks and Sites totalling $549 million over the next regulatory control period.

11.4.6.2 The AER's Draft Distribution Determination

The AER's Draft Distribution Determination raised a number of concerns regarding Ergon Energy's forecast expenditure and proposed the following reductions:

- Removing a 5 per cent increase in unit costs, which cannot be matched against historic records – resulting in a reduction of $12 million [163, 678, 681];
- Removing cumulative growth factors in relation to management of endangered species, declared plants and cultural heritage – resulting in a reduction of $4.7 million [163, 681];
- Reducing the number of locks and keys to be installed to 24,000 - resulting in a reduction of $8.4 million [163, 681, 686]; and
- Expected work volume increases to be reduced from 100 per cent to 30 per cent - resulting in a reduction of $27.5 million [163, 681].

11.4.6.3 Ergon Energy's Response to the Draft Distribution Determination

Given the feedback provided by the AER in its Draft Distribution Determination, Ergon Energy has undertaken a detailed review of the four main areas of concern raised by the AER.

In each area, Ergon Energy reviewed both the justification and the magnitude of the forecast expenditure. As a result, Ergon Energy is able to provide as part of this Revised Regulatory Proposal:

- Clarification of information previously submitted;
- Additional information where the AER previously found the supporting documentation submitted by Ergon Energy to be insufficient;
- An independent report examining the adjustments proposed by the AER; and
- Where appropriate, revised forecasts to reflect adjustments made in light of the new information available.

Ergon Energy accepts that there was an error present in its vegetation management scenario models, which led PB to believe that Ergon Energy had applied a 5 per cent uplift in costs. This error has been rectified and the revised forecast reflects this adjustment.

Ergon Energy does not agree with the basis for, nor the magnitude of, the AER's reduction in expenditure for standard locks and keys. However, Ergon Energy acknowledges that its original forecast relied on incorrect data and modelling assumptions. A revised amount is proposed in the following sections.

Ergon Energy reviewed the justification for its forecast cost increases regarding the management of endangered species, declared plants and cultural heritage. Ergon Energy acknowledges that the underlying rationale for the cumulative growth factors applied was not made available at the time of its June 2009 Revised Regulatory Proposal and, as such, the justification has been detailed below.

After reviewing the available information, Ergon Energy considers the existing forecast reasonably reflects the expenditure of a prudent network operator under Ergon Energy's circumstances and is reinstating its forecasts in its June 2009 Regulatory Proposal.

Given the concerns raised by the AER, Ergon Energy has reviewed all available information and modelling assumptions concerning the forecast for Corrective Maintenance of access tracks. The findings of this review indicate that the "notional" 30 per cent increase proposed by the AER will be insufficient to complete the volume of work that will arise from the new access track inspection program and, as such, Ergon Energy is maintaining the forecast in its June 2009 Regulatory Proposal. Specific responses to each of the concerns raised by the AER regarding this program of work are detailed below.

11.4.6.4 Review of Reductions Specific to Vegetation Management

11.4.6.4.1 Application of a 5 per cent uplift in unit costs

The AER has removed a 5 per cent increase in unit costs, which cannot be matched against historic records. This results in a reduction of $12 million. [163, 679-80, 681]

Ergon Energy confirms that there is no “5 per cent uplift” in costs included in its vegetation cost modelling. Rather, one of the four scenario models contained an error which, once rectified, results in an $11.7 million reduction to the total forecast expenditure for vegetation management. This differs from the $12 million reduction made by the AER. This issue was investigated by Huegin and is discussed in detail in Document RP938c.

11.4.6.4.2 Endangered species, declared plants and cultural heritage

The AER has removed the effect of cumulative growth factors in relation to the management of endangered species, declared plants and cultural heritage. This results in a reduction of $4.7 million to forecast operating expenditure for preventive vegetation management [163, 681].

Ergon Energy notes that the AER made this decision without any detailed justification being provided by Ergon Energy explaining the need for a cumulative growth factor applied to the base year for each of these activities. After a review of the information provided, Ergon Energy acknowledges that the documented rationale for these expenditure increases was not made available to the AER or PB at the time of the June 2009 Regulatory Proposal and Ergon Energy has provided this information below.

Growing legislative compliance requirements

The forecast increases to these cost categories are required to meet the continually changing compliance requirements imposed by recently enacted legislation and the government agencies enforcing that legislation. Ergon Energy must comply with the following relevant Acts:

- *Nature Conservation Act 1992* (amended 2005);
- *Aboriginal Cultural Heritage Act 2003*; and
- *Land Protection (Pest and Stock Route Management) Act 2002*.

Ergon Energy considers that the historical costs are limited and future costs are likely to continue to increase, as there is a growing trend for the relevant Government agencies to demand more information and to impose stricter conditions on the management of these issues. These more onerous requirements are driven by a combination of factors, including:

- The relevant government agencies are regularly increasing their compliance requirements which entail higher compliance costs; and
- The nature of the legislation resulting in frequent changes based on the prevailing conditions, which in turn adds to the growing requirements of the Government agencies.

Forecast to meet most likely scenario is prudent

Ergon Energy considers it imprudent to ignore the likely scenario that recent trends of increasing compliance requirements will continue and ongoing changes within Government agencies (and potential changes to legislation) will result in growing compliance costs.

Ergon Energy has forecast that expenditure in each of the areas covered by the three Acts will increase by $100,000 per year (Real $2009-10) for each subsequent year in the next regulatory control period.

Failure to provide increased funding for these increasingly onerous requirements is likely to result in either a significant funding shortfall for Ergon Energy or non-compliance with Queensland legislation. The latter could entail cost penalties and damage to Ergon Energy’s corporate reputation. Ergon Energy is being prudent in requesting the funding in its Revised Regulatory Proposal to enable it to deal appropriately with these emerging issues and meet its regulatory compliance obligations.

Precedent for accepting costs outside the control of Ergon Energy

Ergon Energy notes that the forecast changes to these costs are outside the control of the DNSP and, as a result, should be allowed in the AER’s final Distribution Determination. This precedent was established in the 2009 NSW Distribution Determination in which the AER relied on a step change criteria test (developed by Wilson Cook & Co) whereby any step change to expenditure necessitated by outside factors is warranted and should be accepted as prudent and efficient expenditure by the AER.

11.4.6.5 AER's reductions specific to Line Access Tracks and Equipment Sites

11.4.6.5.1 Standard Keys and Locks Program

The AER has proposed reducing the number of locks and keys to be installed by Ergon Energy to 24,000 - resulting in a reduction of $8.4 million to Preventive Maintenance expenditure for access tracks and sites [162, 6816]

After a detailed review of the forecasting assumptions for the keys and locks program Ergon Energy discovered a number of errors affecting the forecast amount. Adjustments for these errors have been combined with new information available through a competitive tendering process and a revised and more robust forecast has been developed.

Program aimed at regulatory compliance

In their report to the AER, PB stated that "While conceptually there is some merit and convenience in using a common key system for access tracks, Ergon Energy has not justified this material increase in operating expenditure through either a risk assessment or an economic assessment." [PB Report 134]

Ergon Energy notes that the proposed keys and locks program is not aimed at achieving "convenience" or efficiency as suggested by PB. It is instead aimed at achieving legislative and regulatory compliance concerning public and employee safety.

An initiative is underway in the current regulatory control period to upgrade the security of 496 zone substation, communications sites and generation sites by replacing the keys and locks. This initiative is aimed at addressing inadequacies in the existing system whereby the issue and return of keys has not been adequately controlled in the past. The present situation has resulted in copies of keys being in the possession of the general public, and the issue of keys not being tied to switching operator authorizations. Ergon Energy considers that such situations represent unsafe practice, do not comply with obligations set out in national guidelines and state based legislation, and that all practical efforts should be undertaken to ensure they are avoided. The business case supporting this initiative, which details incidents, issues, risks and options, can be found in Document RP916c. This proposed key and lock replacement program is the next stage of this initiative and will extend the new key and lock system to the distribution and sub-transmission network.

These initiatives are in line with the Energy Network Association's (ENA) National Guidelines for Prevention of Unauthorized Access to Electricity Infrastructure and a commitment given by Ergon Energy to the Electrical Safety Office to ensure compliance with the *Electrical Safety Act 2002* and to ensure the future security of Ergon Energy's network.

Program not limited to access tracks

The proposed program includes replacing the keys and locks on all sub-transmission and distribution switching points, padmount and ground enclosed distribution substations and access track gates. Ergon Energy notes that this program is not limited to access track gates as was implied by the information available in the NARMCOS model and hence reflected in the AER's Draft Distribution Determination.

The revised estimate for the proposed key and lock program is that 40,863 locks will be required. This takes into account:

- One lock per four kilometres of access track (based on best available estimate of the average number of gates on access tracks. This estimate takes into consideration that the number of locks required would be considerably higher in urban areas and less in remote rural areas);
- Two locks per padmount substation;
- 1.5 locks (on average) per ground enclosed substation; and
- One lock per air break switch.

Ergon Energy has further estimated there is a requirement for approximately 2,000 keys to be supplied to Ergon Energy field staff and external contract resources requiring access to assets.

Unit costs established via competitive tender

Ergon Energy's revised forecast has been informed by the actual lock and key costs for the Zone Substation Security Upgrade Project. Tenders were called for the supply of locks and keys and the rates used for the estimates are the contract rates for the zone substation project [Document RP910c and Document RP911c]. As the keys and locks for the re-keying of the distribution systems and access track gates will be the same as for the zone substation project, these rates are applicable to the initiative under consideration in this Revised Regulatory Proposal.

The forecast further assumes that the replacement program will be carried out through existing inspection and maintenance programs such as Asset Inspection or ABS Inspection and Maintenance in order to minimise the cost of the rollout. It is estimated that the total cost over the five year regulatory control period to upgrade the sub-transmission and distribution network will be $3.5 million (Real $2009-10, excluding overheads). This is based on the competitively tendered rates of $68 per lock, $10 per key and an allowance of $17 labour to replace each lock. This represents a reduction of approximately $6.0 million from the original forecast provided in the June 2009 Regulatory Proposal.

11.4.6.5.2 Corrective Maintenance to Access Tracks

The AER has proposed a reduction of $27.5 million in Corrective Maintenance to access tracks to reflect work volume increases from 100 per cent to 30 per cent.

The AER's reduction takes into consideration PB's recommendations, who suggested that the increase in costs had not been substantiated and did not account for efficiencies in subsequent inspection cycles.

In developing its Revised Regulatory Proposal Ergon Energy has conducted a detailed review of the available information as well as the findings of the AER and PB. The findings of this detailed review are as follows.

Differences and interactions between programs

The proposed inspections and subsequent remediation works proposed for access tracks are a separate program of works to that proposed for vegetation management. Each of these programs is conducted by different personnel, using different equipment, operate on different inspection cycles and are focused on the identification and remediation of unrelated issues (i.e. trees contacting power lines as opposed to damaged tracks).

In the AER's Draft Distribution Determination, there appears to be a view that the access track program should be expected to achieve economies of scale as a result of the new vegetation management biodiversity approach. This is not the case as the vegetation biodiversity strategy is wholly concerned with vegetation management and has no impact on the proposed program for access tracks.

In the Draft Distribution Determination, the AER states that PB recommended the reduction to access track works "to account for the flow–on benefits gained as a result of increased spending in other areas of opex activities" [678]. A review of PB's report reveals that this is not the case and that at no point does PB mention any interaction or expected efficiencies between this program and other operating expenditure activities.

As stated by PB, the access track defect remediation program is likely to be informed to a limited extent by other inspection programs (as is already the case – the extent of this interaction is discussed in the Huegin report [Document RP938c]), and that this information will assist Ergon Energy to appropriately target and prioritise remediation works. This interaction however will not, as the AER suggest, result in efficiencies due to increased spending in other areas.

The need for increased expenditure

Ergon Energy agrees with PB's findings regarding the introduction of the new four yearly routine inspection cycle for access tracks. Specifically, PB states that "the increases in preventive maintenance appear prudent" [PB Report 133].

PB went on to say that:

> *Ergon Energy has experienced changes to occupational health and safety work practices that demand a better standard of access tracks that would allow larger and heavier vehicles access to lines; it is also experiencing an increasing need to remediate tracks due to wash-outs and general erosion and deterioration.* [PB Report 133]

In its Draft Distribution Determination, the AER has accepted PB's advice in this regard and approved the expenditure required to deliver the new inspection program. As discussed by Huegin in their report [Document RP938c], the increase in inspections required to achieve the proposed four year inspection cycle reflects a 128 per cent increase on historical rates in terms of kilometres of track inspected per annum.

Ergon Energy has a statutory obligation to maintain tracks under the *Electricity Safety Act 2002* and relevant occupational health and safety legislation. Failure to rectify the defects identified from the prudent and efficient access track inspection program will result in non-compliance, particularly if an incident occurs as a result of poor track conditions that have previously been identified.

Ergon Energy's historical Corrective Maintenance expenditure for access tracks have been inadequate, resulting in only high priority work being completed to address unsafe work conditions for field staff rather than a routine inspection program. This has resulted in a significant backlog of access track inspection and remediation work going into the next regulatory control period. Despite the 2009-10 budget allocation being increased from past years to $4.3 million, current inspection and rectification works have been confined to areas of high environmental sensitivity.

As a result of the poor condition of Ergon Energy's access tracks, asset inspection contractors, who are responsible for inspecting poles to meet regulatory compliance, have suggested that an additional allowance will be factored into their tendered Schedule of Rates for the new asset inspection contracts commencing in 2010-11. These increases will be included to account for issues relating to poor access to Ergon Energy assets, such as damage to contractor vehicles and delays to inspections. Ergon Energy will be a paying a premium for the inspection of poles unless the poor access track condition is rectified. No allowance has been made in this Revised Regulatory Proposal for such an increase in contract rates from 2010-11.

Application of a constant defect rate

The program for the next regulatory period shows an increase in the number of kilometres of access track inspected and a resulting average defect rate has been determined based on best estimates combining historical inspection results and current knowledge of track condition and deterioration rates.

As discussed in Huegin's report [Document RP938c], in determining the required Corrective Maintenance expenditure forecast, Ergon Energy has applied a constant defect rate of 18.5 per cent with a constant unit cost per kilometre of track remediated (reflecting actual historical costs per kilometre). The 128 per cent step change in kilometres of track inspected (from 11,000 kilometres in 2009-10 to 25,000 kilometres in 2010-11) results is a 128 per cent increase in direct costs associated with access track remediation.

Defect rate understated

The AER has allowed the planned increase to access track inspections. However, by recommending a reduction to the forecast Corrective Maintenance expenditure, the AER is implying that the forecast defect rate is too high, and that it should be replaced with a "notional 30 per cent" increase in work volume. As discussed in [Document RP938c], this effectively corresponds to forecast defect rate of 10.5 per cent. Document RP938c investigated Ergon Energy's historic defect rate and found that it was significantly higher than 10.5 per cent and that Ergon Energy's forecast of 18.5 per cent is likely to be an underestimate.

Huegin concludes "that based on the evidence available it would be hard to justify a defect rate of less than that applied by Ergon Energy in their NARMCOS model" [Document RP938c]. Ergon Energy considers that the AER's proposed 30 per cent increase in work volume will be insufficient to cover the corrective work that has been identified as urgent in the current year program as well as defect remediation work identified during the increased access track inspection program from 2010-11 onwards.

Consideration of efficiency gains from subsequent cycles

As stated in the Asset Equipment Plan (AEP) for Access Tracks and Sites, Ergon Energy acknowledges that the long-term costs should decrease in subsequent inspection cycles, however (as noted by PB) the program first needs to move from a reactive mode to a proactive situation, where appropriate maintenance at the right time can avoid long-term problems such as erosion and track washouts. Due to the magnitude of the current backlog, and the fact that the planned inspection program involves a four year cycle commencing in 2010, it is unlikely that Ergon Energy will achieve a steady state access track program until the beginning of the following regulatory control period (i.e. 2016 onwards).

Ergon Energy notes that in the case of vegetation management (as opposed to access tracks), where the effect of increased efficiency in subsequent cycles will be realised during the upcoming regulatory control period due to the 12, 24 and 36 month inspection cycles associated with certain bioregions this effect has been explicitly modelled in the forecasting process. PB's report noted this modelled efficiency, stating that Ergon Energy employed "a costing model which explicitly accounts for the difference between the first cycle and subsequent cycles, progressively decreasing the work volume and costs" [PB Report 133].

Ergon Energy considers the modelling of such efficiencies is critical to providing an accurate forecast of costs. However, in the case of the Access Track Inspection and Remediation Program, given the four year inspection period and the current backlog, such efficiencies will not to be realised until the following regulatory control period at the earliest.

30 per cent increase will be insufficient to remediate the backlog and achieve compliance

As has been shown, the remediation of identified poor condition access track is a legislated requirement. The increase originally proposed by Ergon Energy is necessary in order to meet its obligations and to address existing backlogs. The forecast has been substantiated based on the approved inspection program, forecast defect rates and remediation costs. Finally, Ergon Energy has considered efficiencies arising from subsequent cycles and considers that any such efficiencies will not be realised until after the upcoming regulatory control period.

As a result of these findings, Ergon Energy considers that its original forecast of corrective work to access tracks reasonably reflects the expenditure of a prudent DNSP operating in Ergon Energy's circumstances.

11.4.6.6 Summary of concerns and responses for Vegetation Management and Access Tracks

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Removing cumulative growth factors – reduction of $4.7 million to Preventive Maintenance for Vegetation Management [162-3, 681]	- Unable to ascertain the underlying rationale for the application of cumulative growth factor	- Underlying rationale and detailed justification has been provided as part of the Revised Regulatory Proposal; and - See section 11.4.6.4.2 for full details.
- Reducing number of locks and keys to be installed to 24,000 - reduction of $8.4 million to Preventive Maintenance for Access Tracks and Sites [163, 681]	- Not able to determine the economic justification - Not provided with any information on the risk assessment underpinning the proposed work program	- Program is in response to legislative compliance and safety issues and is not proposed for the purpose of providing economic benefits; - Relevant risks have been addressed in the business case documentation for the zone substation project (submitted at Document RP916c) and are discussed in detail in section 11.4.6.5.1 of the Revised Regulatory Proposal. This results in a reduction of approximately $6 million from the June 2009 Regulatory Proposal.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Expected work volume increases reduced from 100 per cent to 30 per cent - reduction of $27.5 million to Corrective Maintenance for Access Tracks and Sites [163, 681]	- Not able to ascertain how the expected reductions in corrective vegetation maintenance have been incorporated into Ergon Energy's modelling	- Expected reduction in *Vegetation Management* clearly modelled in Ergon Energy's Forecast [see PB report p. 133]; - No reduction expected within the next regulatory period for *Access Tracks and Sites;* - The 100 per cent increase proposed by Ergon Energy is necessary in order to meet its obligations and to address existing backlogs; - See section 11.4.6.5.2 for detailed justification.
- Removing a 5 per cent increase in unit costs which cannot be matched against historic records - reduction of $12 million [163, 681]	- Not able to ascertain the drivers underlying the cost increase	- Ergon Energy confirms that there is no "5 per cent uplift" in costs included in its vegetation cost modelling as suggested by PB. Rather, one of Ergon Energy's four scenario models contained an error, which once rectified results in an $11.7 million reduction to the total forecast expenditure for vegetation management, rather than the $12 million reduction made by the AER. This is discussed in detail in Document RP938c.
- concerned about data collection and management processes [679]		- Ergon Energy is improving its data collection and management processes in relation to vegetation management; and - The vegetation program is now established in Ellipse and regular monthly reporting on the progress of the program is generated from Ellipse. Documentation of all vegetation processes is now well advanced and more rigour has been applied to ensure that all data is correctly entered into the tree management database.

11.4.7 Other operating costs

11.4.7.1 Ergon Energy's June 2009 Regulatory Proposal

As part of its June 2009 Regulatory Proposal, Ergon Energy developed operating expenditure forecasts of $375.34 million for Other Costs, comprising:

- $60.38 million in Meter Reading expenditure;
- $101.28 million in Customer Services expenditure; and
- $213.68 million in Other Operating expenditure (including DMIA and Self Insurance).

11.4.7.2 The AER's Draft Distribution Determination

The AER did not accept Ergon Energy's forecast operating expenditure for all Other Operating expenditure. Specifically, the AER:

- Considered that it could not verify that Alternative Control Services had not been included in the Meter Reading forecast and accordingly determined a reduction of $29.7 million [684-5, 689];
- Considered that it could not verify that Alternative Control Services had not been included in the Customer Services forecast and accordingly determined a reduction of $49.8 million [684-5, 689];
- Accepted Ergon Energy's GSL payments and training forecasts [686];
- Considered that the increase in program management costs for Demand Management were not justified and accordingly determined a reduction of $2.5 million [687, 689]; and
- Considered that the component of the Marketing and Sponsorship expenditure forecast that related to sponsorship and community engagement did not relate to the provision of Standard Control Services nor did it relate to the operating expenditure objectives and as such the AER determined a reduction of $1.5 million [688, 689].

11.4.7.3 Ergon Energy's response to the Draft Distribution Determination

Ergon Energy has considered the AER's Draft Distribution Determination and has:

- Not accepted the AER's decision regarding Customer Service and Meter Reading and has retained its original forecast from its June 2009 Regulatory Proposal;
- Not accepted the AER's decision regarding Demand Management and has retained its original forecast from its June 2009 Regulatory Proposal; and
- Accepted the AER's reduction to its forecast for Marketing and Sponsorship from its June 2009 Regulatory Proposal.

Specific justifications for Ergon Energy's Revised Regulatory Proposal are addressed in the following sections:

- Section 11.4.7.3.1details the reasons for Ergon Energy's decision not to accept the AER's Draft Distribution Determination for Customer Service and Meter Reading operating expenditure; and
- Section 11.4.7.3.2 details the reasons for Ergon Energy's decision not to accept the AER's Draft Distribution Determination for Demand Management operating expenditure.

11.4.7.3.1 Customer Service and Meter Reading

The AER reduced Ergon Energy's Customer Service and Meter Reading forecast on the basis of it not being able to verify that similar Alternative Control Services were not included in the forecast:

> *The AER has not been able to verify that alternative control service costs have not been incorporated into Ergon Energy's modelling of other operating costs for standard control services.* [107]

The AER based this assessment and the associated adjustment on PB's assessment of a report that was provided in support of the forecast Standard Control Services' costs in Ergon Energy's Regulatory Proposal.

> *PB found that there was an overlap of key activities of standard and alternative control services in relation to metering and customer care activities.* [108]

The AER further states that Ergon Energy did not satisfactorily demonstrate that its forecast did not include Alternative Control Services.

> *Ergon Energy was asked to clarify the forecast with reference to source material, but was unable to satisfactorily demonstrate that the opex forecast did not include any alternative control services costs for metering and customer service opex.*[109]

With respect to the clarification reference above, Ergon Energy provided information on Wednesday 9 September 2009 in its email response to AER-PB Q.VP.94. This information related to the materiality and accuracy of the division of Standard and Alternative Control Services in Document AR272c that PB has used in assuming that Ergon Energy has included Alternative Control Services in its forecast.

Materiality of the division of control services in Document AR272c

Ergon Energy advised the AER that whilst the total Customer Services and Meter Reading operating expenditure forecast presented in Document AR272c was used to verify the budget forecasts, the subtotals for the Alternative and Standard Control Services allocation in the same document were immaterial.

The actual forecast model Document PL561c used in the June 2009 Regulatory Proposal correctly removes Alternative Control Services from the forecast figures in accordance with Ergon Energy's Cost Allocation Method approved by the AER.

[107] AER, "Draft Decision Queensland Draft distribution determination 2010-11 to 2014-15", 25 November 2009, p163

[108] Ibid, p163

[109] AER, "Draft Decision Queensland Draft distribution determination 2010-11 to 2014-15", 25 November 2009, p686

Accuracy of the division of control services in Document AR272c

PB assumed that the difference between the Standard Control Services subtotal in Document AR272c and Document PL561c represented a double count of Alternative Control Services. Aside from the immateriality of the subtotal for Standard Control Services presented in Document AR272c, Ergon Energy also advised that the data was inaccurate at the subtotal level. The source of this error is related to:

- The data sources PB compared not being in comparable dollar terms; and
- The classification of services in Document AR272c not being in accordance with Ergon Energy's Cost Allocation Method.

Regarding the second point above, Ergon Energy provided an example of the error in the email response to AER-PB Q.VP.94. The particular error related to $3.93 million ($2008, excluding overheads) of customer meter reading services wrongly attributed to the Alternative Control Services in the Customer Care Forecast Report [Document AR272c]. Ergon Energy contends that the information it provided has not been afforded due consideration by the AER. Huegin's report at [Document RP938c] provides further details regarding the reconciliation of costs reported in the Customer Care Forecast Report [Document AR272c] and the actual forecast model [Document PL561c].

Substitute forecast not in accordance with the operating expenditure criteria

Ergon Energy contends that the substitute forecast for Customer Service and Meter Reading operating expenditure provided by the AER in its Draft Distribution Determination does not consider the circumstances of Ergon Energy, nor reflect a prudent level of expenditure.

The Huegin report [Document RP938c] provides analysis that demonstrates:

- The substitute forecast in the AER's Draft Distribution Determination is significantly lower than Ergon Energy's current expenditure;
- The substitute forecast in the AER's Draft Distribution Determination is significantly lower than other DNSPs expenditure; and
- The substitute forecast represents an unachievable outcome for a network such as Ergon Energy's.

For the reasons detailed, Ergon Energy considers that its original forecast for Customer Service and Meter Reading operating expenditure in its Regulatory Proposal remains prudent and efficient for the next regulatory control period.

11.4.7.3.2 Demand Management

The AER has reduced Other Operating costs by $2.63 million for project management costs (from a total of $15.45 million) associated with the implementation of Non-Network Alternative initiatives related to Demand Management.

The AER states in its Draft Distribution Determination that the adjustment is warranted on the basis that there will be "economies of scale" savings arising from the implementation of the various initiatives:

> *The AER reviewed the costing proposals associated with Ergon Energy's demand management initiatives. The AER considers that the proposed demand management initiatives are prudent, with the exception that economies of scale and productivity improvements should be factored into the programs proposed project management costs.* [110]

The AER, in making this statement, relied on the following advice from PB:

> *However, Ergon Energy is proposing that $15.4m (25% of the DM allowance) was for internal project management, and that $2.63m of this can be directly attributed to an increase required to manage the proposed program compared to the current program. As part of the business case for the Townsville large-customer pilot program, management costs were also included in the scope of work. PB also notes the Ergon Energy lacks a*

[110] Op cit, p164

single, centralised demand management strategy or policy to present the wider objectives of its initiatives. The development of such a document is likely to improve wider co-ordination of the initiatives and capture some economies of scale and therefore further reduce internal project management costs.

PB considers the portion of project management costs associated with the DM activities is not prudent and efficient, and recommends the $2.63m allowance to manage the proposed programs is excluded from the total allowance in accordance with Table 6.36. Economies of scale and productivity improvements arising from work practices associated with the remaining $12.8m for project management should reasonably allow for the new programs to be implemented.[111]

Ergon Energy's forecasts include a number of project and ongoing management costs for the programs. Some costs are captured in the project management costs associated with each implementation as one off costs associated with the implementation. However, as these initiatives are bedded down into the Ergon Energy's normal operating practices there are ongoing incremental costs associated with managing the initiatives. These incremental costs are captured in the forecast, resulting in expenditure of $2.5 million.

Ergon Energy believes that PB and the AER should recognise the need for an ongoing incremental cost associated with the management of the initiatives that will be deployed into Ergon Energy's operating practices.

Ergon Energy therefore considers that its original forecast for the ongoing management of Non-Network alternative initiatives and programs in its June 2009 Regulatory Proposal remains prudent and efficient for the next regulatory control period.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reduction of $83.6 million in other operating costs [164]	- Removal of Alternative Control Services and unregulated costs for metering from Standard Control Services costs - reduction of $29.7 million [163-4, 689]	- As discussed in this chapter, and in Document RP938c, Ergon Energy did not include metering costs associated with Alternative Control Services and unregulated services in its Other Operating Expenditure forecasts for Standard Control Services.
	- Removal of Alternative Control Services and unregulated costs for customer service from Standard Control Services costs - reduction of $50 million [163-4, 689]	- As discussed in this chapter and in Document RP938c, Ergon Energy did not include customer service costs associated with Alternative Control Services and unregulated services in its Other Operating Expenditure forecasts for Standard Control Services.
	- Removal of project management costs for demand management - reduction of $2.5 million [164, 689]	- The $2.5 million relates to the on-going incremental costs arising from the introduction of new programs in demand management.
	- Removal of sponsorship costs - reduction of $1.5 million [164, 689]	- Ergon Energy accepts the AER's reduction and has reflected it into its modelling for this Revised Regulatory Proposal however Ergon Energy believes that it is a legitimate business expense.

[111] Op cit, p 141

11.4.8 Shared Costs (Overheads)

11.4.8.1 Change in GSL arrangements

The QCA has mandated an increase in Guaranteed Service Level (GSL) payments to customers and imposed a requirement that all payments to customers be automated. This means that Ergon Energy needs to significantly increase the forecast GSL expenditure from $66,000 to $1.5 million per annum for the 2010-15 regulatory control period.

Background

The Code sets GSLs that the electricity DNSPs must meet in relation to the quality of service received by individual customers.

GSLs were introduced into Queensland with the commencement of the first edition of the Code in January 2005. The Code requires that a review of the GSL and the GSL payment amounts be undertaken at the beginning of each regulatory control period[112]. The QCA commenced reviewing the GSL arrangements for Queensland during July 2008.

A Final Decision[113] was released by the QCA on 24 April 2009 in which it mandated a 30 per cent increase in the value of GSL payments. These payment increases reflect the amount that Ergon Energy had initially forecast in its June 2009 Regulatory Proposal.

The QCA foreshadowed in its 24 April 2009 Final Decision its intention to conduct another public consultation to examine the GSL claim process. The QCA released its Final Decision[114] on 22 October 2009 to amend the GSL claim process to an automated system. The Code changes for both GSL payment increases and the GSL claim process to an automated system are to come into effect on 1 July 2010.

Impacts on Ergon Energy

Ergon Energy has had to increase its forecast GSL costs significantly in order to ensure that it is compliant with the Code. Ergon Energy's forecast costs in this Revised Regulatory Proposal have incorporated both the 30 per cent increase in GSL payments and the move to an automated GSL payment system.

It is important for the AER to note that Ergon Energy was not aware, at the time of submitting its Regulatory Proposal, of the costs of complying with the new GSL claim process, as the QCA's Final Decision was only published on 22 October 2009. With the release of the QCA's Final Decision, Ergon Energy has been able to forecast that $1.5 million will be required per annum to ensure that Ergon Energy's obligations under the Code are met.

Ergon Energy recognises that, under clause 6.6.1 of the Rules, a DNSP is entitled to seek the approval of the AER to pass through a positive pass through amount for a regulatory change event. However, Ergon Energy submits that given that this amendment is now known and its implementation date is certain (i.e. 1 July 2010), the AER should have regard for Ergon Energy's forecast GSL costs and include these costs in its final Distribution Determination.

Explanation of forecasting methodology

Currently Ergon Energy generates two monthly reports:

- One report outlines actual GSL payments [Document RP932c] made to customers by Ergon Energy; and
- The second report details potential GSL payments [Document RP933c] owed to customers that Ergon Energy has missed or the customer has not proactively claimed against.

From 1 July 2010, Ergon Energy will have to automatically pay all GSLs to customers rather than wait for a customer to initiate a claim against Ergon Energy for not meeting a service standard. The

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[112] Clauses 2.4.4 and 2.5.19

[113] http://www.qca.org.au/electricity/service-quality/RevMinServStandLev.php

[114] http://www.qca.org.au/electricity/service-quality/RevGSLClaimProElC.php

combined monthly reports and the QCA's decision to increase the GSL payments and automate the GSL claim process formed the basis of forecasting Ergon Energy's potential GSL payments for the next regulatory control period in order for Ergon Energy to meet the GSL Code requirements.

Therefore, Ergon Energy has forecast the GSL costs required for the next regulatory control period by maintaining the same level of actual and potential GSL payments (i.e. the rate of GSL payments has not been escalated) and including the 30 per cent increase in GSL payments and the move to an automated GSL payment system.

The total amount required is $7.5 million over the 2010-11 to 2014-15 regulatory control period with an annual forecast of $1.5 million.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Increase of $1.3 million in Guaranteed Service Level payments per annum	-	- The Final Decision paper was not completed by QCA at the time of June 2009 Regulatory Proposal. As such, Ergon Energy did not have an understanding of the changes to the Electricity Industry Code and the financial impact on Ergon Energy. The increase in the GSL payments is a Code requirement commencing the next regulatory period - 1 July 2010. - There will be a significant financial impact in the payment of GSLs to $1.5 million per annum. Document RP932c and Document RP933c outlines the data and formula used to calculate this figure in both number of GSLs and value. The total projected cost of GSLs to Ergon Energy Corporation over the next regulatory period is $7.5 million. - Document RP983c summarises the changes to Electricity Industry Code in particular the increase in GSL values.

11.4.8.2 Other Shared Costs (Overheads)

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reduction of $6.4 million in shared costs (overheads) allocated to operating expenditure [165]	- Majority of ICT projects not supported by analysis that demonstrated prudence or efficiency, with the exception of reconfiguration of the data room [120-1, 568]	- Ergon Energy has provided new information justifying expenditure for DMS, FFA and new ICT infrastructure in section 10.4.8. Ergon Energy has therefore retained its forecast expenditure from its June 2009 Regulatory Proposal.
	- Reduction of $1.5 million for sponsorship and other community engagement activities [121, 568]	- Ergon Energy accepts the AER's reduction and has reflected it into its modelling for this Revised Regulatory Proposal however Ergon Energy believes that it is a legitimate business expense.

11.4.9 Self insurance

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reduction of $21.48 million in self insurance costs so that the AER is only allowing $3,218 per annum in self insurance [167-8] - Ergon Energy requested to remodel self insurance forecasts to reflect AER's adjustments in Appendix K and revised cost escalators in Appendix H [168]	- Self insurance allowances are not prudent and efficient [168]	- For the reasons discussed in its Regulatory Proposal, and detailed below, Ergon Energy considers its self insurance costs estimates to be prudent and efficient and derived in a manner consistent with generally acceptable actuarial practice and reflective of fair and reasonable assumptions adopted.
	- AER has assessed Ergon Energy's self insurance claims using five criteria [693-699]: o Ergon Energy's attitude to managing risk and its capacity to self insure o Approaches to funding a future loss when a self insurance event occurs o Reporting and administering self insurance o Whether premium can be determined and whether self insurance relates to an incurred cost o Whether premium estimated is an efficient cost	- The AER's criteria were not made available to Ergon Energy prior to submitting its Regulatory Proposal. In the absence of any specific guidance from the AER, reference has been made to the AER's recent previous determinations. - Ergon Energy notes, for example, that the AER's Draft Distribution Determination is inconsistent with the Powerlink decision for its 2007-08 to 2011-12 regulatory control period. Ergon Energy applied a similar methodology to Powerlink with adjustments for the different risks involved. The AER fully accepted Powerlink's proposed allowance for both uninsured risks and below-deductible losses - In Document RP915c, Ergon Energy addresses each of the reasons that the AER gave in its Draft Distribution Determination for cutting its self insurance proposal. Ergon Energy's reasoning is also discussed in the remainder of this table.
- Reject self insurance for property damage (storm catastrophe) but consider that Ergon Energy may be able to claim a cost pass through [704]	- Risk not predictable and measurable [704]	- The risk associated with events such as storm damage cannot be predicted or quantified with certainty. Nevertheless, reasonably reliable predictions as to the likelihood and cost can be produced by reference to historical data. - As discussed in Document RP915c and Document RP968c, Finity produced a self-insurance premium for storm damage based on: o Six years of data relating to events and associated losses; o A review of (on average) approximately 500 emergency outages per annum to produce a statistically based distribution of losses that took into account losses ranging from very small (i.e. attritional) losses to very large losses, such as Cyclone Larry; and o The use of data relating to ENERGEX to ensure consistency between the two DNSPs.
	- Can cover non-material losses through operating and capital expenditure [704]	- As discussed in Document RP915c, Finity was careful to ensure that Ergon Energy's claim for self-insurance excluded any amounts from their capital and operating expenditure forecasts. Hence, by disallowing all of the Property Damage claims, losses from storm damage which are not in maintenance budgets and which are below the pass through threshold will be unclaimed. - In any event, Ergon Energy's Board has made a judgment

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
		that the cost of catastrophic storm damage should be met through self insurance, rather than forecast operating and capital expenditure. While the AER may consider, as a matter of business judgment, that a different approach is preferable, this does not mean that the approach proposed by Ergon Energy is not prudent, efficient, or realistic.
	- Finity has used data relating to Cyclone Larry pass through, which should not be used to determine the self insurance premium [704]	- As discussed in Document RP915c, Finity referred to Cyclone Larry only for the purpose of determining a distribution of losses associated with events of different sizes. For the purposes of calculating a self-insurance premium, Finity expressly excluded events in excess of $10 million (such as Cyclone Larry) on the basis that a pass through would be available.
	- Finity's assumption about wind gusts is not realistic [704]	- As discussed in Document RP915c, Ergon Energy notes that the use of an estimate of 200 kilometre per hour is explained in Appendix E to the Finity report [Document AR313c]. The maximum wind gust of 185 kilometre per hour was recorded by the Bureau of Meteorology at a specific location some time after the cyclone had made landfall. The highest reported offshore wind gust for Cyclone Larry was 240 kilometre per hour, and wind gusts were estimated to have reached this speed in areas surveyed after the cyclone made landfall. Finity selected an estimate of 200 kilometre per hour because it was in the more conservative end of this range.
	- Finity's assumptions about 2004 storms not realistic [704]	- See response above under " Finity has used data relating to Cyclone Larry pass through, which should not be used to determine self insurance premium [707]"
- Reject self insurance for public liability risks and reduce allowance to $3,218 per annum [711]	- Application of incurred but not reported (IBNR) benchmarks not appropriate [711]	- As discussed in Document RP915c, an allowance for IBNR claims is required under Accounting Standard AASB 137, APRA General Insurance Standards and the Institute of Actuaries' professional standard 300. The calculation of the IBNR benchmarks is detailed in Tables G.1 and G.2 of its report to Ergon Energy, which is Document AR313c. - While Ergon Energy believes that the IBNR allowance should be included in the estimate of its proposed self insurance premium for public liability risk, even if it was excluded, this would only reduce the premium for below-deductible public liability claims from $16.6 million to $15.5 million.
	- Not consistent with external insurance policies [706]	- Ergon Energy notes that actuaries typically set premiums for insurance companies. Finity is the Appointed Actuaries to more than 30 general insurers in the Australian market and has won the Service Provider of the Year to the Insurance Industry for the past four years. Hence, the premium estimates that Finity arrives at are no less valid than those quoted by an insurer. - Finity has calculated Ergon Energy's proposed self insurance premium for public liability risk consistent with actuarial standards.
	- AER has derived estimate of a premium to cover the deductible for general public liability [706-8]	- As discussed in Document RP915c, Finity has advised that the AER's proportionate calculation of the self insurance premium for public liability risk is not consistent with actuarial standards or any known actuarial practice. In particular, the AER has failed to recognise that the distr bution of loses is highly skewed above and below Ergon Energy's current deductible limits. - Ergon Energy sought a quotation from its current liability insurer [Document RP984c]. However, it was not prepared

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
		to quote for cover below a minimum deductible level of $100,000 for each and every loss for bushfire damage and $25,000 for each and every loss for other claims. - Ergon Energy's current liability insurer provided a quotation of: o $500,000 per annum to reduce the deductible limit from $1 million to $100,000 for bushfires; and o $250,000 per annum to reduce the deductible limit from $100,000 to $25,000 for other claims. - However, claims below these revised deductible limits account for 95 to 98 per cent of the cost of all public liability claims. - This confirms the calculation by Finity based on previous claims history of providing self insurance cover for public liability events. - Ergon Energy cannot obtain insurance in the market for the full amount of its current deductibles and maintains that the actuarial assessment made by Finity is appropriate and that it is not appropriate for the AER to replace this assessment with a pro rated proxy value based on the current insurance premium.

11.4.10 Debt Raising Costs

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reduction of debt raising costs of $72.1 million to $22 million (or an average of $4.4 million per annum) [168-171]	- Ergon Energy has not presented any new evidence in support of inclusion of indirect debt raising costs [169] - AER will continue to apply The Allen Consulting Group's approach to estimate direct debt raising costs with the following revisions [169, 737-8]: o Updates to selection of bonds; and o Accounting for the time value of money. - Updates to benchmark medium term note issue size with the latest available data	- Ergon Energy does not accept the AER's Draft Distr bution Determination, which reduced allowable debt raising costs significantly and maintains its position from its June 2009 Regulatory Proposal. However for modelling purposes for this Revised Regulatory Proposal, Ergon Energy has used the AER's substituted costs.

11.4.11 Equity Raising Costs

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reduction of equity raising costs of $82 million to $11.9 million to be amortised over next regulatory control period [175-6]	- Ergon Energy has misunderstood the need to convert the equity raising cost allowance to an annuity equivalent or perpetuity stream [176]	- The AER provided a model to Ergon Energy to be used in the calculation of equity raising costs. - The AER's model had provision for data to be sourced from the PTRM. Ergon Energy calculated its equity raising costs according to the resultant output from the model. - The AER applied a different approach in its Draft Distribution

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
		Determination by using a model based on the PTRM, which subtracted the value of capital contributions by asset class from the annual capital expenditure forecasts. The AER's model also updated parameters from the model initially provided to Ergon Energy. - Ergon Energy has now updated its modelling to reflect the methodology in the AER's Draft Distribution Determination and has reflected this into this Revised Regulatory Proposal.
	- The AER considers that the proposed allowance for indirect equity raising costs is inconsistent with the regulatory framework [173] - The AER has rejected Ergon Energy's proposed estimates for direct equity raising costs in favour of its own estimates [174-6]. - It has also rejected Ergon Energy's assumptions regarding the proportion of equity funding that is raised via different methods (that is, dividend reinvestment plans, seasoned equity offerings etc). [175]. - The AER also requires that a dividend payout ratio of 100 per cent is applied, rather than the proposed market average of 70 per cent [175-6].	- Ergon Energy does not accept the AER's Draft Distr bution Determination, which reduced equity raising costs significantly and maintains its position from its June 2009 Regulatory Proposal. However, for modelling purposes for this Revised Regulatory Proposal, Ergon Energy has used the AER's substituted costs.
	- Equity raising costs allowance should be amortised over the life of Ergon Energy's RAB for the purposes of providing the equity raising cost allowance associated with the forecast capital expenditure over the regulatory control period [176]	- Ergon Energy does not accept the AER's Draft Distr bution Determination with regards to the treatment of equity raising costs and maintains its position from its June 2009 Regulatory Proposal. However, for modelling purposes for this Revised Regulatory Proposal, Ergon Energy will amortise the AER's substituted allowance for equity raising costs over the life of Ergon Energy's RAB for the purposes of providing the equity raising cost allowance associated with the forecast capital expenditure over the regulatory control period.

11.4.12 Interest rate hedging costs

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reject categorisation of interest rate hedging costs as operating expenditure and reject approval of any allowance for these costs [180]	- Insufficient evidence provided by Ergon Energy to support cost claim and have not demonstrated that [182]: o Hedging costs should be treated as operating	- Ergon Energy does not accept the AER's Draft Distr bution Determination with regards to interest rate hedging costs and maintains its position from its June 2009 Regulatory Proposal. However for modelling purposes for this Revised Regulatory Proposal, Ergon Energy will use the AER's substituted costs, being a zero allowance.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
	expenditure under the Rules (as proposed by Ergon Energy), rather than the cost of capital. o AER's cost of capital allowance is not appropriate o Sufficient compensation not already provided through regulatory framework – specifically, the AER said it has been 'conservative' in assessing both the equity beta (where it applied the upper bound of its range) and the term of the risk-free rate (the risk –free rate is based on a ten year maturity whereas the AER has assumed that the average term of debt funding is 7.37 years). o If interest rate hedging is not undertaken, BBB+ credit rating and 60:40 gearing ratio will be adversely affected	

11.4.13 Input Cost Escalators

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reduction of $264 million in operating expenditure due to revisions in cost escalations [191] - Revised cost escalators for labour and materials [192]	- Not appropriate to apply single escalation rate to internal and contract labour [189-90]	- Ergon Energy considers that it is appropriate to apply a single escalation rate to internal and contract labour for the reasons detailed in section 9.8 of this Revised Regulatory Proposal.
	- Apply specific weighted average escalation rates to internal labour resources based on relative contribution of specialist and general labour resources to the expenditure program [190-1]	- Internal labour, regardless of whether it is specialist or general, is paid the same wage increases based on the UCA. - Ergon Energy therefore sees no reasons to apply a weighting to specialist and general labour resources for the purposes of determining the labour escalation rate to apply in the next regulatory control period. - Instead, the UCA wage increases should be applied uniformly to both specialist and general labour.
	- Apply Queensland EWG escalators to contract labour [190-2]	- As discussed above, Ergon Energy considers that: o The AER has not demonstrated the need to apply separate wage escalation rates for contract labour; and o There is no reason to think that the wage increases payable to Ergon Energy's contractors will be lower than those payable to Ergon Energy's own employees. - For these reasons, Ergon Energy considers that the AER should not apply the Queensland EWG escalators to contract labour but rather should apply the UCA rate to wage

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
		escalations.

11.5 Ergon Energy's Revised Regulatory Proposal

Ergon Energy's revised calculation of operating expenditure forecasts for Standard Control Services for the period 1 July 2010 to 30 June 2015 is detailed in Table 11-3.

Table 11-3: Forecast Operating Expenditure – by Category Driver – 2010-15 ($M Real $2009-10)

Category Driver	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Network Operating Costs	26.16	26.31	26.56	27.08	27.32	133.43	26.69
Network Maintenance Costs							
Preventive Maintenance	106.70	119.05	117.67	119.05	119.41	581.88	116.38
Corrective Maintenance	119.02	119.00	119.51	114.46	102.27	574.26	114.85
Forced Maintenance	41.35	41.61	41.74	41.55	40.92	207.17	41.43
Subtotal	267.07	279.66	278.92	275.06	262.60	1,363.31	272.66
Other Costs							
Meter Reading	11.69	11.84	12.03	12.30	12.44	60.30	12.06
Customer Services	19.92	20.15	20.33	20.65	20.74	101.79	20.36
Other Operating Costs	44.06	45.58	46.61	48.52	50.50	235.27	47.05
Subtotal	75.67	77.57	78.97	81.47	83.68	397.36	79.47
Total Operating Expenditure	368.90	383.54	384.45	383.61	373.60	1,894.10	378.82

Source: Revised Submission Tables for Proposal 26.1

11.6 Rules' Requirements

In submitting this Revised Regulatory Proposal in relation the operating expenditure for Standard Control Services, Ergon Energy has had regard for clauses 6.4.3(a)(7), 6.4.3(b)(7), 6.5.6, 6.12.1(4) and S6.1.2 of the Rules.

11.7 Relevant documents provided by Ergon Energy

The following documents are relevant to this Chapter, some of which have been previously provided to the AER, while others are new since, or were not provided to the AER with, Ergon Energy's June 2009 Regulatory Proposal:

Email 09-09-09	EE response to PB Q.VP.94
AR272c	EE_Customer Care Forecast Report including Meter Reading_13Feb09
AR313c	Finity_EE Self Insurance Arrangements for 2010-15_V2_Mar09
PL561c	PL561c_SCOpex Data Model.xls
RP910c	RP910c_EE_Provision of Keyed Locks Evaluation_Contract 2007-0157-T_15May08.doc

RP911c	RP911c_EE_Provision of Keyed Locks 2nd Yr Review_Contract 2007-0157-T_Apr09.xls
RP915c	RP915c_EE_Self Insurance for RRProposal_23Dec09.doc
RP916c	RP916c_EE_NIRC Business Case_Key & Lock Replacement_V6_23Aug07.doc
RP932c	RP932c_EE_GSL Payment Figures_Oct09_23Dec09.xls
RP933c	RP933c_EE_GSL Potential Payment Figures_Oct09_23Dec09.xls
RP938c	RP938c_Huegin Report for EE_V1.0_12Jan10.pdf
RP966c	RP966c_BME_FINAL-Report EE-2009.pdf
RP967c	RP967c_Aust Timber Pole Resources for Energy Networks_Oct06.doc
RP968c	RP968c_FINITY_Response to AER.pdf
RP983c	RP983c_EE_Memo_GSL Increases & Claim Process_28Oct09.doc
RP984c	RP984c_AON_Ergon Liability Insurance_Reduction of Self Insured Retention_8Jan10.rtf

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12 ESTIMATED CORPORATE INCOME TAX

In response to the AER's Draft Distribution Determination Ergon Energy:

- Rejects of the gamma value of 0.65 proposed by the AER in its Statement of Regulatory Intent (SORI);
- Has applied the AER's PTRM in order to recalculate a revised corporate income tax building block for the next regulatory control period based on applying a gamma value of 0.2; and
- Has provided additional information to support its contention that a gamma value of 0.2 should be used.

12.1 Ergon Energy's June 2009 Regulatory Proposal

Chapter 38 of its June 2009 Regulatory Proposal and RIN Pro Forma 2.2.2 detailed Ergon Energy's estimate of the cost of corporate income tax for each year of the regulatory control period, 2010-11 to 2014-15. The estimated amounts are reproduced in Table 12-1.

Table 12-1: Original Corporate Income Tax for 2010-11 to 2014-15 ($M Nominal) Forecast

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Tax payable	0.00	21.67	77.22	94.56	100.49	293.94
Less value of imputation credits	0.00	4.33	15.44	18.91	20.10	58.79
Net corporate income tax allowance	0.00	17.34	61.77	75.65	80.39	235.15

Source: Revised Submission Tables for Proposal 38.3

In accordance with clause 6.5.3 of the Rules, the estimate of the corporate income tax building block relates to a benchmark efficient entity, rather than Ergon Energy per se. This contrasts with the approach taken by the QCA in the current regulatory control period, which estimated corporate income tax based on Ergon Energy's actual tax paid and payable.

12.2 AER's November 2009 Draft Distribution Determination

On the basis of advice from McGrathNicol, the AER considers that the tax inputs into Ergon Energy's PTRM and RFM are consistent with the tax provisions of the Rules. However, the AER has rejected Ergon Energy's proposed use of a gamma of 0.2, and retained the use of a 0.65 gamma as set in the SORI.

Ergon Energy's allowances for corporate income tax determined by the AER are presented in table 9.3 on page 218 of the Draft Distribution Determination. The total allowance over five years of $116.50 million represents a reduction of $118.65 million from the $235.15 million that Ergon Energy requested in its June 2009 Regulatory Proposal. The reduction is due to the revision of gamma from 0.2 proposed by Ergon Energy to 0.65 provided for in the AER's SORI.

12.3 Ergon Energy's Response to AER's Draft Distribution Determination

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reject 0.2 gamma proposed by Ergon Energy and retain 0.65 gamma as set in the SORI [217]	- Ergon Energy has not identified specific areas of concern with gamma of 0.65 [217]	- In its Regulatory Proposal, Ergon Energy identified a number of concerns with the AER's assumed value for gamma and submitted new evidence to question the reliability of the study that was used to establish the AER's upper bound value for the range that it used to determine theta. (Theta is the value of franking credits. This is multiplied by the assumed distribution rate to arrive at a value for gamma). This was

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
		based on an analysis prepared by Synergies.
	- Gamma of 0.2 would [217]: o Result in rate of return above forward looking rate of return commensurate with prevailing conditions in the market for funds and the risk involved in providing regulated distribution services o Not be consistent with National Electricity Objective	- Ergon Energy continues to consider that a gamma of 0.2 better meets the requirements of the Rules than the value of 0.65 provided for in the AER's SORI. Considerable evidence was submitted by the Joint Industry Associations as part of the review of the SORI to support this value. Gamma is one of the main areas where the AER was seen to be in error in the Statement of Regulatory Intent. - In addition to Ergon Energy's concerns with the AER's upper bound value for theta (which were addressed in its Regulatory Proposal), it has fundamental concerns with the two other key assumptions underpinning the AER's gamma estimate, being the lower bound value for theta (or the value of franking credits) and the distr bution rate. - Ergon Energy proposes to continue to depart from the SORI on Gamma in relation to the value for theta. It has new evidence to submit to support this proposal, based on a report prepared by SFG Consulting [Document RP969c]. This report addresses some of the concerns with the AER's position in relation to the value for theta and concludes that a value of 0.23 is the most appropriate value at the current time. - Ergon Energy does not wish to submit any further evidence to support a continued departure in relation to the distribution rate. However, even if a 100 per cent distribution rate is applied, based on the estimate produced by SFG Consulting, a gamma of 0.2 is still reasonable.

12.4 Ergon Energy's Revised Regulatory Proposal

Ergon Energy previously proposed that the value of gamma was between 0 and 0.2 and hence proposed a point estimate of 0.2. Ergon Energy remains of the view that 0.2 is an appropriate estimate for gamma, even if an assumed distribution rate of 100 per cent is applied. Ergon Energy had proposed 70 per cent which was rejected by the AER.

To support its original position, Ergon Energy has new evidence from SFG Consulting [RP969c] that questions the reasonableness of all the assumptions underpinning gamma as determined by the AER, that is the distribution rate and the value of franking credits. In particular, SFG's report contains compelling evidence regarding the assumed value of franking credits and shows that the best estimate of this value at the current time is 0.23. Even if a distribution rate of 100 per cent is applied, this new evidence shows that Ergon Energy's proposed value of 0.2 is reasonable.

Ergon Energy therefore proposes to continue to depart from the SORI in relation to the value of gamma and has applied a value of 0.2 for the purposes of modelling for this Revised Regulatory Proposal. The estimated amounts are reproduced in Table 12-2.

Table 12-2: Revised Corporate Income Tax for 2010-11 to 2014-15 ($M Nominal) Forecast

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Tax payable	31.91	93.93	102.99	121.13	120.18	470.15
Less value of imputation credits	6.38	18.79	20.60	24.23	24.04	94.03
Net corporate income tax allowance	25.53	75.15	82.39	96.91	96.15	376.12

Source: Revised Submission Tables for Proposal 38.3

12.5 Rules' requirements

In submitting this Revised Regulatory Proposal in relation the corporate income tax building block, Ergon Energy has had regard for clauses 6.4.2(b)(4), 6.4.3(a)(4), 6.4.3(b)(4), 6.5.3, 6.12.1(7) and S6.1.3(11) of the Rules.

12.6 Relevant documents provided by Ergon Energy

The following documents are relevant to this Chapter but are new since, or were not provided to the AER with, Ergon Energy's June 2009 Regulatory Proposal:

RP969c	SFG_Gamma Response_rcd 14Dec09.pdf

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13 DEPRECIATION

In response to the AER's Draft Distribution Determination, Ergon Energy:

- Accepts the adjustments to the calculation of depreciation detailed in the AER's Draft Distribution Determination.

This Chapter provides revised depreciation building blocks for the next regulatory control period based on the AER's adjustments.

13.1 Ergon Energy's June 2009 Regulatory Proposal

Chapter 37 of its June 2009 Regulatory Proposal detailed Ergon Energy's regulatory depreciation building blocks for Standard Control Services for the period 1 July 2010 to 30 June 2015. These building blocks are reproduced in Table 13-1.

Table 13-1: Original Depreciation Building Blocks for Standard Control Services for 2010-15 ($M Nominal)

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Straight line depreciation	274.84	313.78	339.62	385.52	420.28	1,734.05
Inflation on Opening Regulatory Asset Base	171.49	197.01	225.91	255.05	285.98	1,135.44
Regulatory Depreciation	103.36	116.77	113.71	130.46	134.30	598.60

Source: Revised Submission Tables for Proposal 37.1

Chapter 37 of its June 2009 Regulatory Proposal explains that Ergon Energy prepared its depreciation schedules:

- Based on an opening value of the RAB of $4,232.4 million (July 2005 dollars) that was nominated by the QCA and accepted by the AER in its "Final framework and approach paper - Application of schemes - ENERGEX and Ergon Energy 2010–15" (F&A Stage 2);
- Using the RFM and the PTRM;
- Using a straight-line approach over the remaining economic lives of the asset classes for assets within the opening RAB;
- Using a straight-line approach over the standard economic life applied to forecast capital expenditure within the 2010-15 regulatory control period; and
- On the basis that the sum of the real value for any asset over its economic life must be equivalent to the value at which that asset or category of assets was first included in the RAB.

13.2 AER's November 2009 Draft Distribution Determination

The AER's Draft Distribution Determination adjusted Ergon Energy's depreciation building blocks for the next regulatory control period by:

- Revising the remaining asset lives, which results in an increase in the depreciation allowance; and
- Reducing the accelerated depreciation allowance for Cyclone Larry from $11 million to $10 million.

13.3 Ergon Energy's Response to AER's Draft Distribution Determination

13.3.1 Remaining asset lives

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Revised remaining asset lives results in an increase in depreciation allowance – see Table 10.3 [225]	- Ergon Energy made an error in the way remaining asset lives were calculated by dividing real depreciation figures by a nominal closing balance [224-5]	- Ergon Energy has corrected this arithmetic error in this Revised Regulatory Proposal.

13.3.2 Accelerated depreciation

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reduction in accelerated depreciation for Cyclone Larry from $11 million to $10 million [226]	- Adjustment reflects Ergon Energy's response to a question from the AER [226]	- Ergon Energy has adjusted the carry over amount to $10 million in this Revised Regulatory Proposal.

13.4 Ergon Energy's Revised Regulatory Proposal

Ergon Energy's revised calculation of its depreciation building blocks for Standard Control Services for the period 1 July 2010 to 30 June 2015 is detailed in Table 13-2.

Table 13-2: Revised Depreciation Building Blocks for Standard Control Services for 2010-15 ($M Nominal)

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Straight line depreciation	325.55	354.22	386.64	430.95	445.12	1,942.48
Inflation on Opening Regulatory Asset Base	175.76	201.82	230.52	260.20	292.06	1,160.37
Regulatory Depreciation	149.78	152.40	156.12	170.75	153.06	782.11

Source: Revised Submission Tables for Proposal 37.1

13.5 Rules' requirements

In submitting this Revised Regulatory Proposal in relation the depreciation building block, Ergon Energy has had regard for clauses 6.4.3(a)(3), 6.4.3(b)(3), 6.5.5, 6.12.1(8), 6.12.1(18), S6.1.3(12), S6.2.1(e)(5) and S6.2.3 of the Rules.

13.6 Relevant documents provided by Ergon Energy

There are no additional documents that are relevant to this Chapter that were not provided to the AER with Ergon Energy's June 2009 Regulatory Proposal.

14 COST OF CAPITAL

In response the AER's Draft Distribution Determination, Ergon Energy:

- Does not accept the AER's proposed indicative nominal post tax vanilla WACC of 10.06 per cent per annum; and
- Considers the WACC parameters as stated in its 2009 Regulatory Proposal continue to be appropriate.

However, for modelling purposes, Ergon Energy has used the AER's proposed WACC parameters in this Revised Regulatory Proposal.

14.1 Ergon Energy's June 2009 Regulatory Proposal

Ergon Energy's June 2009 Regulatory Proposal proposed an indicative nominal post tax vanilla WACC of 9.49 per cent per annum. Chapter 41 of the June 2009 Regulatory Proposal detailed and justified the parameters that Ergon Energy used to calculate its proposed rate of return. Table 14-1 reproduces the values that Ergon Energy used to calculate its proposed rate of return.

Table 14-1: Original parameters to calculate Nominal Post Tax Weighted Average Cost of Capital

Parameter	Symbol	Value
Nominal Risk-Free Rate	Rf	5.08%
Real Risk-Free Rate	Rrf	2.57%
Inflation Rate	f	2.45%
Cost of Debt Margin	DRP	3.88%
Market Risk Premium	MRP	6.50%
Corporate Tax Rate	T	30.0%
Gamma	γ	0.20
Proportion of Equity Funding	E/V	40.0%
Proportion of Debt Funding	D/V	60.0%
Equity Beta	βe	0.80

Source: SCPTRM Submission Model

14.2 AER's November 2009 Draft Distribution Determination

The AER's SORI defines a number of WACC parameter values which are to be adopted by Ergon Energy for the purposes of setting a rate of return, unless there is a material change in circumstances. For the parameters where the values are calculated based upon a method – the nominal risk-free rate and the Cost of Debt Margin - the SORI sets out the method to be used by the AER for determining the values.

The AER has calculated an indicative nominal vanilla WACC of 10.06 per cent based on definitions and methods for calculations of parameters as defined in the SORI. The AER has rejected any departures from the SORI as proposed by Ergon Energy. The indicative WACC provided for in the Draft Distribution Determination is higher than that proposed by Ergon Energy because the nominal risk–free rate and Cost of Debt Margin have increased since the time Ergon Energy prepared its June 2009 Regulatory Proposal. The WACC determined by the AER does not include a proposed convenience yield.

14.3 Ergon Energy's Response to AER's Draft Distribution Determination

14.3.1 Nominal Risk Free Rate

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- No change in calculation of nominal risk free rate from that in SORI [257]	- No persuasive evidence to justify departure from method in SORI for calculating nominal risk free rate [256-257]	- Ergon Energy does not accept the AER's Draft Distr bution Determination for the calculation of the nominal risk free rate, exclusive of an adjustment to the risk-free rate (via the convenience yield), and considers that Ergon Energy's June 2009 Regulatory Proposal is appropriate for the reasons already stated. However, for modelling purposes for this Revised Regulatory Proposal, Ergon Energy has used the AER's SORI position on this parameter.

14.3.2 Debt Risk Premium

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Increase in debt risk premium from Ergon Energy proposal of 3.88 per cent to 4.24 per cent [278]	- AER considers CBA Spectrum's BBB+ fair value curve provides the best available prediction of observed yields for determining the yield on the benchmark BBB+ 10 year corporate bond [278]	- Ergon Energy has concerns with the AER's approach applied in estimating the debt margin. At the time of the final Distribution Determination, the use of Bloomberg, CBA Spectrum or a mid-point may be applied. This creates some uncertainty for the business. - In this regard, it is noted that it is not clear how the Bloomberg ten year estimate will be determined (given the cessation of publication of its eight year BBB, eight year A and ten year A bond yields). Ergon Energy suggests two methods of estimation that should be given consideration. The first is a linear interpolation method, which extrapolates Bloomberg's seven year BBB rate based on the difference between five and seven year BBB yields. The second adds the difference between Bloomberg's AAA (corporate) seven and ten year yields to its seven year BBB yield. Given neither method could be considered an ideal proxy, Ergon Energy recommends that consideration is given to both methods. - Furthermore, the AER has indicated that it is currently reviewing its own methodology for estimating the cost of debt in the absence of a liquid market for long-term BBB debt, though it is noted as a longer term goal that will not be implemented prior to the final Distr bution Determination. If any change in methodology was proposed prior to the final Distribution Determination, Ergon Energy requests that it is given reasonable opportunity to provide feedback on any proposed change before this occurs. - Ergon Energy does not accept the AER's Draft Distr bution Determination for the calculation of debt risk premium, and considers that Ergon Energy's June 2009 Regulatory Proposal is appropriate for the reasons already stated. However, for modelling purposes for this Revised Regulatory Proposal, Ergon Energy has used the AER's SORI position on this parameter (that is, the estimate based on CBA Spectrum).

14.3.3 Expected Inflation

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Inflation forecast of 2.45 per cent over 10 year period [280-1]	- Calculate 10 year inflation forecast using a geometric average of the RBA short term forecasts for the first two years and the mid-point of the RBA's target inflation range for the remaining years [280, 595-6] - Geometric average preferable to simple average given forecast inflation has a compounding effect in the PTRM [281, 595-6]	- Ergon Energy had proposed the use of an arithmetic average of inflation on the basis that the annual inflation forecasts that are being averaged are independent. - However, on the basis that the impact of the differences between Ergon Energy's preferred arithmetic average approach and the AER's proposed geometric average approach are not material, Ergon Energy accepts the AER's proposed inflation forecast used by the AER in its Draft Distribution Determination. - Ergon Energy has used the AER's substituted approach to estimating this parameter as per the Draft Distr bution Determination.
	- The AER also observed that the Commonwealth Government has recommenced issuing inflation-indexed bonds. Prior to using the averaging method that is currently used, inflation was estimated by calculating implied inflation based on Commonwealth Government indexed and nominal bond yields. - The AER has flagged that it will re-examine the liquidity of the indexed bond market prior to the Final Decision [281]	- There are merits in market-based approaches to estimating future inflation (that is, deriving values from indexed bond yields) however the reliability of that estimate depends on their being sufficiently liquidity in the market. Lack of liquidity has always been an issue in this market, even before the Commonwealth Government ceased its issuance program in 2003. - Ergon Energy questions how the AER will assess whether there is sufficient liquidity in the market and emphasises the need to be given the opportunity to respond to any changes in this methodology if that is done prior to the final Distribution Determination. - Ergon Energy submits that the AER's proposal to re-examine the liquidity of the indexed bond market prior to its final decision is not consistent with clause 6.4.2(b), which requires the method that the AER determines is likely to result in the best estimates of expected inflation to be included in the PTRM. - Ergon Energy has arrived at what it regards as its best estimate of forecast inflation having regard to a range of indicators, including published forecasts and the target range of inflation of the Reserve Bank of Australia. Ergon Energy submits that, as its estimate of forecast inflation has been developed in accordance with the PTRM, this estimate is to be accepted by the AER in accordance with clause 6.12.3(d).

14.3.4 Weighted Average Cost of Capital

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- WACC of 10.06 per cent [281-2]	- Based on parameters in Table 11.10 [281-2]	- As noted above, Ergon Energy does not accept the AER's Draft Distr bution Determination in relation to WACC in its entirety. However for modelling purposes for this Revised Regulatory Proposal, Ergon Energy has used the AER's parameters as detailed in its Draft Distribution Determination. - As discussed in Chapter 12, Ergon Energy proposes to continue to depart from the AER's SORI in relation to gamma for the purposes of determining the corporate income tax building blocks.

14.4 Ergon Energy's Revised Regulatory Proposal

Ergon Energy's proposed indicative nominal post tax vanilla WACC is 10.06 per cent per annum. Table 14-2 reproduces the values that Ergon Energy used to calculate its proposed rate of return for the purposes of this Revised Regulatory Proposal. Ergon Energy does not accept the AER's Draft Distribution Determination in relation to WACC in its entirety and considers that Ergon Energy's June 2009 Regulatory Proposal is appropriate for the reasons already stated. However, for modelling purposes for this Revised Regulatory Proposal, Ergon Energy has used the AER's parameters as detailed in its Draft Distribution Determination.

Table 14-2 - Parameters to calculate Nominal Post Tax Weighted Average Cost of Capital

Parameter	Symbol	Value
Nominal Risk-Free Rate	Rf	5.44%
Real Risk-Free Rate	Rrf	2.92%
Inflation Rate	f	2.45%
Cost of Debt Margin	DRP	4.24%
Market Risk Premium	MRP	6.50%
Corporate Tax Rate	T	30.0%
Gamma	γ	0.20
Proportion of Equity Funding	E/V	40.0%
Proportion of Debt Funding	D/V	60.0%
Equity Beta	βe	0.80

Source: SCPTRM Submission Model

14.5 Rules' requirements

In submitting this Revised Regulatory Proposal in relation the cost of capital, Ergon Energy has had regard for clauses 6.4.3(a)(2), 6.4.3(b)(2), 6.5.2, 6.5.4(c), 6.5.4(e), 6.5.4(f),6.5.4(g), 6.5.4(h), 6.5.4(i), 6.12.1(5), S6.1.3(8) and S6.1.3(9) of the Rules.

14.6 Relevant documents provided by Ergon Energy

There are no additional documents that are relevant to this Chapter that were not provided to the AER with Ergon Energy's June 2009 Regulatory Proposal.

15 SERVICE TARGET PERFORMANCE INCENTIVE SCHEME

In response to the AER's Draft Distribution Determination, Ergon Energy:

- Supports the application of the STPIS in the next regulatory control period; and
- Believes that the STPIS reliability performance targets should be based on the lower of the MSS under the Code or its historical reliability performance, to be consistent with the AER's "Framework and Approach Paper, Application of Schemes, Energex and Ergon Energy 2010-15, November 2008".

15.1 Ergon Energy's June 2009 Regulatory Proposal

Chapter 44 of Ergon Energy's June 2009 Regulatory Proposal proposed that the STPIS will apply to it in the next regulatory control period in accordance with Chapter 6 of the Rules, the AER's STPIS Guidelines, the AER's F&A Stage 2 and the following other provisions:

- The reliability performance parameters detailed in section 44.4 of the Regulatory Proposal;
- The customer service parameters detailed in section 44.5 of the Regulatory Proposal;
- The approach for determining and applying annual s-factors detailed in section 44.6.1 of the Regulatory Proposal;
- The application of the s-bank detailed in section 44.6.2 of the Regulatory Proposal; and
- The approach to dealing with the overlap between regulatory control periods detailed in section 44.6.3 of the Regulatory Proposal.

15.2 AER's November 2009 Draft Distribution Determination

The AER's Draft Distribution Determination details the basis on which the AER intends applying the STPIS to Ergon Energy in the next regulatory control period, including that:

- The reliability performance targets will be set on the basis of Ergon Energy's internal targets, as detailed in Table 12.7 of the Draft Distribution Determination; and
- The telephone answering parameter will be set at 77.3 per cent for each year of the next regulatory control period.

15.3 Ergon Energy's Response to AER's Draft Distribution Determination

15.3.1 Performance Targets

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Set SAIDI and SAIFI performance targets based on Ergon Energy's internal targets rather than MSS targets [304]	- AER considers that setting SAIDI and SAIFI performance targets based on MSS would result in Ergon Energy receiving a benefit under the STPIS for improving performance where this improved performance has already been funded through its expenditure allowances [304-5]	- Ergon Energy does not agree with the AER's Draft Distribution Determination to set the SAIDI and SAIFI performance targets based on Ergon Energy's internal targets because: o Ergon Energy's approach to setting the proposed STPIS targets is consistent with that set out in clause 2.5.3 of the AER's "Framework and Approach Paper, Application of Schemes, ENERGEX and Ergon Energy 2010-15, November 2008". For each feeder type, the adjusted MSS for each year of the next regulatory control period were more onerous than Ergon Energy's average historical unplanned reliability performance for the feeder

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
		type. Therefore, in accordance with clause 2.5.3, Ergon Energy proposed that the adjusted MSS be adopted as the STPIS targets for the next regulatory control period. Ergon Energy's proposal for the revised STPIS targets which takes consideration of the actual performance results for 2008/09 are presented in Table 15-1. The Reliability Parameters Incentive Rates updated to include the revised STPIS targets and updated energy consumption by feeder category are presented in Table 15-2; o Neither the MSS targets nor the (unadjusted) MSS-10 per cent internal business targets were used to develop Ergon Energy's capital and operating expenditure programs for the 2010-15 regulatory control period. Furthermore, the MSS set by the QCA are based on an assessment of historical reliability trends and the anticipated reliability improvements that would result from the forecast capital and operating expenditure; o Ergon Energy's MSS-10 per cent internal business targets adjusted for planned outages are not based on Ergon Energy's average historical unplanned performance, and are not indicative of Ergon Energy's likely unplanned performance in the next regulatory control period; and o The (unadjusted) MSS-10 per cent internal business targets are Key Performance Indicators that provide an incentive to management to improve planned outage performance. The internal MSS targets are set independently of management by the company's Board Consequently, this internal incentive will have no impact on Ergon Energy's performance under the STPIS, which is designed to focus on unplanned outage performance; o The review by PB and the AER's assessment of this area has examined data up to 30 June 2008 and has noted the improved MSS performance of Ergon Energy in 2006-07 and 2007-08. The impact of unplanned outages are significantly reduced in years when the company's network is subject to relatively benign weather patterns such as 2006-07 and 2007-08 compared with severe weather patterns experienced in 2005-06(Cyclone Larry) and 2008-09 (three tropical cyclones); and o The AER Draft Determination does not take account of Ergon Energy's latest performance results in 2008-09, where MSS limits were exceeded and internal MSS targets were not met, due to a wide range of factors, including a more severe storm season and an increase in planned outages due to various industrial issues and a suspension of live line works to address potential safety issues. These latter two factors will continue to impact overall MSS performance in 2009-10, including achievement of internal MSS targets. - Each of these reasons for disagreeing with the AER's assessment is explained in detail in Document RP899c.
- Set telephone answering target at 77.3 per cent for each year of the next regulatory control period [304]	- Ergon Energy can exclude telephone calls associated with a major event day and the average impact of excluding events is a 0.5 per cent improvement. This gives a performance	- Ergon Energy accepts the AER's revised telephone answering target of 77.3 per cent on the basis that Ergon Energy can exclude major event days from its reported telephone answering performance.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
	of 77.3 per cent of calls answered in 30 seconds.	

Table 15-1 - Ergon Energy Proposed STPIS Targets (Updated to include the actual performance results for 2008-09)

Parameter	Ergon Energy Adjusted 2010-11 MSS	Ergon Energy Adjusted 2011-12 MSS	Ergon Energy Adjusted 2012-13 MSS	Ergon Energy Adjusted 2013-14 MSS	Ergon Energy Adjusted 2014-15 MSS
Urban SAIDI	138.66	137.73	136.80	135.87	134.94
Urban SAIFI	1.85	1.83	1.81	1.79	1.77
Short Rural SAIDI	318.96	314.44	309.93	305.42	300.90
Short Rural SAIFI	3.32	3.28	3.24	3.20	3.16
Long Rural SAIDI	758.03	745.44	732.86	720.28	707.70
Long Rural SAIFI	6.09	6.01	5.93	5.84	5.76

Table 15-2 - Reliability Parameters' Incentive Rates (Updated to include actual performance results for 2008-09 and updated energy consumption by feeder category)

Parameter	Incentive Rate
Urban SAIDI	0.0173
Urban SAIFI	1.3488
SR SAIDI	0.0180
SR SAIFI	1.8735
LR SAIDI	0.0037
LR SAIFI	0.4953

15.3.2 Major Event Day Exclusions

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Alternative means of excluding Major Event Days where the historical performance data is not log-normally distributed. [Appendix D, STPIS November, 2009]	- Where it can be demonstrated that the unplanned daily SAIDI data used in calculating the Major Event Day Threshold (for the 2.5 Beta Method) is not log-normally distributed, Ergon Energy must propose an alternative data transformation method to the log-normal transformation, and demonstrate that this alternative transformation will lead to an outcome that is consistent with the objectives of the STPIS. In considering the proposed data transformation, the AER	- Ergon Energy supports the AER's proposal to explicitly allow a DNSP to propose an alternative transformation method where the historical daily unplanned SAIDI data (after Step 3 in Appendix D of STPIS) used to calculate the Major Event Day threshold (TMED) is not normally distributed. Ergon Energy also welcomes the proposal to allow a DNSP to propose a threshold greater than 2.5 beta. - Ergon Energy notes that the AER's chosen methodology to calculate TMED aligns with Ergon Energy's current approach as applied in its Regulatory Proposal submitted to the AER. Furthermore, Ergon Energy has tested all of its daily unplanned SAIDI data collected under the scheme to calculate the TMED for log normal distr bution and it has been proven that the data exhibits a log normal distribution after Step 3 in Appendix D. Under current drafting of Appendix D, this would suggest Ergon Energy is not required to employ a transformation technique to transform its daily unplanned SAIDI data. o The historical data used to calculate the STPIS Major Event Day Threshold (T_{MED}) of 9.80 SAIDI was analysed to test for Lognormal Distribution. This Data included the

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
	may have regard for the number of expected Major Event Days that may be excluded as a result of the alternative transformation, when compared to the expected number of Major Event Days using the 2.5 Beta Method.	Unplanned Daily SAIDI for five financial years, 2003-04 to 2007/8, with: ▪ Upstream of Ergon Energy's transmission and generation events removed; and ▪ Including Service Fuse and Beyond Events. o A natural log value of each daily SAIDI was calculated and a range of "Ln (SAIDI by day) values" established. Using this – the range values for the Excel frequency function was entered from -6.00 to +7.50 in 0.10 increments. o The frequency of the Ln values was calculated in order to graphically represent the distribution of the data. A normal distribution curve was generated using the average and standard deviation of the set of Ln SAIDI values. The above calculations are detailed in RP972c.

15.3.3 Reporting and Compliance

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- DNSPs to report as per Appendix Q - Report annual performance against the following parameters, consistent with section 3.1 of the national distr bution STPIS o Unplanned SAIDI o Unplanned SAIFI o MAIFI, as they are able to provide this information	- The AER may use MAIFI data to set targets in future regulatory control periods	- The MAIFI parameter should not be applied to Ergon Energy as it does not currently have the capacity to measure momentary interruptions and therefore cannot report them on the basis that would be required by Appendix Q.

15.4 Ergon Energy's Revised Regulatory Proposal

Ergon Energy's Revised Regulatory Proposal is therefore that the:

- The STPIS reliability performance targets for the next regulatory control period should be those detailed in Table 15-1 of this Revised Regulatory Proposal;
- The STPIS reliability parameters' incentive rates for the next regulatory control period should be those detailed in Table 15-2 of this Revised Regulatory Proposal;
- The other reliability performance parameters should remain as detailed in section 44.4 of Ergon Energy's June 2009 Regulatory Proposal;
- The customer service parameters should remain as detailed in section 44.5 of Ergon Energy's June 2009 Regulatory Proposal, although the telephone answering target should be increased to 77.3 per cent on the basis that Ergon Energy can exclude major event days from its reported telephone answering performance; and
- STPIS should be applied as detailed in section 44.6 of Ergon Energy's June 2009 Regulatory Proposal.

15.5 Rules' requirements

In submitting this Revised Regulatory Proposal in relation the STPIS, Ergon Energy has had regard for clauses 6.3.2(a)(3), 6.4.3(a)(5), 6.4.3(b)(5), 6.6.2, 6.8.1(b)(2), 6.12.1(9), S6.1.2(4), S6.1.3(4) and 11.16.5 of the Rules.

15.6 Relevant documents provided by Ergon Energy

The following documents are relevant to this Chapter but are new since, or were not provided to the AER with, Ergon Energy's June 2009 Regulatory Proposal:

RP899c	RP899c_EE_STPIS Supporting Information_FINAL_12Jan10.doc
RP906c	RP906c_ANPR 2008_09 Final_221209.pdf
RP907c	RP907c_ANPR 2008_09_Appendices E_to_K_ 221209.pdf
RP972c	RP972c_Ergon Energy STPIS Model RevisedRegProposal_11012010.xls

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16 EFFICIENCY BENEFIT SHARING SCHEME

In response to the AER's Draft Distribution Determination, Ergon Energy:

- Confirms the cost categories that will be excluded from Ergon Energy's operating expenditure in its EBSS calculations; and
- Proposes that the deadline for additional EBSS reporting requirements be 31 October of each year.

16.1 Ergon Energy's June 2009 Regulatory Proposal

Chapter 43 of its June 2009 Regulatory Proposal detailed Ergon Energy's proposed application of the EBSS. In particular, it confirmed that it:

- Proposed no further adjustments to the EBSS other than those set out in the EBSS Guideline and section 3 of the AER's F&A Stage 2;
- Does not anticipate any changes to its capitalisation policy;
- Will advise the AER at the end of the next regulatory control period if it considers that, for the purposes of calculating the carryover amounts, any adjustments are required to the forecast operating expenditure for the cost consequences of any differences between forecast and actual demand growth over the regulatory control period;
- Proposed excluding expenditure on non-network alternatives and the DMIA from the operation of the EBSS;
- Proposed excluding operational expenditure associated with recognised pass through events from the operation of the EBSS;
- Will identify and quantify the cost associated with any change in responsibility if they occur during the next regulatory control period;
- Proposed a carryover period of five years; and
- Supported the calculation of the annual carryover amount set out in section 2.3.4 of the EBSS Guideline.

16.2 AER's November 2009 Draft Distribution Determination

The AER's Draft Distribution Determination concluded that, given Ergon Energy did not propose demand growth adjustment mechanisms, the AER will not adjust the EBSS carryover for the consequences of changes in demand growth during the next regulatory control period. Noting that Ergon Energy did not anticipate changes to capitalisation policies during the next regulatory control period, the AER will (prior to the 2015-20 regulatory control period) consider adjustments to future carryover amounts if it is advised of any changes to capitalisation policies affecting actual operating expenditure.

The AER will include adjustments for non-network alternatives and recognised cost pass through events.

The AER also considered it appropriate to exclude the following additional (uncontrollable) forecast operating expenditure costs, to the extent approved by the AER in its Distribution Determination, from the operation of the EBSS for Ergon Energy for the next regulatory control period:

- Debt raising costs;
- Insurance and self insurance costs;
- Superannuation costs for defined benefits and retirement schemes; and
- The Demand Management Innovation Allowance (DMIA) expenditure.

As Ergon Energy did not provide specific operating expenditure cost exclusions relating to the outcomes of the EDSD Review, the AER will not exclude these costs from the EBSS. In any case, the AER considered costs associated with responding to these recommendations to be discretionary and controllable.

16.3 Ergon Energy's Response to AER's Draft Distribution Determination

16.3.1 Excluded cost categories

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- The following are to be treated as excluded cost categories in the next regulatory control period in addition to the adjustments and exclusions detailed in section 2.3.2 of the EBSS [317]: o Debt raising costs; o Insurance and self insurance costs; o Superannuation costs for defined benefits and retirement schemes; and o DMIA.	- AER assessed these costs to be non-controllable cost categories in additional to adjustments [312-4]	- Ergon Energy notes the AER nominated cost categories as being uncontrollable, and suitable for exclusion from operating expenditure in EBSS calculations. - Ergon Energy notes that these cost categories will be excluded in addition to costs relating to non-network alternatives and recognised cost pass through events.

16.3.2 Reporting and Compliance

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- DNSPs to report as per Appendix Q - For each year, actual operating expenditure excluding the following cost categories: o Actual debt raising costs; o Actual self insurance costs; o Actual insurance costs; o Actual superannuation costs relating to defined benefit and retirement schemes; o Actual Demand Management Incentive Allowance expenditure; o Actual non–network alternatives costs; and o Actual costs of recognised pass through events.	- Identify the proposed actual operating expenditure amounts attributable to each approved excluded cost category incurred during each regulatory year - Identify the actual total controllable operating expenditure for EBSS purposes after these exclusions. - Determine the rolling carryover amount each year for the application of the AER's EBSS.	- Ergon Energy acknowledges the additional reporting requirements imposed in Appendix Q. Ergon Energy proposes that consistent with requirements for Ring-Fencing compliance and regulatory reporting statements, the deadline be 31 October of each year. - Ergon Energy will seek to engage further with the AER on reporting requirements. It is proposed that this consultation would extend to include matters relating to Regulatory Reporting Statement templates associated with compliance under the Regulatory Reporting Guidelines.

16.4 Ergon Energy's Revised Regulatory Proposal

Ergon Energy does not propose any further adjustments to the EBSS other than those set out in the AER's Draft Distribution Determination or required by AER as set out in section 2.3.2 of the EBSS. Ergon Energy therefore notes that operating expenditure in relation to the following categories will be excluded from the actual and forecast operation expenditure amounts used to calculate carryover gains or losses under the EBSS:

- Debt raising costs;
- Self insurance costs;
- Insurance costs;
- DMIA expenditure;
- Superannuation costs relating to defined benefit and retirement schemes;
- Non–network alternatives costs; and
- Costs of recognised pass through events.

Table 16-1 provides a breakdown of Ergon Energy's revised proposed operating expenditure for use as part of the EBSS.

Table 16-1 - Forecast Operational Expenditure for purposes of EBSS ($M Real $2009-10)

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Total Operating Expenditure [115]	368.90	383.54	384.45	383.61	373.60	1,894.10
Less:						
DMIA Allowance	1.00	1.00	1.00	1.00	1.00	5.00
Self Insurance Costs	4.07	4.07	4.17	4.27	4.38	20.95
General Insurance	2.99	2.99	2.99	2.99	2.99	14.96
Superannuation	4.46	4.34	1.18	1.07	0.92	11.98
Solar Bonus	2.38	2.87	3.25	3.64	4.04	16.18
Non-Network Alternatives	12.11	12.81	12.89	12.97	13.05	63.85
Operational Expenditure for EBSS	341.89	355.45	358.97	357.66	347.21	1,761.18

Source: Revised Submission Tables for Proposal 43.3.1

1. The following adjustments cannot be forecast on reasonable grounds; (a) Changes in Operating Expenditure attributable to differences between Forecast and Actual Demand Growth, (b) Forced Operating Expenditure required to respond to events giving rise to a Major Event Day, and (c) Operating Expenditure associated with recognised Cost Pass Through Events.

[115] The Total Operating Expenditure amount excludes debt raising costs.

[redacted]

16.5 Rules' requirements

In submitting this Revised Regulatory Proposal in relation the EBSS, Ergon Energy has had regard for clauses 6.3.2(a)(3), 6.4.3(a)(5), 6.4.3(b)(5), 6.5.8, 6.6.3(d), 6.8.1(b)(3), 6.12.1(9), S6.1.3(3), and 11.16.4 of the Rules.

16.6 Relevant documents provided by Ergon Energy

There are no additional documents that are relevant to this Chapter that were not provided to the AER with Ergon Energy's June 2009 Regulatory Proposal.

17 DEMAND MANAGEMENT INCENTIVE SCHEME

In response the AER's Draft Distribution Determination, Ergon Energy:

- Accepts the introduction of the DMIA in the next regulatory control period; and
- Will seek to engage further with the AER in relation to the associated reporting requirements.

17.1 Ergon Energy's June 2009 Regulatory Proposal

Chapter 44 of its June 2009 Regulatory Proposal detailed Ergon Energy's support for the AER's view expressed in the F&A Stage 2 that:

- The DMIA should apply in the next regulatory control period;
- The amount of the DMIA should be $1 million (Nominal) for each regulatory year of the next regulatory control period; and
- A foregone revenue recovery mechanism should not apply in the next regulatory control period.

17.2 AER's November 2009 Draft Distribution Determination

The AER has maintained its position from its F&A Stage 2:

- To apply Part A (i.e. the DMIA) as outlined in the F&A Stage 2 at $5 million over the next regulatory control period at the rate of $1 million per annum; and
- Not to apply Part B (i.e. the foregone revenue recovery mechanism) over the next regulatory control period.

Ergon Energy is to report to the AER in accordance with Appendix Q of the Draft Distribution Determination.

17.3 Ergon Energy's Response to AER's Draft Distribution Determination

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- DNSPs to report as per Appendix Q - Submission of annual report on DMIA expenditure for each year of the regulatory control period. Details of reporting requirements are set out in Section 3.1.4 of *DMIS – Energex, Ergon Energy & ETSA Utilities 2010–15, October 2008*	- *Ex–post assessment of expenditure* and compliance with the DMIA criteria, and approval of expenditures	- Ergon Energy acknowledges the additional reporting requirements imposed in Appendix Q. Ergon Energy proposes that consistent with requirements for Ring-Fencing compliance and regulatory reporting statements, the deadline be 31 October of each year. - Ergon Energy will seek to engage further with the AER on reporting requirements. It is proposed that this consultation would extend to include matters relating to Regulatory Reporting Statement templates associated with compliance under the Regulatory Reporting Guidelines.

17.4 Ergon Energy's Revised Regulatory Proposal

Ergon Energy's Revised Regulatory Proposal is that it accepts the introduction of the DMIA in the next regulatory control period but will seek to engage further with the AER in relation to the associated reporting requirements.

17.5 Rules' requirements

In submitting this Revised Regulatory Proposal in relation the DMIS, Ergon Energy has had regard for clauses 6.3.2(a)(3) 6.4.3(a)(5) 6.4.3(b)(5) 6.6.3, 6.8.1(b)(4), 6.12.1(9) and S6.1.3(5) of the Rules.

17.6 Relevant documents provided by Ergon Energy

There are no additional documents that are relevant to this Chapter that were not provided to the AER with Ergon Energy's June 2009 Regulatory Proposal.

18 PASS THROUGH ARRANGEMENTS

In response to the AER's Draft Distribution Determination, Ergon Energy:

- Identifies several additional events that Ergon Energy considers should be treated as pass through events; and
- Seeks the AER's specific clarification on various matters of interpretation and application of the materiality threshold.

18.1 Ergon Energy's June 2009 Regulatory Proposal

In Chapter 46 of its June 2009 Regulatory Proposal, Ergon Energy proposed that the following be included as regulatory change events should they arise in the next regulatory control period:

- Change to minimalist transitioning approach;
- Introduction of smart meters and smart meter trials;
- Transfer of functions to a national regulatory framework;
- Introduction of an emissions trading scheme;
- Distribution loss event;
- Network obligation in relation to electric and magnetic fields;
- Changes in reporting requirements; and
- Changes in taxes or other levies.

Further, Ergon Energy requested that the following nominated events be approved for pass through should they arise in the next regulatory control period:

- Force majeure; and
- Change of business structure (that is externally imposed).

18.2 AER's November 2009 Draft Distribution Determination

In its Draft Distribution Determination, the AER:

- Amended the factors that it will consider for nominating events as pass through events, although this would appear only to apply to "specific nominated pass through events" that the AER will specify in its Distribution Determination;
- Identified circumstances when "general nominated pass through events" will apply;
- Determined that only three events will be "specific nominated pass through events" – Smart Meter Event, CPRS Event and Feed-In Tariff Event;
- Stated that it will apply the same materiality threshold approach as it applied in its final Distribution Determinations for New South Wales;
- Determined a materiality threshold for "general nominated pass through events" as being when costs are 1 per cent or more of that year's ARR – and a materiality threshold for "specific nominated pass through events" as being based on administrative costs; and
- Disallowed Ergon Energy's request to have Feed-In Tariffs and Unfunded Shared Network Events adjustments to occur as a Control Mechanism feature. Instead, the AER said these two events would be pass through events. However, the AER dealt with Feed-In Tariffs but not Unfunded Shared Network Events in its Draft Distribution Determination.

18.3 Ergon Energy's Response to AER's Draft Distribution Determination

Having regard for the AER's Draft Distribution Determination, Ergon Energy is concerned about the following matters:

- The AER's proposed treatment and, in particular, its materiality threshold for the four pass through events under the Rules (i.e. the statutory pass through events);
- How the 1 per cent materiality threshold for the general pass through will actually apply in practice. In particular, Ergon Energy wishes to confirm that the materiality threshold is 1 per cent of ARR and not a 1 per cent impact on revenue (i.e. not based on the change in revenue as a result of the pass through event);
- How Ergon Energy's proposed Unfunded Shared Network Events will be treated;
- The AEMC is currently processing ETSA Utility's Rule Change request to have Feed-In Tariffs treated as an annual revenue adjustment consistent with what Ergon Energy proposed in its June 2009 Regulatory Proposal. This Rule change may occur before the AER's final Distribution Determination and may therefore impact on the AER's final Distribution Determination;
- Ergon Energy has proposed an amendment to the definition for a CPRS event to reflect recent events; and
- Ergon Energy has proposed two new "specific nominated pass through events" on the basis of new information that has arisen since Ergon Energy's June 2009 Regulatory Proposal.

Ergon Energy requests that the AER include the necessary clarifying discussion and decisions in relation to these matters in its final Distribution Determination.

18.3.1 Criteria for assessed proposed pass through events

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Amend relevant factors for nominating events as pass through events from the eight assessment criteria listed in NSW Distribution Determination [332-3, 347-9]	- Nominated pass through events should be "highly likely" to occur, not just "foreseeable" [332]	- Ergon Energy does not object to the AER's proposal to change the wording in the factors on page 332 of the AER's Draft Distribution Determination from being "foreseeable" to being "highly likely" to occur. - However, Ergon Energy understands that the factors on page 332 will only apply for deciding whether to nominate an event as a "specific nominated pass through event" and will not apply to a cost pass through event defined in the Rules. Ergon Energy understands that a cost pass through event defined in the Rules will apply if it meets the Rules' definition – there will be no other conditions placed on these events. - Ergon Energy seeks the AER's confirmation of these matters in its final Distribution Determination in order to ensure clarity and certainty in the next regulatory control period.
- Amend relevant factors for general pass through events [333-5, 348-9]	- General pass through events should be "unexpected" rather than "unforeseeable" [334-5]	- As discussed above, Ergon Energy understands the AER's Draft Distribution Determination to mean that the factors listed on page 332 will not apply in assessing "general nominated pass through events" but will only apply in determining whether an additional pass through event should be specified in the Distribution Determination. Ergon Energy accepts this approach, but seeks the AER's confirmation of these arrangements in its final Distr bution Determination in order to ensure clarity and certainty in the next regulatory control period.

18.3.2 Materiality

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Materiality threshold for "general cost pass through events" to be 1 per cent of smoothed revenue allowance, which must meet threshold for each year of the regulatory control period costs being claimed [335-7]	- Consistent with NSW Distr bution Determination [336]	- Subject to Ergon Energy's understanding of the AER's intention set out below, Ergon Energy accepts the application of the same materiality threshold for a "general cost pass through event" as the AER has applied for the NSW DNSPs when the costs of the event are incurred or accounted for in one year. However, Ergon Energy does not support the AER's treatment where the costs are incurred or accounted for over multiple years. - On page 296 of the "Final decision - New South Wales distribution determination 2009–10 to 2013–14", the AER stated the materiality threshold to be the "costs associated with the event would exceed 1 per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred". - Ergon Energy understands this to mean that: o The 1 per cent applies to costs, not revenues. Page 280 of the NSW Distribution Determination states that the AER released a preliminary position that the materiality threshold be based on revenue not costs, however on the same page it indicates that it subsequently changed this to costs (from revenues) in its Final Decision. Ergon Energy supports this approach; o Operating expenditure would be assessed as a straight cost in the year in which it is incurred, although capital expenditure would be assessed based on the return on, and of, assets from the year in which the capital expenditure is incurred until the end of the regulatory control period. - By way of example, Ergon Energy understands this materiality threshold for "general pass through events" to mean that the materiality threshold would be met if: o The DNSP's ARR for a regulatory year was $100 million and in that year the DNSP incurred, as a result of a "general pass through event", $0.7 million in operating expenditure and capital expenditure which would attract a return on, and of, capital in each remaining year of a regulatory control period of $0.4 million – in this case, $1.1 million would be allowed to be passed through in the year the event occurred as it is greater than $1 million, (being 1 per cent of $100 million); and o The DNSP's ARR over two regulatory years was $100 million per annum and over these two years the DNSP incurred, as a result of a general pass through event, $0.3 million in year 1 and $1.2 million in year 2 in operating expenditure and capital expenditure which would attract a return on and of capital. in each remaining year of the regulatory control period, of $0.2 million – in this case, there would be no pass through for year 1 (since the total costs are $0.5 million) but the materiality threshold would be satisfied in year 2, as the costs would be $1.4 million in that year. - Ergon Energy accepts the AER's approach where the costs of a pass through event occur in a single year. However, costs associated with a pass through event can often be incurred over more than one regulatory year or may not be accounted for in one regulatory year. In these cases, materiality should be assessed on the basis of the total cost of the event over the period in which the costs are incurred or accounted for. To the extent that costs are incurred over multiple years there is no reason to limit the assessment of costs to one year. The materiality of an event should be measured by comparing the total cost of the event with Ergon

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
		Energy's ARR for the year in which the event occurred. - Ergon Energy therefore requests that the AER amend its approach to materiality (set out at pages 336-7 of its Draft Distribution Determination) to allow the assessment of costs (and revenues) to be made over multiple regulatory years in order to recognise the practical reality of how costs are incurred and accounted for. The AER has given no good reason to limit the period over which the cost of an event will be assessed, or to require the materiality threshold to be satisfied in each year that costs are incurred. . Indeed, such an approach has the potential to distort expenditure decisions by encouraging a response that result in costs being incurred over a single year in order to satisfy the materiality threshold.
- Materiality threshold for "specific nominated events" to be the administrative costs of assessing an application [337]	- Accept that threshold should be low for specific nominated events [337]	- Ergon Energy accepts that the application of a materiality threshold for a "specific nominated cost pass through event" to be based on the administrative costs of assessing an application.

The AER briefly mentions the statutory pass through events that are set out in Chapter 10 of the Rules, viz:

(a) a regulatory change event;

(b) a service standard event;

(c) a tax change event;

(d) a terrorism event.

…..

An event nominated in a distribution determination as a pass through event is a pass through event for the determination (in addition to those listed above).

However, other than brief references in other sections relating to the AER's likely interpretations, the AER has not provided guidance about its administration of these statutory pass through events. In particular, the AER is silent on the important matter of materiality thresholds for the statutory pass through events. While the AER may not be able to make binding determinations on what these thresholds will be, providing guidance at this stage will assist Ergon Energy to plan for the impact of future pass through events.

Ergon Energy believes that the materiality threshold for these events should also be based on the administrative costs of assessing an application for such an event – that is, the same threshold as applies to "specific nominated pass through events".

This is because, like "specific nominated cost pass through events", the costs associated with a cost pass through event defined in the Rules are not included in the forecast costs at the time of the final Distribution Determination because, at the time the Regulatory Proposal was submitted, the nature and time of the event and / or the cost impact of the event could not be forecast on a reasonable basis. Ergon Energy considers that, like "specific nominated cost pass through events", there are certain cost pass through events arising from the definitions in the Rules that are "highly likely" to occur in the next regulatory control period. While Ergon Energy accepts the AER's decision not to classify these Rule-defined events as "specific nominated cost pass through events" in its Draft Distribution Determination, the fact that these events are "high likely" to occur means they should be subject to a lower materiality threshold than for a "general nominated cost pass through event".

18.3.3 Nominated Pass Through Events accepted by AER

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- AER has determined that the following matters being "specific nominated cost pass through events" [337-340]: o Smart Meter event o CPRS event o Feed-In Tariff event	- These events satisfy the relevant factors for nominating events as "specific nominated pass through events" [337-340]	- Ergon Energy agrees that Smart Meter events and CPRS events should be treated as a treated as "specific nominated cost pass through events" in the next regulatory control period. - However, Ergon Energy proposes that the definition for a CPRS event should be amended due to the increased uncertainty which now exists as a result of the Senate's rejection of the Australian Government's proposed legislation to establish a CPRS. While the creation of an emissions trading scheme remains Government policy, the final form of this scheme is now less clear. The CPRS event approved by the AER is specifically designed for a 'cap and trade' scheme. It would not, for example, apply to a straight proh bition on emissions above a certain level. Further, it is now more difficult to predict how costs will be imposed under a scheme to reduce carbon pollution and by whom such costs are to be borne. Accordingly, Ergon Energy has proposed the changes set out below to widen the scope of the pass through to accommodate other forms of carbon pollution reduction programs: *A CPRS event is an event which <u>consists of or</u> results in the imposition of legal obligations ~~on a DNSP~~ arising from the introduction or operation of a ~~carbon emissions trading~~ scheme <u>to reduce carbon emissions (whether by restricting emissions, imposing a cost on emissions or otherwise)</u> imposed by the Commonwealth or Queensland government during the course of the next regulatory control period and which:* *(a) does not fall within the following:* *i) the definition of 'regulatory change event' in the NER (read as if paragraph (a) of the definition, was not part of the definition)* *ii) any other category of pass through event; <u>and</u>* *(b) materially increases the cost of the DNSP providing direct control services.* - Ergon Energy continues to believe that Feed-In Tariff events should be treated as an unders-and-overs feature of the revenue cap Control Mechanism, and not as a cost pass through event. Furthermore, Ergon Energy notes that ETSA Utilities has lodged a Rule change request with the AEMC on 7 October 2009 (released by the AEMC as the commencement of the consultation process on 16 December 2009) that essentially proposes that Feed-In Tariffs be treated as Ergon Energy proposed in its Regulatory Proposal. For the purpose of modelling this Revised Regulatory Proposal, Ergon Energy has included a Feed-In Tariff forecast. The calculation methodology is set out in Document RP897c. However, Ergon Energy submits that its original arrangement should be adopted in the AER's final Distribution Determination, and a pass through maintained only if the AER does not adopt Ergon Energy's original proposal or if this issue is not addressed by way of a Rule change prior to the AER's final Distribution Determination. - Similarly to Feed-In Tariff under-and-overs, Ergon Energy proposed in its June 2009 Regulatory Proposal section 51.2.4 that Unfunded Shared Network events relating to the residual risk that Ergon Energy bears associated with the cost of building shared network assets for large customers should be a feature of the revenue cap Control Mechanism and operate as an annual unders-and-overs adjustment. The AER incorrectly stated in its Draft Distribution Determination on page 30 that *"Ergon Energy proposed …. For cost pass throughs approved by the AER, including feed in tariff/solar bonus scheme, and unfunded shared network events."* Ergon Energy <u>did</u> seek to have cost pass throughs

<table>
<tr><th>AER's Amendment / Criticism</th><th>AER's Reasons</th><th>Ergon Energy's Response</th></tr>
<tr><td></td><td></td><td>recognised in the annual revenue adjustments. However, Ergon Energy <u>did not</u> seek to have Feed-In Tariffs and Unfunded Shared Network events treated as cost pass through events.

The AER states in section 4.3.2.2 of its Draft Distribution Determination that it discusses this matter in Chapter 15 of its Draft Distribution Determination[116], however there is in fact no consideration of this matter in that chapter.

Ergon Energy maintains its original position that Unfunded Shared Network Events should be a feature of the revenue cap Control Mechanism.

In the event that the AER declines to treat Unfunded Shared Network events in this manner, Ergon Energy considers that its costs should be treated as a "specific nominated cost pass through event" because:

o The event is highly likely to occur as there will be large new customers that connect to Ergon Energy's network in the next regulatory control period and this typically involves a need to build both shared network assets and dedicated connection assets. The design and construction of dedicated connection assets are classified as Alternative Control Services, however all shared network assets relate to Standard Control Services;

o The costs of the event are not subject to insurance and cannot be self-insured; and

o Passing through the costs of the event would not undermine the incentive arrangements in the regulatory regime, as the costs will only be incurred if Ergon Energy is required to build shared network in order to connect unexpected large customers.

Ergon Energy therefore proposes that the AER approve a specific nominated pass through event in the following terms:

'An unfunded shared network event is an event which results in Ergon Energy being required to augment the shared network as a result of the connection of a new large customer, where the need of the augmentation:

(a) was not foreseen by Ergon Energy at the time of this Distribution Determination; and

(b) materially increases the cost of providing direct control services.</td></tr>
<tr><td>- AER did not accept that the following as being "specific nominated pass through events" [343-</td><td>- Reasons given for not accepting these as specific nominated events:</td><td></td></tr>
</table>

116 AER, "Ergon Energy – Draft Distribution Determination 2010-11 to 2014-15", 25 November 2009, page 30

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
346]: o Change in minimalist transitioning approach event o Transfer of regulatory functions to a national regulatory framework event / changes in reporting requirements event o Distribution loss event o Network obligations in relation to electric and magnetic fields event o Changes in taxes and other levies event o Force majeure event o Change of business structure	o Change in minimalist transitioning approach event – may constitute a regulatory change event o Transfer of regulatory functions to a national regulatory framework event / changes in reporting requirements event – may constitute a regulatory change event o Network obligations in relation to electric and magnetic fields event – not highly likely to occur and may constitute a regulatory change event o Changes in taxes and other levies event – not highly likely to occur and may constitute a regulatory change event	- Ergon Energy accepts the AER's approach to these events. However, it notes that the basis on which the AER has declined to approve a pass through for these events is the likelihood that they will constitute regulatory change events. If the AER subsequently determines that any of these events are not regulatory change events, its Draft (and presumably its final) Distribution Determinations will have been based on an incorrect premise. If a pass through is sought for any of these events as regulatory change events, Ergon Energy expects the AER to administer the Rules in a manner that is consistent with the spirit of its Distr bution Determination with respect to the treatment of these events.
	o Distribution loss event – not highly likely to occur and may be general pass through event o Force majeure event – not highly likely to occur and may be "general nominated pass through event" o Change of business structure – not highly l kely to occur and may be general pass through event	- Ergon Energy accepts the AER's approach to these events. However, it notes that a basis on which the AER has declined to approve a pass through for these events is the likelihood that they will constitute general pass through events. If the AER subsequently determines that these events are not pass through events, its Draft (and presumably its final) Distribution Determinations will have been based on an incorrect premise. If a pass through is sought for any of these events, Ergon Energy expects the AER to administer the Rules in a manner that is consistent with the spirit of its Distribution Determination with respect to the treatment of these events. Ergon Energy also accepts the AER's approach to these events on the basis that the 1 per cent materiality threshold for "general nominated pass through events" applies on the basis of Ergon Energy's interpretation detailed in section 18.3.2.

18.3.4 Additional Pass Through Events

In light of the substantial materiality threshold proposed by the AER for a general pass through event under the Draft Distribution Determination, Ergon Energy submits that it is appropriate to specify two further nominated pass through events in the AER's final Distribution Determination.

18.3.4.1 Confidential event

Ergon Energy asks the AER to approve the event described below as a specified nominated pass through event. At the time of submitting this Revised Revenue Proposal Ergon Energy is unable to publish details of this event for reasons of commercial confidentiality. However, Ergon Energy expects that it will be able to make details of this pass through event public before the AER is required to make its final Distribution Determination, and in sufficient time to enable the AER to undertake any third party consultation that may be appropriate.

18.3.4.3 Energy Efficient Lighting event

Ergon Energy considers that the AER should treat an Energy Efficient Lighting event as a “specific nominated cost pass through event” in the next regulatory control period.

This relates to a requirement by the Queensland Government to roll out energy efficient street lighting. Ergon Energy considers that its costs of any energy efficient street lighting rollout should be treated as a “specific nominated cost pass through event” because:

- The event is not caught by existing pass through events;
- The event is clearly defined;
- The event is uncontrollable, in that the Queensland Government will determine if such a requirement is to be imposed on Ergon Energy;
- The event is highly likely to occur as the Queensland Government is committed to finding ways for customers to be more energy efficient and reduce energy consumption. The key deliverable of the energy efficiency street lighting trial is to provide recommendations on the most appropriate lamps for particular environmental conditions;
- The costs of the event are not subject to insurance and cannot be self-insured;
- The timing and/or cost of the event are not yet clear, as it will depend on the outcome of the trial. Further, the costs of the event are not included in Ergon Energy’s capital or operating expenditure forecasts for the next regulatory control period; and
- Passing through the costs of the event would not undermine the incentive arrangements in the regulatory regime, as the costs will only be incurred if the Queensland Government requires Ergon Energy to undertake a rollout of energy efficient street lighting.

Ergon Energy therefore submits that the AER should approve a specific nominated pass through event in the following terms:

> ‘An **energy efficient lighting event** is an event which results in an obligation being externally imposed on Ergon Energy to install energy efficient street lighting or to conduct trials of energy efficient street lighting, regardless of whether that requirements takes the form of a statutory obligation, and which:
>
> (a) does not fall within:
>
> (i) the definition of a regulatory change event in the NER (read as if paragraph (a) of the definition was not included in the definition); and
>
> (ii) any other category of pass through event; and
>
> (b) materially increases the cost of providing direct control services.’

18.4 Ergon Energy’s Revised Regulatory Proposal

Ergon Energy’s Revised Regulatory Proposal is to generally accept the AER’s Draft Distribution Determination decisions with the exception of:

- Feed-In Tariff events – which Ergon Energy continues to propose should be treated as an unders-and-overs feature of the revenue cap Control Mechanism. However, if these events are not treated in this manner, Ergon Energy supports the AER’s proposal to make these events “specific nominated pass through events”;
- Unfunded Shared Network events – which Ergon Energy continues to propose should be treated as an unders-and-overs feature of the revenue cap Control Mechanism. However if these events are not be treated in this manner, Ergon Energy submits that they should be treated as “specific nominated pass through events”;

- A proposed amended definition for a CPRS event; and
- The proposal for two additional “specific nominated pass through events” being:
    - A confidential event [redacted] and
    - An “Energy Efficient Lighting event”.

Ergon Energy also seeks the AER’s specific clarification on matters of interpretation and application of the materiality threshold.

18.5 Rules’ requirements

In submitting this Revised Regulatory Proposal in relation the cost pass through provisions, Ergon Energy has had regard for clauses 6.2.6(c), 6.6.1, 6.12.1(14), S6.1.3 and 11.16.9 of the Rules.

18.6 Relevant documents provided by Ergon Energy

The following documents are relevant to this chapter:

RP897c RP897c_Feed In Tariff Forecast_21Dec09.xls

19 BUILDING BLOCK REVENUE REQUIREMENTS

In response to the AER's Draft Distribution Determination, Ergon Energy:

- Proposes revised ARR and X factors for Standard Control Services for the next regulatory control period that result from the changes in the building blocks detailed in this Revised Regulatory Proposal.

19.1 Ergon Energy's June 2009 Regulatory Proposal

Chapter 49 of its June 2009 Regulatory Proposal and Ergon Energy's Post Tax Revenue Model detailed Ergon Energy's AARs for Standard Control Services for the period 1 July 2010 to 30 June 2015. These AARs are reproduced in Table 19-1.

Table 19-1: Original Annual Revenue Requirements for Standard Control Services for 2010-15 ($M Nominal)

	2010-11	2011-12	2012-13	2013-14	2014-15	Total	Average of 5 year Total
Annual Revenue Requirements (smoothed)	1,100.22	1,213.87	1,339.25	1,477.59	1,630.21	6,761.15	1,352.23

Source: Tables for Proposal 49.2

Chapter 42 of its June 2009 Regulatory Proposal detailed Ergon Energy's proposed X factors for Standard Control Services for each regulatory year of the next regulatory control period, 2010-15. These X factors are reproduced in Table 19-2.

Table 19-2: Original X Factors for Standard Control Services for 2010-15 (per cent)

	2010-11	2011-12	2012-13	2013-14	2014-15
X factors	-27.05%	-7.69%	-7.69%	-7.69%	-7.69%

Source: Tables for Proposal 42.1

Chapter 52 of its June 2009 Regulatory Proposal detailed Ergon Energy's indicative prices for Standard Control Services for each regulatory year of the next regulatory control period, 2010-15. These indicative prices are reproduced in Table 19-3.

Table 19-3: Original Indicative Prices for Standard Control Services by Customer Grouping 2010-15 (c/KWh Real $2009-10)

	2010-11	2011-12	2012-13	2013-14	2014-15
ICC	0.857	0.889	0.949	0.992	1.057
CAC	4.057	4.230	4.490	4.741	5.060
SAC	10.416	10.821	11.241	11.676	12.126
EG	0.101	0.107	0.113	0.120	0.127

19.2 AER's November 2009 Draft Distribution Determination

The AER's Draft Distribution Determination results in a total revenue requirement over the next regulatory control period of $6,364 million, compared to $6,776 million proposed by Ergon Energy. The main reasons for this difference reflect the net effect of:

- The removal of $1,020 million from Ergon Energy's forecast capital expenditure;
- The removal of $479 million from Ergon Energy's forecast operating expenditure;
- A reduced allowance for corporate income tax, reflecting in part a higher gamma;

- A reduced allowance for equity raising costs;
- The addition of $106 million to Ergon Energy's opening RAB as at 1 July 2005;
- The correction of remaining asset lives, which has the effect of increasing the depreciation allowance; and
- A higher WACC than proposed by Ergon Energy.

The impacts of these matters on Ergon Energy's building blocks, ARRs and X factors are detailed in Table 19-4.

Table 19-4: AER conclusions on Ergon Energy's annual revenue requirements and X factors ($M Nominal) [117]

	2010-11	2011-12	2012-13	2013-14	2014-15
Regulatory depreciation [a]	151.0	158.3	157.9	171.4	152.2
Return on capital [a]	715.1	791.0	875.8	971.1	1,077.4
Operating expenditure [b]	328.3	335.1	327.7	323.5	311.6
Tax allowance	0.0	20.1	29.3	34.0	33.1
Capital contr butions	-112.0	-121.2	-107.9	-117.5	-135.2
Revenue from shared assets	-3.2	-3.3	-3.4	-3.5	-3.5
Accelerated depreciation	10.4				
Annual revenue requirements	1,089.6	1,180.0	1,279.4	1,379.0	1,435.7
Expected revenues	1,096.6	1,178.5	1,266.5	1,361.1	1,462.8
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors [c] (%)	-26.63	-4.90	-4.90	-4.90	-4.90

Notes:

(a) Includes equity raising costs.

(b) Includes debt raising costs, demand management incentive allowance and self insurance.

(c) Negative values for X indicate real price increases under the CPI-X formula.

19.3 Ergon Energy's Response to AER's Draft Distribution Determination

The AER made a number of reductions to Ergon Energy's capital and operating forecast building blocks, which are discussed in previous chapters of this Regulatory Proposal, as well as various adjustments to other areas of Ergon Energy's June 2009 Regulatory Proposal, such as the forecast:

- Inflation rates;
- WACC parameters;
- Escalation rates;
- Asset lives; and
- Shared costs (overheads), which are reallocated in accordance with the Cost Allocation Method.

These adjustments impact all capital and operating expenditure forecasts beyond those detailed for each of the building blocks in the previous chapters.

The following table summarises all of the adjustments that Ergon Energy has made to its original Regulatory Proposal in this Revised Regulatory Proposal. It is noted that, except where stated in the table, Ergon Energy has not made an adjustment to its forecasts.

[117] AER, "Ergon Energy - Draft Distribution Determination 2010-11 to 2014-15", 25 November 2009, page xl

Parameter/Forecast	AER Position	Ergon Energy Position	Comment
CPI	Use geometric method for forecasting CPI.	Modified modelling to reflect AER requirement.	Changes in CPI as per AER Draft Distribution Determination.
	Use March to March annual CPI.	Modified modelling to reflect AER requirement.	Changes in CPI as per AER Draft Distribution Determination.
WACC parameters	AER adjusted WACC parameters to reflect the AER SORI on WACC.	Ergon Energy reflected these adjustments in its modelling with the exception of Gamma.	Changes in WACC parameters as per AER Draft Distribution Determination (with the exception of gamma which is as per Ergon Energy's June 2009 Regulatory Proposal, therefore the tax liability is calculated as originally proposed).
RAB and Carry Forward Tax Losses Update forecasts for 2008/09 actual results	AER did not make any adjustment, using the June 2009 Regulatory Proposal estimates for 2008-09.	Ergon Energy has reflected actual 2008-09 results in its modelling.	Updated 2008-09 estimates to record actual results for 2008-09. Closing value of RAB in the RFM and opening value of RAB in the PTRM updated as a consequence. Carried forward tax losses updated as a consequence.
Escalations	AER adjusted escalation figures for both capital and operating expenditure.	Ergon Energy has reflected the escalation adjustments in its modelling with the exception of labour input costs escalations.	Revised escalation figures for both operating and capital expenditure (from SKM). Labour input escalations as per the June 2009 Regulatory Proposal.
Shared costs (overheads) - SPARQ	AER reduced the shared cost pool to reflect lower SPARQ finance charges resulting from adjustments to the SPARQ capital work program forecast.	Ergon Energy has retained the SPARQ works program and revised SPARQ WACC to reflect the Draft Determination WACC of 10.06 per cent.	Revised SPARQ modelling for 10.06 per cent WACC and retained capital expenditure items.
Shared costs (overheads) - SPARQ	AER did not make any adjustment instead using the June 2009 Regulatory Proposal forecasts for 2008/09.	Ergon Energy has updated the SPARQ charges to reflect actual 2008-09 results.	Revised SPARQ overheads for 10.06 per cent WACC and other capital expenditure items
Accelerated depreciation carry over amount for Cyclone Larry	AER adjusted this amount to reflect the correct escalation and asset lives.	Ergon Energy has reflected this adjustment in its modelling.	Changed carry over amount for Cyclone Larry as per Draft Distribution Determination.
Adjustment to remaining lives for depreciation	AER adjusted the calculation of remaining lives.	Ergon Energy has reflected this adjustment in its modelling.	Revised methodology for determining opening remaining lives as per discussions with AER.
Operating Expenditure – Equity Raising Costs	AER removed equity raising costs as operating expenditure.	Ergon Energy has reflected this adjustment in its modelling.	Removed equity raising costs and now calculating as per AER Draft Distribution Determination i.e. removing capital contributions and included now as part of Capital expenditure in first year (2010-11) (Refer last item in table).

Parameter/Forecast	AER Position	Ergon Energy **Position**	Comment
Operating Expenditure - Solar Bonus Scheme	AER changed the proposed method for treatment of Solar Bonus Scheme from an annual revenue adjustment to a forecast operating expenditure amount subject to pass through adjustments.	Ergon Energy submits that its original arrangement should be adopted in the AER's final Distribution Determination, and a pass through maintained only if the AER does not adopt Ergon Energy's June 2009 Regulatory Proposal or if this issue is not addressed by way of a Rule change prior to the AER's final Distribution Determination.	Included new item in Other Operating Expenditure for Solar Bonus Scheme.
Operating Expenditure - Capex/Opex tradeoff	AER made a reduction to recognise Capex/Opex tradeoffs.	Ergon Energy has reflected this reduction in its modelling.	Made allowance in Preventive and Corrective Maintenance for Capex/Opex trade off as per PB report.
Operating Expenditure - Preventive Maintenance – Keys and Locks	AER made a reduction to the keys and locks program.	Ergon Energy has reviewed the forecast and made a reduction in its modelling.	Updated Preventive Maintenance for the revised data for keys and locks.
Operating Expenditure - Vegetation Management Forecasts	AER made a reduction to the vegetation management forecasts.	Ergon Energy has reflected this reduction in its modelling.	Updated vegetation management costs for 5 per cent error in rates as identified by PB and as calculated by Huegin.
Capital Expenditure System – Customer Initiated Capital Works Forecasts	AER made a reduction to the CICW forecast.	Ergon Energy has increased this forecast above its June 2009 Regulatory Proposal in its modelling.	Updated CICW and associated capital contributions.
Alternative Control Services Capital expenditure – Street lighting capital forecast	AER decided that Ergon Energy should apply the limited building block to street lights and that it should include the establishment of new streetlight assets.	Ergon Energy has reflected this requirement in its modelling.	Included new estimate for New Streetlight capital expenditure in line with AER Draft Distribution Determination.
Capital expenditure – Non-System - Change Program	AER removed the change program from the capital building block.	Ergon Energy has reviewed the forecast and included a lower forecast than the June 2009 Regulatory Proposal amount in its modelling.	Revised change program estimates.
Capital expenditure – Non-System Property Program	AER made an adjustment to the property capital expenditure forecast.	Ergon Energy has reviewed the forecast and retained the original forecast amount with adjustments in value and timing in its modelling.	Revised property program estimates.
Capital expenditure – System - Smart Meters Trial	AER made no adjustment.	Ergon Energy has reviewed the forecast and made adjustments in value and timing in its modelling.	Revised timing and values for Smart Meters Trial.
Capital expenditure – Non-System Include Equity Raising Costs	AER made an adjustment to the treatment of equity raising costs, moving it from an operating expenditure to an annuity in the capital asset base.	Ergon Energy has reflected this adjustment in its modelling.	Included Equity Raising Costs (See previous Operating expenditure item).

Ergon Energy has reflected these adjustments through its modelling by making adjustments to the direct costs (which are in $2007-08). The direct cost forecasts are then allocated their share of the shared cost (overhead) pool in accordance with Ergon Energy's approved Cost Allocation Method and then escalated to $2009-10 for input into the AERs PTRM and RFM. The escalations applied are in accordance with the adjustments specified in the table above.

The direct cost adjustments to operating expenditure are summarised in Table 19-5.

Table 19-5: Ergon Energy's Direct Cost Adjustments to Operating Expenditure ($M Real $2007-08)

Operating Forecasts - Adjustment in Direct Costs $2007-08	2010-11	2011-12	2012-13	2013-14	2014-15
Preventive Maintenance – Capex/Opex tradeoffs & Vegetation Management	-0.99	-0.48	-1.48	-2.57	-1.17
Corrective Maintenance – Capex/Opex tradeoffs, Vegetation Management & Keys & Locks	-1.51	-1.82	-2.08	-2.12	-1.95
Other Operating Costs – Solar Bonus Scheme & Equity Raising Costs	3.71	4.19	4.55	4.92	5.31
Total Operating Costs	1.21	1.89	0.99	0.23	2.19

Source: Proposal Comparatives

The direct cost adjustments to capital expenditure are summarised in Table 19-6.

Table 19-6: Ergon Energy's Direct Cost Adjustments to Capital Expenditure ($M Real $2007-08) [118]

Capital Forecasts Adjustments in Direct Costs $2007-08	2010-11	2011-12	2012-13	2013-14	2014-15
System capital expenditure					
Customer Initiated Capital Works	10.53	11.52	4.06	5.27	8.66
Other System capital expenditure – Smart Meter Trial	3.61	0.13	-	-	-
Total System capital expenditure	14.13	11.65	4.06	5.27	8.66
Non-System capital expenditure					
IT Systems	-8.00	-8.00	-8.00	-8.00	-8.00
Buildings	5.00	-24.60	-	7.00	12.00
Land & Easements	-	-0.40	-	-2.00	-
Total Non-System capital expenditure	-3.00	-33.00	-8.00	-3.00	4.00
Total Capital expenditure	11.13	-21.35	-3.94	2.27	12.66

Source: Proposal Comparatives

19.3.1 Annual Revenue Requirements

Ergon Energy does not have any specific issues to raise in relation to the calculation of its ARR as they are an outcome of the decisions that the AER has made in other Chapters of its Draft Distribution Determination.

[118] AER, "Draft Decision Queensland Draft distribution determination 2010-11 t0 2014-15", 25 November 2009, page xl

19.3.2 X factors

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reduced X factors for 2010-11 from -27.05 per cent to -26.93 per cent and for 2011-12 to 2014-15 from -7.69 per cent to –4.9 per cent	- Reductions made on the basis of changes to Annual Revenue Requirements and requirements of clause 6.5.9(2) of the Rules	- Ergon Energy recognises that the X factors are a result of meeting constraints imposed by Chapter 6 of the Rules.

19.4 Ergon Energy's Revised Regulatory Proposal

Table 19-8 compares the building blocks that make up Ergon Energy's total unsmoothed ARR for its Standard Control Services for 2010-11 to 2014-15 as detailed in Ergon Energy's June 2009 Regulatory Proposal, the AER's Draft Distribution Determination and this Revised Regulatory Proposal.

Table 19-7 – Building Block Comparison – Standard Control Services

	Ergon Energy's June 2009 Regulatory Proposal	AER's Draft Distribution Determination	Ergon Energy's Revised Regulatory Proposal	Difference between Ergon Energy's Revised Regulatory Proposal and June 2009 Regulatory Proposal	Difference between Ergon Energy's Revised Regulatory Proposal and AER's Draft Distribution Determination
Regulatory Depreciation	598.60	790.80	782.11	183.51	-8.69
Return on Capital	4,397.18	4,430.40	4,766.50	369.32	336.10
Operating Expenditure	2,144.86	1,626.20	2,063.75	-81.11	437.55
Tax Allowance	235.15	116.50	376.12	140.97	259.62
Capital Contributions	-593.77	-593.80	-729.73	-135.96	-135.93
Revenue from Shared Assets	-16.87	-16.90	-16.82	0.05	0.08
Accelerated Depreciation	11.27	10.40	10.45	-0.82	0.05
Annual Revenue Requirements (Unsmoothed)	**6,776.42**	**6,363.70**	**7,252.39**	**475.97**	**888.69**
Expected Revenues (Smoothed)	**6,761.15**	**6,365.50**	**7,234.65**	**473.50**	**869.15**

Source: Revised Submission Tables for Proposal and SCPTRM

Table 19-8 details Ergon Energy's revised smoothed ARR for Standard Control Services for each year of the period 1 July 2010 to 30 June 2015.

Table 19-8: Revised Annual Revenue Requirements for Standard Control Services for 2010-15 ($M Nominal)

	2010-11	**2011-12**	**2012-13**	**2013-14**	**2014-15**	**Total**	**Average of 5 year Total**
Annual Revenue Requirements (smoothed)	1,208.11	1,317.21	1,436.17	1,565.87	1,707.28	7,234.65	1,446.93

Source: Revised Submission Tables for Proposal 49.2

Ergon Energy’s revised X Factors for Standard Control Services for the period 1 July 2010 to 30 June 2015 are detailed in Table 19-9.

Table 19-9: Revised X Factors for Standard Control Services for 2010-15 (Per cent)

	2010-11	2011-12	2012-13	2013-14	2014-15
X factors	-39.51	-6.42	-6.42	-6.42	-6.42

Source: Revised Submission Tables for Proposal 42.1

Ergon Energy’s revised indicative prices for Standard Control Services for the period 1 July 2010 to 30 June 2015 are detailed in Table 19-10.

Table 19-10: Revised Indicative Prices for Standard Control Services by Customer Grouping 2010-15 (c/KWh Real $2009-10)

	2010-11	2011-12	2012-13	2013-14	2014-15
ICC	1.136	1.194	1.258	1.326	1.397
CAC	4.774	5.035	5.306	5.592	5.894
SAC	11.701	12.166	12.648	13.148	13.668
EG	0.189	0.199	0.208	0.217	0.226

19.5 Rules’ requirements

In submitting this Revised Regulatory Proposal, Ergon Energy has had regard for the following relevant clauses of the Rules:

- Annual Revenue Requirements – clauses 6.3.2(a)(1), 6.4.2(a), 6.12.1(2)(i), 6.4.2(a), 6.12.3.(d), 6.4.3(a) and (b); and
- X factors – clauses 6.5.9, 6.12.1(11) and S6.1.3(6)(i).

19.6 Relevant documents provided by Ergon Energy

The following documents are relevant to this Chapter but are new since, or were not provided to the AER with, Ergon Energy’s June 2009 Regulatory Proposal:

RP917c	RP917c RRP AER Data_V1_Data Room_07Jan10
RP982c	RP982c_EE_Revised Regulatory Proposal Models_12Jan10

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20 ALTERNATIVE CONTROL SERVICES - STREET LIGHTING

In response to the AER's Draft Distribution Determination, Ergon Energy has:

- Applied the AER's control mechanisms for Street Lighting Services and proposes revised ARRs and X factors to apply to Street Lighting Services in the next regulatory control period.

20.1 Ergon Energy's June 2009 Regulatory Proposal

Chapter 53 of Ergon Energy's June 2009 Regulatory Proposal addressed the requirements of the Rules and the AER's April 2009 RIN in relation to Street Lighting Services.

In particular:

- Section 53.1 distinguished between new street lighting services (Street Lighting Service 1), the operation, repair, replacement and maintenance of street lighting assets (Street Lighting Service 2) and the alteration and relocation of existing street lighting assets (Street Lighting Service 3);
- Section 53.2 responded to the AER's requirement to apply a price cap control mechanism to street lighting services by proposing that Street Lighting Services 1 and 3 be charged on a quoted fee basis and that Part C of Chapter 6 of the Rules be applied to Street Lighting Services 2 by using a simplified building block approach; and
- Sections 53.6 to 53.19 detailed the calculation of Ergon Energy's AARs for Street Lighting Service 2 for the period 1 July 2010 to 30 June 2015. These AARs are reproduced in Table 20-1.

Table 20-1: Annual Revenue Requirements for Street Lighting Services for 2010-15 ($M Nominal)

Category Driver	2010-11	2011-12	2012-13	2013-14	2014-15	Total	Average of 5 year Total
Annual Revenue Requirements (smoothed)	25.79	26.69	27.62	28.58	29.57	138.24	27.65

Source: Tables for Proposal 53.19

- Section 53.21 detailed actual and indicative prices for Street Lighting Service 2.

20.2 AER's November 2009 Draft Distribution Determination

In Chapter 17 of its Draft Distribution Determination, the AER:

- Applied the control mechanism from its F&A Stage 1;
- Requested Ergon Energy to provide a forecast capital allowance for new street lights as part of the limited building block approach in its Revised Regulatory Proposal;
- Adjusted Ergon Energy's opening asset base to reflect the QCA's indexation method. This increased the opening asset base from $52 million to $53 million;
- Accepted Ergon Energy's demand forecasts;
- Adjusted Ergon Energy's forecast capital expenditure by $3.3 million to remove expenditure associated with the proposed energy efficient street lighting rollout and by $1.2 million to reflect the AER's input cost escalators;
- Adjusted Ergon Energy's forecast operating expenditure by $10.4 million to reflect the AER's material cost escalators;
- Accepted Ergon Energy's proposed allowance for corporate income tax;
- Identified an error in Ergon Energy's calculation of remaining lives;

- Applied a WACC of 10.06 per cent;
- Applied the pass through events set out in Chapter 15 of the AER's Draft Distribution Determination; and
- Set out the prices and price paths for the next regulatory control period.

20.3 Ergon Energy's Response to AER's Draft Distribution Determination

20.3.1 Control Mechanism

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- AER rejects Ergon Energy's treatment of new street lighting services as Quoted Services [378-380] - Ergon Energy must provide forecast of capital expenditure on new street lighting services in its Revised Regulatory Proposal [380]	- Treating new street lighting services as a quoted service is not consistent with the AER's F&A Stage 1 and is an incorrect interpretation of the limited building block price cap control mechanism [379]	- Ergon Energy believes that its proposed treatment of new street lighting services as a Quoted Service is consistent with the AER's F&A Stage 1. This is because the building block would be the build-up of the actual costs of installing new street lights on an individual customer-by-customer basis and prices would be capped on an individual basis by applying the Quoted Services formula. - Further, Ergon Energy's proposed approach is likely to benefit customers as prices would be charged on the same basis as Ergon Energy's competitors, This means that customers could compare services on a l ke for like basis, which is likely to result in increased competition in the provision of new street lighting assets. - Ergon Energy notes the AER's request to provide forecast capital expenditure of new street lighting assets in its Revised Regulatory Proposal. - For the purposes of modelling this Revised Regulatory Proposal, Ergon Energy has included a forecast of capital expenditure on new street lighting services in this Revised Regulatory Proposal. However, Ergon Energy submits that its June 2009 Regulatory Proposal should be adopted in the AER's final Distribution Determination.
- Alteration and relocation of street lighting services to be treated as Quoted Services in the same manner as supply enhancement and rearrangements of network asset services [380]	- No need to distinguish between alteration and relocation of street lighting services to be treated as Quoted Services in the same manner as supply enhancement and rearrangements of network asset services [380]	- Ergon Energy accepts the AER's decision that alteration and relocation of street lighting services is to be treated as a Quoted Service in the same manner as a supply enhancement and rearrangement of network assets. - Ergon Energy notes that it only separated street lighting assets from other assets in terms of the services supply enhancement and rearrangement of network assets so that Chapter 53 of its Regulatory Proposal contained a complete and stand alone picture of the arrangements for street lighting assets.

20.3.2 Opening Street Lighting Asset Base

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Ergon Energy's opening street lighting asset base should be $53 million [382, 394-5]	- Opening street lighting asset base should be increased from $52 million to $53 million after applying revised CPI [382]	- Ergon Energy accepts the AER's adjustment to the opening street lighting asset base for revised CPI. - Ergon Energy has revised its opening street lighting asset base to reflect 2008-09 actual results.

20.3.3 Limited Building Block Elements

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Reduction of $4.5 million in forecast street lighting capital expenditure [387]	- Reduction of $3.3 million in capital expenditure to exclude expenditure associated with energy efficient street lighting rollout [387]	- Ergon Energy accepts that the AER has excluded expenditure associated with the energy efficient street lighting rollout. - Ergon Energy accepts the AER's decision that the pass through arrangements may be appropriate should a rollout be required. - Ergon Energy requests that the rollout of energy efficient street lighting be a specific nominated pass through event as discussed in chapter 18 of this Revised Regulatory Proposal.
	- Reduction of $1.2 million in capital expenditure to account for errors in the application of input cost escalators [387]	- Ergon Energy does not accept the AER's proposed escalators. The reasons for this are discussed in Chapters 9, 10 and 11 of this Revised Regulatory Proposal. - Ergon Energy has applied the same escalators as those used for Standard Control Services in this Revised Regulatory Proposal.
- Reduction of $10 million in forecast street lighting operating expenditure [390, 394-5]	- Ergon Energy made errors in the application of input cost escalators [387]	- Ergon Energy does not accept the AER's proposed escalators. The reasons for this are discussed in Chapters 9, 10 and 11 of this Revised Regulatory Proposal. - Ergon Energy has applied the same escalators as those used for Standard Control Services in this Revised Regulatory Proposal.
- Revised remaining asset lives results in an increase in depreciation allowance – see Table 17.14 [391-2, 394-5]	- Ergon Energy made an error in the way remaining asset lives were calculated by dividing real depreciation figures by a nominal closing balance [224-5, 391-2]	- Ergon Energy accepts that it made an error in the way remaining asset lives were calculated. This has been corrected in the Revised Regulatory Proposal.
- WACC of 10.06 per cent [392, 394-5]	- Based on parameters in Table 11.10 [282, 392]	- As for Standard Control Services, Ergon Energy has applied a WACC of 10.06 per cent for the purposes of modelling this Revised Regulatory Proposal. Chapter 14 of the Revised Regulatory Proposal sets out Ergon Energy's comments on WACC.
- Reduced X factors for 2010-11 from -66.04 per cent to -64.13 per cent and for 2011-12 to 2014-15 from -1.00 per cent to 2.00 per cent [395]	- Reductions made on the basis of changes to Annual Revenue Requirements [394-5]	- Ergon Energy notes the adjustments the AER has made to X factors to reflect changes to the ARRs. Ergon Energy's updated X factors are set out in section 20.4 of this Revised Regulatory Proposal.

20.3.4 Prices and Price Paths

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Not possible for the AER to evaluate the price outcomes of Ergon Energy's proposed limited building block requirement [398] - AER will review the underlying methodology used to derive street	- AER can't evaluate because Ergon Energy stated that its indicative prices are not the basis on which it intends to charge for street lighting services [397-8]	- Ergon Energy provided indicative prices for street lighting service 2 in Chapter 52 of its Regulatory Proposal. - On the 24 November 2009, Ergon Energy provided the AER with the model [Document PL878c] it intends to use to calculate street lighting prices so that the AER could review the underlying methodology. - Ergon Energy has revised its indicative prices and price paths in this Revised Regulatory Proposal and they are set out in section 20.4. The pricing model [Document RP927c]

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
lighting prices as part of its final Distribution Determination [398]		will also be provided to the AER.

20.4 Ergon Energy's Revised Regulatory Proposal

As discussed above, Ergon Energy has revised its forecasting for street lighting services to reflect issues raised by the AER. Specifically Ergon Energy has:

- Included a forecast for capital expenditure on new street lighting assets;
- Revised the opening RAB in accordance with the AER's adjustment for CPI and actual expenditure for 2008-09;
- Removed expenditure associated with the rollout of energy efficient street lighting;
- Adjusted forecasts for the escalators used for Standard Control Services;
- Recalculated the remaining lives of assets to remove the error identified by the AER; and
- Applied a WACC of 10.06 per cent.

These forecasts are reflected in Ergon Energy's PTRM for street lighting assets.

20.4.1 New Street Lighting Assets

As discussed above, for the purposes of modelling this Revised Regulatory Proposal, Ergon Energy has developed a forecast of capital expenditure for new street lighting assets constructed by Ergon Energy by sourcing actual data from the 2007-08 Regulated Accounts and forecasting forward on the basis of a continuation of business as usual conditions. The forecast is set out in Table 20-2. However, Ergon Energy submits that its June 2009 Regulatory Proposal should be adopted in the AER's Final Decision.

Table 20-2: Forecast of Capital Expenditure on New Street Lighting Assets for 2010-15 ($M Real $2009-10)

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Capital Expenditure – new street lighting assets	9.63	9.95	10.27	10.52	10.68	51.05

Source: Revised Submission Tables for Proposal 53.9

If forecasts for new street lighting assets are to be included in the limited building block for street lighting assets, then similar to the approach proposed by ENERGEX and accepted by the AER, Ergon Energy proposes that where a non-standard street lighting asset is requested, the incremental cost difference (between the standard and non-standard asset) will be charged as a Quoted Service. A non-standard street lighting asset is one where the cost of the service is not fully recovered through Ergon Energy's annual prices and the incremental cost represents the uneconomic cost of the service. The incremental cost will be calculated as the shortfall between the present value of expected charges paid by the customer over the life of a standard street lighting asset and the estimated cost of providing the non-standard street lighting asset. This is consistent with Ergon Energy's capital contribution policy approved by the QCA.

20.4.2 Annual Revenue Requirements

Ergon Energy's revised AARs and X factors for Street Lighting Services 1 and 2 for the next regulatory control period are detailed in Table 20-3.

Table 20-3: Ergon Energy's Annual Revenue Requirements and X factors for Street Lighting Service ($M Nominal)

	2010-11	2011-12	2012-13	2013-14	2014-15
Regulatory depreciation	6.34	6.97	7.65	8.37	9.15
Return on capital	7.04	7.43	7.82	8.20	8.57
Operating expenditure	15.03	15.03	15.42	16.23	16.92
Tax allowance	2.06	2.10	2.14	2.19	2.24
Annual revenue requirements (unsmoothed)	30.47	31.53	33.03	34.99	36.88
Annual revenue requirements (smoothed)	30.08	31.65	33.31	35.05	36.88
Forecast CPI (per cent)	2.45%	2.45%	2.45%	2.45%	2.45%
X factors (per cent)	-93.62%	-2.71%	-2.71%	-2.71%	-2.71%

Source: Revised Submission Tables for Proposal 23

20.4.3 Indicative Prices

Ergon Energy has recalculated its indicative prices for Street Lighting Services 1 and 2 to reflect its revised ARR and X factors. The indicative prices for each year of the next regulatory control period are set out in Table 20-4.

Table 20-4: Indicative Prices for Street Lighting Assets for 2010-15 ($/day, GST Exclusive)

	2010-11	2011-12	2012-13	2013-14	2014-15
East – Major	0.50	0.51	0.52	0.55	0.57
Price Path (per cent)		2.14	3.39	4.57	4.03
East – Minor	0.74	0.76	0.78	0.82	0.85
Price Path (per cent)		2.13	3.39	4.57	4.03
West – Major	0.78	0.81	0.85	0.90	0.95
Price Path (per cent)		3.39	4.66	5.86	5.31
West – Minor	0.77	0.79	0.83	0.88	0.93
Price Path (per cent)		3.38	4.65	5.85	5.30
Mt Isa – Major	0.47	0.49	0.51	0.54	0.57
Price Path (per cent)		3.07	4.34	5.53	4.98
Mt Isa – Minor	0.47	0.49	0.51	0.54	0.56
Price Path (per cent)		3.05	4.32	5.52	4.97

20.5 Rules' requirements

In submitting this Revised Regulatory Proposal in relation to its Street Lighting Services, Ergon Energy has had regard for clauses 6.2.6(b)(c), 6.3.1, 6.3.2, 6.4, 6.5.1, 6.5.2, 6.5.3, 6.5.4, 6.5.5, 6.5.6(a)-(d), 6.5.6(e)(1)(2)(3) & (5), 6.5.7(a)-(d), 6.5.7(e)(1)(2)(3) & (5), 6.5.9 and 6.6.1, 6.8.1(c), 6.8.2(c), 6.12.1(1), (12), (13), 6.12.3(c), 6.18, S6.1.1, S6.1.2 and 11.16.10 of the Rules.

20.6 Relevant documents provided by Ergon Energy

The following documents are relevant to this Chapter but are new since, or were not provided to the AER with, Ergon Energy's June 2009 Regulatory Proposal:

PL878c	PL878c_EE response to SL Modelling Request_Streetlighting Pricing Calculator_23Nov09.xls
PL881c	PL PTRM
RP922c	RP922c_RRP_Street Lighting Capex_18Dec09.xls
RP927c	RP927c_Streetlighting Pricing Calculator_7Jan10.xls
RP986c	RP986c_EE Email to AER_Street Lighting Modelling Request_24 Nov 09.rft

21 ALTERNATIVE CONTROL – QUOTED AND FEE BASED SERVICES

In response to the AER's Draft Distribution Determination, Ergon Energy provides:

- Further information to clarify its June 2009 Regulatory Proposal.

21.1 Ergon Energy's June 2009 Regulatory Proposal

Chapters 54 and 55 of Ergon Energy's June 2009 Regulatory Proposal recognised that the AER's F&A Stage 1 set out the requirement to apply a price cap form of control to Ergon Energy's Quoted and Fee Based Services using a formula based approach.

Ergon Energy proposed that the following formula apply to Ergon Energy's Quoted Services and Fee Based Services for the next regulatory control period:

$$Pi = Li + Mi + OCi + CAi + GSTi$$

In this formula, "Li" relates to the cost of labour, "Mi" relates to the cost of non-capitalised materials, "OCi" relates to one-off costs (inclusive of overheads), "GSTi" relates to the Goods and Services Tax and "CAi" relates to a charge applied to reflect the use of non-system physical assets owned by Ergon Energy involved in the delivery of the service.

Ergon Energy provided:

- A series of worked examples of the calculation of possible Quoted Services in section 54.6.2 of its June 2009 Regulatory Proposal; and
- Indicative prices for Fee Based Services in section 55.10 of its June 2009 Regulatory Proposal.

21.2 AER's November 2009 Draft Distribution Determination

In Chapter 18 of its Draft Distribution Determination, the AER:

- Applied the control mechanism from its F&A Stage 1;
- Applied a price path for each formula component to be used to derive prices for Quoted and Fee Based Services;
- Applied 2008-09 base labour rates as accepted by the QCA;
- Requested Ergon Energy to provide further information on the inclusion of contractor base rates;
- Requested Ergon Energy to provide a demonstration of how employee classifications have been applied in its illustrative Quoted Services examples;
- Applied labour cost escalators consistent with those it applied to Standard Control Services;
- Noted that Ergon Energy procures and manages its materials efficiently and therefore the cost of materials in the first year of the regulatory control period are reasonable;
- Applied material cost escalators consistent with those it applied to Standard Control Services;
- Has not provided a capital allowance for non-system assets, but will consider further information provided in Ergon Energy's Revised Regulatory Proposal to determine an appropriate capital allowance;
- Proposed an on-cost rate of [redacted] per cent and an overhead rate of [redacted] per cent in each year of the next regulatory control period;
- Removed the "other cost" component from Ergon Energy's formula;
- Accepted the inclusion of GST in the calculation of the price for Quoted Services; and

- Requires Ergon Energy to include prices for Fee Based Services and prices for illustrative configurations of Quoted Services in its Pricing Proposal as well as the volumes and revenues recovered in the preceding regulatory year.

21.3 Ergon Energy's Response to AER's Draft Distribution Determination

21.3.1 First Regulatory Year – Internal Labour

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- AER applied 2008-09 base labour rates for the employee classifications accepted by the QCA to develop capped labour prices for quoted and Fee Based Services [407-8, 422] - Ergon Energy to provide information in its Revised Regulatory Proposal that demonstrates how each employee classification has been applied in its illustrative quoted service examples [407]	- Ergon Energy's proposed base labour rates are not consistent with the 2008-09 labour rates accepted by the QCA [407]	- As discussed in Ergon Energy's response to AER.ERG.24.04 (16 October 2009), the labour rates used to prepare Ergon Energy's prices for 2008-09 as accepted by the QCA were Ergon Energy's budgeted labour rates for 2008-09. That is because Ergon Energy's pricing submission was required to be submitted prior to actual labour rates being finalised. - Table 172 of Ergon Energy's Regulatory Proposal provided Ergon Energy's actual labour rates for 2008-09. - In its June 2009 Regulatory Proposal, Ergon Energy used its actual labour rates for 2008-09 to prepare its proposed prices for Quoted and Fee Based Services as it was considered appropriate to use actual costs rather than budgeted costs as the basis for calculating future prices. - Ergon Energy accepts the AER's decision to adopt the QCA accepted labour rates for 2008-09.
	- Ergon Energy has proposed three additional employee classifications for its Quoted Services to those approved by the QCA in 2008-09 [407]	- The AER's statement that Ergon Energy proposed three additional employee classifications is incorrect. As discussed in Ergon Energy's response to AER.ERG.30.2 (23 October 2009), Ergon Energy only proposed two additional employee classifications to those approved by the QCA in 2008-09. Contractors and Trainees. System Operator is not an additional employee classification. The employee classification Control Room (as accepted by the QCA) has been renamed System Operator. - Ergon Energy notes that in 2006-07 and 2007-08, labour rates for Trainees were the same as the labour rates for Apprentices. Therefore Ergon Energy proposes to treat Trainees as Apprentices and apply the QCA approved 2008-09 labour rate for Apprentices to Trainees. - Ergon Energy notes that the employee classification for Contractors relates to contractors that are employed to fill positions within Ergon Energy on a temporary basis. For example, if an employee is on leave and the position cannot be filled by other internal staff, then a contractor may be used. This Contractor classification is not used in the provision of Quoted or Fee Based Services. Therefore, Ergon Energy has not proposed a labour rate for Contractors in its Revised Regulatory Proposal - As discussed in Ergon Energy's response to AER.ERG.07.2 (29 August 2009), where hire or supply of additional labour is required to provide part of a Quoted Service, the costs are included in the price for the service through the "other cost" component of the formula. This is consistent with the approach currently applied under the QCA.
	- AER has not been able to review Ergon Energy's allocation of its employee	- Ergon Energy confirms that it has correctly allocated its employee classifications in its illustrative Quoted Services. - Ergon Energy will provide the AER will the calculation of

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
	classifications in its illustrative quoted service examples as labour was allocated at an aggregate level [407]	labour costs in its Revised Regulatory Proposal so that the AER can review its allocation of employee classifications for Quoted Services. The calculation and application can be seen in Document RP920c, Document RP921c, Document RP923c, Document RP924c, Document RP925c, Document RP926c and Document RP928c.

21.3.2 First Regulatory Year – External Labour

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- AER has not included Ergon Energy's contractor employee classification's base rate [408] - Ergon Energy to provide further information in its revised regulatory proposal that supports the inclusion of its contractor employee classification's base rate [408]	- Insufficient information to justify inclusion of Ergon Energy's contractor employee classification's base rate [408]	- As discussed above, the employee classification for Contractors relates to contractors that are employed to fill positions within Ergon Energy on a temporary basis. For example, if an employee is on leave and the position cannot be filled by other internal staff, then a contractor may be used. This Contractor classification is not used in the provision of Quoted or Fee Based Services. Therefore, Ergon Energy has not proposed a labour rate for Contractors in its Revised Regulatory Proposal. - As discussed in Ergon Energy's response to AER.ERG.07.2 (29 August 2009), where hire or supply of additional labour is required to provide part of a Quoted Service, the costs are included in the price for the service through the "other cost" component of the formula. This is consistent with the approach currently applied under the QCA.

21.3.3 Price Path – Labour

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- AER to apply its labour cost escalators to base labour rates to establish a capped price for each employee classification in the first regulatory year and to establish a price path for subsequent regulatory years [409-10] - Price path for Ergon Energy's internal labour services at Table 18.2 [410] - AER has not established a price path for Ergon Energy's contractor services [410] - Ergon Energy to provide information in its revised regulatory proposal that supports the inclusion of its contractor employee classification's base rate, in which case the AER will determine the appropriate labour cost escalator in its Distribution Determination	- AER has revised Ergon Energy's labour cost escalators with the AER's own escalators for the reasons discussed in Chapter 8 of the Draft Distribution Determination [409-10]	- Refer to Chapter 9 of this Revised Regulatory Proposal for a discussion of why the labour escalation rates proposed by Ergon Energy are prudent and efficient. - Ergon Energy has applied its labour cost escalators in the calculation of indicative prices in its Revised Regulatory Proposal.
	- AER doesn't have sufficient information about Ergon Energy's contractor employee classifications to allow it to establish a price path for its contractor services [409]	- As discussed above, the employee classification for Contractors relates to contractors that are employed to fill positions within Ergon Energy on a temporary basis. For example, if an employee is on leave and the position cannot be filled by other internal staff, then a contractor may be used. This Contractor classification is not used in the provision of Quoted or Fee Based Services. Therefore, Ergon Energy has not proposed a labour rate for Contractors in its Revised Regulatory Proposal - As discussed in Ergon Energy's response to AER.ERG.07.2 (29 August 2009), where hire or supply of additional labour is required to provide part of a Quoted Service, the costs are included in the price for the service through the "other cost" component of the formula. This is consistent with the approach currently applied under the QCA.

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
[410]		

21.3.4 Price Path – Materials

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Ergon Energy should apply material cost escalators in Appendix H to its Quoted Services [411, 423]	- Ergon Energy's illustrative Quoted Services examples for large customer connections do not align with its proposed material cost escalators [411]	- Ergon Energy notes the AER has identified an error in Ergon Energy's calculation of material costs for new large customer design and construction in its Regulatory Proposal. - This error was corrected in Document PL874c (provided to the AER on 20 November 2009) in response to the request for Modelling of Quoted and Fee Based Services. - Ergon Energy has corrected this error in its Revised Regulatory Proposal and applied the escalators used for Standard Control Services in the calculation of indicative prices for all Quoted Services.
	- AER's assessment of material cost escalators is detailed in Appendix H of its Draft Distribution Determination [575-616]	- Refer to Chapter 10 of this Revised Regulatory Proposal for a discussion on material cost escalators. - Ergon Energy has applied the escalators it used for Standard Control Services in the calculation of indicative prices for all Quoted Services in this Revised Regulatory Proposal.

Ergon Energy has used material cost escalators in modelling this Revised Regulatory Proposal to provide an indication of likely future prices. Ergon Energy is concerned with the AER's proposed approach to fixing material escalators for Quoted Services in its final Distribution Determination to apply for the entire regulatory control period. Under the current approach with the QCA, materials are a direct pass through to the customer such that customers see actual costs at the time of performing the service. Under the AER's approach, Ergon Energy will be exposed to the actual movement in material costs.

For example, if material costs are higher than forecast, then Ergon Energy will be limited to charging customers a price that is lower than actual cost. For those services which are offered in a competitive market (i.e. New Large Customer Design and Construct and Street Lighting Services), Ergon Energy's price will necessarily be lower than its competitors – since they won't be subject to caps on material costs. This could either result in a reduction in the level of competition in the provision of these services or have a negative impact on Ergon Energy's competitors. Ergon Energy notes the same situation does not apply if actual costs are lower than forecast, as the price set by the AER is the maximum price Ergon Energy can charge. Therefore, if actual costs are lower than forecast, Ergon Energy would be entitled to use actual costs in the calculation of its quotes to customers (as long as the actual cost is lower than that calculated using the AER's escalators).

Ergon Energy therefore believes that the AER, in its final Distribution Determination, should adopt the same approach accepted by the QCA, which is to allow actual material costs to be passed through to customers.

21.3.5 Capital Allowance – Non-System Assets

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- AER has not included Ergon Energy's proposed capital allowance for non-system assets in its Draft Distribution Determination	- Ergon Energy has not demonstrated how its proposed capital allowance is calculated [413]	- Ergon Energy provided the AER will an explanation of the calculation of the capital allowance for non-system assets. This information was provided in Ergon Energy's response to AER.ERG.24.06 (dated 16 October 2009), which referred to a spreadsheet that was inadvertently not included with the

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
[413-4, 422] - AER will consider further information provided by Ergon Energy on its capital allowance in its Revised Regulatory Proposal [413-4]		response but has now been provided to the AER. - The capital allowance was calculated based on historical trends for actual 2008-09 prices and forecast 2009-10 prices. Ergon Energy took the non vehicle capital allowance (CNSi) for each fixed and price on application service in 2008-09 and 2009-10 and divided it by the direct costs for each service (Li + Mi + Oi) in the same year. Ergon Energy then calculated the average percentage across all services for both years to determine the capital allowance. - Ergon Energy has revised the calculation of its capital allowance to reflect actual 2009-10 prices. This calculation is provided in Document RP928c**.**
	- AER has not been provided with sufficient information to substantiate Ergon Energy's proposed capital allowance and has therefore not been able to assess its efficiency [413]	- As discussed above, Ergon Energy provided the AER with an explanation of the calculation of the capital allowance for non-system assets. This information was provided in Ergon Energy's response to AER.ERG.24.06 (dated 16 October 2009), which referred to a spreadsheet that was inadvertently not included with the response, but has now been provided to the AER in RP928c.

21.3.6 Capital Allowance – Vehicles

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- AER has not included Ergon Energy's proposed capital allowance for vehicles in its Draft Distribution Determination [414, 423] - AER will consider further information provided by Ergon Energy on its capital allowance in its Revised Regulatory Proposal [414]	- AER will only permit Ergon Energy to recover depreciation consistent with remaining asset life of its vehicles, being 7.7 years [414]	- In its response to AER.ERG.24.04 (dated 16 October 2009), Ergon Energy advised the AER of an error in the calculation of prices for its Fixed and Quoted Services. Ergon Energy provided the AER with revised prices after correcting for this error. - Ergon Energy notes the AER has identified an error in the calculation of remaining asset lives. - Ergon Energy has used revised remaining asset lives in the calculation of prices in its Revised Regulatory Proposal.
	- Ergon Energy has not demonstrated how the proposed depreciation rates are calculated [414]	- Ergon Energy calculates base depreciation rates by grouping each vehicle in Ergon Energy's fleet into vehicle classes. Costs are calculated from Ergon Energy's finance systems for each vehicle class and then divided by the estimated total hours of use to derive an hourly rate. - This is the same methodology that was used to calculate base vehicle rates for 2008-09 as accepted by the QCA. The only differences being that Ergon Energy undertook a review of vehicle rates including refining vehicle classes, updating vehicle data and available hours before preparing its 2009-10 vehicle rates. - Ergon Energy proposes to use its 2009-10 vehicle rates as the base vehicle rates in calculating indicative prices for this Revised Regulatory Proposal, rather than the QCA accepted 2008-09 vehicle rates. That is, as a result of the review undertaken by Ergon Energy, the 2009-10 vehicle rates more accurately reflect the current vehicle classes, vehicle data and available hours used by Ergon Energy. Therefore, Ergon Energy considers it is more appropriate to use the 2009-10 vehicle rates.
	- AER has not been provided with sufficient information that substantiates Ergon Energy's proposed capital	- As discussed above, vehicle rates have been calculated using the same methodology used to calculate 2008-09 vehicle rates. - The QCA accepted Ergon Energy's 2008-09 vehicle rates

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
	allowance and has therefore not been able to assess its efficiency [414]	calculated using this methodology.

21.3.7 On-Costs and Overheads

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- AER will apply its benchmark labour on cost rate of 0.3124 in each regulatory year of the next regulatory control period [415] - AER has applied 9 per cent superannuation has been added to the benchmark labour on cost rate for Ergon Energy [417]	- AER does not accept that Ergon Energy's on-costs are prudent and efficient [417]	- Ergon Energy believes its on-cost rates are prudent and efficient as they represent the actual costs incurred by the business. - The methodology used to develop on-cost rates is consistent with that used to develop the 2008-09 on-cost rate accepted by the QCA.
	- AER will not apply Ergon Energy's proposed overtime labour on cost rate of 8 per cent as labour on costs should be applied to employee classifications after hours base labour rate [417]	- In its Regulatory Proposal, Ergon Energy proposed an on-cost rate of [redacted] during business hours and [redacted] after hours. That is, the [redacted] only is applied to ordinary hours and the [redacted] only is applied to after hours' rates. The [redacted] applied to after hours is not in addition to the [redacted]. As explained in Ergon Energy's response to AER.ERG.24.04 (dated 16 October 2009), the on-costs applied to overtime rates are significantly less as payroll tax is the only on-cost applied to overtime rates. - Therefore, Ergon Energy does not believe it is appropriate to apply the same on-cost rate to both ordinary and after hours' base rates. - Ergon Energy has applied its on-cost rates in the calculation of indicative prices for this Revised Regulatory Proposal.
	- Superannuation was not otherwise included in Ergon Energy's labour cost [417]	- Ergon Energy confirms that superannuation is not otherwise included in Ergon Energy's labour costs. - Ergon Energy does not accept the AER's inclusion of an amount of 9 per cent for superannuation. - Within Ergon Energy, staff can either be on Defined Benefits or Defined Contr bution superannuation requirements. Ergon Energy's Defined Benefit rate is currently [redacted]. Approximately [redacted] of Ergon Energy's workforce is on the Defined Benefit Scheme. Ergon Energy's Defined Contribution rate is [redacted]. The calculation of superannuation on-costs for Ergon Energy therefore results in an amount of [redacted] - As discussed above, has applied its on-cost rates in the calculation of indicative prices for this Revised Regulatory Proposal.

Ergon Energy notes the AER's intention to fix overhead rates throughout the next regulatory control period to provide certainty to customers. While recognising that it provides certainty to both Ergon Energy and customers, Ergon Energy is concerned with this proposed approach. As advised to the AER, Ergon Energy calculates overhead rates in accordance with its approved Cost Allocation Method. The overhead rates provided to the AER in Ergon Energy's Regulatory Proposal and this Revised Regulatory Proposal represent Ergon Energy's forecast of future overhead rates. Ergon Energy calculates overhead rates on an annual basis. This means that the actual overhead rate in each year will be different from previous years. Therefore, the overhead rates the AER applies will not reflect the actual overhead rates incurred by the business. Ergon Energy therefore believes it is more appropriate to provide a forecast of overhead rates for the forthcoming year as part of the annual Pricing Proposal process.

21.3.8 Other costs

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Remove "other costs" component from Ergon Energy's formula for Quoted Services [422]	- Not appropriate to include "other cost" component as it relates to contingency costs and does not represent efficient costs of providing Quoted Services [422]	- Ergon Energy does not accept the AER's decision to remove the "other costs" component from Ergon Energy's formula. - The AER has not understood the intent of the "other cost" component. The explanation the AER referred to in its Draft Distribution Determination related to the explanation of how "other costs" were calculated for one scenario of a New Large Customer Design and Construct service – not the definition of "other costs" generally. - As discussed in section 54.6.1 of Ergon Energy's Regulatory Proposal, "other costs" relates to one-off service delivery costs including hire or supply of additional equipment, assets or labour and contingency costs. This was also explained in Ergon Energy's response to AER.ERG.07.2 on 29 August 2009. That is, "other costs" does not just represent contingency costs but any "other" costs Ergon Energy incurs in performing a service such as hire of equipment or assets etc. - "Other costs" are incurred as the result of a request for a specific service from a customer. That is, Ergon Energy would not otherwise incur those costs. Therefore, it is appropriate that these costs be passed through to the customer. - The QCA accepted the inclusion of "other costs" (referred to as other direct costs) in the approved formula for 2008-09 and 2009-10. - Therefore, Ergon Energy believes that the "other cost" component should be included in the formula for Quoted Services.

21.3.9 Demonstration of compliance

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- Compliance for Quoted Services to be demonstrated by Ergon Energy providing, as part of its Pricing Proposals, the prices for each quoted service illustrative configurations in the relevant year of the regulatory control period [423]	- Ergon Energy did not specifically address how it would demonstrate compliance for Quoted Services [423]	- Ergon Energy accepts the AER's decision to demonstrate compliance for Quoted Services by providing prices for illustrative configurations for each Quoted Service in its Pricing Proposal. - Ergon Energy will provide prices for each Quoted Service illustrative configuration in its Pricing Proposal for the relevant year.
- Compliance for Fee Based Services to be demonstrated by Ergon Energy providing, as part of its Pricing Proposals, the prices for each fee based service for the relevant year of the regulatory control period [423]	- Ergon Energy did not specifically address how it would demonstrate compliance for Fee Based Services [423]	- Ergon Energy accepts the AER's decision to demonstrate compliance for Fee Based Services by providing prices for each Fee Based Service in its Pricing Proposal. - Ergon Energy will provide prices for each Fee Based Service in its Pricing Proposal for the relevant year.

21.3.10 Formula for Quoted and Fee Based Services

AER's Amendment / Criticism	AER's Reasons	Ergon Energy's Response
- AER amended following formula for quoted and Fee Based Services [422]: $P_i = L_i + M_i + CNS_i + CV_i + GST_i$	- AER removed "Other Costs" from Ergon Energy's formula [422]	- Ergon Energy does not accept the AER's decision to remove the "other costs" component from its formula for Quoted Services. - Refer to 21.3.8 above for a discussion of Ergon Energy's reasons. - Ergon Energy has included the "other costs" component in its formula for Quoted Services in this Revised Regulatory Proposal.

Ergon Energy notes that the AER has requested that Ergon Energy provide volumes and revenues for both Quoted and Fee Based Services in the preceding year in its annual Pricing Proposal. Ergon Energy seeks confirmation from the AER on its requirements given the annual Pricing Proposal will be submitted during the preceding year i.e. submitted in May 2010 for the 2010-11 financial year. Therefore, Ergon Energy seeks confirmation on whether the AER requires forecast revenues and volumes for the immediate proceeding year (i.e. t-1) or whether the AER are seeking actual revenues and volumes for the previous full financial year (i.e. t-2).

As discussed previously in this Revised Regulatory Proposal, Ergon Energy will seek to engage with the AER on reporting requirements including the provision of volumes and revenues for Quoted and Fee Based Services.

21.3.11 Indicative Prices and Price Paths

Ergon Energy notes that the AER has included prices and price paths for Ergon Energy's Fee Based Services in Appendix P of its Draft Distribution Determination. On the 17 November 2009, the AER requested Ergon Energy to undertake modelling of its Fee Based Services for the AER's Draft Distribution Determination. Ergon Energy provided this modelling to the AER on 20 November 2009. The prices for Fee Based Services were set out in Document PL875c.

Ergon Energy notes that some of the prices in Appendix P of the AER's Draft Distribution Determination are not the same as those provided by Ergon Energy. Prices for the services Subdivision Fees through to Supply Abolishment do not align with Ergon Energy's modelling. However, services from Temporary Builders Supply to Wasted Truck Visit do align. Ergon Energy therefore assumes that there is an error in the AER's Appendix P.

21.4 Ergon Energy's Revised Regulatory Proposal

As discussed above, Ergon Energy has revised its modelling of Fee Based and Quoted Services. Specifically Ergon Energy has:

- Used the 2008-09 base labour costs as accepted by the QCA;
- Used Ergon Energy's 2009-10 base vehicle costs;
- Applied the cost escalators used for Standard Control Services in this Revised Regulatory Proposal;
- Revised its capital allowance calculation to reflect actual 2009-10 prices; and
- Applied on-cost and overhead rates as set out in Ergon Energy's Regulatory Proposal.

Ergon Energy has provided the AER with a demonstration of the calculation of both Fee Based and Quoted Services. The indicative prices for Fee Based and Quoted Services are set out below.

21.4.1 Fee Based Services

Ergon Energy has calculated the indicative prices for 2010-11 as discussed above. A price path of 4.5 per cent has been applied to labour only services and a price path of 3.82 per cent has been applied to all other services. These indicative prices are detailed in Table 21-1.

Table 21-1: Fee Based Services – $ per service GST Exclusive

Service	2010-11	2011-12	2012-13	2013-14	2014-15
Subdivision Fees	733.64	766.65	801.15	837.20	874.88
Project Fees	733.64	766.65	801.15	837.20	874.88
De-energisation during business hours - urban/short rural feeders	116.33	120.77	125.39	130.19	135.17
De-energisation during business hours - long rural / isolated feeders	568.09	589.82	612.38	635.80	660.11
Re-energisation during business hours - urban/short rural feeders	92.50	96.04	99.71	103.52	107.48
Re-energisation during business hours - long rural / isolated feeders	529.46	549.71	570.74	592.56	615.23
Re-test at customer's installation during business hours - urban/short rural feeders	397.45	412.65	428.43	444.81	461.83
Re-test at customer's installation during business hours - long rural / isolated feeders	794.90	825.30	856.86	889.63	923.65
Supply Abolishment during business hours - urban/short rural feeders	397.45	412.65	428.43	444.81	461.83
Supply Abolishment during business hours - long rural / isolated feeders	794.90	825.30	856.86	889.63	923.65
Temporary Builders Supply, not in permanent position- single phase metered - business hours - urban/short rural feeders	662.41	687.75	714.05	741.36	769.71
Temporary Builders Supply, not in permanent position- single phase metered - business hours - long rural / isolated feeders	1,059.86	1,100.40	1,142.48	1,186.17	1,231.54
Temporary Builders Supply not in permanent position - multi phase metered - business hours - urban/short rural feeders	662.41	687.75	714.05	741.36	769.71
Temporary Builders Supply not in permanent position - multi phase metered - business hours - long rural / isolated feeders	1,059.86	1,100.40	1,142.48	1,186.17	1,231.54
Restoration of supply required due to customer action, during business hours - urban/short rural feeders	397.45	412.65	428.43	444.81	461.83
Restoration of supply required due to customer action, during business hours - long rural / isolated feeders	794.90	825.30	856.86	889.63	923.65
Wasted truck visit - one person crew - urban/short rural feeders	84.66	87.90	91.26	94.75	98.37
Wasted truck visit - one person crew - long rural / isolated feeders	338.64	351.59	365.04	379.00	393.49
Wasted truck visit - two person crew - urban/short rural feeders	131.77	136.81	142.04	147.47	153.11
Wasted truck visit - two person crew - long rural / isolated feeders	527.07	547.23	568.15	589.88	612.44

21.4.2 Quoted Services

Ergon Energy's indicative prices for Quoted Services for 2010-11 to 2014-15 are detailed in Table 21-2.

Table 21-2: Quoted Services – $ per service - GST Exclusive

Service	2010-11	2011-12	2012-13	2013-14	2014-15
New Large Customer Design and Construct – Example 1	173,315.71	178,653.02	180,988.51	186,637.13	221,513.60
New Large Customer Design and Construct – Example 2	9,906,580.27	10,232,830.18	10,432,158.27	10,750,172.96	10,810,813.08
New Large Customer Design and Construct – Example 3	10,831,851.59	11,186,659.86	11,390,856.15	11,720,688.03	11,845,213.14
Street Lighting – Example 1	1,570.94	1,614.14	1,653.39	1,725.32	1,762.46
Street Lighting – Example 2	4,295.54	4,429.28	4,507.03	4,669.94	4,726.60
Street Lighting – Example 3	17,654.61	18,167.27	18,487.63	19,143.94	19,392.10
Street Lighting – Example 4	59,750.37	61,603.12	62,603.02	64,756.35	65,440.11
Removal or Relocate Asset	32,233.23	33,277.16	33,717.31	34,762.60	34,983.86
Relocation Point of Attachment	794.90	816.17	840.58	882.86	907.86
Tiger Tails	464.73	476.71	490.48	514.35	528.48
Meter Data Provider Services	124.19	128.02	132.39	139.95	144.39
Meter Data Provider (Above Minimum	428.77	440.81	454.59	478.45	492.53
Meter Test	454.48	467.31	482.00	507.42	522.42
Change Tariff	280.30	287.76	296.32	311.15	319.92
Change Time Switch	140.15	143.88	148.16	155.57	159.96
Removal of Meter	227.24	233.65	241.00	253.71	261.21
Removal of Load Control Device	227.24	233.65	241.00	253.71	261.21
Special Meter Read	69.74	71.58	73.69	77.34	79.50
Reprogram Card Meters	420.46	431.64	444.48	466.72	479.88
Exchange Meter	340.86	350.48	361.50	380.57	391.82
Move Meter	340.86	350.48	361.50	380.57	391.82
Connection Service (Above Min)	928.95	955.46	975.82	1,014.89	1,032.73
Overhead Service Upgrade	662.41	680.14	700.48	735.72	756.55
Underground Service Upgrade	4,271.74	4,409.28	4,481.08	4,637.42	4,684.77
Meter Service (Above Min)	763.13	787.03	801.81	832.11	843.39
Prepayment Meters at Request	1,087.10	1,120.05	1,145.70	1,194.61	1,217.14
Temporary Disconnect and Reconnect	340.86	350.48	361.50	380.57	391.82
De-energisation After Hours	236.46	243.26	251.04	264.50	272.44
Re-energisation After Hours	188.02	193.43	199.62	210.32	216.64
Attend Loss of Supply	483.92	497.22	512.47	538.87	554.47
Emergency Recoverable Works	1,375.58	1,411.91	1,453.62	1,525.89	1,568.64
Subdivision Fees	1,261.67	1,300.61	1,345.01	1,421.76	1,466.91
Project Fees	485.26	500.23	517.31	546.83	564.19
High Load Escort	6,515.36	6,710.11	6,932.52	7,317.10	7,543.57
Rectify Illegal Connections	585.92	602.51	621.50	654.36	673.75
Conversion of Aerial Bundled Cables	907.82	932.40	955.59	997.69	1,019.98
Provision of Service or Additional Crew	350.38	359.70	370.40	388.94	399.90

21.5 Rules' requirements

In submitting this Revised Regulatory Proposal in relation to its Quoted and Fee Based Services, Ergon Energy has had regard for clauses 6.2.6(c), 6.8.2(c)(3) and (4), 6.18 and S6.1.3(6) of the Rules.

21.6 Relevant documents provided by Ergon Energy

The following documents are relevant to this Chapter but are new since, or were not provided to the AER with, Ergon Energy's June 2009 Regulatory Proposal:

Email 29-08-09	EE response to AER.ERG.07.2
Email 16-10-09	EE response to AER.ERG.24.04
Email 16-10-09	EE response to AER.ERG.24.06
Email 23-10-09	EE response to AER.ERG.30.2
PL874c	PL874c_Revised PL860c_All Quoted Services_Summary_19Nov09.xls
PL875c	PL875c_Revision to PL856c_EE_Fixed Fee Services_Indicative Prices Calculation_19Nov09.xls
RP918c	RP918c_RRP_All Quoted Services_Summary_22Dec09.xls
RP919c	RP919c_RRP_EE_Fixed Fee Services_Indicative Prices Calculation_21Dec09.xls
RP920c	RP920c_RRP_LCDC Calculation_21Dec09.xls
RP921c	RP921c_RRP_Other POA Services_Base Estimates_21Dec09.xls
RP923c	RP923c_SL_Estimate 1_Indicative Prices_22Dec09.xls
RP924c	RP924c_SL_Estimate 2_Indicative Prices_22Dec09.xls
RP925c	RP925c_SL_Estimate 3_Indicative Prices_22Dec09.xls
RP926c	RP926c_SL_Estimate 4_Indicative Prices_22Dec09.xls
RP928c	RP928c_Allocators for Capital Allowance_21Dec09.xls

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22 CERTIFICATION STATEMENT

The directors certify that:

- In accordance with clause S6.1.1(5) of the Rules, the key assumptions that underlie the capital expenditure forecast set out in pro forma 2.3.3 of the Regulatory Information Notice are reasonable.
- In accordance with clause S6.1.2(6) of the Rules, the key assumptions that underlie the operating expenditure forecast set out in pro forma 2.3.3 of the Regulatory Information Notice are reasonable.

Signed in accordance with a resolution of directors:

Dr Ralph Howard Craven 14th January 2010

Director

John Alan Bird 14th January 2010

Director

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23 CHIEF EXECUTIVE'S STATUTORY DECLARATION

Oaths Act 1867 (Qld)

I, Graeme Robert Finlayson of [redacted] Queensland, Acting Chief Executive of Ergon Energy Corporation Limited (Ergon Energy), do solemnly and sincerely declare that, in relation to this Revised Regulatory Proposal:

(a) the information and documentation provided to the Australian Energy Regulator (AER) in accordance with the Regulatory Information Notice served on Ergon Energy by the AER on 22 April 2009 is complete in all material respects; and

(b) the information and documentation provided to the AER in accordance with the Regulatory Information Notice are accurate in all material respects and can be relied upon by the AER to assess the Revised Regulatory Proposal submitted by Ergon Energy to the AER on or before 14 January 2010 and to make a distribution determination for Ergon Energy.

And I make this solemn declaration conscientiously believing the same to be true and by virtue of the provisions of the *Oaths Act 1867*.

Signature

Declared by Graeme Robert Finlayson at Brisbane on the 14th January 2010.

Before me,

Signature

Sarah Bronwyn Williamson, [redacted] 14th January 2010
solicitor

Name, address and qualification of person before whom the declaration is made