



## FINAL REPORT

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Queensland Competition Authority

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# Calculation of the Benchmark Retail Cost Index 2009-10

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## TABLE OF CONTENTS

1.	INTRODUCTION.....	1
1.1.	BACKGROUND.....	1
1.2.	ORGANISATION OF THIS REPORT .....	3
2.	THE REQUIREMENTS FOR CALCULATION OF THE BRCI .....	5
2.1.	CALCULATION OF THE BRCI AS BENCHMARK RETAIL COST PER UNIT OF NET LOAD .....	5
2.2.	THE TOTAL BENCHMARK RETAIL COST .....	5
2.2.1.	Cost of energy.....	6
2.2.2.	Network costs .....	7
2.2.3.	Retail costs .....	8
2.2.4.	Other relevant costs.....	9
2.3.	WORKING OUT THE NEM LOAD .....	9
2.4.	FIXING OF FUTURE PRINCIPLES.....	9
2.5.	INPUTS FROM THE AUTHORITY'S CONSULTATION PROCESS .....	10
2.5.1.	Submissions to the Interim Consultation Notice.....	10
2.5.2.	Comments and Workshop on consultant's First Report.....	10
2.5.3.	Comments and Workshop on consultant's draft Second Report.....	11
2.5.4.	Comments on Consultant's Final Second Report and Authority's Draft Decision .....	12
2.6.	CRA'S TERMS OF REFERENCE FOR THIS STUDY .....	12
2.7.	DATA PROVIDED BY THE AUTHORITY .....	14
2.8.	QUEENSLAND GOVERNMENT POLICY OBJECTIVE .....	14
2.8.1.	Submissions to the Interim Consultation Notice.....	16
2.8.2.	Submissions to the draft First Report regarding the Queensland Government policy objective 16	
2.8.3.	Workshop discussion regarding the Queensland Government policy objective.....	17
2.8.4.	Summary of responses to the Final Second Report and Draft Decision .....	18
2.9.	ADDRESSING UNCERTAINTY ASSOCIATED WITH POLICIES WHOSE IMPLEMENTATION DETAILS AND TIMING HAVE NOT BEEN FULLY DEFINED .....	19
2.10.	CUT OFF DATES FOR DATA AND INFORMATION TO BE INCLUDED IN CRA'S REPORTS .....	19
2.11.	INFLATION FORECASTS .....	20
2.11.1.	Consumer price index (CPI) .....	20
2.11.2.	Wage price index (WPI).....	20
2.12.	STATUS OF THE DATA USED IN THIS FINAL REPORT .....	21
3.	COST OF ENERGY .....	22
3.1.	ENERGY COST FRAMEWORK IN QUEENSLAND .....	22

8 June 2009

3.2.	THE LRMC OF ENERGY .....	25
3.2.1.	LRMC considerations and approach .....	25
3.2.2.	Definition of the LRMC.....	27
3.2.3.	Issues in modelling LRMC .....	27
3.2.4.	Options and approaches taken to the LRMC conceptual framework .....	30
3.2.5.	Options available and approaches taken in the LRMC modelling .....	33
3.2.6.	The CRA model used to derive the LRMC.....	35
3.2.7.	Summary of issues raised in submissions to the Final Second Report and Draft Decision 36	
3.2.8.	Load data requirements for the LRMC calculation.....	39
3.2.9.	Renewable Energy Targets and Queensland Gas Scheme.....	39
3.2.10.	Treatment of reserve margin .....	43
3.2.11.	LRMC modelling input assumptions.....	44
3.2.12.	LRMC results .....	55
3.3.	COST OF PURCHASING ENERGY .....	56
3.3.1.	Conceptual comparison between the LRMC and actual costs .....	57
3.3.2.	Summary of issues raised in submissions to the Final Second Report and Draft Decision 57	
3.3.3.	Approach to estimating the actual cost of purchasing energy .....	58
3.3.4.	Inputs to the calculation of the cost of purchasing energy.....	61
3.3.5.	Calculations .....	65
3.3.6.	Application of network losses .....	68
3.3.7.	Energy purchase costs results .....	68
3.4.	COMBINATION OF LRMC AND ENERGY PURCHASE COST RESULTS.....	69
3.5.	OTHER ENERGY COSTS.....	69
3.5.1.	Mandatory Renewable Energy Target (MRET).....	70
3.5.2.	Queensland Gas Scheme.....	71
3.6.	NEMMCO COSTS.....	72
3.6.1.	Participant and FRC fees.....	72
3.6.2.	Ancillary Services Charges.....	72
3.7.	OVERALL SUMMARY RESULTS FOR THE COST OF ENERGY .....	73
3.8.	NEM LOAD .....	74
4.	RETAIL COSTS AND MARGINS.....	75
4.1.	CUSTOMER NUMBERS.....	75
4.2.	RETAIL COSTS .....	75
4.2.1.	Categories of retail costs .....	75
4.2.2.	Retail costs for a standalone retail business as against an integrated utility .....	77
4.2.3.	Discussion of fixed and variable components of retail costs .....	77
4.2.4.	Approach to estimating retail costs for the BRCI calculations .....	79

8 June 2009

4.2.5.	Summary of issues raised in submissions to the Final Second Report and Draft Decision regarding retail operating costs excluding customer acquisition costs .....	80
4.2.6.	Conclusion on retail operating costs excluding customer acquisition costs .....	80
4.2.7.	Customer acquisition costs .....	80
4.2.8.	Summary of the results for retail costs .....	88
4.3.	RETAIL MARGIN .....	88
4.3.1.	Terminology .....	88
4.3.2.	Submissions to the draft First Report regarding retail margin .....	90
4.3.3.	Summary of submissions to the Second Report and workshop regarding retail margin 91	
4.3.4.	Conclusion on retail margin in previous years of calculation of the BRCI .....	91
4.3.5.	Conclusion on retail margin for 2009-10 .....	92
5.	NETWORK COSTS AND OTHER RELEVANT COSTS .....	93
5.1.	NETWORK COSTS .....	93
5.2.	OTHER RELEVANT COSTS .....	93
6.	RESULTS .....	94
APPENDIX A : OUTLINE OF CONSULTANCY FROM THE TERMS OF REFERENCE		95
APPENDIX B : APPROACHES USED TO DETERMINE ALLOWABLE ENERGY COSTS IN OTHER JURISDICTIONS .....		96
B.1	VICTORIA .....	96
B.2	SOUTH AUSTRALIA .....	97
B.3	NEW SOUTH WALES .....	98
B.3.1	NSW 2004 Price Determination .....	98
B.3.2	NSW 2007 Price Determination .....	99
APPENDIX C : CEMOS MODEL .....		101
C.1	CEMOS MODELLING FRAMEWORK .....	101
C.1.1	Long-term generation capacity expansion and dispatch .....	102
C.1.2	Generation offer strategy using CONE .....	103
C.1.3	Short term dispatch analysis using STEMM .....	104
C.2	CALIBRATION OF CEMOS .....	106
C.3	TRANSMISSION SYSTEM AND SCALING FACTORS .....	110
C.4	RECENT MAJOR APPLICATIONS OF CEMOS .....	113
APPENDIX D : GRAPHS OF D-CYPHA TRADE PRICES USED IN ESTIMATING THE COST OF PURCHASING ENERGY IN 2009-10 .....		116

8 June 2009

D.1	FLAT SWAP CONTRACT PRICES .....	116
D.1.1	Q3 2009 – July to September 2009.....	116
D.1.2	Q4 2009 – October to December 2009 .....	117
D.1.3	Q1 2010 – January to March 2010.....	118
D.1.4	Q2 2010 – April to June 2010.....	119
D.2	PEAK SWAP CONTRACT PRICES .....	120
D.2.1	Q3 2009 – July to September 2009.....	120
D.2.2	Q4 2009 – October to December 2009 .....	121
D.2.3	Q1 2010 – January to March 2010.....	121
D.2.4	Q2 2010 – April to June 2010.....	122
D.3	CAP CONTRACT PRICES (AT \$300 CAP) .....	123
D.3.1	Q3 2009 – July to September 2009.....	123
D.3.2	Q4 2009 – October to December 2009 .....	124
D.3.3	Q1 2010 – January to March 2010.....	124
D.3.4	Q2 2010 – April to June 2010.....	125
APPENDIX E : INPUT ASSUMPTIONS FOR THE LOAD DATA USED IN THE LRMC CALCULATION .....		126
E.1	PEAK AND ENERGY PROJECTIONS.....	126
E.2	40 LOAD BLOCK LDC FOR QUEENSLAND IN THE 2009-10 TARIFF YEAR .....	126
APPENDIX F : CONSISTENCY CHECKS PERFORMED ON CEMOS MODELLING OUTPUTS .....		129
F.1	CONSISTENCY CHECKS PERFORMED ON LRMC OUTPUTS.....	129
F.2	CONSISTENCY CHECKS PERFORMED ON STEMM OUTPUTS.....	130

## TABLE OF FIGURES

Figure 1: Indicative costs of generating technologies.....	28
Figure 2: Indicative price duration curve.....	29
Figure 3: Interaction of CEMOS components.....	101
Figure 4: Queensland Price Duration Curve Normalisation .....	108
Figure 5: New South Wales Price Duration Curve Normalisation.....	108
Figure 6: Time-Weighted Average prices 2007/08 (\$/MWh).....	109
Figure 7: CEMOS vs. actual NEM spot price duration curve for Queensland.....	109

8 June 2009

Figure 8: d-cypha Trade prices for Queensland flat swap contracts for Q3 2009 – July to September 2009 .....	116
Figure 9: d-cypha Trade prices for Queensland flat swap contracts for Q4 2009 – October to December 2009 .....	117
Figure 10: d-cypha Trade prices for Queensland flat swap contracts for Q1 2010 – January to March 2010 .....	118
Figure 11: d-cypha Trade prices for Queensland flat swap contracts for Q2 2010 – April to June 2010 .....	119
Figure 12: d-cypha Trade prices for Queensland peak swap contracts for Q3 2009 – July to September 2009 .....	120
Figure 13: d-cypha Trade prices for Queensland peak swap contracts for Q4 2009 – October to December 2009 .....	121
Figure 14: d-cypha Trade prices for Queensland peak swap contracts for Q1 2010 – January to March 2010 .....	121
Figure 15: d-cypha Trade prices for Queensland peak swap contracts for Q2 2010 – April to June 2010 .....	122
Figure 16: d-cypha Trade prices for Queensland \$300 cap contracts for Q3 2009 – July to September 2009 .....	123
Figure 17: d-cypha Trade prices for Queensland \$300 cap contracts for Q4 2009 – October to December 2009 .....	124
Figure 18: d-cypha Trade prices for Queensland \$300 cap contracts for Q1 2010 – January to March 2010 .....	124
Figure 19: d-cypha Trade prices for Queensland \$300 cap contracts for Q2 2010 – April to June 2010 .....	125
Figure 20: Queensland's 2009-10 tariff year LDC compared to the 2008-09 tariff year LDC .....	128

## TABLE OF TABLES

Table 1: Outturn and forecast changes in CPI used in this report .....	20
Table 2: Outturn and forecast changes in WPI used in this report .....	21
Table 3: Summary of approaches used to calculate energy cost in other jurisdictions .....	24
Table 4: Annual RET targets .....	40
Table 5: Calculating NEM sent-out generation as a % of total Australian sent-out generation .....	41
Table 6: Annual Renewable Energy Targets .....	42

8 June 2009

Table 7: Annual Queensland Gas Scheme Targets (% of Queensland generation/year) .....	43
Table 8: Concept Economics capital costs (2009-10\$/kW installed) by installation year used in the 2009-10 tariff year LRMC calculation .....	48
Table 9: Concept Economics annualised capital costs (2009-10\$/MW/year) by installation year used in the 2009-10 tariff year LRMC calculation.....	49
Table 10: Concept Economics coal fuel costs used in the 2009-10 tariff year LRMC calculation .	50
Table 11: Concept Economics fuel costs for CCGT plant used in the 2009-10 tariff year LRMC calculation.....	51
Table 12: Concept Economics fuel costs for OCGT plant used in the 2009-10 tariff year LRMC calculation.....	51
Table 13: Concept Economics FOM and VOM .....	52
Table 14: Concept Economics thermal efficiencies and auxiliaries .....	53
Table 15: Concept Economics availability factors .....	53
Table 16: Concept Economics WACC assumptions.....	54
Table 17: The LRMC of energy.....	56
Table 18: Installed capacity and generation based on Concept Economics inputs, 2009-10 and 2017-18.....	56
Table 19: Criteria used to purchase hedge contracts for Queensland load .....	60
Table 20: Average spot market prices for each quarter in 2008-09 (\$/MWh) – 10POE calculation .....	63
Table 21: Average spot market prices for each quarter in 2008-09 (\$/MWh) – 50POE calculation .....	64
Table 22: Average spot market prices for each quarter in 2008-09 (\$/MWh) – 90POE calculation .....	64
Table 23: Average spot market prices for each quarter in 2009-10 (\$/MWh) – 10POE calculation .....	64
Table 24: Average spot market prices for each quarter in 2009-10 (\$/MWh) – 50POE calculation .....	64
Table 25: Average spot market prices for each quarter in 2009-10 (\$/MWh) – 90POE calculation .....	65
Table 26: Average costs of energy contracts for each quarter (\$/MWh).....	67
Table 27: Average Loss Factor (ALF) .....	68
Table 28: Energy purchase costs – scenario results, weightings and weighted values (\$/MWh) .	69
Table 29: Energy cost component of BRCI for 2008-09 and 2009-10 .....	69

8 June 2009

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Table 30: Estimated NEM fees (\$/MWh) .....	72
Table 31: Summary of the cost of energy (\$/MWh) .....	73
Table 32: Summary of retail costs (\$/customer) .....	88
Table 33: BRCI calculation results .....	94
Table 34: Scaling factors to convert sent-out energy to generator terminal basis .....	113
Table 35: Selected applications of CEMOS .....	114
Table 36: Details of the 40 load blocks for Queensland in the 2009-10 tariff year LRMC calculation .....	127
Table 37: Output checks for LRMC modelling in CEMOS .....	129
Table 38: Output checks for STEMM modelling in CEMOS .....	131

8 June 2009

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## 1. INTRODUCTION

### 1.1. BACKGROUND

With the introduction of Full Retail Competition (FRC) in the Queensland energy market on 1 July 2007, licensed electricity retailers have been able to offer market contracts to all electricity customers. For those customers who do not enter into a market contract, **notified prices** apply. In addition, at the conclusion of a market contract, customers are able to revert to a notified price for their electricity supply.

Prior to 1 July 2007, the notified prices that applied to non-contestable customers were set by the Minister for Mines and Energy (the Minister), and in the several years leading up to 2007 prices had increased each year in line with CPI. With the introduction of FRC, a new method of adjusting notified prices applies each year, as set out in amendments to the *Electricity Act 1994* (the Act).<sup>1</sup> Commencing in 2007-08, changes are made to the notified prices with reference to movements in the Benchmark Retail Cost Index (BRCI). The BRCI provides a method for quantifying the year to year changes in the various costs that would be incurred by a large electricity retailer in serving a cross section of the Queensland customer base. Under the BRCI, the estimated change in these costs is used as a factor to adjust the rates from one year to the next.

Because the notified prices are to be varied at 1 July each year in accordance with movements in the BRCI, in the first year (2007-08) the BRCI had to be calculated for the two tariff years 2006-07 and 2007-08 to enable notified prices to be in place from 1 July 2007.<sup>2</sup>

When the BRCI was calculated to enable notified prices to be reset from 1 July 2008, there was a change in the theoretical framework for calculating the cost of energy since the previous calculation of the BRCI for 2007-08. Therefore, the BRCI for 2007-08 was recalculated using the new theoretical framework that was applied to the calculation of the BRCI for 2008-09.<sup>3</sup>

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<sup>1</sup> These amendments to the Act were incorporated in the *Electricity and Other Legislation Amendment (EOLA) Act 2006*. The EOLA Act can be downloaded from [www.legislation.qld.gov.au/LEGISLTN/ACTS/2006/06AC060.pdf](http://www.legislation.qld.gov.au/LEGISLTN/ACTS/2006/06AC060.pdf).

All references in this report to requirements in the Act for the calculation of the BRCI are based on Reprint No. 7B of the Act, as in force on 1 October 2008, sourced at [www.legislation.qld.gov.au/LEGISLTN/CURRENT/E/ElectricA94.pdf](http://www.legislation.qld.gov.au/LEGISLTN/CURRENT/E/ElectricA94.pdf).

<sup>2</sup> Various documents relating to the initial setting of notified prices from 1 July 2007, including previous CRA reports, have been published on the Authority's website at [www.qca.org.au/electricity-retail/NEP](http://www.qca.org.au/electricity-retail/NEP).

<sup>3</sup> Various documents relating to the re-setting of notified prices from 1 July 2008, including previous CRA reports, have been published on the Authority's website at [www.qca.org.au/electricity-retail/NEP0809](http://www.qca.org.au/electricity-retail/NEP0809).

8 June 2009

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The Queensland Competition Authority's (the Authority) Final Decision Benchmark Retail Cost Index: 2008-09 was published in May 2008. In August and September 2008 AGL Energy Limited ("AGL") and Origin Energy Retail Limited ("Origin") respectively commenced separate proceedings in the Supreme Court against the Authority and the Minister for Mines and Energy challenging the decision of the Authority regarding the 2008-09 BRCI and the notified prices of electricity that followed from it, and seeking that that decision be set aside.

The Supreme Court handed down its decision on the matter on 28 April 2009. The Court decided that:

- *in working out the benchmark retail cost for both the relevant tariff year and the preceding tariff year, the Authority did not form a view of the likely total costs to be incurred during that year to purchase energy to supply the NEM load of the State for that year, as required by s92(1) of the Act; and*
- *in working out the total benchmark retail cost for the preceding year, the Authority used data which had not been used in working out that cost when the year to 30 June 2008 had been the relevant tariff year, and which the Authority was not otherwise entitled to use in this decision.*

The Court concluded that "the Authority will have to recalculate the benchmark retail cost index for the year to 30 June 2009"

This report continues the work that was begun in the First Report and Second Report on the Calculation of the Benchmark Retail Cost Index 2009-10, both of which are available on the Authority's website, but modifies the approach and data used in those reports in several ways, as follows:

- The calculation of the cost of purchasing energy has been undertaken using the NEM load as clarified in the Court's decision.
- All data being used has been reviewed and where required modified to conform with the Court's decision that the calculation of the BRCI for the target year should use, except in very limited instances, the same data for the previous year as was used when that year was the target year.
- Some new sources of data have been used with regard to the 2009-10 target year. Where required, these have also been used in recalculating the 2008-09 BRCI to provide a consistent basis for assessment of the movement of costs across the two years.

8 June 2009

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This report calculates the BRCI for 2009-10 only. The results of this calculation of the BRCI for 2009-10 is then compared to the Authority's remade calculation of and decision regarding the BRCI for 2008-09, which is being published simultaneously with this report, and which was calculated in conformance with the Supreme Court Decision of 28 April 2009. The tariffs that will pertain from 1 July 2009 will be calculated by applying the BRCI of the remade decision to the original 2008-09 BRCI and then subsequently applying the 2009-10 BRCI to the remade BRCI of 2008-09.

The Authority<sup>4</sup> has engaged CRA International Pty Ltd (CRA) to provide assistance in calculating the BRCI for 2009-10.

This report is CRA's Final Report on the calculation of the BRCI for 2009-10, and is an update to and supersedes the draft First Report which was released on 15 August 2008 and the Final Second Report which was released on 1 December 2008, which the Authority used in preparing its Draft Decision, which was also issued in December 2008.<sup>5</sup> The Authority is using this Final Report as input to its Final Decision on the BRCI for 2009-10. This report includes discussion of the approach that has been taken to the development of the various components of the BRCI and the data sources that have been used, as well as a final calculation of the BRCI and its component parts. It also incorporates comments from stakeholders on methodology, data sources and presentation, and updated data that has become available or has been developed for the BRCI process since the publication of our Final Second Report.

## 1.2. ORGANISATION OF THIS REPORT

The remainder of this report is structured as follows:

- Section 2 discusses the requirements for calculation of the BRCI, as set out in the legislative and regulatory framework documentation, as well as the Government policy objectives within which the BRCI is expected to operate. It also documents the scope of work undertaken in this assignment, and inputs that were received from the Authority (including those that arose within the Authority's consultation process). It discusses the timetable for the preparation of the 2009-10 BRCI and its implications for the calculation, and addresses certain key data definitions and values.
- Sections 3, 4 and 5 discuss in detail the cost components of the BRCI – these being the cost of energy, retail costs and margins, network costs, and other relevant costs.
- Section 6 summarises the results of the calculation of BRCI.

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<sup>4</sup> Queensland legislation refers to the Authority as the *pricing entity* in regard to the Authority's responsibilities that are relevant to the calculation of the BRCI.

<sup>5</sup> An earlier draft Second Report was provided dated 27 October 2008.

8 June 2009

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- Appendix A contains the Outline of Consultancy from the Terms of Reference for this study.
- Appendix B summarises approaches that have been used to determine allowable energy costs in other jurisdictions in the National Electricity Market (the NEM).
- Appendix C contains background information on CRA's proprietary model CEMOS, which has been used in our calculation of energy costs.
- Appendix D provides graphs of d-cypha Trade prices that have been used in our estimation of the cost of purchasing energy.
- Appendix E contains details of the input assumptions we have applied in our calculation of the BRCI.
- Appendix F provides the results of consistency checks we have conducted on the LRMC and pool price modelling.

## 2. THE REQUIREMENTS FOR CALCULATION OF THE BRCI

The Minister has delegated to the Authority the responsibility for calculating the BRCI for Queensland. The *Electricity Regulation 2006* (the Regulation) provides guidance to the Authority on how the BRCI should be determined, and also sets out the requirements for the consultative process that the Authority must undertake in its determination of the BRCI.<sup>6</sup> Thus all of the following need to be taken into account in determining the BRCI:

- The Act;
- The Regulation; and
- The Certificate of Delegation from the Minister.<sup>7</sup>

The impacts that each of these instruments has on various aspects of CRA's assistance to the Authority in the calculation of the BRCI are set out in this section of the report.

### 2.1. CALCULATION OF THE BRCI AS BENCHMARK RETAIL COST PER UNIT OF NET LOAD

The Act sets out that the BRCI ("B") for the State for a particular year is calculated and expressed in ¢/kWh by dividing the total benchmark retail cost of electricity for the State for the year ("R") by the total NEM load of the State for the relevant tariff year ("L"):

$$B = R / L$$

Where:

B is the BRCI for the year;

R is the total benchmark retail cost for the year; and

L is the total NEM load of the State for the year.

### 2.2. THE TOTAL BENCHMARK RETAIL COST

The total benchmark retail cost – the numerator of the BRCI calculation equation – is to be expressed in cents,<sup>8</sup> and comprises the following benchmark retail cost elements:

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<sup>6</sup> All references in this report to requirements in the Regulation for the calculation of the BRCI are based on Reprint No. 2D of the Regulation, as in force on 1 July 2008, sourced at [www.legislation.qld.gov.au/LEGISLTN/CURRENT/E/ElectricR06.pdf](http://www.legislation.qld.gov.au/LEGISLTN/CURRENT/E/ElectricR06.pdf).

<sup>7</sup> The current Certificate of Delegation from the Minister is dated 3 June 2009, and revoked the previous Certificate of Delegation. A copy of the current and copies of all previous Certificates of Delegation can be found on the Authority's website.

8 June 2009

- The cost of energy;
- Network costs;
- Retail costs; and
- Any other relevant costs.

The way in which each of these components is defined is set out in turn below. Each component is also subject to any relevant provision under the Regulation.

### 2.2.1. Cost of energy

Sub-section 92(1) of the ACT requires that *“the cost of energy must reflect . . . the likely total of the costs to be incurred . . . to purchase energy”* to supply all of the NEM load of the State for the relevant tariff year. However, Division 2 of the Regulation (sections 104 through 107) requires that this view is to be based on the Long Run Marginal Cost (LRMC) of energy in the part of the State connected to the national grid, and must include the costs of retailers’ compliance with the Queensland 13% Gas Scheme and the Commonwealth Mandatory Renewal Energy Target (MRET) Scheme.

The LRMC must take into account the most efficient combination of generating plant to supply all of the NEM load of the State for the relevant year, and the Regulation prescribes that the approach to estimating the LRMC of energy for each tariff year must be a theoretical framework that complies with the following principles:

- It is generally recognised and understood in economic theory;
- The application of the theoretical framework results in a cost per unit of electricity expressed in \$/MWh;<sup>9</sup>
- The LRMC is calculated as the cost of supplying the generation required to satisfy the demand profile (called the NEM load shape) formed over each half-hour electricity trading period of the State for the previous calendar year;<sup>10</sup> and
- There is no double counting of costs of meeting the Queensland 13% Gas Scheme or the Commonwealth Mandatory Renewal Energy Target (MRET) Scheme.

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<sup>8</sup> Given that  $B = R / L$ , B is measured in ¢/kWh, and L is measured in kWh, it follows that R must be measured in cents. The Act states instead that the benchmark retail cost is expressed in ¢/kWh, but this cannot be correct.

<sup>9</sup> As stated in section 2.1 above, as a component of total benchmark retail cost, the cost of energy needs to be in cents. Therefore the cost of electricity in \$/MWh needs to be divided by 10 to give ¢/kWh, then multiplied by the total NEM load in kWh to give the required cost of energy in cents.

<sup>10</sup> The Regulation thus requires that the LRMC calculation for 2009-10 shall be based on the NEM load shape for Queensland in 2008.

8 June 2009

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There is no allowance made for weather normalisation or any other normalising adjustments for exceptional circumstances that may have occurred in the year used as the basis of the relevant load for the purpose of calculating the LRMC (i.e. the calendar year that ends six months prior to the year for which the notified price is being developed; in the case of the 2009-10 tariff year the load is taken from calendar year 2008).

The Regulation also prescribes that the theoretical framework must take into account ancillary services needed to meet the NEM load of the State for the relevant tariff year.

The theoretical framework must be the same (or substantially the same) from tariff year to tariff year, unless there is a clear reason for change. If there is a change in the framework, the BRCI for the previous year should be re-calculated to determine what it would have been, based on the changed framework.

As a matter of practice, the cost of energy component of the BRCI has been calculated as a 50/50 weighting of the LRMC calculated according to the considerations outlined above and using a greenfield approach, and an assessment of the likely cost of purchasing energy in the NEM, which requires consideration of the wholesale pool price and a hedging strategy that is broadly representative of the perspective and needs of a large electricity-only retailer operating in the Queensland mass market. Section 3.2 describes the approach used to calculating the LRMC; section 3.3 describes the approach used to estimate the cost the retailer will incur to purchase energy.

### 2.2.2. Network costs

Network costs are defined in the Act to be the pricing entity's view of the likely total revenue requirements for the relevant year for transmission and distribution entities in the State.<sup>11</sup>

The current Certificate of Delegation sets a requirement that in calculating the network cost component of the BRCI the Authority "must apply the Aggregate Annual Revenue Requirement (AARR) determined for each year of Ergon Energy's current access arrangement (covering the period 2005-06 to 2009-10), and any changes to the AARR for any approved cost pass through made subsequent to the finalisation of the current access arrangement, without undertaking any smoothing of these AARR amounts".<sup>12</sup>

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<sup>11</sup> Though this BRCI component is titled "network costs", the values that are to be used to calculate this BRCI component are revenue requirements. The actual costs incurred by retailers for transmission and distribution services in any given year, however, can vary significantly from the annual revenue requirement, which is calculated on assumptions about demand and energy consumption by customer class.

<sup>12</sup> The original Certificate of Delegation did specify smoothing of Ergon Energy's AARR in the calculation of network costs, but the current Certificate of Delegation specifically states that such smoothing should not now be undertaken.

8 June 2009

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### 2.2.3. Retail costs

The retail costs taken up in the BRCI are to reflect the pricing entity's view of the likely cost of providing customer retail services to Queensland customers connected to the national grid, based on an efficient entity carrying on an electricity retail business that meets all of the following criteria:

- It is carried on separately from any other business;
- It has a significant market share of the State's electricity retail business;
- It provides customer retail services to a cross-section of customers; and
- It earns a reasonable retail margin.

The Regulation prescribes that in forming a view of the likely cost of providing customer retail services the pricing entity must assume that the retail entity under consideration has a proportion of customers, separated into customer types defined by their consumption level within particular consumption bands, which is substantially the same as the proportion for the bands for the whole Queensland customer base.

The Regulation gives as an example:

- 88% of the customer base comprises domestic customers with annual consumption less than 100 MWh;
- 11% of the customer base comprises business customers with annual consumption less than 100 MWh;
- 0.5% of the customer base comprises business customers with annual consumption between 100 and 200 MWh; and
- The remaining 0.5% of the customer base comprises business customers with annual consumption more than 200 MWh.

The Regulation further prescribes that the pricing entity must consider the following cost categories for the provision of customer retail services:

- Billing;
- Customer call centres;
- Credit management;
- Energy trading activities;
- Corporate overheads, including, for example, treasury functions, human relations and facilities management;
- Information technology systems; and

8 June 2009

- Any other cost category the pricing entity considers reasonable.

As was the case in regard to the cost of energy, if the framework is changed from one tariff year to the next, the pricing entity must calculate what the BRCI for the previous year would have been based on the changed framework – this is necessary so that the BRCI calculations for consecutive years can be compared meaningfully.

#### 2.2.4. Other relevant costs

The Act defines these as any other relevant costs that the Authority considers to be relevant.

### 2.3. WORKING OUT THE NEM LOAD

The NEM load is the denominator of the BRCI calculation equation.

As defined in the Act, the NEM load (which is to be expressed in kWh) is the pricing entity's view of the sum of the total loads supplied at each **transmission connection point** to a supply network within the State, as adjusted for any matter prescribed under a regulation. The term **transmission network connection point** in the Act refers to a Queensland transmission network connection point as defined under the National Electricity Rules. The NEM load therefore should include only the energy delivered from the transmission network to the distribution system and on to end-use customers, and should *exclude* any end-user load that is directly connected to the transmission system.

Attachment B, *Methodology of Annual Indexation of Notified Prices*, to the Minister's letter and original Certificate of Delegation of 16 March 2007 stated in section 2.1 – *Working out the NEM Load*:

*For consistency purposes, the period for measuring 'L' should be the same from year to year. Therefore, NEM Load for a prospective tariff year will be the twelve months of data to 31 December in the calendar year immediately prior. Eg for tariff year 2007/08 NEM load data will be measured from calendar year 2006.*

Thus, for the calculation of the BRCI for 2009-10, the NEM Load is measured from calendar year 2008.

### 2.4. FIXING OF FUTURE PRINCIPLES

The Act enables the pricing entity to fix principles to apply for a benchmark retail cost element. For example, it may fix a principle that, over a period of several years, retail costs will increase each year by the rate of increase in CPI. However, the current Certificate of Delegation from the Minister specifically states:

*This delegation does not include the power to fix principles under section 95 of the Act.*

On that basis, the possible application of fixed principles is not considered in this report.

## 2.5. INPUTS FROM THE AUTHORITY'S CONSULTATION PROCESS

### 2.5.1. Submissions to the Interim Consultation Notice

On 2 July 2008, the Authority released an Interim Consultation Notice on the calculation of the BRCI for 2009-10.<sup>13</sup> In response, the Authority received the following submissions, which are listed below in the order in which they are listed on the Authority's website:

- AGL (Jul 08) (PDF, 158KB)
- Australian Power and Gas (Jul 08) (PDF, 789KB)
- EnergyAustralia (Jul 08) (PDF, 322KB)
- Ergon Energy (Jul 08) (PDF, 63KB)
- Integral Energy (Jul 08) (PDF, 156KB)
- Origin Energy (Jul 08) (PDF, 146KB)
- Queensland Consumers' Association (Jul 08) (PDF, 53KB)
- TRUenergy (Jul 08) (PDF, 37KB)
- Queensland Council of Social Service (Jul 08) (PDF, 108KB)

The issues raised in these submissions were discussed in our draft First Report.

### 2.5.2. Comments and Workshop on consultant's First Report

CRA's draft First Report was made available to stakeholders on 15 August 2008. Several data files used by CRA in preparing its draft First Report were also released for the information of stakeholders. In response, the Authority received the following submissions, which are listed below in the order in which they are listed on the Authority's website:

- TRUenergy (Aug 08) (PDF, 35KB)
- Integral Energy (Aug 08) (PDF, 225KB)
- Origin Energy (Aug 08) (PDF, 175KB)
- AGL (Aug 08) (PDF, 498KB)

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<sup>13</sup> *Benchmark Retail Cost Index for Electricity: 2009-10 – Interim Consultation Notice*, Queensland Competition Authority, July 2008.

8 June 2009

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- Queensland Electricity (Aug 08) (PDF, 293KB)
- Sun Water (Aug 08) (PDF, 47KB)

A Stakeholders' Workshop was held in Brisbane on 27 August 2008, at which stakeholders had the opportunity to make comments on and ask questions about the draft First Report.

Supplementary papers on the following two topics were prepared by CRA and posted on the Authority's website on 10 October 2008, along with some additional data files:

- A review of various aspects of the transmission system modelling and the use of scaling factors in the BRCI calculations for 2009-10; and
- Review, revision and detailed discussion of the methodology used to calculate energy purchase costs in the 2009-10 BRCI.

Comments on these papers were received from:

- AGL (Oct 08) (PDF, 112KB)
- Origin Energy (Oct 08) (PDF, 39KB)

### 2.5.3. Comments and Workshop on consultant's draft Second Report

CRA's draft Second Report was made available to stakeholders on 27 October 2008, along with a report from ACIL Tasman.<sup>14</sup> The ACIL Tasman report provided was commissioned by the Authority to provide inputs to the LRMC calculation. These inputs – which concern capital and fuel costs of electricity generation plant and other generation plant operating characteristics – were presented in two ways: (a) as an updated version of the regression analysis that ACIL had undertaken in its 2007 report to NEMMCO, and (b) in terms of the most recent costs regarding each of these inputs. These two perspectives were referred to as the regression scenario and the step-change scenario respectively.

Several data files used by CRA in preparing its draft Second Report were also released for the information of stakeholders. In response, the Authority received the following submissions, which are listed below in the order in which they are listed on the Authority's website:

- AGL (Nov 08) (PDF, 750KB)
- Integral (Nov 08) (PDF, 205KB)
- Origin Energy (Nov 08) (PDF, 75KB)

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<sup>14</sup> *Fuel and capital costs in the NEM*, ACIL Tasman, for QCA, October 2008.

8 June 2009

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- TRU Energy (Nov 08) (PDF, 27KB)

On 3 November 2008, the Authority hosted a second workshop to provide an opportunity for interested parties to discuss the reports by CRA and ACIL Tasman. The workshop was attended by 22 representatives from 13 organisations. As discussed in our Final Second Report, various amendments were made to the BRCI calculations following that workshop, and updated data files that were by CRA in preparing the Second Report were placed on the Authority's website.

#### 2.5.4. Comments on Consultant's Final Second Report and Authority's Draft Decision

The Authority released its Draft Decision on 2 December 2008, along with CRA's Final Second Report. Submissions were received from the following stakeholder organisations and individuals, listed in the order they appear on the Authority's website:

- AGL (Dec 08) PDF, 135 KB)
- Chamber of Commerce and Industry Queensland (Dec 08) (PDF, 3.7MB)
- Department of Mines and Energy (Dec 08) (PDF, 165KB)
- Origin Energy (Dec 08) (PDF, 1.2MB)
- Queensland Consumers Association (Dec 08) (PDF, 55KB)
- Queensland Council of Social Service (Dec 08) (PDF, 95KB)
- TRUenergy (Dec 08) (PDF, 30KB)
- C. Cameron (Dec 08) (PDF, 15KB)
- D. Auberson (Dec 08) (PDF, 15KB).

#### 2.6. CRA'S TERMS OF REFERENCE FOR THIS STUDY

Appendix A contains the Outline of Consultancy from the original Terms of Reference for this study that we received from the Authority in July 2008. We note in particular the following:

*The Authority established the framework for determining each element of the benchmark retail cost index in its May 2008 Final Decision on the 2008-09 BRCI. It is currently expected that the same framework will be adopted in calculating the BRCI for 2009-10. Given the shortened timeframe for this assessment, it is currently not anticipated that there will be any changes to the method of calculation, and therefore no requirement to recalculate the BRCI for 2008-09.*

8 June 2009

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The draft First Report was prepared on the basis of the expectation that was specified as above in our Terms of Reference, i.e. that the framework that the Authority will adopt in calculating the BRCI for 2009-10 will be that which the Authority adopted in its May 2008 Final Decision on the BRCI for 2008-09.<sup>15</sup> In our final advice to the Authority on the calculation of the BRCI for 2008-09,<sup>16</sup> we provided a range of possible calculation methods and frameworks, from which the Authority made its selection of one particular calculation method in its Final Decision. That calculation method entailed decisions regarding the following specific matters:

- In the calculation of the LRMC of energy, trended capital and fuel costs were used rather than year-to-year costs; and
- In the calculation of the LRMC of energy, and in the calculation of energy purchase costs, the modelling was based on the full Queensland load, including the directly connected customers in the State.

The BRCI calculations for 2009-10 in the First Report were also based on this framework and method.

However, the then most recent Certificate of Delegation (that of 26 August) had extended the timeframe for calculation of the BRCI for 2009-10 to 1 March 2009, and this gave the Authority the opportunity to reconsider the direction given to CRA that it was not anticipated that there would be any changes to the method of calculation of the BRCI for 2009-10.

Based on the discussions that took place in the Workshop held on 27 August 2008, the Authority commissioned ACIL to investigate the possibility that a 'step change' had taken place in generation capital and fuel costs. These were then used to provide a second LRMC scenario. In its Draft Decision the Authority used the LRMC value that resulted from the trended-cost inputs.

Subsequently, the Authority commissioned Concept Economics to undertake a review and refinement of the ACIL LRMC inputs. This review and refinement was undertaken in recognition of the dramatic changes that had taken place due to the global financial crisis and the change in economic conditions that followed it, which in turn were seen to be producing changes in commodity prices and economic activity levels that could potentially affect the demand for and cost of capital equipment and fuels used in generating electricity. The Concept Economics analysis was undertaken to determine whether the latest available information on these matters would alter the inputs to the LRMC calculation. Concept Economics provided an initial review of these inputs at the end of January and a revised review in mid May in order to have the benefit of the most recent economic activity and cost information.

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<sup>15</sup> *Benchmark Retail Cost Index for Electricity: 2008-09*, Final Decision, Queensland Competition Authority, May 2008.

<sup>16</sup> *Calculation of the Benchmark Retail Cost Index for 2007-08 and 2008-09*, Addendum, CRA, 26 May 2008.

8 June 2009

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The Concept Economics data inputs and scenario are discussed in section 3.2.11, and the results of the LRMC calculation based on those inputs are presented in section 3.2.12 below.

After the 28 April 2009 Supreme Court decision was delivered, the Authority instructed CRA to revise the approach to the calculation of the 2009-10 BRCI in accordance with the details of that ruling, including recalculation of the 2008-09 BRCI<sup>17</sup>.

## 2.7. DATA PROVIDED BY THE AUTHORITY

The Authority has provided to CRA the following data for the purposes of this assignment:

- The NEM load for the State for the complete calendar year 2008. As stated in section 2.3 above, this NEM load should include only the energy delivered from the transmission connection network that flows through the distribution system to customers, and should exclude any end-user load that is directly connected to the transmission system;
- Estimated total number of customers in the State, by customer size, for 2009-10; and
- AARR figures as required for the calculation of the “network costs” for the BRCI for 2009-10 as described in section 2.2.2 above. As noted above, these are revenue requirements and are not the costs actually incurred by retailers for transmission and distribution services in any given year.

## 2.8. QUEENSLAND GOVERNMENT POLICY OBJECTIVE

The current Certificate of Delegation sets a requirement that the Authority must consider a policy objective of the Queensland Government when exercising the delegated powers and functions, which consists of the following two policy intents:

- The annual indexation of electricity tariffs by the index should ensure that existing retail headroom in the tariffs at the date of the original delegation made prior to the commencement of full retail competition<sup>18</sup> remains relatively stable (although not necessarily the same from year to year); and
- The policy of enabling small market customers to revert to notified prices should not result in a retail entity providing customer retail services to non-market customers at a loss.

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<sup>17</sup> The recalculation of the 2008-09 BRCI is presented in CRA's report entitled *Calculation of the Benchmark Retail Cost Index 2008-09: Remade Decision*, Final Report, 3 June 2009.

<sup>18</sup> There is a minor (non-material) discrepancy between (a) the footnote to the current delegation, which states that the original delegation was made on 27 March 2007, and (b) the original delegation, which was dated 16 March 2007.

8 June 2009

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Wording similar to the Government's policy objective was included in a letter dated 1 November 2006 from the Queensland Government to prospective bidders for the retail business. A copy of this letter was provided by the Minister as an attachment alongside the original delegation.

A letter from the Minister to the Chairman of the Authority which accompanied the original delegation provided the following points of clarification:

- In relation to the first policy intent, headroom refers to the difference between the cost of supply and the current tariff level; and
- The second policy intent is to apply where retailers have acted reasonably in providing retail services to customers. It is not intended to protect retailers from any losses attributable to an incorrect assessment of the profitability of a customer or a change in the circumstances of the customer or retailer that is not related to changes in the cost of electricity supply reflected in the BRCI.

The cover letter to the second delegation<sup>19</sup> provided the following additional guidance:

*The Queensland Government's objective is to foster competition in the energy market so that the economy and customers derive the benefits of a competitive energy sector. Efficient and sustainable energy pricing is essential to meeting these objectives, particularly in the face of the significant growth currently occurring in south-east Queensland.*

*In line with achieving efficient and sustainable energy pricing, the Government wishes to ensure that only genuine cost increases are passed on to consumers through the application of the BRCI.*

Since its inception, the calculation of the BRCI has conformed to the requirements that are prescribed in the Act and in the Regulation, but has not explicitly assessed the actual headroom provided in the notified prices from year to year. Therefore, the analysis that has been undertaken has not extended to consideration of whether a change in tariffs based on the change in the BRCI as calculated would meet the Government's policy objective.

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<sup>19</sup> This delegation was dated 11 March 2008.

8 June 2009

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### 2.8.1. Submissions to the Interim Consultation Notice

#### *Origin Energy*

In its submission to the Authority's Interim Consultation Notice, Origin Energy included a section on Change in Retail Headroom, and this included an analysis of annual change in headroom in 2007-08 and 2008-09, for residential customers on the regulated tariffs 11, 31 and 31 on the Energex network. Origin Energy's calculations included taking into account actual revenues and network costs for these customers. The results show a lessening of headroom in both 2007-2008 and 2008-09, based only on the treatment of the network costs. Origin Energy's submission noted the cause of this lessening of headroom: "In other words, the estimated cost of supplying electricity for each residential customer in the Energex area was well above the BRCI escalation and subsequent retail tariff change. As a result, energy retailers are seeing a \$25-\$40 reduction in headroom over a two year period."<sup>20</sup>

#### *AGL*

Origin Energy's explanations of its calculations clearly show that Origin Energy was interpreting headroom to mean net margin rather than gross margin. On the other hand, AGL's submission to the Interim Consultation Notice included a graph that illustrated movement in gross margin,<sup>21</sup> suggesting that AGL is interpreting this to be the headroom referred to in the Government's first policy intent.

A further difference of interpretation between AGL and Origin Energy is in regard to whether the Minister's clarification of the definition of headroom should refer to the actual difference between the cost of supply and the current tariff level measured in \$/customer, or should be measured as a percentage of revenue.

### 2.8.2. Submissions to the draft First Report regarding the Queensland Government policy objective

The relevant submissions to the draft First Report regarding the Queensland Government policy objective are summarised here.

**Integral Energy** stated that it believed that notwithstanding the difficulties that were documented in the draft First Report, it was important for the Authority to demonstrate how it is satisfied, in its exercise of its delegated authority, that the Government's policy objectives have been met for the "efficient entity" that is contemplated for the purposes of the BRCI calculation. Integral Energy stated that it did not suggest that an assessment of headroom and "cost to serve" should be undertaken on a retailer-by-retailer basis.

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20 Origin Energy submission to the Authority on the Interim Consultation Notice for the BRCI 2009-10, July 2008, page 16.

21 AGL submission to the Authority on the Interim Consultation Notice for the BRCI 2009-10, July 2008, page 8.

8 June 2009

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Integral Energy considered that at a minimum these policy intents should form objectives against which the BRCI methodology is tested, and proposed that there should be a requirement to demonstrate that the methodology is consistent with the principles enunciated by the Government. Integral Energy suggested that this would be of particular value:

- In those circumstances where the Authority has raised, or is considering, methodology or calculation “options” (i.e. choices in approach); and
- In providing a pragmatic means of testing the BRCI recommendations and of balancing concerns regarding the assumptions, input and data supporting the detailed modelling of the cost components.

**Origin Energy** stated that the calculation of the BRCI by the Authority must attempt to replicate the change in the annual cost of supplying energy. Origin Energy said that it had already demonstrated in its submission to the Interim Consultation Notice that the “smoothing” of the Ergon and Energex costs had eroded headroom. Noting that the Minister’s delegation had explicitly required the Authority to undertake the smoothing of network costs, Origin Energy further stated that this did not mean that the Authority did not have the responsibility to consider the impact of this approach and to adjust parameters under its control in order to ensure that annual indexation keeps retail headroom at the date of the Delegation relatively stable.

Origin Energy also referred to previous decisions of the Authority having been detrimental to the maintenance of stable margins.

Origin Energy stated its view that it is the obligation of the Authority to investigate the stability of retail headroom in 2009-10. Origin Energy stated that it believed that the theoretical approach is the most appropriate approach, without detailed knowledge of actual costs, because the BRCI methodology is not designed to capture an individual retailer’s actual costs in any of the BRCI components: both the energy costs and retail costs are theoretical or benchmark costs, while network costs in the BRCI clearly do not relate to individual retailer network costs. The required analysis does not, and should not require examination of “actual” retail headroom for any individual retailer.

### **2.8.3. Workshop discussion regarding the Queensland Government policy objective**

At the stakeholders’ workshop held in Brisbane on 27 August 2008, it was decided that the Second Report should discuss how the policy intent of the BRCI – and particularly the objective of maintaining headroom – can be integrated into the BRCI.

Retailers were also asked to provide their view on what headroom was at the relevant start date (in March 2007), what it is now, and the reasons for the change. No such views were received from any of the retailers.

8 June 2009

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#### 2.8.4. Summary of responses to the Final Second Report and Draft Decision

This section of the report summarises comments related to headroom that were received in response to the Second Final Report and the Authority's Draft Decision. As a result, not every submission is mentioned.

##### *AGL*

AGL expressed support for the use of the gross margin as a percentage of total revenue as being the best metric to use in ensuring that the Government's policy intent of maintaining headroom is met. AGL proposed that the gross margin that Sun Retail and Powerdirect were achieving at the time they were sold, as determined from the data room materials that had been provided to bidders, serve as the benchmark. This calculation would take into account:

- The hedge position the businesses had at the time of the sale;
- The network costs they were incurring at the time of the sale; and
- The tariffs that pertained at the time of the sale, their customer numbers and the average electricity consumption of those customers.

This benchmark gross margin would then be compared to the margin that would be obtained from:

- Revenue calculated the original customer base and current year tariffs (i.e., the tariffs that pertain in the year preceding the target year);
- Actual network costs including "the ability . . . historical willingness of Energex to rebalance tariffs fully into its small customer base";
- Projected wholesale electricity costs based on prudent hedging strategy, which is further explained as the cost of flat contract hedge prices over the preceding 12 months, scaled to ensure a like for like comparison; and
- Where the margin for the target year differed from that of the benchmark, the Authority would use the "other relevant cost" provision of section 91G(d) to adjust the margin of the target year BRCI as appropriate.

##### *Origin Energy*

Origin commented that in its view, headroom did not need to be, and should not be, calculated with regard to the costs and revenues of a specific retailer. They noted that the recalculation of various parameters of the BRCI in the original 2008-09 Final Decision had served to reduce headroom and that such approaches be avoided in the future. They also recommended that the use of even simplified headroom analyses, such as the approach they provided in their response to the Interim Consultation Notice would serve to assist the Authority in ensuring that their decisions conform with the Government's policy intent in this regard.

8 June 2009

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### *Queensland Council of Social Service (QCOSS)*

QCOSS stated its objection to any inflation of prices for the purpose of increasing competition, particularly in light of its view that there is no compelling evidence that retail electricity competition has delivered any benefits to Queensland. QCOSS noted that it is difficult to get reliable information concerning retailers' costs and therefore to make accurate decisions about headroom. They also noted that the 2008 World Energy Retail Market Ranking Report ranks Queensland as the seventh most active retail markets among the 50 markets it analyses. This suggests to QCOSS that there is sufficient headroom in the notified prices.

## **2.9. ADDRESSING UNCERTAINTY ASSOCIATED WITH POLICIES WHOSE IMPLEMENTATION DETAILS AND TIMING HAVE NOT BEEN FULLY DEFINED**

At any point in time, changes to existing policies or the introduction of new policies are likely to be under consideration that, if implemented prior to or during the tariff year and analysis period being assessed, could have a material impact on the costs incurred by Queensland electricity retailers and therefore the BRCI.

The Carbon Pollution Reduction Scheme (CPRS) is a relevant example. The Commonwealth Government has repeatedly said it is committed to implementing the scheme. Because the initial target date of 2010 and possibly even some of the details of the scheme may be re-visited, it is very difficult to estimate the costs that retailers are likely to incur under the scheme, and when these costs will pertain.

Under such conditions, there are three options: (1) the costs can be estimated under the most likely outcome (though this still leaves the question of determining what the most likely outcome is), (2) the costs can be estimated for a range of outcomes (though this leaves the question of defining the range and then either picking a point in the range or combining the points in some way), or (3) not estimating the costs until the details and timing of the policy are known.

In the case of the CPRS, the Authority asked CRA to undertake the second approach in our Final Second Report. Three scenarios were considered: no CPRS, CPRS with a 10% carbon reduction target and CPRS with a 20% reduction target. After consideration of the results and further developments regarding CPRS, the Authority decided in its Draft Decision to use the no CPRS case as the basis for the BRCI. Accordingly, this Final Report does not explicitly consider the likely future costs of the CPRS in the assessment of energy costs.

## **2.10. CUT OFF DATES FOR DATA AND INFORMATION TO BE INCLUDED IN CRA'S REPORTS**

In order to meet our obligations to the Authority and thus enable the Authority to meet its timetable, we have taken into account data and information available as at 20 May 2009.

8 June 2009

## 2.11. INFLATION FORECASTS

Of relevance to the calculation of the BRCI, the Australian Bureau of Statistics (ABS) publishes the Consumer Price Index (CPI) (ABS index 6401.0) and the Wage Price Index (WPI) (ABS index 6345.0) in retrospect for each quarter of the year. These published figures have been used for historical financial periods as appropriate. As at the cut-off date of data and information for this report the last published full tariff year ABS data for both CPI and WPI is for the year to June 2008.

In some parts of the BRCI calculation, we also need estimates of the change in CPI and the WPI for 2008-09 and 2009-10. These forecasts are discussed below.

### 2.11.1. Consumer price index (CPI)

The Reserve Bank of Australia (RBA) publishes CPI forecasts in its quarterly *Statement on Monetary Policy*, every February, May, August and November.<sup>22</sup> In this report we are using CPI forecasts from the RBA's *Statement on Monetary Policy* dated 8 May 2009, as shown in Table 1 below.

**Table 1: Outturn and forecast changes in CPI used in this report**

Period for CPI outturn or forecast	Outturn or forecast change in CPI for this period
The 12 months to June 2008 – outturn (Brisbane)	5.12%
The 12 months to June 2009 – forecast	1.5%
The 12 months to June 2010 – forecast	2.5%

Source: ABS, RBA

### 2.11.2. Wage price index (WPI)

In our Addendum report on the 2008-09 BRCI we discussed various sources of commentary and data on forecast wage increases. We had previously used pre-election Treasury forecasts dating from November 2007, with which some stakeholders raised concerns, and this was not a source of information that is published and could be used regularly. We found an apparently reliable source to be ANZ's quarterly Economic Outlook<sup>23</sup> – this publication gave results that matched the pre-election Treasury forecasts and which matched other non-quantified commentary. In this report we are using WPI forecasts from the ANZ's Economic Outlook for the June quarter 2009, which was published on 6 April 2009, as shown in Table 2 below.

<sup>22</sup> These are available at [www.rba.gov.au/PublicationsAndResearch/StatementsOnMonetaryPolicy/index.html](http://www.rba.gov.au/PublicationsAndResearch/StatementsOnMonetaryPolicy/index.html).

<sup>23</sup> Published at [www.anz.com/aus/corporate/Economic-Research-And-Publications/Economic-Research/Economic-Outlook/default.asp](http://www.anz.com/aus/corporate/Economic-Research-And-Publications/Economic-Research/Economic-Outlook/default.asp).

8 June 2009

**Table 2: Outturn and forecast changes in WPI used in this report**

Period for WPI outturn or forecast	Outturn or forecast change in WPI for this period
The 12 months to June 2008 – outturn	4.21%
The 12 months to June 2009 – forecast	3.90%
The 12 months to June 2010 – forecast	3.40%

Source: ABS, ANZ

## 2.12. STATUS OF THE DATA USED IN THIS FINAL REPORT

The following data items were not available for the Final Second Report, but were available for consideration in this Final BRCI calculation for 2009-10:

- The LRMC calculations for each tariff year are based on the Queensland load for the previous calendar year. Hence the LRMC calculations for the tariff years 2006-07, 2007-08 and 2008-09 were based on the Queensland load for calendar years 2005, 2006 and 2007 respectively. The full 2008 calendar year load is now known and has been used as the basis for the load shape for the LRMC calculation for 2009-10.
- The cost of purchasing energy is based on contract prices in the 24 months up to the start of the tariff year. For this Final Report, contract data up to 19 May 2009 has been used.
- Similarly, more recent data for the costs of ancillary services and for the costs of Renewable Energy Certificates are available for this Final Report than were available at the time the Final Second Report was prepared. For this Final Report, ancillary services data up to 19 May 2009 has been used, and RECS data up to 20 May 2009 has been used.

### 3. COST OF ENERGY

This section of the report considers the energy cost component of the BRCI in Queensland. This report section:

- Describes the framework adopted for calculating the cost of energy in Queensland, which involves consideration of both the LRMC and the actual cost of purchasing energy;
- Describes the approaches adopted for determining the LRMC and the actual cost of purchasing energy, and presents the results of the modelling in each case; and
- Describes the other energy related products that a retailer is required to purchase and other related costs that a retailer would incur.

Section 3.7 below presents the overall summary results of the modelling that has been undertaken to determine an appropriate allowance for the cost of energy, including the allowances for the other energy-related costs.

Finally, section 3.8 below reports the values for NEM load that are being used in the BRCI calculations for 2009-10.

#### 3.1. ENERGY COST FRAMEWORK IN QUEENSLAND

Section 92 of the Act describes the framework to which the Authority must adhere when calculating the energy cost component of the BRCI. It states that:

- The cost of energy must reflect the pricing entity's view of the likely total of the costs to be incurred during the relevant tariff year to purchase energy to supply all of the NEM load of the State for the relevant tariff year.
- The view must be based on the pricing entity's most recent estimate of the LRMC of energy in the part of the State connected to the national grid, after taking into account:
  - The 13% gas scheme under chapter 5A; and
  - The scheme under the *Renewable Energy (Electricity) Act 2000* (Commonwealth).
- The estimate must take into account the most efficient combination of generating plant to supply all of the NEM load of the State for the relevant tariff year.

As we noted in our reports in previous years on the calculation of the BRCI for 2006-07, 2007-08 and 2008-09, the requirement in Sub-section 92(1) for the cost of energy to reflect the total (i.e. actual) costs incurred for purchasing energy could be viewed as being inconsistent with the requirement in Sub-section 92(2) that the energy cost be based on the LRMC.

8 June 2009

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As a matter of practice this has been addressed by calculating the LRMC and estimating the likely cost that a large mass-market retailer will incur in the tariff year for purchasing and hedging energy from the wholesale market, and then taking the average of the two. This is the same general approach we used in calculating the BRCI for 2008-09. The approach takes account of both the LRMC of energy and energy purchase costs as required by Sub-sections 92(1) and 92(2) of the Act. We calculate the LRMC of energy for Queensland's retail load as a greenfield estimate of the cost of supplying an additional MWh of load throughout the tariff year, and we also calculate the energy purchase costs for the Queensland load based directly on Queensland characteristics. The approach used to calculating the energy purchase costs, which is described in section 3.3 below, is to (a) determine the combination of derivative contracts that a prudent retailer would purchase to manage the risks of purchasing energy for the load, and then (b) calculate the combined cost of purchasing hedge contracts and spot market energy for the load.

Having calculated these two estimates, which are required by the Act to be inputs to the cost of energy, the issue becomes how they can be combined into a single cost of energy for use in the BRCI. Our approach is to apply weightings to the LRMC and purchase cost of energy to determine a blended energy cost. Section 3.4 below gives the results of this calculation.

As in previous years, we also include in the energy cost component allowances for ancillary services charges and NEMMCO participant and FRC fees, as well as the costs of compliance with the Mandatory Renewable Energy Target (MRET) and the Queensland 13% Gas Scheme.

While the overall approach remains unchanged, some aspects of the approach and the data that we are using have changed, for the following reasons:

- The inputs to the LRMC analysis for 2009-10 were updated in light of the significant changes that have taken place due to the global financial crisis and recessionary conditions with regard to the costs and demands for commodities such as steel, coal and natural gas, which are major determinants of LRMC.
- As discussed in section 2.6 above, in our final advice to the Authority on the calculation of the BRCI for 2008-09, we provided a range of possible calculation methods and frameworks, from which the Authority made its selection of one particular calculation method and framework in its Final Decision. The Supreme Court in its review of the 2008-09 Final Decision ruled that some of these selections should not have been made. The approach taken in the calculation of the energy cost component of the BRCI for 2009-10 has now been adjusted to take account of the Court's ruling. In particular:
  - Calculation of the cost of purchasing energy has been analysed with regard to the NEM load, rather than the total load of Queensland,
  - The cost of purchasing energy in 2008-09 has not been recalculated based on outturn loads and prices, but rather preserved as forecast in the remade decision for 2008-09.

8 June 2009

- A different approach for developing load traces for the NEM load, and which uses a different historical period for the basis of developing the load profile to be used in assessing energy purchase costs base year was instituted.
- In consultation with stakeholders, we have introduced the use of a probabilistic basis for determining the cost of purchasing energy.
- Following on from its Draft Decision and the fact that no definite timeframe or details for the implementation of the Commonwealth Government's Carbon Pollution Reduction Scheme (CPRS) have as yet been put in place, the Authority has decided to omit consideration of the CPRS from the analysis of LRMC.
- The cost of energy will also be affected by changes that have been announced but have yet to be fully implemented with regard to the Mandatory Renewable Energy Target (MRET), which is to be transformed into the National Renewable Energy Target (NRET), and the Queensland gas scheme.
- As mentioned in section 2.5 above, we have also taken into account comments received in submissions to the Authority's Interim Consultation Notice and to the consultant's First Report, Second Report and supplementary papers, as well as discussion at the Stakeholders' Workshops held on 27 August 2008 and 3 November 2008.

In all other respects, the BRCI calculations for 2009-10 in this report are based on the same framework and calculation method that the Authority chose to use in its Final Decision for 2008-09.

#### *Approach used to calculate energy cost in other jurisdictions*

It is also worth noting that other jurisdictions have used different methods to calculate the energy cost component of the tariff that will apply to small-volume electricity customers who are not offered or do not choose to take a market offer. These approaches can be viewed as spanning a continuum that ranges from consideration of only the LRMC to consideration of actual costs alone. Appendix B provides a discussion of the approaches used to calculate energy cost in other jurisdictions, and how they differ from the approach used to calculate the energy cost component of the BRCI in Queensland alone. Table 3 below summarises the approaches in other jurisdictions.

**Table 3: Summary of approaches used to calculate energy cost in other jurisdictions**

Region	Approach	Comment
New South Wales	LRMC and energy costs modelled separately	IPART considered both the LRMC and energy costs and adopted the energy cost approach because it supports its objective of ensuring that retailers charge prices at cost reflective levels by 2010
South Australia	Energy costs, with the LRMC used as input	ESCOSA used contract and pool purchase costs rather than the LRMC to determine the allowance for energy. The LRMC was modelled and used to determine appropriate pool price scenarios

8 June 2009

Region	Approach	Comment
Victoria	Energy costs	No consideration was given to the LRMC in the analysis, with the energy allowance being based on a benchmarking approach to the costs that a prudent and efficient retailer would be likely to incur in purchasing energy

Source: CRA analysis

The approach taken for calculating the energy cost component of the BRCI as described in this report is most similar to the approach taken by IPART, which uses both the LRMC and actual energy costs to form a view on the appropriate allowance for energy in retail tariffs.

### 3.2. THE LRMC OF ENERGY

This section defines the LRMC of energy, describes the approach and the data sources that we have used to calculate the LRMC, and provides the results of our analysis.

#### 3.2.1. LRMC considerations and approach

##### *Considerations*

The Regulation states that the theoretical framework for determining the LRMC of energy must comply with the following principles:

- It is generally recognised and understood in economic theory;
- The application of the theoretical framework should result in a cost per unit of electricity, expressed in \$/MWh, that constitutes the cost of energy; and
- The LRMC of energy should be calculated to meet the demand profile (called the NEM load shape) formed over each half-hour electricity trading period of the State for the previous calendar year.<sup>24</sup>

In selecting the appropriate framework, the following considerations have also been taken into account:

- Single-point estimates of costs are required as inputs to the BRCI; and

<sup>24</sup> It should be noted that in its 28 April 2009 decision the Supreme Court determined that the LRMC should be calculated “for the aggregate State load which is connected to the national grid”; that is, the load including customers that are directly connected to the transmission system (see paragraph 70 and preceding reasoning of the paragraphs the decision in *AGL Energy Ltd v Queensland Competition Authority & Anor; Origin Energy Retail Ltd v Queensland Competition Authority & Anor* [2009] QSC 90.

8 June 2009

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- The LRMC of energy must be calculated from a retailer's perspective, i.e. it is the cost of purchasing for a retail load.

### *Approach*

The overall approach we are using to calculate the LRMC of energy for Queensland, as part of the BRCI calculations for 2009-10 is the same as that which was used previously as part of the BRCI calculations for 2007-08 and 2008-09.<sup>25</sup> It has the following features:

- Queensland is treated as part of the NEM rather than as an isolated region;
- The LRMC has been calculated for a greenfield system where the existing generation is removed and the most efficient combination of new plant to meet load is determined;
- The modelling uses a multi-year approach, whereby the LRMC is calculated based on the lowest cost combination of generating plant to meet projected load from the base year; and
- The modelling approach optimises investment across the NEM regions to calculate the optimal portfolio taking into account the characteristics of the existing transmission system.<sup>26</sup>

The Regulation requires that the LRMC be calculated to meet the demand profile formed over each half-hour for the previous calendar year. Therefore, the LRMC for 2009-10 is calculated on the basis of the generation required to meet demand in calendar year 2008. In the Final Second Report, actual data for the period from 1 January to 15 October 2008 was available, and the rest had to be estimated. For this Final Report, all of the actual data for calendar year 2008 is available, and no load data had to be estimated.

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<sup>25</sup> This report calculates the BRCI for 2009-10 only. Re-calculation of the 2008-09 BRCI in accordance with the 28 April 2009 decision of the Queensland Supreme Court is reported on in CRA's report entitled *Calculation of the Benchmark Retail Cost Index 2008-09: Remade Decision*, Final Report, 3 June 2009.

<sup>26</sup> The approach used does not optimise the transmission system, but rather assumes that the transmission system that will be used to deliver the energy generated by the optimised generation system is represented by the existing transmission system and known planned retirements, reinforcements, replacements and extensions. Further detail on the treatment of the transmission system in the CEMOS modelling is provided in Appendix C.

8 June 2009

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### 3.2.2. Definition of the LRMC

The LRMC is commonly defined as the additional cost of servicing additional demand in the long run. The long run represents the useful service life of new capacity that is required to meet expected incremental demand. Definitions of the LRMC vary in operational practice, but the intent is broadly the same – to estimate long-run generation system expansion costs. For example, the LRMC can be defined as the average incremental cost from expanding output, or the change or perturbation in costs and quantities from an underlying growth baseline.<sup>27</sup>

When calculating the LRMC of new generation, the costs considered include all costs relevant to the investment decision,<sup>28</sup> including capital recovery costs (depreciation), return on capital investment, taxes, fixed operating and maintenance costs as well as the expected short run operating costs (fuel, water, chemicals) over the relevant life of the asset, at appropriate capacity factors.

The approach that has been adopted calculates the marginal cost of supplying one additional MWh in every hour of the tariff year. This equates to the shadow price of meeting the demand constraint. More specifically, the LRMC for 2009-10 is defined as the cost of supplying one additional MWh in every hour of 2009-10 from a generation system that has been optimised to meet the forecast load and load shape based on the actual load of CY 2008 and forecast growth in energy and peak demand.

It should be recognised that the least-cost means for meeting that additional increment of load will depend on the specifics of the load shape and the relativities of the capital and fuel costs associated with the available generation options.

### 3.2.3. Issues in modelling LRMC

The LRMC of generation for a region/system, as the term implies, needs to recognise the cost of meeting an increment of demand in the long run considering both operating and fixed costs associated with new investment.

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<sup>27</sup> The latter approach has been applied in the water sector (for example by Ofwat and the Essential Services Commission Victoria) with timeframes of approximately 20-25 years.

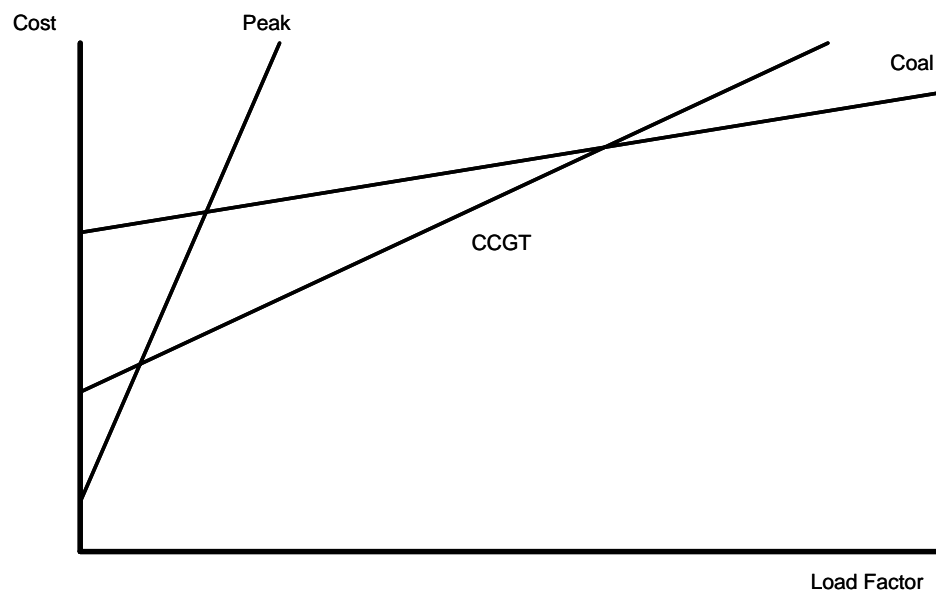
<sup>28</sup> See for example *Fuel Resource, New Entry and Generation Costs in the NEM: Report 2 – Data and Documentation*, ACIL Tasman, draft prepared for NEMMCO, 27 March 2007, p.12.

8 June 2009

The load duration curve<sup>29</sup> expected to pertain for the relevant time period has implications for dispatch and investment decisions. That is, the variation of demand across peak and off-peak periods implies a portfolio of peaking, mid-merit and base-load plants that can most efficiently meet the demand rather than a single type of plant.

As system load factor varies and as various technologies are used to varying degrees, the total cost changes. Depending on their cost characteristics, some generating technologies are better suited to peaking duty whereas others are best matched for base load duty. These relationships are straightforward, and are summarised graphically in Figure 1 below.

**Figure 1: Indicative costs of generating technologies**



Source: CRA

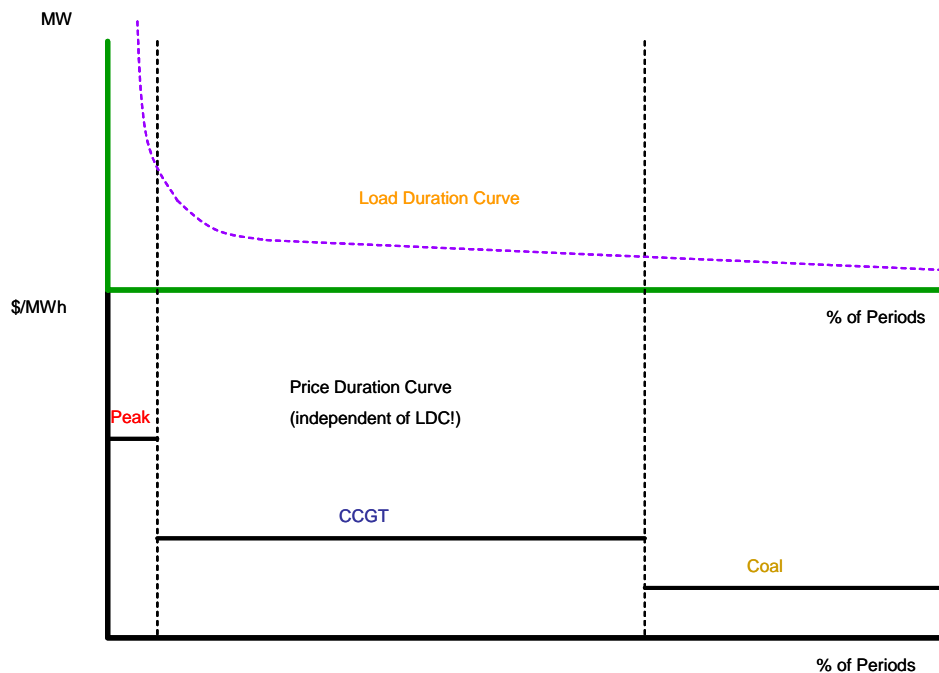
It is then possible to develop the corresponding LRMC by mapping the costs of each “optimal” technology to derive the price duration curve that would support investment in the appropriate technology mix, as shown in Figure 2 below.

<sup>29</sup> The load duration curve (LDC) is a plot of electricity demand on the y-axis against the percentage of time during the year that the load is exceeded on the x-axis. Presenting the load data in this manner provides a view of how ‘peaky’ demand is in the system. Also, by overlaying the LDC with a chart of plant cost by load factor (Figure 1) it is possible to determine which generating plant type will be the marginal plant to meet particular levels of demand. Assuming plants bid at short run marginal cost (SRMC), for each demand point on the LDC there will be a corresponding price set by the marginal plant.

Investment and dispatch should be optimal; i.e. the portfolio of investment decisions and dispatch decisions should meet demand at least cost. A least-cost investment and dispatch plan also implies that the plants built to meet demand in the long term are revenue sufficient (or revenue adequate) in that the revenue earned by the plants is equal to total system cost.

The definition implies long-term supply-demand equilibrium of the system. In reality different technologies are likely to be either in excess or deficit supply in the system relative to the optimal level. As a result, the year-on-year marginal cost for the system may vary substantially from the long-term equilibrium level. For example, if there is surplus base-load capacity, an incremental MWh during this period may not incur any incremental capital cost, whereas deficit peaking capacity may result in a very high marginal cost of supply during peak periods.

**Figure 2: Indicative price duration curve**



Source: CRA

Policy constraints and/or the physical availability of resources may restrict investment and dispatch decisions. Relevant examples include minimum gas generation requirements, minimum renewable generation requirements, limitations to the total amount of coal-fired (or any other type of) generation that can physically be installed within a certain timeframe, maximum allowable carbon emissions, or the imposition of a carbon tax.

8 June 2009

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The LRMCs of interconnected regions are likely to be interdependent because the optimal portfolio of generation can be located in different regions. Access to cheaper fuel and technology choices available to specific regions may imply the overall system cost is lower if excess generation capacity is built in one region and the surplus is exported to a neighbouring region.

Finally, although many of the parameters underlying the LRMC (including demand, fuel prices, and technology / capital costs) are inherently uncertain, the BRCI requires a single solution for the LRMC. Therefore, the analysis must seek to identify the best single estimate of each input to the LRMC, or at least the best single output from the range of calculations using a range of inputs.

#### 3.2.4. Options and approaches taken to the LRMC conceptual framework

As discussed in calculating the LRMC for the BRCI in previous years, there are several choices that must be made in developing the conceptual framework to be used in calculating the LRMC of an electricity system. These are discussed below.

##### *Greenfield<sup>30</sup> vs. incremental*

Consideration needs to be given to whether the modelling is done on the basis of supplying an increment of load beginning from the existing generation capacity base (i.e. incremental investment approach), or on a re-optimised, clean sheet basis ignoring the existing base of plant (a greenfield or re-optimised approach).

After consultation with stakeholders,<sup>31</sup> we considered that the greenfield approach is more in keeping with the intent of the clause in the Act that states that “*the estimate [of the cost of energy] must take into account the most efficient combination of generating plant to supply all of the NEM load of the State for the relevant tariff year*”. The greenfield approach provides the most scope for assessing the most cost-efficient means of meeting a given energy and demand requirement, as it allows optimisation of the cost of supplying the entire load. By contrast, an incremental approach would start with all existing plant, and the LRMC would have to be calculated based on the unamortized costs of these plants, and the least-cost means for serving any additional load resulting from load growth and/or plant retirement. It is also important to note that the greenfield approach provides a result for the LRMC which is consistent from year to year in the sense that the estimated LRMC is not affected by the over- and under-capacity resulting from lumpy, existing investments. It also produces a result for the LRMC that reflects the full mix of investments in different types of capacity that would be required to meet all aspects of the load curve (i.e. base load, mid-merit and peaking).

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30 The term ‘greenfield’ was adopted in the CRA Addendum Report of May 2008. Previously, this approach had been referred to as ‘stand-alone’.

31 This issue was discussed at the Stakeholder Workshop held in April 2007 as part of the process that developed the notified prices for 2007-08.

8 June 2009

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In undertaking the greenfield analysis, we also considered how the issue of 'lumpiness' in generation investment should be addressed, and have opted to assume that generation can be built to meet any specified level of demand, at least on an aggregate (as opposed to single unit) basis. While there may be practical minimum and maximum sizes to the various types of generation plant to be included in the candidate set for purposes of the LRMC, plant could be specified at any specific size within that range. In addition, a combination of different practical sizes could be chosen to accommodate a wide range of aggregate requirements for a given capacity requirement of a particular plant type. Finally, we note that the Act specifies that the cost of energy be based on the most efficient combination of generating plant, and take this to apply to the amount as well as the type of capacity required.

*Isolated vs. interconnected*

Queensland is part of a larger, interconnected system, the diversity of which offers the potential to meet the energy and demand requirements of Queensland (and indeed each other region) at lower cost than would be the case if Queensland (and each other region) operated as a physically isolated system.<sup>32</sup> Therefore, the approach used addresses Queensland as part of the interconnected system that serves the NEM. This aspect of the approach was also used in calculating the LRMC portion of the BRCI for 2008-09.<sup>33</sup>

*Single vs. multi-year – whether to allow for load growth and change in load factor*

LRMC has a time dimension. It can be defined as the cost to meet an increment of load in a particular year or over a period of time. In a single year approach, the mix of plant chosen is that which would meet the load duration curve for the year being considered plus the requirement to provide another MWh of load in every hour of the year at lowest cost, based on the aggregate annualised capital and fixed and variable operating and maintenance costs, including fuel. However, generating plants are built to last for periods of up to 30 years or longer. As a result, the most cost-efficient mix of plant to service the load of a particular year may not be the most efficient when considered over a longer period of time. This can be especially problematic when the load in question has not been normalised to remove short-term variability which can arise from factors such as variations in the weather. Multi-year analyses attempt to capture the range and effect of such variables over the longer term in identifying the optimal mix of plant chosen.

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<sup>32</sup> Indeed, these efficiencies provided the original rationale for interconnection between the states and ultimately for the NEM.

<sup>33</sup> The first calculation of LRMC in the BRCI process, for the 2007-08 tariff year, was different. In that initial analysis, the LRMC of meeting the Queensland load was developed in isolation from the NEM, using a screening curve. That approach was used at that time due to the limited time available for the analysis.

8 June 2009

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In the case of the BRCI, the Regulation specifies that the LRMC is calculated to meet the demand profile formed over each half-hour electricity trading period of the State for the previous calendar year. As such, a single year is specified as the basis for identifying the optimal mix of generation plant, and changes in the LRMC from year to year will reflect, in part, differences in the load characteristics that pertained in the calendar year that preceded each of the tariff years in question.

CRA has adopted an approach that seeks to incorporate at least some aspects of the multi-year approach by optimising the generation system with regard to how the single-year load would be expected to grow over the mid term. We have used the specified calendar year to serve as the base year load shape in Queensland for the optimisation and then grown that load using the 50% probability of exceedance, medium demand and energy growth projections from the NEMMCO *Statement of Opportunities* (SOO) published immediately prior to the tariff year to create a nine-year forecast load that serves as the base for the selection of an optimal generation system.<sup>34</sup>

This approach provides some consideration of the expected pattern of growth in the Queensland load in selecting the most efficient set of generation plant on which to base the LRMC for the subject tariff year, though it still rests on a historical year load as its base, which, as we have discussed previously, constitutes a source of potentially significant volatility in the BRCI.

The base year and load forecasts used for the other NEM jurisdictions are comprised similarly. The load duration shape is taken from specified CY data (CY 2008 for the 2009-10 tariff year calculation) and nine-year peak and energy forecasts for each of the NEM regions are taken from the corresponding SOO publications.

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<sup>34</sup> The use of a nine-year forecast horizon was adopted in the final calculation of the LRMC for the 2009-08 tariff year reported in the Addendum Report of May 2008. Previously, the timeframe extended to 2030. The forecast for the years past the end of the SOO forecast beginning each tariff year was taken from *Australian Energy National and State Projections to 2029-30*, ABARE Research Report 06, 26 December 2006. The use of the two sources required a calibration step so that the starting point of the ABARE forecast could be made to line up with the end of the SOO forecast period. Further analysis revealed that the LRMC of the tariff year that resulted when the timeframe was restricted to the SOO horizon differed very little from that which resulted from the longer timeframe that required the ABARE forecast. In addition, it was recognised that the ABARE forecast is only updated periodically, and between updates, the period on which the LRMC would be calculated would vary. Based on these two considerations, the decision was made to restrict the forecast period to that covered by the SOO. More generally, we note that it is important that modelling account for the plant investments well past the period of interest and it is only viable to restrict analysis to the nine year period of the SOO because the only value of interest the first year.

### *Deterministic vs. probabilistic modelling*

Many of the input costs (e.g. demand, fuel prices and technology costs) and operating conditions (e.g. plant availability) that determine the LRMC are inherently uncertain. Probabilistic analysis using Monte Carlo modelling is able to capture the combined effects of many of the uncertainties and can produce a range of LRMC values from which an average or expected value can be chosen. This is particularly valuable when the analysis is seeking to identify the range of outcomes that could result from operational uncertainties.

By contrast, the BRCI is a ratio of how the costs of supplying electricity change between two years in which the load to be served and the costs of electricity plant and operation are known (or at least taken to be known), thereby allowing the optimum plant mix to be readily identified. This framework – including the formulation of the BRCI itself and its application as a factor that is used to adjust the level of the notified prices – is more suited to the use of a deterministic approach, using the best estimates of input values rather than probabilistic or scenario approaches for developing data or estimating results.

As a result, the LRMC calculations undertaken for the BRCI use deterministic, single-point estimates. Development of the single-point estimates used in the LRMC calculations for the 2009-10 tariff year horizon is discussed in section 3.2.11 below.

### **3.2.5. Options available and approaches taken in the LRMC modelling**

There are different modelling approaches for estimating the LRMC, which range from the simple, to those that involve complex data and are computationally intensive. These methods can be grouped into three categories, as discussed below. Not surprisingly, decisions regarding the conceptual approach to be taken to the LRMC, as discussed above, will make some of the modelling approaches more or less applicable.

- ***Dominant technology*** – Methods that identify a dominant form of technology that set the LRMC of the system based on certain rules, or alternatively a simple screening curve. These methods are obviously simple but generally will not ensure the optimality of the investment decisions taking into account other issues that may influence investment/dispatch in a system.

- **Explicit optimisation (single year, single region)** – Methods that explicitly optimise the portfolio of generation investment to meet demand and calculate the LRM as the marginal cost of meeting an increment of demand over the longer term. The analysis for the 2004 IPART determination adopted this approach for NSW.<sup>35</sup> The linear programming model that was used for IPART optimised the investment and dispatch decisions to meet load represented as an annual load duration curve. The shadow price of the optimisation model of meeting demand in the long term was explicitly quantified using three generic technologies: coal, closed cycle gas turbines (CCGT) and open cycle gas turbines (OCGT). However, this approach did not deal with the interconnection of NSW to the rest of the NEM, or the long-term evolution path of the system over multiple years. Instead, it was based on a snapshot year for a single region (NSW).
- **Explicit optimisation (multiple years, multiple regions)** – A multi-year, multi-region approach optimises investment across interconnected regions over a period of years to calculate the optimal portfolio, taking into account the initial portfolio of optimal generation assets and how it will evolve over the years to the long-term equilibrium to elicit the LRM. This is obviously the most comprehensive of the three methods, but its use is also very data intensive and demanding. Such an approach was used to estimate the LRM of energy for NSW in the 2007 IPART determination<sup>36</sup>.

We have used an explicit optimisation approach that incorporates multiple years and multiple regions. This approach recognises that:

- The set of plants that would be selected to meet the energy and demand requirements of a given year may not be the most cost-effective mean for meeting energy and demand requirements over a somewhat longer period, particularly as generation plant represents long-lived assets. Such consideration is of increased concern in application to the BRCI because the energy and demand requirements used for the initial year are not weather normalised.
- Queensland is part of a larger, interconnected system, the diversity of which offers the potential to meet the energy and demand requirements of Queensland (and indeed each other region) at lower cost than would be the case if Queensland (and each other region) operated as a physically isolated system.

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<sup>35</sup> *The Long Run Marginal Cost of Generation in New South Wales*, Report to IPART, IES, February 2004.

<sup>36</sup> *Energy Costs*, Report to IPART, Frontier Economics, April 2007.

### 3.2.6. The CRA model used to derive the LRMC

We have used CRA's proprietary CEMOS model to derive the required LRMC. CEMOS comprises three modules for undertaking long-term (PEPPY), short-term (STEMM) and strategic bidding (CONE) analyses of the electricity market. The LRMC analysis uses the long-term module of CEMOS only.<sup>37</sup>

The long-term module of CEMOS models the bidding and dispatch of individual power stations to match expected electricity demand profiles and levels over multiple years, taking into account the regional structure of the NEM and other important characteristics of the market:

- CEMOS uses a five region (Queensland, New South Wales, Victoria, South Australia and Tasmania) representation of the NEM that reflects inter-regional network limitations (constraints). Each of these regions is modelled as a "node" (i.e. a single location in the market) – demand and generation are modelled relative to that node. The nodes are connected by interconnectors, where limits are placed on the level of transfer between the nodes.<sup>38</sup> CEMOS does not optimise transmission expansion and uses only those transmission expansion options that are identified as part of the Annual National Transmission Study (ANTS). In other words, the interconnector limits in the future may typically be higher by the amount identified in the ANTS as cost-effective (that is, they meet the relevant investment test under the NER). This modelling representation is reflective of the actual dispatch and pricing process performed by the market clearing engine in the NEM; and
- The long-term module was configured using a load block modelling approach similar to that used in other long term models. Dispatch and pricing outcomes are assessed using an annual load duration curve of 40 time periods per year or "blocks" of demand. Each demand block can be assigned a variable number of hours in the year when that level of demand occurs. These load blocks are developed from the half-hourly load data used in the short-term modelling, i.e. the STEMM model; the ability to vary the number of hours in each block allows the blocks to closely approximate the shape of the load duration curve.

CEMOS models investment and dispatch of generators to meet the demand in each of the 40 blocks of demand in each year. The dispatch optimisation process also yields the regional spot prices for each of the load conditions modelled.

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<sup>37</sup> Appendix C has a detailed account of the functionalities of the PEPPY module. Short-term and strategic bidding analyses in combination with the long-term PEPPY module have been used to derive a near-term forecast of half-hourly market prices for the energy purchase cost analysis as discussed later in this report.

<sup>38</sup> The Snowy region was abolished from 1 July 2008. We have therefore not modelled Snowy as a separate region, but have allocated the generators previously positioned in the Snowy region to Victoria and NSW in accordance with the realignment of region boundaries determined by the AEMC

8 June 2009

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CEMOS incorporates a range of capabilities, and has two features that are particularly important for modelling actual and long-term market outcomes:

- CEMOS' long-term capacity expansion module optimises decisions on timing, generalised location and technology of new generation capacity as and when required in order to meet growing demand over the entire analysis timeframe; and
- In doing so, CEMOS explicitly recognises the role of fixed costs (i.e. capital and fixed operation and maintenance costs) and variable costs (i.e. fuel and non-fuel variable operation and maintenance costs) across multiple regions that are connected by the inter-regional transmission lines.

The optimisation incorporates both a price “trigger” (a point at which future investment would become viable) and a reliability “trigger” (a point at which policy makers would intervene if there were too many electricity outages), so that capacity would be built even if spot prices were not high enough to justify a commercial investment. CEMOS finds the plant investment and dispatch patterns that minimise the overall cost of meeting the demand by performing an inter-temporal optimisation for capacity, looking ahead over the entire planning period, while solving the operational dispatch problem for each year simultaneously. As a result, investment occurs in the year in which it is needed. A limitation of the approach is that it implies perfect foresight on the part of investors as the optimisation “knows” with certainty the future demands and plant costs.

Appendix C contains further background on the CEMOS model and its application, and provides references to reports that are available in the public domain containing additional details.

### **3.2.7. Summary of issues raised in submissions to the Final Second Report and Draft Decision**

This section of the report summarises comments related to the LRMC that were received in response to the Second Final Report and the Authority's Draft Decision. As a result, not every submission is mentioned.

While opinions varied on most aspects that drew comments, there was general agreement that there is not at present an established or accepted approach for incorporating the costs of the CPRS in the BRCI calculation, and that the development of an agreed approach is an important matter that needs to be progressed with urgency.

#### ***AGL***

AGL stated that they were of the strong opinion that the LRMC should be calculated based on the NEM load, where that term is defined as the load that is transferred from the transmission system to the distribution system and therefore excluding the loads of customers that are directly connected to the transmission system.

8 June 2009

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AGL also stated that they believe that the step change capital and fuel cost scenario is more reflective of recent cost trends, and expressed disappointment that the Authority had based its Draft Decision on the trended cost scenario. They suggested that if a trended cost approach was to be used that the time frame over which the regression is based should be shortened to preferably three and no more than five years.

AGL questioned several of the inputs to the calculation of the WACC, namely the debt basis point premium, the inflation rate, and the risk premium. These inputs have all been reviewed as part of Concept Economics' review and recalculation of the inputs to the LRMC.

AGL supported the exclusion of the CPRS from the LRMC analysis until such time as the costs of the scheme are incurred by the electricity retailers.

#### *Department of Mines and Energy (DME)*

DME supported the use of the total Queensland electricity load for calculation of the LRMC, because it was consistent with the direction that the LRMC should represent the most efficient combination of generation plant to supply all of the NEM load for the relevant tariff year.

The Department also supported the exclusion of the CPRS from the LRMC calculation but noted that "it is not possible to rule out that some increased costs are already being priced into the market through generators' risk profiles and impact on availability of long term contracts".

#### *Origin Energy*

Although Origin Energy stated that they were "generally supportive of the LRMC model specifications used for the 2009-10 BRCI" they also stated that they felt several of the input values used costs that were too low, citing as examples the capital costs of OCGT plant and gas fuel costs.

More important in their opinion was that the analysis should be undertaken on a year-to-year cost change basis, rather than the regression analysis approach such as the Authority had selected. Origin also urged the Authority to make such decisions mindful of the fact that they should be robust enough to be used consistently into the future in order to provide. They also stated that if a regression approach were to be selected that it should use a relatively short timeframe in order to more accurately capture and reflect sharp price changes that can result from factors such as the introduction of the CPRS.

They also reiterated their belief that the LRMC should be calculated with reference to the NEM load (that being the load excluding those customers directly connected to the transmission system).

8 June 2009

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Origin also expressed concern that retailers are likely to incur costs prior to the implementation of the CPRS scheme and that the current approach being taken to the calculation of the BRCI has no way to recognise this. The result is that the intent of the scheme – that these costs be fully passed through to customers so that it affects their behaviour – is not being realised.

#### *Queensland Consumers Association*

The Queensland Consumers Association expressed concern that the Draft Decision had to be based on estimated load data due to the fact that significant differences could result when actual load data is subsequently used for the final decision. They suggested that the timing of the BRCI process be amended to allow the draft decision to be based on actual load data.

#### *Queensland Council of Social Service (QCOSS)*

QCOSS supported the Authority's use of the regression scenario because they did not believe that the case had been proven that "a permanent fundamental cost increase in energy generation has occurred". They also supported the exclusion of the CPRS from the LRMC analysis because these costs are not presently incurred by the electricity retailers.

#### *TRUenergy*

TRU stated that it did not support the Authority's decision to adopt the regression analysis approach, and noted that the analysis that it had provided in its earlier submission indicated that "the 2009/10 estimated capital costs for all plant types were outside the 90% confidence limit of the regression analysis, with three of the four well outside the 95% confidence level".

TRU also stated that the 50/50 weighting of the LRMC and energy purchase costs would "unacceptably delay the ability of retailers to pass through the full costs of an emission trading scheme" and recommended that "the marginal cost calculated in accordance with the current LRMC method is adjusted to reflect the carbon intensity of the NEM for the regulatory period"..

In this regard we note that if the approach used in the 2009-10 BRCI (exclusion of the PRS from the LRMC) were to be continued, TRU's point about the delay that would be incurred in passing the cost of the carbon policy through in prices would indeed be delayed. However, if the CPRS is included in the LRMC analysis as currently implemented, the LRMC portion of the energy cost component of the BRCI will actually anticipate the cost of the CPRS due to the greenfield perspective. TRU's suggestion for addressing this is not consistent with the greenfield approach. This not to say that TRU's suggestion should not be considered, but taking it up would require a change to the LRMC methodology.

### 3.2.8. Load data requirements for the LRMC calculation

The Regulation requires that the LRMC be calculated to meet the demand profile formed over each half-hour electricity trading period of the State for the previous calendar year.<sup>39</sup> Therefore, the LRMC for the 2009-10 BRCI should be calculated with reference to the actual loads experienced in CY 2008.

While estimates for parts of the 2008 calendar year load were developed to carry out draft BRCI calculations in the First and Second Reports, the full 2008 calendar year of load data is now available and has been used as the basis of the load shape for this Final Report and thus to inform the Authority's Final Decision on the BRCI for 2009-10.

### 3.2.9. Renewable Energy Targets and Queensland Gas Scheme

#### *Renewable energy targets*

The Federal Government has announced that the Australia-wide Mandatory Renewable Emissions Target (MRET) is to be revised, and more details have become available since the calculation of the 2008-09 BRCI. The original scheme required that renewable energy sources account for at least 2% of the electricity generated across Australia by 2010, which equated to an additional 9,500 GWh by that year as compared to the base level of renewable energy established in 2000. The revised scheme has been defined as increasing the percentage of energy generation to be derived from renewables to 20% by 2020, which will require an additional 45,000 GWh across Australia.

From the perspective of calculating the LRMC, this requires that an additional constraint be placed on the plant mix to be selected in the greenfield generation system expansion/optimisation analysis that is at the heart of the LRMC analysis.

At its 30 April 2009 meeting the Council of Australian Governments (COAG) agreed the design of the expanded national Renewable Energy Target (RET), including the profile of annual targets that will be used to reach the 20% renewable energy electricity generation target.<sup>40</sup> Those annual Australia wide targets are shown in Table 4 below.

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<sup>39</sup> The Queensland Supreme Court decision of 28 April 2009 clarified that for purposes of the LRMC this demand profile should be that of "the aggregate State load which is connected to the national grid" (see footnote 27 above).

<sup>40</sup> Renewable Energy Target Scheme Design, available from <http://www.climatechange.gov.au/renewabletarget/index.html>

8 June 2009

**Table 4: Annual RET targets**

Year	Annual RET Target (GWh)
2008	6,800
2009	8,100
2010	12,500
2011	14,400
2012	16,300
2013	18,200
2014	20,100
2015	22,000
2016	26,600
2017	31,200
2018	35,800
2019	40,400
2020	45,000

Source: Department of Climate Change

Proportional RET targets for the NEM were calculated by reference to the ESAA's 2008 "Electricity Gas Australia" report which details the sent-out generation in each Australian jurisdiction, as shown in Table 5 below.

8 June 2009

**Table 5: Calculating NEM sent-out generation as a % of total Australian sent-out generation**

	Sent-out generation (GWh year ending 30 June 2007)	NEM jurisdiction (Y/N)
<b>NSW &amp; ACT</b>	65,549	Yes
<b>VIC</b>	49,293	Yes
<b>QLD</b>	55,578	Yes
<b>SA</b>	11,814	Yes
<b>WA</b>	15,341	No
<b>TAS</b>	9,252	Yes
<b>NT</b>	1,405	No
<b>Snowy<sup>41</sup></b>	2,940	Yes
<b>Total all jurisdictions</b>	<b>211,171</b>	-
<b>Total NEM</b>	<b>194,426</b>	-
<b>NEM % of total</b>	<b>92.07%</b>	-

Source: esaa

The NEM percentage of generation was then applied to the MRET target for 2009 and the RET annual targets for 2010 to 2020 to provide proportional annual RET targets for the NEM, which were then converted from their calendar year basis to a fiscal year basis to match the timing requirements of the BRCI. The resulting NEM fiscal year targets that were used in the calculation of the LRMC are shown in Table 6 below.

<sup>41</sup> Snowy is no longer a NEM region but the energy generated there is still counted within the NEM. It is worth noting, however, that Snowy generation for 2007 was uncharacteristically low.

8 June 2009

**Table 6: Annual Renewable Energy Targets**

Year	NEM Renewable Energy Target (GWh/year)
2009-10	9,483
2010-11	12,383
2011-12	14,133
2012-13	15,882
2013-14	17,631
2014-15	19,381
2015-16	22,373
2016-17	26,608
2017-18	30,843

Source: CRA analysis

*Queensland Gas Scheme*

The Queensland gas scheme annual targets have been revised as follows:

- For 2008 and 2009: 13%;
- For 2010: 15%; and
- For any year after 2010: a percentage, not more than 18%, prescribed under a regulation.

Together with QCA we developed a schedule of calendar year targets for the period over which the LRMC modelling runs. These are then translated to financial year targets by averaging consecutive calendar years, as shown below in Table 7.

8 June 2009

**Table 7: Annual Queensland Gas Scheme Targets (% of Queensland generation/year)**

Calendar Year	Queensland Gas Scheme Target	Financial Year	Queensland Gas Scheme Target
2009	13%	2009-10	14%
2010	15%	2010-11	15%
2011	15%	2011-12	15%
2012	15%	2012-13	15.5%
2013	16%	2013-14	16%
2014	16%	2014-15	16%
2015	16%	2015-16	16.5%
2016	17%	2016-17	17%
2017	17%	2017-18	17%
2018	17%		

Source: CRA analysis

### 3.2.10. Treatment of reserve margin

A question arose as to whether an explicit reserve margin constraint is set in the CEMOS modelling of LRMC. It is not, and we have considered the issue of adding an explicit reserve margin to the generation system requirements to be subjected to the LRMC analysis.

This would most logically be done by imposing a reserve capacity constraint as a function of peak demand. While it is true that no system will work without reserve, it is also the case that the NEM is not built to a reserve margin in this manner (i.e., through a central plan/requirement function). Rather, the NEM addresses reserve requirements in the first instance through a check that the market can be expected to deliver what can be considered to be a (minimum) acceptable level of capacity determined by NEMMCO as sufficient to meet a reliability standard of there being no more than 0.002% unserved energy.

We note that the greenfield approach as we have modelled it identifies an optimum Medium 50POE plant mix including allowance for the typical forced and maintenance outage rates of each type of generating plant being considered. As a result, the selected plant mix already includes a measure of reserve and the appropriate test of the adequacy of the reserve is whether, under expected operating conditions, the reliability standard will be met, rather than whether the capacity reserve margin specified in the SOO by NEMMCO is met.

8 June 2009

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In practice, if the reliability standard is not met, NEMMCO would contract for additional capacity under the Reliability and Emergency Reserve Trader (RERT) provisions of the Rules.<sup>42</sup> If the standard is not met in the greenfield modelling it would indicate that under expected conditions the market was not sustainable and in the first instance suggest the price cap (VoLL) was too low. This would be a surprise as our modelling for the Reliability Panel (published as part of the AMEC Comprehensive Reliability Review) suggested the market would be viable with the current plant mix and hence it should be for a greenfield analysis. This indeed was the case as the results showed unserved energy always within the reliability standard and capacity reserve margin (as generated basis) of between 3.53% and 11.15%.

Within this reserve margin we have assumed there will be sufficient plant with sufficient ancillary service capability and have included an allowance of \$0.36/MWh for ancillary service costs in the BRCI calculation. This value is based on (a) the average historical ancillary charge across the NEM for all FCAS raise services (only raise services are charged to customers) and (b) allowances for ancillary services under contract to NEMMCO. We have not attempted to calculate the greenfield cost of ancillary service given that it is a small percentage of energy costs and presumably the greenfield optimum cost will be no more than this level – this leads to a potentially conservative allowance in the BRCI

In summary, inclusion of a reserve margin target is not explicitly required by either the Act or the Regulation in the calculation of the LRMC, and is inconsistent with the theoretical framework of the Greenfield approach in the NEM that has been adopted for assessing the LRMC. Notwithstanding that, a check on the unserved energy and reserve margin in the analysis results is crucial. The check conducted on the results of the greenfield modelling indicates that the selected plant mix does meet the reliability standard, and therefore the system has sufficient reserve capacity, the cost of which is therefore included in the LRMC as calculated.

Based on these considerations we do not believe that introducing the inclusion of an explicit reserve margin in the LRMC component is justified.

### 3.2.11. LRMC modelling input assumptions

Key inputs are:

- Generation plant capital costs;
- Fuel costs – coal, gas, geothermal, biomass;
- Fixed O&M;

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<sup>42</sup> Rule 3.20.3(f) provides procedures whereby the cost of plant contracted under the Reliability and Emergency Reserve Trader arrangement are allocated to the jurisdictions that have occasioned the need for it. Rule 3.15.9 specifies that the costs incurred by NEMMCO to provide this reserve are to be charged to Market Participants.

8 June 2009

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- Variable O&M;
- Thermal efficiencies and auxiliaries;
- Plant availability;
- WACC; and
- Project life.

Each of these is discussed in the following sections.

#### *Generation plant capital costs*

In the Stakeholders' Workshop held in Brisbane on 27 August 2008, stakeholders suggested that capital costs had increased dramatically over the past two years. In response, the Authority commissioned ACIL Tasman to provide the following inputs for use in the LRMC calculation:

- Updated information on the installed cost of electricity generation plant by plant type and jurisdiction for the years 2007 and 2008,
- Forecasts of those installed generation capital costs through 2017-18,
- Updated information on the fixed and variable operation and maintenance costs of each type of electricity generation plant
- Updated and forecast prices for coal and gas by jurisdiction and by plant type (where relevant), and
- Updated information various other inputs that need to be considered in calculating the LRMC, including thermal efficiency, auxiliary power requirements, and availability rates.

From these data, ACIL Tasman was also asked to provide for use in the calculation of the LRMC:

- A forecast of installed generation capital costs based on recent installed costs and forecast costs based on relevant cost drivers, and
- An updated version of the regression analysis of the electricity generation plant costs that ACIL Tasman had provided in its 2007 report to NEMMCO in which data on the actual cost of generation plant that has been installed subsequent to the analysis undertaken in 2007 is added to the data and the earliest two years of data in the previous regression analysis are removed.

8 June 2009

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These two schedules of capital costs were referred to respectively in the Final Second Report as the step change and regression scenarios, and an LRMC analysis and a BRCI calculation was performed for each. The Authority based its Draft Decision on the regression scenario results.

Subsequent to its Draft Decision and due to the significant changes in economic conditions that have been observed since ACIL provided their cost estimates, the Authority commissioned Concept Economics to review, and where it deemed appropriate, to update the inputs used in the ACIL regression scenario analysis for the BRCI of 2009-10.

The sections below detail the inputs that were provided by Concept Economics. The full Concept Economics paper<sup>43</sup> can be found on the Authority's website.

#### *Concept Economics generation plant capital costs*

Table 8 presents the schedule of generation plant capital costs in 2009-10\$/kW that were developed by Concept Economics. Those costs are then presented in annualised form (2009-10\$/MW/yr) in Table 9.

It should be noted that geothermal plant was constrained out of the available plant mix until after 2015<sup>44</sup>, after which time it was subject to a maximum annual build rate of 150 MW/yr. The lack of availability in the earlier year of the horizon reflects the current and projected commercial viability and availability of this type of plant. The maximum annual build rate after that time reflects the fact that much of the geothermal resource is located at a distance from existing transmission lines, and is therefore likely to require extensions to the transmission system to be undertaken. This further limits how much geothermal resource is likely to be able to be developed each year.

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43 *Review of inputs to cost modelling of the NEM*, Concept Economics, for QCA, 14 May 2009

44 *Fuel resource, new entry and generation costs in the NEM. Final Report*, ACIL Tasman, for the Inter-Regional Planning Commission, April 2009, see discussion page 53 and Table 33, page 56.



8 June 2009

**Table 8: Concept Economics capital costs (2009-10\$/kW installed) by installation year used in the 2009-10 tariff year LRMC calculation**

Installation year	Black Coal	Brown Coal	CCGT	OCGT	Wind	Hydro	Geothermal	Biomass
2009-10	2,209	2,424	1,202	902	2,323	2,705	5,022	5,006
2010-11	2,203	2,417	1,199	899	2,291	2,705	5,007	4,992
2011-12	2,195	2,408	1,194	895	2,256	2,705	4,985	4,973
2012-13	2,187	2,398	1,189	892	2,222	2,705	4,964	4,953
2013-14	2,179	2,389	1,185	888	2,188	2,705	4,943	4,934
2014-15	2,171	2,379	1,180	885	2,155	2,705	4,921	4,914
2015-16	2,163	2,370	1,175	881	2,122	2,705	4,900	4,895
2016-17	2,155	2,361	1,171	878	2,090	2,705	4,880	4,876
2017-18	2,147	2,352	1,166	874	2,058	2,705	4,859	4,856

Source: Concept Economics

**Table 9: Concept Economics annualised capital costs (2009-10\$/MW/year) by installation year used in the 2009-10 tariff year LRMC calculation**

Installation year	Black Coal	Brown Coal	CCGT	OCGT	Wind	Hydro	Geothermal	Biomass
<b>2009-10</b>	222,205	243,835	120,949	90,694	233,725	272,132	505,251	503,649
<b>2010-11</b>	221,639	243,161	120,610	90,440	230,445	272,132	503,670	502,244
<b>2011-12</b>	220,821	242,210	120,133	90,084	226,951	272,132	501,519	500,267
<b>2012-13</b>	220,006	241,263	119,658	89,729	223,510	272,132	499,376	498,298
<b>2013-14</b>	219,194	240,320	119,186	89,375	220,121	272,132	497,243	496,337
<b>2014-15</b>	218,384	239,380	118,715	89,023	216,783	272,132	495,119	494,384
<b>2015-16</b>	217,578	238,445	118,246	88,672	213,496	272,132	493,003	492,438
<b>2016-17</b>	216,775	237,512	117,778	88,323	210,259	272,132	490,897	490,500
<b>2017-18</b>	215,975	236,584	117,313	87,974	207,071	272,132	488,800	488,570

Source: CRA from Concept Economics

8 June 2009

*Concept Economics fuel costs – coal*

Concept Economics provided estimates for coal by region for the nine years of LRMCM modelling. These are shown below in Table 10.

**Table 10: Concept Economics coal fuel costs used in the 2009-10 tariff year LRMCM calculation**

	Queensland (2009-10\$/GJ)	New South Wales (2009-10\$/GJ)	Victoria (2009-10\$/GJ)
<b>2009-10</b>	1.244	1.465	0.595
<b>2010-11</b>	1.307	1.538	0.595
<b>2011-12</b>	1.320	1.553	0.595
<b>2012-13</b>	1.326	1.560	0.595
<b>2013-14</b>	1.330	1.565	0.595
<b>2014-15</b>	1.336	1.573	0.595
<b>2015-16</b>	1.340	1.577	0.595
<b>2016-17</b>	1.344	1.581	0.595
<b>2017-18</b>	1.347	1.586	0.595

Source: Concept Economics

*Concept Economics fuel costs – gas*

Estimates of regional gas costs for CCGT and OCGT plant are shown in Table 11 and Table 12, respectively. The OCGT costs are calculated using a 50% uplift on CCGT costs.

8 June 2009

**Table 11: Concept Economics fuel costs for CCGT plant used in the 2009-10 tariff year LRM calculation**

	Queensland (2009-10\$/GJ)	New South Wales (2009-10\$/GJ)	Victoria (2009-10\$/GJ)	South Australia (2009-10\$/GJ)	Tasmania (2009-10\$/GJ)
<b>2009-10</b>	3.64	3.87	3.51	4.10	4.45
<b>2010-11</b>	3.89	4.11	3.76	4.35	4.70
<b>2011-12</b>	4.27	4.49	4.14	4.73	5.07
<b>2012-13</b>	4.75	4.97	4.62	5.21	5.56
<b>2013-14</b>	5.32	5.55	5.19	5.78	6.13
<b>2014-15</b>	5.97	6.19	5.84	6.43	6.78
<b>2015-16</b>	6.64	6.87	6.52	7.11	7.45
<b>2016-17</b>	7.33	7.55	7.20	7.79	8.14
<b>2017-18</b>	8.00	8.22	7.87	8.46	8.80

Source: Concept Economics

**Table 12: Concept Economics fuel costs for OCGT plant used in the 2009-10 tariff year LRM calculation**

	Queensland (2009-10\$/GJ)	New South Wales (2009-10\$/GJ)	Victoria (2009-10\$/GJ)	South Australia (2009-10\$/GJ)	Tasmania (2009-10\$/GJ)
<b>2009-10</b>	5.46	5.81	5.27	6.15	6.69
<b>2010-11</b>	5.84	6.17	5.64	6.53	7.05
<b>2011-12</b>	6.41	6.74	6.21	7.10	7.61
<b>2012-13</b>	7.13	7.46	6.93	7.82	8.34
<b>2013-14</b>	7.98	8.33	7.79	8.67	9.20
<b>2014-15</b>	8.96	9.29	8.76	9.65	10.17
<b>2015-16</b>	9.96	10.31	9.78	10.67	11.18
<b>2016-17</b>	11.00	11.33	10.80	11.69	12.21
<b>2017-18</b>	12.00	12.33	11.81	12.69	13.20

Source: Concept Economics

8 June 2009

*Concept Economics fuel costs for biomass generation*

Concept Economics agreed with our use of the biomass fuel cost taken from the CCSD Technology Assessment Report 72, published 2008. This report outlined that biomass fuel cost would be, on average, \$1.50/GJ. This estimate was in 2005 dollars, so the assumed long-run CPI of 2.5% has been applied for the cost to be \$1.697/GJ in 2009-10 dollars.

*Concept Economics fuel costs for other types of renewable generation*

Wind, hydro and geothermal generators do not incur fuel costs.

*Concept Economics fixed and variable generation operation and maintenance costs*

Estimates of fixed and variable operation and maintenance costs were provided for each plant type in the LRMC modelling. These are shown in Table 13.

**Table 13: Concept Economics FOM and VOM**

	FOM (2009-10\$/MW/year)	VOM (2009-10\$/MWh)
<b>Black Coal</b>	41,819	1.25
<b>Brown Coal</b>	41,819	1.25
<b>CCGT</b>	13,382	5.07
<b>OCGT</b>	7,841	7.84
<b>Wind</b>	46,018	0.00
<b>Hydro</b>	52,274	7.32
<b>Geothermal</b>	78,411	0.00
<b>Biomass</b>	50,769	4.81

Source: Concept Economics

*Concept Economics thermal efficiencies and auxiliaries*

Concept Economics provided estimates for thermal efficiencies and auxiliaries, as shown in Table 14.

8 June 2009

**Table 14: Concept Economics thermal efficiencies and auxiliaries**

Plant type	Thermal efficiency	Auxiliaries
Supercritical black coal	42%	7.5%
Supercritical brown coal	33%	9.5%
CCGT	52%	2.4%
OCGT	31%	2.0%
Wind	n/a	0%
Hydro	n/a	0%
Geothermal	10%	0%
Biomass	30%	0%

Source: Concept Economics

*Concept Economics plant availability*

The plant availability factors used for each type of plant in the LRMC modelling are shown below in Table 15.

**Table 15: Concept Economics availability factors**

	Availability factor
Black coal	90.0%
Brown Coal	90.0%
OCGT	92.0%
CCGT	97.0%
Wind	93.4%
Hydro	92.2%
Geothermal	90.0%
Biomass	85.0%

Source: Concept Economics

*Concept Economics WACC*

The WACC parameters provided by Concept Economics are shown below in Table 16 below.

8 June 2009

**Table 16: Concept Economics WACC assumptions**

Parameter	Value
<b>Input parameters</b>	
Liabilities	100%
Debt	60%
Equity	40%
Risk-free rate of return	6%
Risk premium	6%
Market rate of return	12%
Corporate tax rate	30%
Effective tax rate	22.50%
Imputation adjusted tax	15%
Debt basis point premium	200
Cost of debt	8.0%
Gamma	0.50
Asset beta	0.80
Debt beta	0.16
Equity beta	1.74
Required return on equity	16.5%
Inflation	2.6%
<b>WACC values</b>	
Post tax real WACC	6.71%
Pre-tax real WACC	<b>9.38%</b>

Source: Concept Economics

***Concept Economics project life***

Concept Economics agreed that a project life of 30 was appropriate for the 2009-10 LRMC modelling.

***Other inputs and modelling assumptions***

Other data input sources used for the LRMC analysis are as follows:

8 June 2009

- Future electricity demand projections as detailed by NEMMCO;<sup>45</sup>
- Generator outage statistics based on Energy Supply Association of Australia estimates;
- Current and announced environmental schemes are sourced from multiple sources:
  - The current Mandatory Renewable Energy Target (MRET) scheme:  
[www.climatechange.gov.au/renewabletarget/mret.html](http://www.climatechange.gov.au/renewabletarget/mret.html)
  - The new expanded national Renewable Energy Target (RET) scheme:  
[www.climatechange.gov.au/renewabletarget/index.html](http://www.climatechange.gov.au/renewabletarget/index.html)
  - Department of Energy, Utilities and Sustainability, NSW Renewable Energy Target (NRET), November 2006:  
[www.deus.nsw.gov.au/Energy/Renewable%20Energy/Renewable%20Energy.asp](http://www.deus.nsw.gov.au/Energy/Renewable%20Energy/Renewable%20Energy.asp)
  - Department of Mines and Energy, Queensland Gas Scheme  
<http://www.dme.qld.gov.au/Energy/gasscheme.cfm>

All model runs are based on what we have called a business as usual (BAU) scenario, which has the following assumptions:

- Medium demand growth projections assuming average weather condition, i.e. 50% probability of exceedance (POE) level load.<sup>46</sup> No extreme peaks, such as 10% POE peaks, or water shortages have been modelled.
- Continuation of the New South Wales Greenhouse Gas Reduction Scheme (GGAS) and (revised) Queensland Gas Scheme, and introduction of increased national Renewable Energy Targets but discontinuation of the Victorian VRET scheme once the increased national Renewable Energy Targets are in place.

Further details on the input assumptions are available in Appendix E.

### 3.2.12. LRMC results

Table 17 below presents the LRMC of energy for 2009-10 based on the inputs developed by Concept Economics, as described above.

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<sup>45</sup> *Australia's National Electricity Market 2008 Energy and Demand Projections*, Summary Report, NEMMCO, July 2008. The updated peak projections published by NEMMCO on 14 August 2008 as a result of data revisions by Powerlink have been included.

<sup>46</sup> This is a measure developed by NEMMCO to capture weather-related factors.

8 June 2009

**Table 17: The LRMC of energy**

Year	\$/MWh
2009-10	<b>\$53.28</b>

Source: CRA analysis

Various consistency and “sanity” checks were applied to the results of each scenario run to confirm the robustness of model outputs. A summary of these checks is given in Appendix F.

Table 18 presents the plant and generation mix that result in 2009-10 and 2017-18 from the LRMC calculation based on the Concept Economics inputs.

**Table 18: Installed capacity and generation based on Concept Economics inputs, 2009-10 and 2017-18**

	2009-10		2017-18	
	MW	GWh	MW	GWh
<b>Total</b>	9,409	61,492	13,262	72,024
<b>% by plant type</b>				
Biomass	1.14%	1.30%	0.81%	1.11%
CCGT	39.76%	27.35%	34.61%	15.67%
Geothermal	0.00%	0.00%	3.39%	4.93%
OCGT	0.00%	0.00%	6.41%	0.72%
Small Hydro	0.00%	0.00%	0.64%	0.29%
SC Black Coal	59.11%	71.35%	52.74%	76.61%
Wind	0.00%	0.00%	1.40%	0.68%

Source: CRA analysis

### 3.3. COST OF PURCHASING ENERGY

This section considers the cost of purchasing energy to supply Queensland’s NEM load in 2009-10. Consideration of the cost of purchasing energy is a required input to the BRCI under Sub-section 92(1) of the Act.

8 June 2009

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### 3.3.1. Conceptual comparison between the LRMC and actual costs

The LRMC of energy is meant to define the average cost over the long term of supplying incremental energy requirements. Investors must expect that their investments will be commercially viable or they will not invest. Therefore, it is reasonable to assume that a competitive market will produce price outcomes that align with the LRMC over the long term.

Prices in the short term, however, will be dominated by existing market conditions, which could reflect a period of supply out of sync with demand (either too high or too low). Therefore, at any point in time, the actual energy purchase costs as incurred by a retailer may differ from the LRMC due to factors such as variations in supply and demand conditions, pre-existing hedge portfolios, and ever changing expectations about the future (including expectations regarding fuel costs, environmental regulation, technology cost, performance characteristics, load developments, and so forth). Each retailer manages its risk through hedge contracting and pool purchasing strategies, among other means. Therefore, a retailer's costs may be higher or lower than the estimated LRMC in any given year.

In addition, due to the lumpy nature of investment in power stations and various policy constraints, the observed capacity mix will likely differ from the idealised greenfield capacity mix. Also, the capacity mix will be determined by past decisions where the historic technology costs for power stations may have been different from the ones assumed in the forward looking LRMC analysis based on today's prices. These issues also have implications for generator bidding.

These deviations can be significant. As noted above, Sub-section 92(1) of the Act requires that "*the cost of energy must reflect ... the likely total of the costs to be incurred ... to purchase energy*". This is interpreted to mean that at least some regard must be had with respect to actual prices in the short-term, as these will have an influence on "*the likely total of the costs to be incurred ... to purchase energy*".

### 3.3.2. Summary of issues raised in submissions to the Final Second Report and Draft Decision

This section of the report summarises comments related to the cost of purchasing energy that were received in response to the Second Final Report and the Authority's Draft Decision. As a result, not every submission is mentioned.

#### *AGL*

AGL stated that the 'weighted' (i.e., probabilistic) approach that was adopted in the Second Final Report was a significant improvement on the deterministic approach that had been used previously to settle the forecast load against pool prices and the hedge position.

8 June 2009

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They also reiterated their firm view that energy purchase costs should be assessed with regard to the NEM load (i.e., the load excluding the loads of customer directly connected to the transmission system). This approach is taken in this report.

AGL also commented that the approach CRA had used in applying marginal loss factors (MLF) was incorrect. We note that the assessment of energy purchase costs in this Final Report reverts to the use of average loss factors (ALF), consistent with the methodology used in the 2008-09 BRCI.

#### *Origin Energy*

Origin stated that it “generally supports the approach adopted by CRA in calculating the energy purchase cost”, but expressed concern that the use of marginal loss factors as applied in the Final Second Report was not correct and possibly constituted a change in methodology. As noted above, the assessment of energy purchase costs in this Final Report reverts to the use of average loss factors (ALF), which is consistent with the methodology used in the 2008-09 BRCI.

### 3.3.3. Approach to estimating the actual cost of purchasing energy

As was the case in our previous calculation of the BRCI for 2008-09, the approach that CRA has used to estimate the cost of purchasing energy for the purposes of calculating the BRCI for 2009-10, and re-calculating the BRCI for 2008-09, is to calculate a benchmark price that a rational retailer should be able to match, given reasonable purchasing decisions and risk policies. The approach is not intended to replicate the actual purchasing decisions or the actual risk policies of any particular retailer. It is, however, conservative, and will be expected to result in some over-contracted positions. The approach involves:

- Determining how much contract volume is purchased and the time periods over which these purchases take place; and
- Applying benchmark prices to cost these purchases.

To recognise the uncertain nature of load, we have applied three different energy demand scenarios and weighted the results. The load **forecast** in all scenarios is the same and is based on NEMMCO's Medium 50POE energy and peak projections. However, the load **outcomes** differ between the scenarios, with actual load being calculated using:

1. Medium 10POE load – weighted 30.4%;
2. Medium 50POE (this implies perfect foresight since actual = forecast) load – weighted 39.2%; and

8 June 2009

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### 3. Medium 90POE load – weighted 30.4%.<sup>47</sup>

#### *Use of contract price data from d-cypha Trade*

Actual contract pricing is confidential, so the approach relies on contract prices published by d-cypha Trade, actual historic pool prices, and forecasts of pool prices.

Data published by d-cypha Trade has been used because it represents actual contract price settlements in the NEM. Data from the other major source of contract prices, the Australian Financial Markets Association (AFMA), is based on a survey of participants about the price that they would be prepared to buy and sell particular products. It does not represent actual traded prices. In addition, d-cypha Trade also publishes prices for cap contracts, which AFMA does not. The cap prices published by d-cypha Trade refer to \$300 caps for all periods rather than \$300 caps for peak periods only. We therefore correspondingly use these caps in the Energy Purchase Cost to cover all periods.

The d-cypha Trade data does have some limitations, including the fact that it is based on the futures contract market which generally trades small volume contracts. Retailers and generators also enter into large volume contracts at prices that are not publicly available, and which may differ from d-cypha Trade quoted prices. It is unknown, however, whether the use of the d-cypha Trade data on its own provides either a systematically low or high estimate of the cost of contracts in total.

#### *Contract volumes and portfolio strategies*

Determining the level of contracting that retailers engage in is complex because:

- Future load and future pricing is uncertain, but contracts must be purchased in advance;
- Retail load changes on a daily basis both in shape (load profile) and total energy required;
- There are many instruments available for retailers to use to hedge their portfolios but only the simplest have publicly available benchmark prices; and
- Spot prices are correlated with demand. This means that periods of high demand typically coincide with high spot prices, particularly at the more extreme (higher demand) range – meaning that the risks of being uncovered due to high demand are multiplied.

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<sup>47</sup> Weightings are a CRA adaptation of the weights that NEMMCO applies in its SOO/ANTS modelling, namely 30.4% on 10POE and 69.6% on 50POE.

8 June 2009

### *Hedge contract parameters*

In general, the shape of the peak and off-peak load duration curve for each quarter determines the mix of contracts that a retailer will purchase. We have assumed that the objective for a retailer is to purchase contracts that match its load as closely as possible so that it is not exposed to the spot market during potentially high-priced peak periods and it is not over-contracted during off-peak periods when spot prices are likely to be lower than contract prices.

While meeting these objectives is not possible all of the time, the position that a retailer will take depends on their appetite for risk – generally, although not always, higher levels of contracting lead to higher average energy costs but a narrower range of potential energy cost outcomes, thereby offering protection from extreme prices in the spot market.

The criteria shown in Table 19 below to determine the volume of hedge contracts that a retailer would purchase each quarter were used in the calculation of the BRCI for 2008-09, and continue to be used now in the calculation of the BRCI for 2009-10, and the re-calculation of the BRCI for 2008-09. These benchmarks represent prudent levels of contracting and have been used in analyses that CRA and others have undertaken in standard tariff processes in other jurisdictions.

**Table 19: Criteria used to purchase hedge contracts for Queensland load**

Contract type	Criteria
Flat Swaps	80 <sup>th</sup> Percentile of Off Peak Load
Peak Swaps	90 <sup>th</sup> Percentile of Peak Load
\$300 Caps	105% of Maximum Peak Load

Source: CRA analysis

### *Timing of purchasing decisions*

A prudent retailer purchases its hedges over time, building up its portfolio slowly rather than attempting to purchase all its required contracts in one block immediately prior to the contract period.

The Act requires the cost of energy to be calculated for the total NEM load for the State, yet the purchasing strategies can be very different depending on whether they are to cover the load of customers on fixed term market contracts, or market contracts that are not fixed term, or regulated tariffs. Because of the difficulty that would be inherent in defining and assessing separate strategies, we have assumed that the retailer's strategy for purchasing energy to meet the NEM load is the same in all cases.

8 June 2009

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In reality, however, the timing of contract purchases is strongly influenced by the degree of certainty regarding the volume and shape of the retail load. For the load of customers that have accepted a fixed term market contract with a retailer, the retailer will generally purchase energy contract cover for the length of the retail contract, prior to the commencement of the retail contract, to ensure it does not have a net short position. However, for a retailer, the forecast load of customers on regulated tariffs or market contracts that are not of fixed length is more uncertain since, at any point in the future, customers can elect to remain on (or revert to) the regulated tariff, accept a market contract with the local retailer or accept a market contract with a competing retailer. Moving between a regulated tariff and a market contract without switching retailer does not change the retailer's load; this only changes when customers switch between retailers.

In general, a retailer will have a high degree of confidence of supplying a particular proportion of its customer load. As the retailer develops greater understanding of churn rates, it can make more accurate forecasts of its customers' load over shorter time periods.

Overall, a prudent retailer is likely to purchase contracts to meet its customers' loads over a period of about two years. Purchasing contracts over a period of this length reduces the upward pressure on contract prices caused when there is a high demand for contracts in a short space of time. We have assumed that the retailer being represented in the calculation of the BRCI spreads its purchases of energy contracts for each tariff year evenly over a period of two years, in advance of the tariff year for which the energy is being hedged. We recognise that this is a simplification of a retailer's actual purchasing strategies, and that the actual strategy adopted will vary by retailer depending on its risk assessment and the degree of certainty of its customer load.

Thus, we have assumed for the purposes of calculating the BRCI that the retailer spreads its purchases of swap and cap contracts:

- For 2008-09: evenly over the two-year period 1 July 2006 to 30 June 2008; and
- For 2009-10: evenly over the two-year period 1 July 2007 to 30 June 2009.

#### **3.3.4. Inputs to the calculation of the cost of purchasing energy**

The key inputs to the calculation of the cost of purchasing energy are as follows:

- Half-hourly load data used for the purposes of constructing a hedging strategy;
- Half-hourly load data used for the purposes of settlement;
- Contract price data published by d-cypha Trade; and
- Half-hourly NEM price data for settlement.

Each of these inputs is now discussed in more detail.

8 June 2009

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*Half-hourly load data used for the purposes of constructing a hedging strategy*

In accordance with the recent Supreme Court Judgment, the half-hourly load data that we are using for the purposes of constructing a hedging strategy for the tariff years 2008-09 and 2009-10 represents an estimate of the Queensland load, excluding the load associated with directly connected customers. Previously, CRA used its own estimate of this load.

On 8 May 2009, the Authority released a Consultation Paper proposing an alternative method for estimating the NEM load to be used in this calculation.<sup>48</sup> The Authority also released a paper prepared by ACIL Tasman on this issue. On 19 May 2009, the Authority released ACIL Tasman's half hour NEM load trace forecasts for 2007-08, 2008-09 and 2009-10 based on the methodology outlined in its paper. The Authority stated that it proposed to use the load traces for 2008-09 and 2009-10 in its Final Decision on the 2009-10 BRCI. For this final report on the BRCI for 2009-10, we have therefore used the load data for Queensland that has been provided by ACIL Tasman for this purpose, as published by the Authority on 19 May 2009.

*Half-hourly load data used for the purposes of settlement*

Settlement is modelled for three load outcomes: one based on the NEMMCO Medium 10POE, one on the Medium 50POE and the third on the Medium 90POE. The 50POE half-hourly load data used for the purposes of settlement is the same as the half-hourly load data used for the purposes of constructing a hedging strategy (Medium 50POE). The load data for the 10POE and 90POE scenarios differ. Again, as required by the Authority, the load data for Queensland that is used for the purposes of settlement in the calculation of energy purchase costs is now provided by ACIL Tasman.

*Contract price data published by d-cypha Trade*

Data published by d-cypha Trade have been used as inputs in regard to the prices of peak and flat electricity swap contracts. We have used the daily settled prices for flat swaps, peak swaps and \$300 caps that were published:

- For 2008-09: from 1 July 2006 to the cut-off date for the finalisation of the input data for our previous calculation of the BRCI for 2008-09 (this being 30 April 2008); and
- For 2009-10: from 1 July 2007 to the cut-off date for the finalisation of the input data for this report (this being 19 May 2009).

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48 See [www.qca.org.au/electricity-retail/NEP0910/ConsulPapNEM.php](http://www.qca.org.au/electricity-retail/NEP0910/ConsulPapNEM.php).

8 June 2009

### *Half-hourly NEM price data for settlement*

Half-hourly NEM price forecasts are developed in our STEMM model of the NEM, from where they have been extracted for use in this estimation of the cost of purchasing energy. These price forecasts are now developed based on the ACIL Tasman load data for Queensland, combined with CRA forecasts of load data for the other NEM jurisdictions. STEMM optimises the dispatch of generators to meet expected demands. Checks were applied to the STEMM price results to assess whether the Cumulative Price Threshold (CPT) is breached. Results of these checks are given in Appendix F.

**Error! Reference source not found., Error! Reference source not found., and Error! Reference source not found.** below summarise the NEM prices used in the analysis in this report, resulting from the 10POE, 50POE and 90POE load forecasts respectively for 2008-09.

Table 23, Table 24 and Table 25 below summarise the NEM prices used in the analysis in this report, resulting from the 10POE, 50POE and 90POE load forecasts respectively for 2009-10.

These prices are intended to be estimates of market prices that would eventuate in each year given the load forecasts and as such are based on the plant mix that currently exists in the NEM (as opposed to the greenfield approach which is adopted for the LRMC calculation). As discussed above, the 50POE forecast is used in our demand forecasting, the three forecasts are together used in our forecasting of demand outcomes, with the results weighted as discussed above. These prices are presented both as the time-weighted average (TWA) and the load-weighted average (LWA) for each quarter. The load used to calculate the LWA prices is the forecast half-hourly Queensland total load from the STEMM module of CEMOS.

**Table 20: Average spot market prices for each quarter in 2008-09 (\$/MWh) – 10POE calculation**

NEM Prices	2008-09			
	Q3 2008	Q4 2008	Q1 2009	Q2 2009
Time-weighted average price (TWA)	39.76	62.30	199.19	37.06
Load-weighted average price (LWA)	42.51	73.73	266.13	39.48

Source: CRA analysis

8 June 2009

**Table 21: Average spot market prices for each quarter in 2008-09 (\$/MWh) – 50POE calculation**

NEM Prices	2008-09			
	Q3 2008	Q4 2008	Q1 2009	Q2 2009
Time-weighted average price (TWA)	39.71	51.15	108.99	37.02
Load-weighted average price (LWA)	42.45	57.13	135.76	39.44

Source: CRA analysis

**Table 22: Average spot market prices for each quarter in 2008-09 (\$/MWh) – 90POE calculation**

NEM Prices	2008-09			
	Q3 2008	Q4 2008	Q1 2009	Q2 2009
Time-weighted average price (TWA)	39.88	49.24	90.91	37.15
Load-weighted average price (LWA)	42.66	54.37	109.84	39.59

Source: CRA analysis

**Table 23: Average spot market prices for each quarter in 2009-10 (\$/MWh) – 10POE calculation**

NEM Prices	2009-10			
	Q3 2009	Q4 2009	Q1 2010	Q2 2010
Time-weighted average price (TWA)	37.17	44.99	93.55	32.18
Load-weighted average price (LWA)	39.47	52.14	117.38	33.55

Source: CRA analysis

**Table 24: Average spot market prices for each quarter in 2009-10 (\$/MWh) – 50POE calculation**

NEM Prices	2009-10			
	Q3 2009	Q4 2009	Q1 2010	Q2 2010
Time-weighted average price (TWA)	38.76	41.79	78.95	33.05
Load-weighted average price (LWA)	41.19	47.14	97.04	34.48

Source: CRA analysis

8 June 2009

**Table 25: Average spot market prices for each quarter in 2009-10 (\$/MWh) – 90POE calculation**

NEM Prices	2009-10			
	Q3 2009	Q4 2009	Q1 2010	Q2 2010
Time-weighted average price (TWA)	39.30	40.02	64.30	33.35
Load-weighted average price (LWA)	41.79	44.47	76.21	34.79

Source: CRA analysis

### 3.3.5. Calculations

*Processing of the half-hourly load data for the purpose of determining the swap contracts to be modelled*

The various steps of processing the half-hourly load data for each tariff year are as follows:

1. Split the load data into four quarters, i.e. Q3 (July to September), Q4 (October to December), Q1 (January to March) and Q2 (April to June).
2. Within each quarter, separate the peak load from the off-peak load. Peak load corresponds to load from 07:00 hours to 22:00 hours Monday to Friday, excluding public holidays. Off-peak load corresponds to load at all other times. At this stage, the half-hourly load data has been separated into eight different divisions: peak and off-peak for each of the four quarters.
3. Calculate the 0 to 100 percentile load points for each of the eight divisions.<sup>49</sup>

*Calculating swap and cap contracts to be modelled*

Based on the above half-hourly load data, we modelled swap and cap contract purchases<sup>50</sup> as follows for each quarter of each tariff year, and for each scenario of including or excluding directly connected customers:

<sup>49</sup> A percentile is the value of a variable below which a certain percent of observations fall. For example, the load is less than the 90% percentile load in 90% of the half-hourly periods in the data being analysed.

<sup>50</sup> An electricity swap means an agreement between two parties to exchange the difference between a fixed price per megawatt hour (MWh) of electric energy and the NEM spot price at a stated reference node.

A peak swap is an electricity swap that only applies in peak hours. Peak hours are between 07:00 and 22:00 Monday to Friday, excluding public holidays.

8 June 2009

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- Flat swaps are purchased up to the 80<sup>th</sup> percentile of off-peak load;
- Peak swaps are purchased up to the 90<sup>th</sup> percentile of peak load; and
- \$300 caps are bought beyond the cover of swaps to cover up to 105% of the maximum peak load.

#### *Pricing of contracts*

As explained in section 3.3.2 above we have assumed for the purposes of calculating the BRCI that the retailer spreads its purchases of energy contracts for 2008-09 evenly over the two-year period 1 July 2006 to 30 June 2008, and for 2009-10 evenly over the two-year period 1 July 2007 to 30 June 2009.

For each contract type, we would therefore seek to price the swap and cap contracts to cover the tariff year 2008-09 based on the average of the daily settled prices quoted from 1 July 2006 to 30 June 2008, and for the tariff year 2009-10 based on the average of the daily settled prices quoted from 1 July 2007 to 30 June 2009. However, in this report we have only been able to use the prices available for flat swaps, peak swaps and \$300 caps:

- For 2008-09: in accordance with the recent Supreme Court Judgment, that were published from 1 July 2006 to the cut-off date for the finalisation of the input data for the previous calculation of the BRCI for 2008-09 (this being 30 April 2008)
- For 2009-10: that were published from 1 July 2007 to the cut-off date for the finalisation of the input data for this report (this being 19 May 2009).

We have included in Appendix D graphs showing the d-cypha Trade prices for each type of contract that we have considered in this analysis for the tariff year 2009-10, showing daily settled prices quoted from 1 July 2007 to 19 May 2009. For the tariff year 2008-09, the graphs are as previously published in Appendix C.2 of *Calculation of the Benchmark Retail Cost Index for 2007-08 and 2008-09: Addendum Report*, 26 May 2008, which is available on the Authority's website.

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A cap is a series of half-hourly options, which places a ceiling on the price the buyer pays for electricity. The seller will compensate the buyer to the extent the NEM spot price is greater than the strike price. A \$300/MWh peak cap is a cap with a strike price of \$300/MWh that only applies in peak hours as defined by NEMMCO.

These contracts are the most commonly traded financial instruments in the NEM.

8 June 2009

For the tariff year 2009-10, we have estimated the contract data for the period from 20 May 2009 to 30 June 2009. Forecasting contract prices over the period where data is not available is difficult, particularly given the price volatility in the contract market that has been seen in the last couple of years. It is difficult to model a definitive trend that can be used to forecast future contract prices, and there is no clear best method. We have, for example, considered whether there are any historical trends in the contract prices as the date of delivery nears, or whether there is any seasonal pattern that makes contracts for the same delivery period more or less costly to purchase if they are purchased at particular times of the year. No such trend or pattern is evident.

For the purposes of this report, we have determined the average price of each contract type in the period from 20 March 2009 to 19 May 2009, and applied those prices to each day from 20 May 2009 to 30 June 2009. This approach implies that the most recent prices are the best predictor of future prices. We are not saying that we expect prices to stay exactly the same over the next eleven and a half months as they averaged over the past two months. Rather, we are saying that we have no basis for suggesting there is a better method that will more accurately predict the outturn prices over this period.

Exactly the same approach was taken to estimating the contract data for the period from 1 May to 30 June 2008 in the original BRCI calculation for 2008-09. That approach is now again used in the re-calculation of the BRCI for 2008-09: i.e. we have determined the average price of each contract type in the period from 3 March to 30 April 2008, and applied those prices to each day from 1 May to 30 June 2008.

Table 26 below summarises the contract prices used in the analysis in this report, as derived from d-cypha Trade data, for the tariff years 2008-09 and 2009-10.

**Table 26: Average costs of energy contracts for each quarter (\$/MWh)**

	2008-09				2009-10			
	Q3 2008	Q4 2008	Q1 2009	Q2 2009	Q3 2009	Q4 2009	Q1 2010	Q2 2010
Flat Swaps	42.66	50.25	65.35	33.75	36.51	44.66	70.96	36.09
Peak Swaps	59.29	76.93	108.14	45.67	47.02	64.86	106.51	45.86
\$300 Caps	4.66	8.52	33.77	4.82	4.49	10.48	34.31	4.92

Source: d-Cypha Trade data and CRA analysis

### *Settlement of contracts and NEM prices to create the energy purchase costs*

We calculated a settlement value for each half-hour for each load scenario, as the total dollar cost of the load in each half-hour, taking into account in each case the appropriate data inputs for estimated loads, prices and contract cover, as discussed above. In each case, we then added up all those settlement values across all the half-hours for each scenario and for each tariff year, and divided by the total energy (MWh) each year (the total energy being the half the sum of the half-hourly MW loads in each case). We thus obtained an average cost of purchasing energy in \$/MWh for each scenario for each tariff year.

#### 3.3.6. Application of network losses

The Queensland load data used for our analysis, which was provided to us by the Authority, is measured at the connection points between the transmission and distribution networks. These connection points are referred to as transmission nodes. NEMMCO calculates the Marginal Loss Factor (MLF) for each transmission node on the network each financial year, and applies the appropriate MLF to the amount of energy that is measured at each transmission node in order to determine the amount of energy for which settlement is undertaken in the wholesale market.

In previous years, the BRCI was calculated using an Average Loss Factor (ALF) for Queensland, as calculated by Powerlink. In our Draft and Final Second Reports, we proposed to switch to the use of the MLF, but (a) several stakeholders felt that our approach for doing so was incorrect, and (b) there was some concern that a switch to the use of MLFs would constitute a change in methodology. In light of the lack of support from stakeholders for the switch, we were requested by the Authority to revert to the use of the ALF, as calculated from data provided by Powerlink in its 2007 Annual Planning Report (Table 3.7, page 33) for 2008-09, and in the 2008 Annual Planning Report (Table 3.8, page 34) for 2009-10. The ALF values for Queensland used in the Energy Purchase Cost calculation for each year are given in Table 27 below.

**Table 27: Average Loss Factor (ALF)**

	2008-09	2009-10
<b>Average Loss Factor</b>	1.0401	1.0399

Source: Powerlink and CRA analysis

#### 3.3.7. Energy purchase costs results

Table 28 below summarises the energy purchase costs for 2008-09 and 2009-10. The three scenarios are given with their respective weightings and the resulting average Energy Purchase Cost.

8 June 2009

**Table 28: Energy purchase costs – scenario results, weightings and weighted values (\$/MWh)**

	Scenario weighting	2008-09	2009-10
Energy purchase costs (\$/MWh) – 10POE	30.4%	58.70	57.88
Energy purchase costs (\$/MWh) – 50POE	39.2%	57.79	57.65
Energy purchase costs (\$/MWh) – 90POE	30.4%	57.58	57.59
<b>Energy purchase costs (\$/MWh) – Weighted</b>		<b>58.00</b>	<b>57.70</b>

Source: CRA analysis

### 3.4. COMBINATION OF LRMC AND ENERGY PURCHASE COST RESULTS

In section 3.2, we determined the LRMC of energy, and in section 3.3 we determined the average cost of purchasing energy for each of the tariff years 2008-09 and 2009-10. As discussed, these are inputs to the BRCI that are required by the Act. However, since these are independent and unrelated calculations of the cost of energy, a method is required to combine these into a single energy cost that can be used as part of the BRCI.

Our approach is to apply weightings to the LRMC and purchase cost of energy to form a single energy cost. The resulting energy cost for each year, in \$/MWh, is then used as the input to the BRCI. The weightings should be determined by the policy objectives of the Government in relation to the setting of tariffs. As required by the Authority, we have adopted an equal weighting for the LRMC and purchase cost of energy factors – i.e. 50% each. These are the same weightings as were used in our previous calculation of the BRCI for 2008-09. The result of this weighting is given in Table 29 below. It is acknowledged that alternative weights could be adopted to reflect different views on the legislative intent in calculating the BRCI.

**Table 29: Energy cost component of BRCI for 2008-09 and 2009-10**

Cost Item	2008-09	2009-10
LRMC	\$42.61	\$53.28
Energy purchase costs	\$58.00	\$57.70
<b>Energy: results of weighting LRMC (50%) with energy purchase costs (50%)</b>	<b>\$50.31</b>	<b>\$55.49</b>

Source: CRA analysis

### 3.5. OTHER ENERGY COSTS

Each electricity retailer in Queensland is required to comply with the following schemes:

8 June 2009

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- The Mandatory Renewable Energy Target (MRET), and its replacement scheme; and
- The Queensland Gas Scheme.

These schemes, which encourage increased renewable energy generation in Australia and gas-fired generation in Queensland respectively, mandate that each year each retailer either meets its target for purchasing particular types of generation or pays a penalty. The costs to a retailer of complying with these schemes are discussed below.

### 3.5.1. Mandatory Renewable Energy Target (MRET)

As set out in section 3.2.9 above, the Federal Government has announced that the Australia-wide Mandatory Renewable Emissions Target (MRET) is to be revised, and more details have become available since the calculation of the 2008-09 BRCI. The original scheme required that renewable energy sources account for at least 2% of the electricity generated across Australia by 2010, which equated to an additional 9,500 GWh by that year as compared to the base level of renewable energy established in 2000. The revised scheme has been defined as increasing the percentage of energy generation to be derived from renewables to 20% by 2020, which will require an additional 45,000 GWh across Australia.

The annual targets for renewable energy are discussed in section 3.2.9 above.

These annual targets are allocated proportionally to each electricity retailer and wholesale buyer using a factor called the Renewable Power Percentage (RPP). The RPP is simply each year's renewable energy target divided by the corresponding annual load forecast. The RPP is published by 31 March each year as an amendment to the *Renewable Energy (Electricity) Regulations*. The RPP for 2009 is 3.64%. Based on the above energy targets, we are estimating the RPP for 2010 to be 5.38%.

Each retailer can either purchase (or generate) Renewable Energy Certificates (RECs) to cover this liability, or pay the penalty of \$40/MWh for any shortfalls in RECs relative to its liability.

To determine the costs to a retailer of complying with the MRET scheme, weekly market prices for RECs published by the Australian Financial Markets Association (AFMA) have been used. This approach is the same as that used in our report last year on the BRCI for 2008-09. Prices are quoted for calendar year periods.

The cost of complying with the Renewable Energy Target requirements in 2008-09 as used in the calculations of the BRCI for that year was **\$1.35/MWh**, and this value continues to be used now, in order to maintain the integrity of the index.

8 June 2009

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Multiplying the average REC price by the estimated RPP for each of 2009 and 2010 gives an overall cost of compliance with the Renewable Energy Target requirements of \$1.74/MWh for 2009 and \$3.10/MWh for 2010. Averaging those results by weighting of the component of 2009-10 load that is in each of 2009 and 2010 provides an overall result that the cost of complying with the Renewable Energy Target requirements is estimated to be **\$2.43/MWh** in 2009-10.

### 3.5.2. Queensland Gas Scheme

In 2005, the Queensland Government implemented a scheme whereby liable parties (i.e. retailers) are required to source at least 13% of their electricity from gas fired generation. The design of the scheme is similar to the Commonwealth MRET scheme. The annual targets for this scheme have since been revised, as discussed in section 3.2.9. Accredited generators (gas-fired generators that support Queensland electricity load) create and sell Gas Electricity Certificates (GECs) to liable parties for each MWh generated. If a liable party does not meet its annual liability by the compliance date, it is required to pay a penalty. The penalty is calculated each year according to a formula specified in the Act.

For retailers in Queensland, the cost of purchasing energy includes the cost of purchasing GECs for the required percentage of their retail load. The current price for GECs in Queensland reflects the level of supply and demand for GECs.

There are two methods which we have previously considered for calculating GEC prices for the BRCI calculation. The prices could be based either on penalty prices, or on prices for trades, which have been published by AFMA since 21 February 2007.

In our original calculation of the BRCI for 2007-08, quoted prices were not yet available, and therefore we used penalty prices by default.

When we then calculated the BRCI for 2008-09, and also at the same time needed to re-calculate the BRCI for 2007-08, we considered whether we should continue to estimate the prices of GECs based on penalty prices, or alternatively whether we should start to base the pricing of GECs on prices for trades which have been published by AFMA. At that time, if we had used quoted prices, we would have had only a small number of data points on which to base the GEC price for 2007-08, and this would therefore not have been a robust basis on which to estimate the cost of compliance with the Queensland Gas Scheme in 2008-09. We needed a consistent approach for calculating the GEC prices for the two tariff years 2007-08 and 2008-09, and therefore we estimated the prices of GECs based on penalty prices rather than on AFMA-quoted prices for both 2007-08 and 2008-09.

At the time of the calculation for 2007-08 and 2008-09, we recommended a transition to using market quoted prices rather than penalty prices in future years. While we could now follow that recommendation and base the GEC prices for 2009-10 on market quoted prices, we have been requested to continue to base our calculations on the penalty prices.

8 June 2009

The cost of complying with the Queensland Gas Scheme requirements in 2008-09 as used in the calculations of the BRCI for that year was **\$2.29/MWh**, and this value continues to be used now, in order to maintain the integrity of the index.

Based on CPI inflation to date and the forecasts for CPI shown in section 2.11.1 above, a penalty price calculation would see GEC prices now estimated at \$18.07 for 2009 and \$18.43 for 2010. GECs account for 13% of retail load in 2009 and 15% in 2010, so the average cost to a retailer calculated on this basis would be \$2.35/MWh in 2009 and \$2.76/MWh in 2010. The average figure for the 2009-10 tariff year is calculated to be **\$2.56/MWh**.

### 3.6. NEMMCO COSTS

#### 3.6.1. Participant and FRC fees

Participant and FRC fees are fees payable to NEMMCO to cover its operational expenditure. In addition, there is a charge for FRC establishment and operation.

The approach used to estimate participant fees for 2009-10 is the same as that used previously to estimate the participant fees for 2008-09. The method is to apply a linear trend to total costs for each component of NEM fees, and the load used to determine the \$/MWh fee over the period since 2004-05.

The cost of these fees in 2008-09 as used in the calculations of the BRCI for that year was **\$0.32/MWh**, and this value continues to be used now, in order to maintain the integrity of the index.

The estimated NEM fees for 2009-10 are provided in Table 30 below.

**Table 30: Estimated NEM fees (\$/MWh)**

	<b>2009-10</b>
<b>NEMMCO Participant Fees</b>	\$0.26
<b>FRC Establishment and Operation</b>	\$0.07
<b>Total</b>	<b>\$0.33</b>

Source: NEMMCO and CRA analysis

#### 3.6.2. Ancillary Services Charges

NEMMCO controls key technical characteristics of the electricity system, such as frequency and voltage, through Ancillary Services (AS) including:

- Automatic generation control;

8 June 2009

- Governor control;
- Load shedding;
- Rapid generating unit loading;
- Reactive power;
- Rapid generating unit unloading; and
- System restart.

NEMMCO sources AS on a competitive basis with generators having the option of providing energy for the wholesale market or keeping capacity in reserve for the AS market. The decision on whether to provide capacity for the AS market will to an extent depend on the opportunity cost of providing energy for the wholesale market. Therefore, AS costs should show some correlation to energy prices over time. However, while compensation to providers for AS is undertaken on a regional basis, the costs to users are spread across the NEM thereby diluting any correlation between energy prices and AS costs.

Given this, historic AS costs to users have been reviewed, in order to determine likely future AS costs. There was a discontinuity in mid 2005 due to a renegotiation of AS costs.

The estimate of AS charges in 2008-09 as used in the calculations of the BRCI for that year was **\$0.39/MWh**, and this value continues to be used now, in order to maintain the integrity of the index.

Our framework for estimation of AS charges for 2009-10 is based on averaging the ancillary services costs for the last 52 weeks. This is unchanged from the framework previously deployed to estimate the AS charges in calculating the BRCI for 2008-09.

On that basis, our estimate for 2009-10, based on data up to week 20 of 2009 (week ending 19 May 2009) is **\$0.40/MWh**.

### 3.7. OVERALL SUMMARY RESULTS FOR THE COST OF ENERGY

Table 31 below shows an overall summary of the results for the cost of energy in \$/MWh for 2008-09 and 2009-10.

**Table 31: Summary of the cost of energy (\$/MWh)**

Cost Item	2008-09	2009-10
LRMC	\$42.61	\$53.28

8 June 2009

Cost Item	2008-09	2009-10
Energy purchase costs	\$58.00	\$57.70
<b>Energy: results of weighting LRMC (50%) with energy purchase costs (50%)</b>	<b>\$50.31</b>	<b>\$55.49</b>
<b>RECs</b>	<b>\$1.35</b>	<b>\$2.43</b>
<b>GECs</b>	<b>\$2.29</b>	<b>\$2.56</b>
<b>NEM fees</b>	<b>\$0.32</b>	<b>\$0.33</b>
<b>Ancillary services</b>	<b>\$0.39</b>	<b>\$0.40</b>
<b>Total cost of energy (\$/MWh)</b>	<b>\$54.66</b>	<b>\$61.20</b>

Source: CRA analysis

### 3.8. NEM LOAD

As discussed in section 2.3 above:

- The NEM load (L) for the whole of 2007 is required as the denominator to enable the calculation of the BRCI for 2008-09; and
- The NEM load (L) for the whole of 2008 is required as the denominator to enable the calculation of the BRCI for 2009-10.

The NEM load includes only the energy delivered from the transmission connection network that flows through the distribution system to customers, and *excludes* any end-user load that is directly connected to the transmission system.

The Authority previously provided us with the NEM load for the full 2007 calendar year of **37,039,715 MWh**. This was the value that was used in the original calculation of the BRCI for 2008-09. The Authority now provided us with the value of **36,850,890 MWh** as the NEM load for the full 2008 calendar year.<sup>51</sup>

Section 6 below shows the results of multiplying these figures for NEM load with the cost of energy for each year that was shown in Table 31 above.

<sup>51</sup> This value for 2008 was the subject of consultation; see [www.qca.org.au/electricity-retail/NEP0910/ConsulPapNEM.php](http://www.qca.org.au/electricity-retail/NEP0910/ConsulPapNEM.php).

## 4. RETAIL COSTS AND MARGINS

This report section considers separately:

- **Retail costs** – which, as discussed above, reflect the likely cost that would be incurred by an efficient entity in providing retail electricity services to Queensland customers connected to the national grid; and
- **Retail margins** – which an efficient entity might reasonably expect to earn from its retailing activities.

### 4.1. CUSTOMER NUMBERS

The Authority has given us figures for the customer numbers for calculation of the BRCI for both 2008-09 and 2009-10:

- For 2008-09: 1,928,620 customers. This is the same value as was used previously in the calculation of the BRCI for 2008-09.
- For 2009-10: 1,978,965 customers.

### 4.2. RETAIL COSTS

#### 4.2.1. Categories of retail costs

As discussed in section 2.2.3 above, the Regulation prescribes that the Authority must consider the following cost categories for the provision of customer retail services:

- Billing;
- Customer call centres;
- Credit management;
- Energy trading activities;
- Corporate overheads, including, for example, treasury functions, human relations and facilities management;
- Information technology systems; and
- Any other cost category the pricing entity considers reasonable.

Each of these categories is discussed in turn below through consideration and discussion of what activities are included in each category, and what the cost driver is in each case.

8 June 2009

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- *Billing costs:* Billing costs include the activities of validating data for billing, creating bill-ready data, printing and mailing of periodic bills. Much of the cost of billing activities comprises the fixed cost of IT systems. The variable component of the costs of billing is driven by the number of bills that are issued, which is in turn a function of the number of customers and the billing cycle (generally monthly, bi-monthly or quarterly). Each bill also generates a collection cost when the customer pays the bill.
- *Customer call centre costs:* Customer call centre costs involve some fixed costs of establishing the retailer's call centre and the systems and procedures for operation of the call centre. Staff costs make up a significant portion of ongoing operational costs. The number of required staff is directly related to the number of calls made to the call centre, which is driven by the number of customers that are served by the retailer.
- *Credit management costs:* Customers generally pay in arrears for the costs of the electricity they consume, and credit management is therefore an important issue for retailers to address, to ensure that working capital requirements and provisions for bad debt are minimised. Credit management costs include hardship and similar policies to assist customers with payment policies. The costs of credit management are largely driven by the size of the business.
- *The costs of energy trading activities:* These costs include the staff costs of engaging in energy trading, in particular personnel costs. For a given fuel (electricity or gas), these costs are driven by the size of the business, although the complexity of the electricity and gas markets differ.
- *Corporate overheads:* These include treasury functions, human relations and facilities management functions. They are generally driven by the size of the business.
- *The costs of IT systems:* IT costs are largely driven by the size of the business. For a given retail business, the gain or loss of a few customers or does not change the IT costs of the business. Instead there are step changes when the business grows substantially and a new IT architecture is needed. IT costs are not necessarily a cost category apart from other cost categories – rather, these systems support the other categories of activity – such as billing and customer call centres.
- *Other costs:* Retailers incur other costs, but these are not generally itemised – due to their small materiality as compared to the larger cost categories discussed above. These include the costs of regulatory compliance, licensing fees, ombudsman costs, and settlement validation costs. One other cost category that can be itemised separately relates to the costs of customer acquisitions, which is discussed separately in section 4.2.7 below.

8 June 2009

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In a competitive environment, a retailer's operating costs include the costs of complying with the requirements of the competitive market. These costs include the costs of interfacing with industry B2B systems, transferring customers between retailers and validating settlement of the costs of those customers, and providing customer education – through trained call centre staff with tailored scripts, web-site information and perhaps bill inserts. Many of these costs could be categorised as IT systems costs and regulatory compliance costs.

From 2007-08 onwards, retail competition was extended to all customers with the introduction of FRC from 1 July 2007. The IT systems costs and regulatory compliance costs of operating in an FRC environment are now higher than they would have been in the earlier, more limited competitive environment. These costs are separate from the costs that are incurred by electricity network operators, and which are then either borne by the network operators or passed through in network use of system charges as determined by the Authority.

#### **4.2.2. Retail costs for a standalone retail business as against an integrated utility**

The allocation of costs such as corporate costs, IT costs and overheads between distribution and retail functions in an integrated utility is generally at least somewhat open to question. Allocations are also open to question in other cases where there are multiple sources of revenue, as for instance in the case of a dual fuel retailer. In Queensland, the local retailers Sun Retail (owned by Origin Energy) and Powerdirect Australia (owned by AGL) are not affiliated with network businesses, but the remaining Government-owned retailing business, Ergon Energy Queensland, does have network business affiliation. Origin Energy and AGL both certainly have other retailing interests outside Queensland, and dual fuel interests within Queensland. The requirement in the Act that the retail costs included in the determination of the BRCI be based on an efficient retailer business that "is carried on separately from any other business" necessarily means that the retail costs used in determining the BRCI will not be the same as the actual retail costs incurred by the Queensland retailers.

Based on the above considerations, it would seem likely that actual retail costs of the local retailers in Queensland will be lower than the costs calculated in accordance with the Act, because the local retailers in Queensland will be able to share fixed costs and overheads with other business interests, whereas the standalone retail business described in the Act has no such other business interests.

#### **4.2.3. Discussion of fixed and variable components of retail costs**

Frontier Economics considered in a report to IPART<sup>52</sup> to what extent retail operating costs were fixed vs. variable. Frontier Economics stated:

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<sup>52</sup> *Mass Market New Entrant Retail Costs and Retail Margin*, prepared for IPART, Frontier Economics, March 2007.

8 June 2009

*It makes sense that retail operating costs are predominantly fixed. A large component of these costs is related to the systems that an efficient mass market retailer requires, including IT systems – such as billing and revenue collection systems and customer information systems – as well as customer service systems, including those required for the effective operation of call centres. The costs of establishing these systems are largely fixed costs. Once these systems are in place, the costs that vary with customer numbers – which are primarily a function of processing customers' bills, responding to customer queries, etc – are comparatively small.*

*Another way of looking at this is to consider the major elements of operating costs, as reported by the retailers. ..., the four major elements of operating costs reported by the retailers are corporate overheads, billing and revenue collection costs, customer information systems and call centre costs. There is reason to think that each of these four costs elements is predominantly fixed. Corporate overheads, for instance, will not vary significantly with customer numbers. Billing and revenue collection costs and customer information system costs are both likely to consist predominantly of the IT systems required for the retailer to operate effectively. These are predominantly fixed. Finally, while call centre costs are likely to have a significant variable component, because the number of staff required in a call centre is largely dependent on the number of calls the centre receives, there is also likely to be a significant fixed component associated with the development of the systems necessary for the effective operation of a call centre.*

Frontier Economics noted that some regulators were of the view that retail operating costs are predominantly fixed,<sup>53</sup> while other regulators have stated a view that retail operating costs are predominantly variable.<sup>54</sup>

Frontier Economics noted that the uncertainty regarding the fixed or variable nature of retail operating costs is due in part to the nature of retail costs; the Tasmanian Energy Regulator somewhat explained the issue by pointing out that many of the costs associated with electricity retailing are not completely fixed or truly variable. For instance, the costs of IT systems “tend to be incurred in relatively long flat steps” rather than varying directly with customer numbers<sup>55</sup>. This being the case, differences in understanding whether these costs should be treated as fixed or variable are to be expected.

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<sup>53</sup> See for instance *Review of the Effectiveness of Full Retail Competition for Electricity*, Special Investigation, Final Report, Essential Services Commission Victoria, September 2002.

<sup>54</sup> See for instance *Reviews of Public Electricity Suppliers 1998 to 2000*, Supply Price Control Review, Final Proposals, Ofgem, December 1999.

<sup>55</sup> *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania*, Final Report and Proposed Maximum Prices, Office of the Tasmania Energy Regulator, September 2003.

8 June 2009

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Frontier Economics recommended that the retail operating costs of a retailer operating to scale should be treated as 75% fixed (on a per company basis – representing the fixed costs of IT systems, corporate overheads, and other costs that do not vary significantly with customer numbers), and 25% variable (representing costs incurred on a per customer basis such as bill production and revenue collection costs). As recommended by Frontier Economics, the driver of the variable costs is customer numbers, and specifically not the amounts of energy consumed by each customer – although Frontier Economics did report the variable costs as \$/MWh equivalents, based on average customer consumption levels.

IPART accepted the recommendation of Frontier Economics that the retail operating costs of a retailer operating to scale should be treated as 75% fixed and 25% variable.<sup>56</sup>

#### 4.2.4. Approach to estimating retail costs for the BRCI calculations

If the data were available, the best means of estimating the retail operating costs on a per customer basis would be to segment the customer base and to identify the specific costs that are incurred in serving each segment in each cost category. These could all then be added together with the fixed costs to give total retail costs for the electricity retailer. It would appear that this approach is envisaged in the Act.

However, in the absence of detailed information on segmentation of the customer base and data on how the retail operating costs for the different segments vary, such an approach based on segmentation is not practical. This being the case, the approach that has been taken to estimate retail costs in the calculation of the BRCI is based on benchmarking total retail costs across a retailer rather than calculating a bottom-up set of costs by customer segment and cost category.

In previous years' calculations of the BRCI, analysis was undertaken of the regulatory decisions on retail costs that have been made in other Australian jurisdictions and other publicly available sources of data on retail operating costs, and the findings from the analysis were applied to Queensland.

Based on this analysis, the view was taken that a reasonable value for retail operating costs for a retailer operating to scale in an FRC environment (excluding customer acquisition costs or allowance for loss of scale) was \$75/customer which was estimated for 2006-07, and then adjusted for inflation in following years.

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<sup>56</sup> *Promoting Retail Competition and Investment in the NSW Electricity Industry – Regulated Electricity Retail Tariffs and Charges for Small Customers 2007 to 2010*, Final Report and Determination, IPART, June 2007.

8 June 2009

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#### 4.2.5. Summary of issues raised in submissions to the Final Second Report and Draft Decision regarding retail operating costs excluding customer acquisition costs

This section of the report summarises comments related to retail operating costs (excluding customer acquisition costs) that were received in response to the Second Final Report and the Authority's Draft Decision. As a result, not every submission is mentioned.

##### *Origin Energy*

Origin reiterated the comments it made in response to the Draft Second Report that the *Electricity (Retail Billing Guaranteed Service Level Scheme) Code* must either be accounted for as a retail cost or an increased risk (or both).

#### 4.2.6. Conclusion on retail operating costs excluding customer acquisition costs

We conclude that a reasonable value for retail operating costs for a retailer operating to scale in an FRC environment (excluding customer acquisition costs or allowance for loss of scale) remains a value of \$75/customer which was estimated for 2006-07, and then adjusted for inflation in following years. As previously, we have estimated that labour costs account for approximately 60% of total retail operating costs. We have thus used the inflation factors from section 2.11 above, applying the WPI inflation factors to 60% of the retail operating costs, and the CPI inflation factor to the remaining 40%.

This results in retail operating costs excluding customer acquisition costs being estimated at **\$83.19 per customer** for 2009-10.

#### 4.2.7. Customer acquisition costs

##### *Discussion of customer acquisition costs*

In a competitive market, retailers incur marketing, advertising and customer acquisition and retention costs. The amount that each retailer spends on these activities is at its own discretion. Experience in the mass-market in other Australian jurisdictions has shown that the most effective way to gain new customers is through door-knocking. Some retailers have also engaged in expensive TV and mass-circulation advertising to promote their brand names, but the effectiveness of these campaigns is not easily related to the amount spent or the media chosen. Other means of attracting and retaining customers are through direct mail campaigns, outbound telemarketing, less expensive local/neighbourhood print media and through affinity deals with partners such as credit card companies and airline frequent flyer programs. There are many ways of undertaking marketing, and each has its own cost basis.

8 June 2009

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In the past, marketing, advertising and customer acquisition and retention costs were not typically taken into account in regulatory decisions that set prices for customers that do not take a market contract, but rather remain on (or return to) supply under standard (regulated) terms and conditions. These regulatory decisions were made on the basis that retailers do not need to incur any marketing, advertising or customer acquisition and retention costs in order to serve customers that remain on (or return to) supply under standard (regulated) terms and conditions. Therefore it was not considered appropriate to include those costs.

There was also some concern that the retailers that served customers under standard tariffs were the previous monopoly incumbent retailers with 100% market share at market opening. It was considered that a successful competitive market would be best established if all retailers were able to compete equally. It was felt that allowing the incumbent retailers costs of customer acquisition and retention would be anti-competitive since new entrants who would have to self-fund their marketing campaigns would not be competing on a level playing field. On the other hand, inclusion of marketing costs would increase headroom and therefore potential competitive entry, but it would also add significantly to the margins of incumbent retailers, particularly in the early days of FRC.

#### *Decision of IPART to allow customer acquisition costs*

One notable exception was the IPART decision in 2007,<sup>57</sup> where for the first time customer acquisition costs were taken into account, and were explicitly calculated and incorporated in a regulatory decision to set standard (regulated) prices in an Australian jurisdiction.

The reason why that decision took these costs into account is because the Terms of Reference for that IPART investigation and determination specified that the allowances for retail operating costs and retail margin should reflect the retail costs and retail margin of a hypothetical mass market new entrant. This represented a significant change from the approach that IPART had taken in previous determinations, where the allowances for retail operating costs and retail margin had sought to reflect the retail costs and retail margin of the actual standard retailers that supply regulated customers in NSW.

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<sup>57</sup> *Promoting Retail Competition and Investment in the NSW Electricity Industry – Regulated Electricity Retail Tariffs and Charges for Small Customers 2007 to 2010*, Final Report and Determination, IPART, June 2007.

8 June 2009

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IPART's allowances for customer acquisition costs were based on its estimate of the actual cost of acquiring a customer being \$200. These costs included all costs relating to marketing to new customers and the costs associated with the process of transferring customers.<sup>58</sup> The final allowances that IPART determined for customer acquisition costs were:<sup>59</sup>

- For residential customers: \$29/year – based on amortisation of acquisition costs over an eight-year period of customer retention;
- For small business customers: \$37/year – based on amortisation of acquisition costs over a six-year period of customer retention; and
- A weighted average of these figures for residential and small business customers gave an overall result of \$30/year.

#### *Loss of scale – an alternative approach*

As noted above, the IPART allowance for customer acquisition costs is a direct consequence of the decision to base the standard tariff on the costs that would be incurred by a mass market new entrant, whereas most other jurisdictions have used the costs incurred by the incumbent retailers as the basis for setting standard tariffs, and have not included the costs of customer acquisition.

However, where new retailers enter the market, the number of customers served by the incumbent retailer on standard tariffs can be expected to decline over time. Besides any consideration of customer acquisition costs, if the number of customers served by an incumbent retailer decreases, the total cost per customer of that retailer is likely to increase due to the fact that any fixed costs will need to be amortised and recovered over a smaller customer (or sales) base.

Most regulatory decisions on retail prices in Australia have not made any explicit allowance for these losses of scale. There are several possible reasons for this, which could include the following:

- It was assumed that the retailers offering standard prices would still maintain scale even with some loss of customers.
- The increase in retail costs per customer from some loss in scale was not considered to be significant.

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<sup>58</sup> IPART reported that these costs included sales overheads; credit checking; communications, stationery, information booklets and confirmation packs; data and processing, customer transfers and registrations; door to door, commission and agent costs per sale; postage; and telecommunications costs.

<sup>59</sup> In its final decision, IPART adjusted its earlier draft decision estimates downwards by \$5/year from the previous overall result of \$35/year. This downwards adjustment was reported to have been made in order to account for any double counting between retailer operating costs and customer acquisition costs.

8 June 2009

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- The allowance given for retail costs in the regulatory decisions was thought to be sufficient to cover the actual retail costs incurred even with some loss in scale.
- Even without an explicit allowance for these costs, retailers were choosing of their own accord to spend money on customer acquisition and retention and thus maintaining scale, even though this was not a requirement for serving customers on standard contracts. Therefore, there was no need for any further allowance for the costs of losing scale.

A notable exception is a previous determination of ESCOSA of standing contract retail prices for 2005-07, where explicit allowance was made for increasing operating costs to allow for loss of scale. ESCOSA stated:<sup>60</sup>

*The Commission notes that a significant proportion of retail operating costs are attributable to salaries. It further notes that many of the remaining costs are fixed, and will not fall in direct proportion to the number of customers (e.g. billing system, call centre). However, the costs of these systems can be spread by AGL SA over its market contract gas and electricity customers.*

Such an allowance can be seen as an alternative approach for capturing the dynamic effects of a competitive market on the costs incurred by an incumbent retailer.

#### *Recent decisions in ACT and SA*

As noted above, the IPART decision of June 2007 was the first regulatory decision that made an allowance for customer acquisition costs in setting the standard (regulated) prices in Australia.

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<sup>60</sup> *Electricity Standing Contract Price, Price Determination, ESCOSA, December 2004.*

8 June 2009

Recent determinations in the ACT and SA have since taken this determination into account:<sup>61</sup>

- A draft determination by ICRC in the ACT in 2007 proposed an allowance of \$15.09/customer for customer acquisition costs.<sup>62</sup> This equated ICRC's draft determination of \$110/customer (comprising a basic figure of \$94.91 plus \$15.09 customer acquisition costs), with IPART's draft determination of \$110/customer (comprising a basic figure of \$75 plus \$35 customer acquisition costs<sup>63</sup>). However, in its final determination, ICRC decided not to allow any recovery of customer acquisition and retention costs in its benchmark cost base. This decision was made on the basis that ICRC believed that the negative social impact of the inclusion of such costs in this instance outweighed the need to reduce barriers to new entry. ICRC also stated that such costs could be argued to be low on a per customer basis and could be argued to be covered by the CPI allowance that was being applied to the retail operating costs.<sup>64</sup>
- The ICRC again confirmed its decision not to make an allowance for customer acquisition costs in its draft<sup>65</sup> and final<sup>66</sup> decisions in 2008, notwithstanding strong inputs from stakeholders in submissions requesting and arguing that the ICRC should make such an allowance.

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61 A further recent determination by OTTER in Tasmania (September 2007) did not need to consider customer acquisition costs, because FRC has not been implemented in Tasmania.

62 *Retail Prices for Non-contestable Electricity Customers*, Draft Decision, ICRC, May 2007.

63 As noted above, in its final decision, IPART adjusted these earlier draft decision estimates downwards by \$5 per customer to account for any double counting between retailer operating costs and customer acquisition costs.

64 *Retail Prices for Non-contestable Electricity Customers*, Final Decision and Price Direction, ICRC, June 2007.

65 *Retail Prices for Non-contestable Electricity Customers*, Draft Decision, ICRC, April 2008.

66 *Retail Prices for Non-contestable Electricity Customers*, Final Decision and Price Direction, ICRC, June 2008.

8 June 2009

- In SA in 2007, ESCOSA departed from its previous position where allowance had been made for increasing operating costs to allow for loss of scale. Instead, ESCOSA set an allowance for retail operating costs that reduces in real terms by 4.1% per annum. ESCOSA justified this on the basis of AGL SA's projected reductions in operating costs, notwithstanding any loss of scale.<sup>67</sup> ESCOSA also declined to make an additional allowance for customer acquisition costs over and above the allowance it was already making for retail operating costs. ESCOSA made this decision based on its assessment that its allowance for retail operating costs was already sufficient to include customer acquisition costs. In making this decision, ESCOSA took into account actual cost information provided by AGL SA on its overall retail operating costs, including customer acquisition costs.<sup>68</sup>
- In a determination of gas standing contract prices in 2008, ESCOSA again did not provide an allowance for acquiring new customers in the retail operating cost allowance. ESCOSA's basis for its decision-making was that it expected efficiencies in Origin Energy's operations to limit any increase in overall retail operating costs – ESCOSA stated that cost efficiencies and productivity growth could be expected to at least offset any real increases in retail operating costs for each year of the price path period.<sup>69</sup>

#### *AEMC findings*

In its review of the effectiveness of competition in South Australia, the AEMC has reported that in its First Final Report it is "incorporating an explicit allowance of between \$80 and \$150 for customer acquisition costs".<sup>70</sup>

#### *Previous application to the calculation of the BRCI in Queensland for 2008-09*

The Authority's Final Decision on the BRCI for 2008-09 made an allowance for customer acquisition and retention costs to maintain scale.

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67 While not stated directly by ESCOSA, it would seem to reflect a change by ESCOSA from consideration of AGL SA's position in SA in isolation to having regard to AGL's overall cost structure as a national retailer. This in turn would be consistent with AGL's own moves to consolidate its systems nationally and to increase its efficiency nationally through investment in IT systems as a part of Project Phoenix.

68 *2007 Review of Retail Electricity Price Path*, Final Inquiry Report & Price Determination (Public version), ESCOSA, November 2007.

69 *2008 Gas Standing Contract Price Path Inquiry*, Final Inquiry Report & Final Price Determination, ESCOSA, June 2008.

70 *Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia*, AEMC, First Final Report, 19 September 2008, page 37.

8 June 2009

IPART at the time provided the only available benchmark. IPART was considering a new entrant, where all customers have to be acquired, and therefore its calculated extra allowance per customer was added to all customers. However, in calculating the BRCI, the retailer under consideration is not a new entrant. Rather it is already at scale, and the intention of the allowance is to enable the retailer to retain the same customers and the same scale. Therefore, the acquisition and retention costs would only be incurred to win or retain customers to the extent that other retailers may be able to win them away from the retailer under consideration. Thus the acquisition and retention costs were directly related to the extent of competitive activity and churn rates.

The final allowances that IPART determined for customer acquisition costs were:

- For residential customers: \$29/year – based on amortisation of acquisition costs over an eight-year period of customer retention;
- For small business customers: \$37/year – based on amortisation of acquisition costs over a six-year period of customer retention; and
- A weighted average of these figures for residential and small business customers gave an overall result of \$30/year.<sup>71</sup>

IPART annualised the customer acquisition costs based on assumptions of the number of years for which acquired customers would be retained. In assessing the BRCI for 2008-09, we commented that there was not yet enough data available to estimate for how many years customers acquired under FRC in Queensland will be retained, and our analysis of the requirements for the calculation of the BRCI also suggested that costs should be allowed where they are occurred, and not annualised over some future uncertain period of time.

In its draft decision, IPART had estimated customer acquisition costs for 2007-08 to be \$200 per acquired customer, but then in its final decision it reduced its resulting annualised cost figure per acquired customer from \$35/year to \$30/year. This downwards adjustment was reported to have been made in order to account for any double counting between retailer operating costs and customer acquisition costs.

Alternatively, this downward adjustment could be considered as being equivalent to customer acquisition costs being  $\$200 * 30 / 35 = \$171.43$  per acquired customer in 2007-08, with adjustment for inflation in following years. This was the basis on which the BRCI allowance for customer acquisition was set for 2008-09.

We also included in the BRCI calculations for 2008-09 an allowance of \$100.00 for a transfer to a market contract in 2007-08, again with adjustment for inflation in following years.

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<sup>71</sup> *Promoting Retail Competition and Investment in the NSW Electricity Industry – Regulated Electricity Retail Tariffs and Charges for Small Customers 2007 to 2010, Final Report and Determination, IPART, June 2007.*

8 June 2009

*Application to the calculation of the BRCI in Queensland for 2008-09*

The allowances for customer acquisition costs in 2008-09 were \$20.08/customer for switches between retailers, and \$6.57/customer for transfer to a market contract without switch of retailer. These values are retained now, in order to maintain the integrity of the index.

*Application to the calculation of the BRCI in Queensland for 2009-10*

Carrying forward the decision from 2008-09 without amendment of costs would give the following results:

- The allowance for customer acquisition costs for switches between retailers should be \$171.43 per acquired customer in 2007-08, with adjustment for inflation in following years.
- The allowance for transfer to a market contract without switch of retailer should be \$100.00 in 2007-08, again with adjustment for inflation in following years.

*Application of inflation to the calculation of the BRCI in Queensland for 2009-10*

We previously estimated that labour costs account for approximately 60% of total retail operating costs. Using the inflation factors from section 2.11 above, applying the WPI inflation factors to 60% of the retail operating costs, and the CPI inflation factor to the remaining 40% would give the following results for the cost of each transfer between retailers and between contracts with the same retailer in 2009-10, if there are no changes made to the cost numbers:

- \$181.83 for a transfer between retailers; and
- \$106.07 for a transfer to a market contract without switch of retailer.

*Customer acquisition costs – approach to the calculation of the BRCI in Queensland for 2009-10*

Our approach in this Final Report is as in the Second Report. We apply the inflation adjusted allowance for switches between retailer and transfers to a market contract without switch of retailer to the same number of switches and transfers as was projected in the Addendum Report for 2008-09.

Switches between retailers

- $\$181.83 * 217,536 / 1,978,965 = \$19.99$

Transfers to a market contract with the same retailer

- $\$106.07 * 122,032 / 1,978,965 = \$6.54$

8 June 2009

#### 4.2.8. Summary of the results for retail costs

Table 32 below shows a summary of the results for the calculation of retail costs for 2008-09 and 2009-10.

**Table 32: Summary of retail costs (\$/customer)**

Cost Item	2008-09	2009-10
<b>Retail costs benchmark excluding customer acquisition costs (CAC)</b>	\$80.96	\$83.19
<b>CAC for transfers between retailers</b>	\$20.08	\$19.99
<b>CAC for transfers to a market contract with the same retailer</b>	\$6.57	\$6.54
<b>Total retail costs (\$/customer)</b>	<b>\$107.62</b>	<b>\$109.72</b>

Source: CRA analysis

Section 6 below shows the results of multiplying the retail costs for each year shown in Table 32 above with the figures for customer numbers that were given in section 4.1 above.

### 4.3. RETAIL MARGIN

#### 4.3.1. Terminology

The **gross margin** of an electricity retailer is defined as being the retailer's retail revenue minus energy purchase costs, transmission and distribution charges, fees and levies.

Gross margin includes the retailer's operating costs, and the **net margin** is what remains after the retailer's operating costs are subtracted from the **gross margin**. It is the **net margin** that is referred to as the "retail margin" in the Queensland instruments regarding calculation of the BRCI.

Recent regulatory decisions in Australia have considered operating costs separately from net margin, and that method of analysis has also been used in determining the BRCI for each year in this project. A view has been taken on what is an appropriate net margin for the retailer to expect in each of the two years under consideration.

8 June 2009

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Net margin is usually presented as a percentage of total revenue, and thus it is defined as gross margin minus retail operating costs, divided by total revenue. However, recent regulatory decisions in South Australia have defined net margin as a percentage of the retailer's "controllable costs", i.e. it is defined as gross margin minus retail operating costs, divided by wholesale purchase costs plus retail operating costs.<sup>72</sup>

Thus clarity is needed when quoting margins to understand what they represent. With that clarity, a conversion of any % value to a \$/MWh figure to add to the other BRCI cost components is quite straightforward.

Retailers need to expect to earn a sufficient net margin to attract the risk capital necessary to provide an energy retailing service. What investors require by way of expected net margin will depend on various risks deemed to be inherent in the business. Over time, failure to meet or exceed these net margin expectations would be consistent with an inability of the business to sustain necessary and appropriate investment and/or to remain financially viable.<sup>73</sup>

Thus, the net margin is intended to provide an appropriate return for the capital that is invested in the retail business, including working capital and provision for bad debts. Determination of the appropriateness of different levels of expected net margin needs to reflect various business and industry risk factors. If the level of regulated prices is set too low, the resulting net margin could be too low to facilitate entry into the business (or expansion of activities by existing participants), impairing the realisation of the broader policy objective of supporting the development of robust competition in the retail sector over time.

In this analysis, a key issue in determining the appropriate net margin has been the risks that face the retailer. The major risks are typically volume and price risks.

- Volume risks come through customers' usages changing unpredictably, and through gains and losses of customers in the FRC environment.
- Price risks come from volatility of wholesale energy prices.

When determining the risks that are taken into account in the margin calculations, it is important to ensure that costs of risks are not missed or double counted. In particular, the approach to determining appropriate energy costs must be consistent with the net margin calculation, in regard to where compensation for risks lies.

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<sup>72</sup> *Electricity Standing Contract Price – Price Determination*, ESCOSA, December 2004, and subsequent ESCOSA determinations of electricity and gas standing contract prices have defined net margin as a percentage of the retailer's "controllable costs".

<sup>73</sup> This discussion of net margin is based on *Electricity and Gas Standing Offers and Deemed Contracts (2004-2007)*, prepared by CRA for Energy and Security Division, Victorian Department of Infrastructure, December 2003.

8 June 2009

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The approach taken in this study for calculating an allowance for purchasing of energy has taken into account and specifically made an allowance for hedging costs, based on how an efficient retailer would operate in the market. However, there remains the risk that a retailer will purchase energy at a price higher or lower than the price that has been calculated here. The price that a retailer will pay for hedges will depend on many factors, including the timing of purchases. This will mean that the retailer's average purchase price will deviate from the average cost that has allowed here. Therefore, the approach in this study does not eliminate price risk for a retailer.

There is also a volume risk for the retailer. The average price is based on a historic load shape that will differ from the actual load shape for which a retailer has to purchase energy. For example, if there are high demand peaks due to hot weather that lead to correspondingly high pool and contract prices, a retailer will incur a higher average purchase cost than if the load shape is flatter due to milder weather.

#### 4.3.2. Submissions to the draft First Report regarding retail margin

The relevant submissions to the draft First Report regarding retail margin are summarised here.

**AGL** stated that it remained of the view that higher capital costs must be taken into account in the BRCI calculations.

**Origin Energy** noted with concern that the impact of increased costs of capital (particularly working capital) had not been addressed. Origin Energy also stated that the BRCI is calculated on the basis of changes in various cost inputs for a theoretical retailer. Knowledge of a given retailer's actual costs, or changes in costs, was therefore said not to be relevant to this framework.

Origin Energy discussed the conceptual basis for considering the elements of retail margin and why margin requirements may change over time. It includes (simplistically) two components:

- Risk free rate of return on capital investment; and
- Market risk premium.

Changes in the cost of capital are relevant to the first component; changes in the risk profile of the business are relevant to the second component.

Regarding the cost of capital, Origin Energy noted that owners of transmission and distribution assets have had higher costs of funds recognised by the regulator.

8 June 2009

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Regarding the risk profile, Origin Energy raised concerns that other parts of the BRCI calculations do not fully capture the retailer's risks, and those shortfalls should be taken into account here in the retail margin. Origin Energy also raised concern that the BRCI approach may mean that if a step change is not recognised in the year in which it occurs then it may never be fully captured in the BRCI. This was said to be a risk that does not exist in other jurisdictions.

Origin Energy also questioned the basis of the assumption that the retail margin should not be affected by the change in the timetable for the determination of notified prices for 2009-10 which was required by the Certificate of Delegation that was current at the time. Origin Energy noted that in this particular instance the circumstances involve setting a "fixed price" for the provision of retail services seven to eight months in advance of delivery, and well before the cost parameters are known. A retailer in a competitive market faced with this proposition would seek an additional premium in the price compared to a price offered when cost inputs were known.

#### **4.3.3. Summary of submissions to the Second Report and workshop regarding retail margin**

This section of the report summarises comments related to the retail margin that were received in response to the Second Final Report and the Authority's Draft Decision. As a result, not every submission is mentioned.

##### *Origin Energy*

Origin reiterated the comments it made in response to the Draft Second Report that the *Electricity (Retail Billing Guaranteed Service Level Scheme) Code* must either be accounted for as a retail cost or an increased risk (or both). If it is accounted for in whole or part as an increased risk, this should be reflected in a corresponding increase in the net margin.

More generally Origin submitted that (a) they had experienced increased costs for funding working capital, and (b) the rate of return and cost of capital are logically higher than those of a monopoly business and, as a result, regulatory decisions regarding the WACC and rates of return for distribution and transmission entities should be seen as values that the corresponding figures for a retailer must exceed.

#### **4.3.4. Conclusion on retail margin in previous years of calculation of the BRCI**

Based on a benchmarking approach, a retail margin of 5% of revenue was deemed to be an appropriate retail margin in previous years of calculation of the BRCI.

8 June 2009

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#### 4.3.5. Conclusion on retail margin for 2009-10

In order to determine whether the retail margin should be changed in 2009-10 from the previous years' value of 5%, we have considered what if anything has changed in the risk profile of the retailer that is considered in the BRCI framework in 2009-10 as against in previous years. We have concluded that there has been no particular change in the characteristics of the retailer. We believe that the margin that the retailer would seek to obtain in Queensland in 2009-10 would not be materially different from what it would seek to obtain in Queensland in previous years.

## 5. NETWORK COSTS AND OTHER RELEVANT COSTS

### 5.1. NETWORK COSTS

To maintain the integrity of the index, in the re-calculation of the BRCI for 2008-09 we are retaining the previously used value of \$2,131,100,000 for network costs in 2008-09.

The Authority has provided us with network costs of \$2,381,590,000 for the calculation of the BRCI for 2009-10.

### 5.2. OTHER RELEVANT COSTS

As discussed in section 2.2 above, the Act allows for the calculation of the BRCI to include *any other relevant costs* that the Authority considers to be relevant. Careful consideration has been given to what those costs might be, and the view has been reached that as in other regulatory decisions on retail costs in Australia all the relevant costs should be and have been taken into account as the cost of energy, network costs or retail costs as appropriate, and there are no other relevant costs to be included here.

8 June 2009

## 6. RESULTS

Table 33 below shows a summary of the final results for the calculation of BRCI for 2008-09 and 2009-10 as presented in this report.

These BRCI calculations equate to a year-on-year increases from 2008-09 to 2009-10 of 11.82%.

**Table 33: BRCI calculation results**

Cost Item	2008-09	2009-10
<b>Cost of Energy (\$/MWh)</b>	\$54.66	\$61.20
<b>NEM Load (L) (MWh)</b>	37,039,715	36,850,890
<b>Total Cost of Energy (\$)</b>	<b>\$2,024,530,502</b>	<b>\$2,255,416,595</b>
<b>Retail Costs (\$/customer)</b>	\$107.62	\$109.72
<b>Customer Numbers</b>	1,928,620	1,978,965
<b>Total Retail Costs excluding retail margin (\$)</b>	<b>\$207,549,501</b>	<b>\$217,134,133</b>
<b>Total Network Costs (\$)</b>	<b>\$2,131,100,000</b>	<b>\$2,381,590,000</b>
<b>Other Relevant Costs (\$)</b>	<b>\$0</b>	<b>\$0</b>
<b>Total Benchmark Retail Cost excluding retail margin (\$)</b>	<b>\$4,363,180,003</b>	<b>\$4,854,140,728</b>
<b>Margin on Revenue (%)</b>	5.00%	5.00%
<b>Margin on Revenue (\$)</b>	<b>\$229,641,053</b>	<b>\$255,481,091</b>
<b>Total Benchmark Retail Cost (R) including retail margin (\$)</b>	<b>\$4,592,821,056</b>	<b>\$5,109,621,819</b>
<b>BRCI for the Year (equals R / L) (\$/MWh)</b>	<b>\$124.00</b>	<b>\$138.66</b>
<b>BRCI for the Year (equals R / L) (¢/kWh)</b>	<b>12.40</b>	<b>13.87</b>
<b>Implied year-on-year increase in the BRCI (%)</b>		<b>11.82%</b>

## APPENDIX A: OUTLINE OF CONSULTANCY FROM THE TERMS OF REFERENCE

The consultant will be required to assist the Authority to calculate a BRCI for 2009-10, based on the estimated total cost of electricity in 2009-10 and the National Electricity Market (NEM) load for Queensland in 2008. Two reports to the Authority are required as part of this consultancy.

In its first report, the consultant will be required to propose an approach for determining the BRCI subject to the requirements set out in the *Electricity Act 1994*, the *Electricity Regulation 2006* and the 11 March 2008 delegation certificate from the Minister to the Authority.

The Authority established the framework for determining each element of the benchmark retail cost index in its May 2008 Final Decision on the 2008-09 BRCI. It is currently expected that the same framework will be adopted in calculating the BRCI for 2009-10. Given the shortened timeframe for this assessment, it is currently not anticipated that there will be any changes to the method of calculation, and therefore no requirement to recalculate the BRCI for 2008-09. However, the shortened timeframe for this review will require data for some elements of the BRCI, which has in previous years been available as actual data, to be forecast.

The consultant will be expected to respond to issues raised in submissions received by the Authority in response to an interim consultation notice.

In a second report to the Authority, the consultant will be required to update its first report to take account of more recent information and respond to submissions received from interested parties in relation to the Authority's Draft Decision. The consultant will be required to attend and participate in a workshop on or around 27 August 2008 following release of a draft version of its first report.

8 June 2009

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## APPENDIX B: APPROACHES USED TO DETERMINE ALLOWABLE ENERGY COSTS IN OTHER JURISDICTIONS

The approach to calculating the energy component of the prescribed retail tariffs varies between jurisdictions in the NEM. These are summarised below for Victoria, South Australia and NSW:

### B.1 VICTORIA

In Victoria, CRA was engaged by the Victorian Government to determine appropriate allowances for costs, including wholesale energy, in retailers' standing tariff offers for the year 2003, and then for the four-year period 2004 to 2007 inclusive. The analysis of energy costs undertaken by CRA aimed to determine the benchmark range that a prudent and efficient retailer should be able to match, given reasonable purchasing decisions and risk policies.<sup>74</sup> It did not use an LRMC-based approach. Instead it involved:

- Determining how much contract volume is purchased and the time periods over which these purchases take place; and
- Applying benchmark prices to cost the purchases using publicly available contract prices.

AFMA data was used in determining the contract prices because it is publicly available, and is based on a survey sample of contract market participants, so, while it has limitations, it can give a good indication of market prices.

Each year was divided into four quarters and a block approach was used to model energy purchases through swap contracts (flat, peak and off-peak) and cap contracts. A benchmark approach was used to estimate swap contract costs using the AFMA data, with the contracts assumed to be purchased over a 24 month period in advance of the year for which the energy is being purchased. Cap prices were calculated using a proxy of an open cycle gas turbine, assuming a range of input costs. Finally an additional allowance was made for residual risks such as contract mismatch and demand variability.

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<sup>74</sup> *Electricity and Gas Standing Offers and Deemed Contracts (2004 – 2007)*, CRA, December 2003.

8 June 2009

## B.2 SOUTH AUSTRALIA

In South Australia, the Allen Consulting Group (ACG) was engaged by the Essential Services Commission of South Australia (ESCOSA) to determine the wholesale energy cost that should be built into South Australian electricity retail standing contract prices, for the three and a half year period starting January 2005. The approach taken was to calculate the cost that a prudent and efficient retailer would incur in purchasing energy. ACG assumed that a prudent retailer should seek to purchase energy at the best possible price, while appropriately managing risk by contracting to levels that cover at least expected demand under medium growth assumptions.<sup>75</sup>

ACG developed five scenarios that have different forecasts of demand and pool prices. ACG then sought to identify the optimal contracting strategy for the retailer that minimised the financial impact of the variability in load and prices across the scenarios.<sup>76</sup>

This approach was used in preference to using the LRMC as a basis for determining the allowance for wholesale energy costs. However, the Electricity Supply Industry Planning Council (ESIPC) provided a report to ESCOSA on the LRMC of energy based on a mix of base load and peaking generation to meet the mix of small customer load (i.e. new entrant prices).<sup>77</sup> These new entrant prices were used by ACG as an input to scenarios where pool prices averaged new entrant levels, and in calculating new entrant price premiums for contracts.<sup>78</sup>

ESIPC estimated the LRMC based on the optimal mix of plant to supply the load profile applicable to the small customer segment of the market reliably, assuming it is a standalone market. For each plant type it developed a new entrant cost analysis model, based on a cash flow approach, to evaluate the \$/MWh price required by a new entrant generator such that the project is financially viable. It then used an optimising algorithm within a spreadsheet model to determine the optimal mix of base load and peaking/reserve plant such that the LRMC for the load was minimised.

This approach adopted in South Australia differs from the framework for calculating the BRCI. It places a greater emphasis on contract and pool prices for determining the cost of purchasing energy and uses the LRMC only as an input to pool scenarios.

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<sup>75</sup> *Final Report Energy Wholesale Price Study*, ACG, 13 September 2004, p1.

<sup>76</sup> *Inquiry into Retail Electricity Price Path Final Report*, ESCOSA, March 2005, p43.

<sup>77</sup> *Estimates of the Long run Marginal Cost of Supplying Electricity to Small Customers in 2005*, ESIPC, 31 August 2004.

<sup>78</sup> *Final Report Energy Wholesale Price Study*, ACG, 13 September 2004, p22.

8 June 2009

### B.3 NEW SOUTH WALES

In NSW, the approach taken in the 2004 determination and 2007 determination is similar to that in Queensland, with the LRMC forming the basis of allowed energy costs. However, the Terms of Reference for the most recent determination stipulates that the approach should, in addition, take into account hedging costs, risk management and transaction costs.<sup>79</sup> A summary of the approaches taken in 2004 and 2007 is provided below.

#### B.3.1 NSW 2004 Price Determination

For the 2004 Price Determination, IES was appointed to provide advice on the LRMC of energy. Its approach was to determine the LRMC such that each generation development program is based solely on meeting the load profile with the lowest cost combination of new entry generation.<sup>80</sup> This approach is consistent with the approach prescribed for Queensland in Section 92 of the Act.

IES considered three technologies in determining the optimal mix of generation that would meet the energy demand in NSW at lowest cost. These were black coal thermal power stations, combined cycle gas turbines and open cycle gas turbines. For each technology, IES presented three estimates of capital cost and variable operating cost (fuel plus variable operating and maintenance costs). These estimates were modelled as scenarios that represented a high, medium and low range of estimates for each capital and operating cost for each plant type. In calculating the LRMC for each retailer, IES considered each retailer's energy demand independently and did not undertake detailed modelling of the NEM.

Based on the cost of the three technologies and the load of each retailer, IES used a Linear Programming (LP) model to calculate a high, medium and low estimate of the LRMC for each retailer in NSW. IES approximated the Load Duration Curve for each retailer by using 438 data points instead of the 17,520 half-hourly load points available; this was done due to operating constraints of the LP model that IES was using. The LP program was formulated to minimise the total of annual variable costs and annualised capital costs. The mix of plant was selected by the LP program such that the shadow prices produced in each time period, which represent the marginal cost of supply in that time period or load duration segment, provide no producer surplus or deficit.<sup>81</sup>

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<sup>79</sup> *Promoting Retail Competition and Investment in the NSW Electricity Industry – Regulated Electricity Retail Tariffs and Charges for Small Customers 2007 to 2010*, Final Report and Determination, IPART, June 2007, section 6.

<sup>80</sup> *The Long Run Marginal Cost of Electricity Generation in New South Wales*, Report to IPART, IES, February 2004, p2-6.

<sup>81</sup> *The Long Run Marginal Cost of Electricity Generation in New South Wales*, Report to IPART, IES, February 2004, p2-13.

8 June 2009

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Under IPART's Terms of Reference, IES was also required to consider the cost of green energy schemes such as the MRET scheme and the NSW Greenhouse Gas Abatement scheme. However, IES excluded these green energy schemes from its calculation of the LRMC on the basis that the schemes "have fixed targets and therefore on a marginal cost basis their costs to the aggregate NSW energy demand cancel out in the calculation of marginal cost".<sup>82</sup>

### B.3.2 NSW 2007 Price Determination

For the 2007 Price Determination, Frontier Economics was appointed as the consultant to determine energy costs. The approach, as determined by IPART's Terms of Reference, required the LRMC of electricity generation from a portfolio of new entrant generation to supply the load profile of customers remaining on regulated tariffs to form the basis of allowed energy costs.

Frontier Economics adopted a similar approach to that used by IES in the previous determination, although there are key differences that are summarised below. Frontier Economics computed the least-cost mix of generation and greenhouse abatement investments to meet the retailer's load for customers on regulated tariffs, subject to meeting a system reliability target (as determined by NEMMCO) and any greenhouse emission targets.

The approach of Frontier Economics differs from that undertaken by IES in the following ways:

- The Frontier Economics approach optimises (minimises) the total fixed and variable costs of meeting demand for electricity in the NEM, taking into account interconnection between regions. This produces a series of prices in each period modelled, which are multiplied by the regulated load of the retailer in the corresponding period to determine the LRMC of providing energy for that retailer's regulated load. In contrast, the IES approach considers the retailer's load in isolation and computes the LRMC of meeting only this load without considering the total load in NSW or interconnection between regions.
- The Frontier Economics model explicitly calculates the cost of meeting the various green energy targets. The cost of purchasing NGACs are estimated on the basis of incremental costs, that is, having regard to the existing system. This approach takes account of the emission rates of the current stock of plant rather than for a new entrant plant mix that would have lower emissions. The costs of meeting the MRET target have been estimated on the same basis. In contrast, the IES approach did not explicitly model the green energy schemes.

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<sup>82</sup> *The Long Run Marginal Cost of Electricity Generation in New South Wales*, Report to IPART, IES, February 2004, p2-12.

8 June 2009

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- Frontier Economics models the cost of providing the required level of reserve capacity as determined by NEMMCO. The reserve capacity requirement for a region is generally set to the size of the largest generating unit or interconnector transmission line capacity in the respective region. In NSW, NEMMCO currently requires there to be 660 MW of reserve above the 10% Probability of Exceedance (POE) Maximum Demand. This amount remains fixed as load grows into the future. In contrast, IES concluded that *“on a marginal cost basis, given that the required reserve level remains fixed at 660 MW as load increases, reserve costs cancel out in the calculation of marginal cost”*.<sup>83</sup>

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<sup>83</sup> *The Long Run Marginal Cost of Electricity Generation in New South Wales*, Report to IPART, IES, February 2004, p2-11.

8 June 2009

## APPENDIX C: CEMOS MODEL

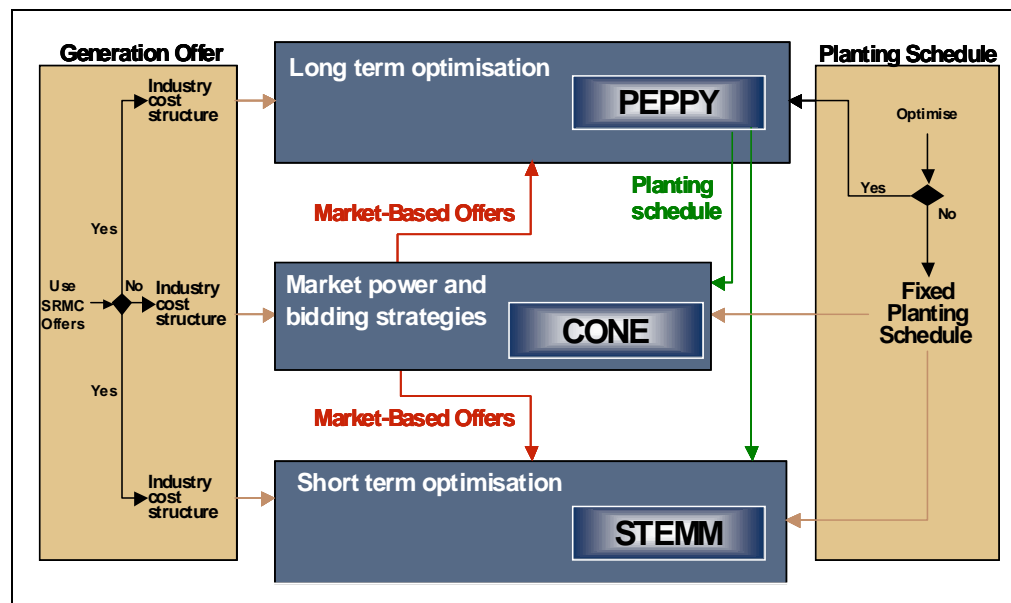
This appendix describes CRA's CEMOS model in more detail:

- Appendix C.1 describes the CEMOS modelling framework;
- Appendix C.2 describes calibration processes for CEMOS; and
- Appendix C.3 describes recent major applications of CEMOS.

### C.1 CEMOS MODELLING FRAMEWORK

CEMOS applies state-of-the-art optimisation technology and theory capable of modelling a wide range of electricity market issues. As shown in Figure 3, CEMOS comprises a core set of models with specialist focus on analysing long-term entry/exit dynamics, short-term dispatch / pricing issues and generator bidding strategies.

Figure 3: Interaction of CEMOS components



CEMOS is also supported by a set of bespoke models that are purpose-built to perform specialist analyses, e.g. detailed transmission power flow studies, gas or hydro storage optimisation and simulation, maintenance optimisation, and statistical analysis of historic spot price volatility.

Within the LRMC modelling context, only the PEPPY component of CEMOS is relevant. Modelling of half-hourly pool prices, which is used to calculate the energy purchase costs, is undertaken using the CONE and STEMM components of CEMOS.

### C.1.1 Long-term generation capacity expansion and dispatch

PEPPY, the long-term module in CEMOS, optimises electricity market investment and operation, taking into account the physical realities of the electrical power system. It provides a framework for developing insights about the implications of key market drivers over the longer term, such as the type and amount of future generation entry, longer term effects of market power, effects of longer term gas supply constraints, etc. PEPPY uses a linear programming (LP) that models the supply and demand sides together, and the fixed and variable costs associated with both resources. Key features of PEPPY include:

- A detailed consideration of fuel contracts, load growth and its temporal/spatial distribution, and new entrant capex;
- Replication of the market clearing process in the NEM;
- Use of load duration curves;
- Transmission; and
- Ancillary services.

Generation capacity optimisation decisions in PEPPY form an integral part of overall system optimisation and are made in conjunction with generation, transfer, transmission investment and load dispatch decisions. The basic premise for bringing in new capacity is that system marginal costs (or “prices”) should reach a level for the new generator to profitably recover its fixed costs including (annualised) capital investment over all future years of operation. Capacity optimisation therefore recognises:

- Demand growth and distribution of demand over seasons and peak/off-peak periods as captured by the LDC;
- Cost of capital and desired return as captured by the annualised capital cost that needs to be covered through pool revenue;
- Operating/fuel costs or, if used in conjunction with CONE, generator bids that may be higher than fuel costs;
- Demand response as captured by price-responsive or other dispatchable loads or price-responsive customer dispatched loads;
- Deterministic planned and forced outages that effectively put a limit on annual energy production;
- Reserve margin constraints which ensures NEM reliability criterion is met;
- Any additional limitation on energy production such as a fixed capacity profile for wind and geothermal energy and hydro generators; and

- Transmission constraints including contingency constraints and, to a limited extent, spinning reserve requirements in the system.

### C.1.2 Generation offer strategy using CONE

CONE is transmission-constrained Cournot model that specifically deals with generation offer creation taking into account value maximising behaviour exhibited by individual gencos.

CONE is a model for analysing market power and competition in an electricity market with few competing firms or companies (characterised as an oligopolistic market in economics parlance). Each company is assumed to maximise its own profit by adjusting the generation supplied to the market while considering the generation supplied from all other competing and non-competing companies and the responsiveness of demand. CONE, therefore, characterises the market as the companies competing solely in terms of generation quantity. This is known as a Cournot game the solution to which comprises generation levels of all firms and the resultant market price is expected to equilibrate. The Cournot-Nash equilibrium solution is found by solving the Cournot game problem, and this yields the generation levels where each company has no incentive to adjust its supply because doing so would reduce its profit. Equilibrium market price is calculated based on the equilibrium generation level.

CONE performs two major functions:

- It calculates the Cournot-Nash equilibrium solution; and
- It creates a set of generation offers based on the equilibrium outcome.

CONE formulates this problem as what is known as a mixed-complementarity problem (MCP) that can also be transformed into an equivalent nonlinear programming (NLP) problem. The MCP/NLP approach simultaneously solves for values of the market price and quantity (or, generation dispatch) variables.

The input data for CONE include:

- Cost: SRMC of each plant;
- Load: an estimate of a demand curve in each period;
- Generation: available generating capacity of each unit in each period; and
- Contracts: contract-for-difference (cfd) quantity.

CONE uses the above inputs to calculate the following outputs:

- Equilibrium quantities of generation for each plant;
- System price; and

- Generation offers that reflect the equilibrium quantity and system price.

An equilibrium solution is found for each period. Typically a multi-year horizon is considered, with each annual load duration curve approximated using non-sequential demand curves representing multiple time periods. CONE is also solved for short-term model for each hourly load condition.

Transmission constraints are modelled in CONE using a DC-approximation of AC power flow constraints. Ancillary services can also be co-optimised in CONE. In other words, CONE is a multi-commodity Cournot model that treats energy and ancillary services as “linked” commodities and gencos trying to maximise value for all commodities.

Last but not the least, CONE is set-up to perform both a perfect competition (PC) mode whereby the social welfare is maximised without considering the dead-weight loss and a Cournot oligopolistic market simulation. The model in fact always performs a PC run to work out the least cost generation target and then develops a contract cover using the PC solution to proceed to perform a Cournot simulation. Indeed the model can be used to perform a standalone perfect competition simulation.

Additional information on the CONE theory is available in the following paper that includes a comparison of outcomes for perfect and imperfect competition regimes:

*Chattopadhyay, D., Multi-commodity Spatial Cournot Model for Generator Bidding Strategy” IEEE Transactions on Power Systems, February, 2004.*

### **C.1.3 Short term dispatch analysis using STEMM**

STEMM is a short term (daily/weekly) unit commitment and dispatch model. It provides a framework to develop insights about the implications of the engineering characteristics of the gas/oil based existing/new units, shape of daily load curve and short term gaming behaviour/bidding strategies.

8 June 2009

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STEMM uses a linear program or as an alternative mixed integer program (MIP)<sup>84</sup> approach that optimises the electricity market operation over a few days up to a week taking into account the physical realities of an electrical power system and generator engineering characteristics. The basis of the mixed integer program that achieves this goal rests on the same fundamental tenets as employed for market dispatch engines in many countries including the Australian NEM Dispatch Engine (NEMDE). STEMM has a half-hourly resolution although it can easily be modified to have a higher or lower resolution.

This model seeks to:

*Achieve the least cost operation of generating units over the planning horizon which may span from a day up to a week, while observing the physical realities and security policies necessary to operate the power system securely.*

The STEMM MIP tries to achieve this fundamental goal by mimicking the market operation in the short term, and is very close in spirit to the actual market dispatch process in real-time.

The key features include:

- Detailed consideration of generating unit start-up/shutdown, ramping for energy/ancillary services;
- Replicating, where possible, the market clearing process of the system;
- Chronological load profile;
- Transmission; and
- Ancillary services.

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84 The term mixed integer program (MIP) refers to a mathematical programming problem (typically a linear program) in which (typically a small) part of the decision variables are discrete or integer in nature (i.e. these variables can assume only a few integer values e.g., 0, 100, 200 etc, but nothing in between) while the majority of the variables are continuous. A special case is when all the integer variables are binary i.e., 0 or 1. Most MIPs including the one underlying STEMM falls in this special category and the binary variables represent the ON/OFF status of the generating units. A MIP is generally a lot more computationally intensive than its linear program counterparts. More precisely, the branch and bound algorithm and its variants employed for solving a MIP involves solving potentially thousands or even millions of linear program sub-problems for even MIPs of moderate size having as low as a few hundred integer variables. The Australian version of STEMM does not use the MIP approach and uses instead a simplified linear program approach consistent with the NEMDE formulation.

8 June 2009

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## C.2 CALIBRATION OF CEMOS

In order to produce spot price forecasts, CEMOS relies on parameters such as a very short term elasticity of demand and the contract level of power stations for which no accurate estimate is available. This is because either quality data does not exist as in the case of the elasticity, or the data exists but cannot be obtained easily because it is commercial in confidence, as is the case for generation contracts. Since these parameters have profound impact on modelling outcomes, a pragmatic way to establish a working model is to find out if the model can reproduce reasonable market outcomes within a plausible range of elasticity values that have been reported in the literature, and prevailing views on contract levels in the market.

Calibration then refers to the process by which we explore the impact of alternative levels of elasticity and contract values and compare the outcomes with observed market values. The basic hypothesis is that the market is generally heavily contracted for baseload generation and less so for mid-merit and peaking generators, and that low elasticity is associated with peak period volatility.

Within these broad guiding principles, the calibration process we use involves drawing up an  $n$ -dimensional grid of the combinations of potential values of the  $n$  parameters being estimated. Then, for each combination in the grid, a series of Cournot results is produced and assessed against the observed market data including observed generation data as to its goodness of fit. The basic premise is that if the model can reliably and reasonably accurately reproduce the market outcomes, including generation, prices, market share etc. using plausible values of elasticity and contract levels (following the broad principles of how these vary with loading condition and generator types), then the model can be used with confidence to produce outcomes going forward for the same inputs on elasticity and contract values.

The contractual obligations of electricity generators (both in respect of their retailer customers and their fuel supplies) form important assumptions in modelling generator behaviour and profitability. As noted before, power stations that are highly contracted have an incentive to compete more vigorously by submitting bids at their short run marginal cost (SRMC) in electricity wholesale market. Conversely, power stations that have few contracts tend to place more “strategic” bids that are higher than SRMC.

8 June 2009

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To derive spot prices for 2008 onwards, CEMOS was calibrated based on the combination of (pseudo-) elasticity estimates and assumed (pseudo-) contract coverage (PCL) levels that yield the best fit to the observed price duration curves.<sup>85</sup> Other important indicators assessed were the total GWh generation for the year by generator type and region.

We used the 2007/08 price duration curve as the basis for calibration. As 2007/08 suffered from some extreme events relating to the effect of the drought we undertook a normalisation process whereby the price duration curve is normalised based on the average price duration curve since market start. The average price duration curve is compared against the 2007/08 price duration curve and we subsequently adjust any prices on the 2007/08 curve which fall significantly outside the normalised curve.

The following two graphs illustrate the outcomes of creating the normalised curve for Queensland and New South Wales. The 'Average' line is the average price duration curve since market start. The '2007/08' is the price duration curve for 2007/08. And the 'Normalised' curve is the resulting curve once prices that are outside the historical trend have been adjusted.

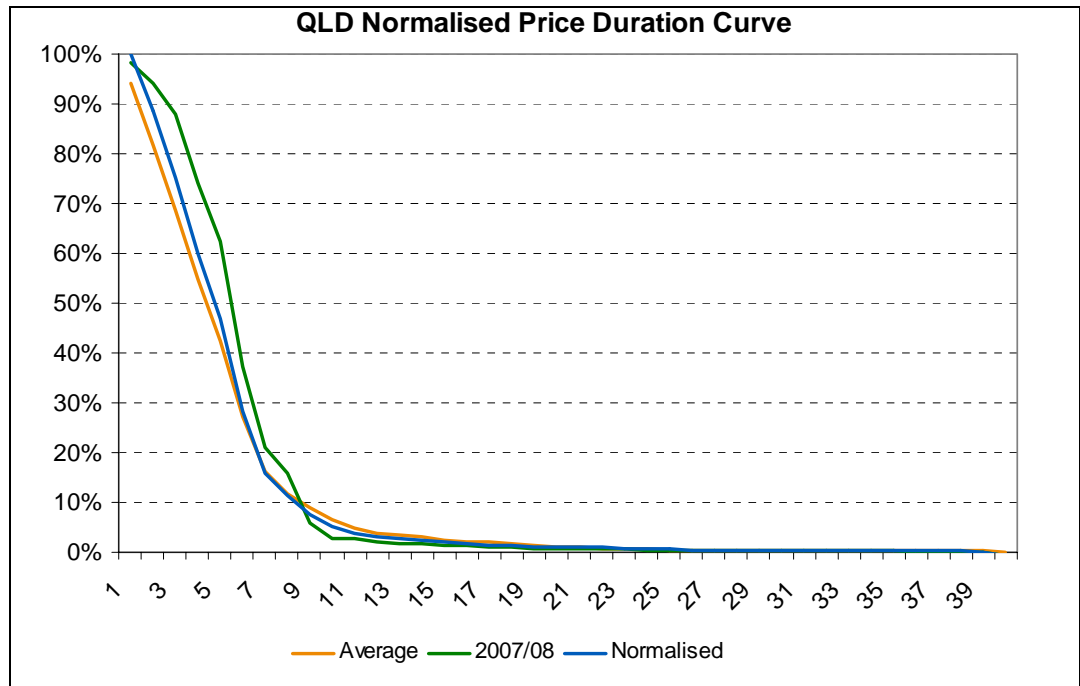
For Queensland the difference between the 2007/08 curve and the normalised curve is not great with peaking prices being only slightly higher than historical levels. However the New South Wales chart shows how different the curves can be, with prices in New South Wales being significantly flatter than what has historically been the case.

As shown in Figure 4 and Figure 5 below, CEMOS has been calibrated to historical 2007/08 market outcomes normalised for the affects of abnormal activity. These outcomes can be replicated to a reasonable degree of accuracy, including the distribution of peak/off-peak prices, assuming relatively aggressive bidding strategies.

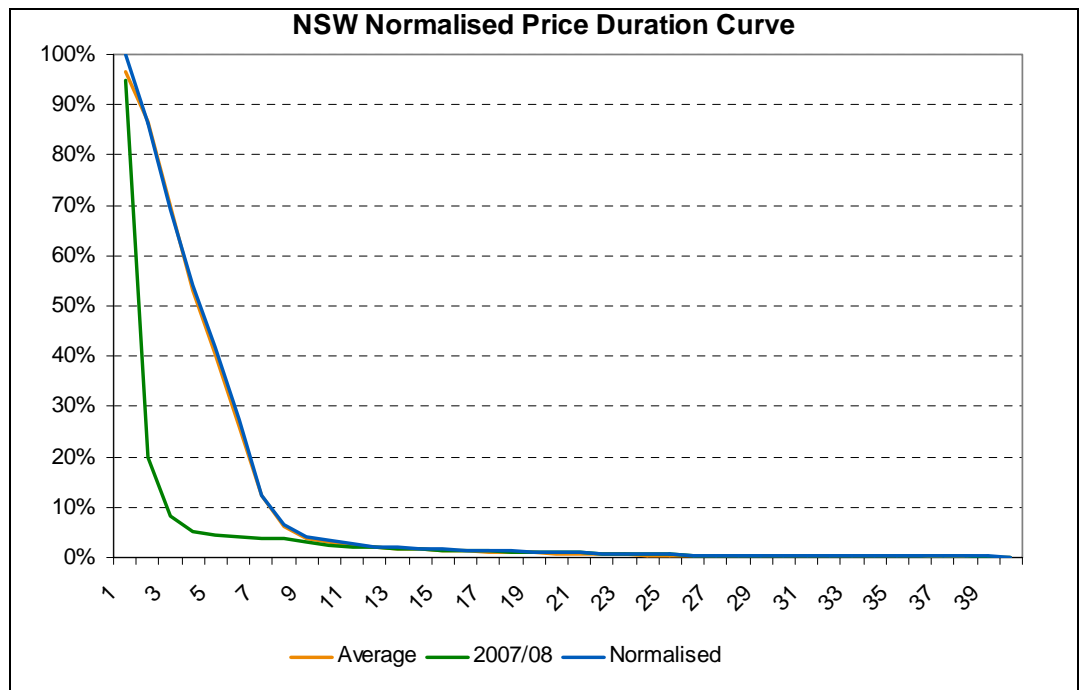
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<sup>85</sup> These are termed "pseudo-values", because they are estimated from market data with the implication that market participants behave as if they were playing a Cournot game with these parameters. See J. Tipping, E. G. Read, D. Chattopadhyay and D.C. McNickle "Can the shoe be made to fit? – Cournot modelling of Australian electricity prices" *Operations Research Society of New Zealand Proceedings*, 2005. Also, J. Tipping, E.G. Read and D. Chattopadhyay, "Incorporating Bottom-up Structures into Top-Down Models of Electricity Market", *Proceedings of International Association of Energy Economics*, 2007.

**Figure 4: Queensland Price Duration Curve Normalisation**

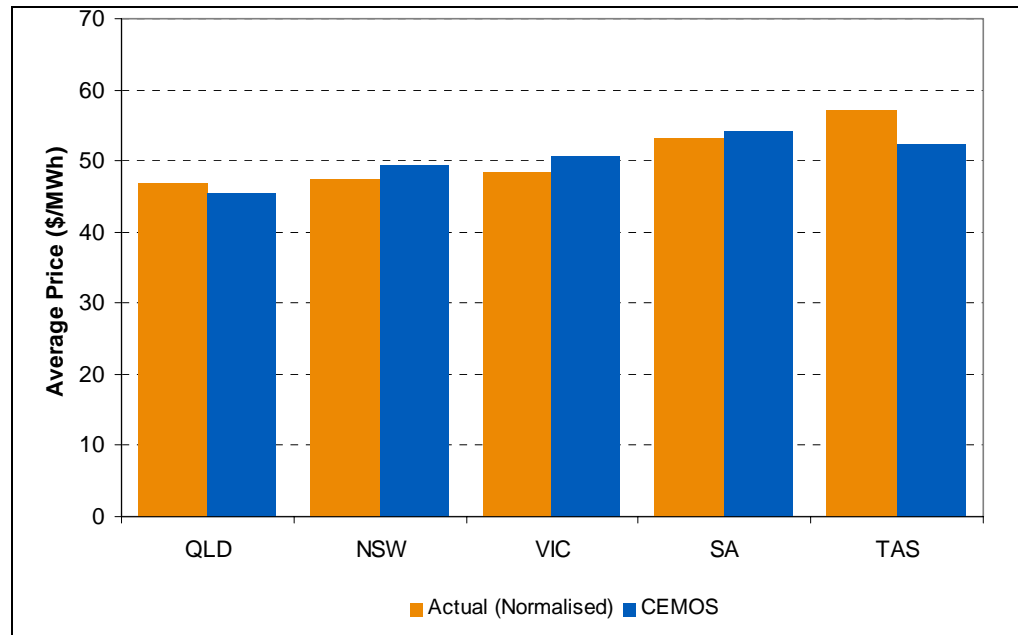


**Figure 5: New South Wales Price Duration Curve Normalisation**



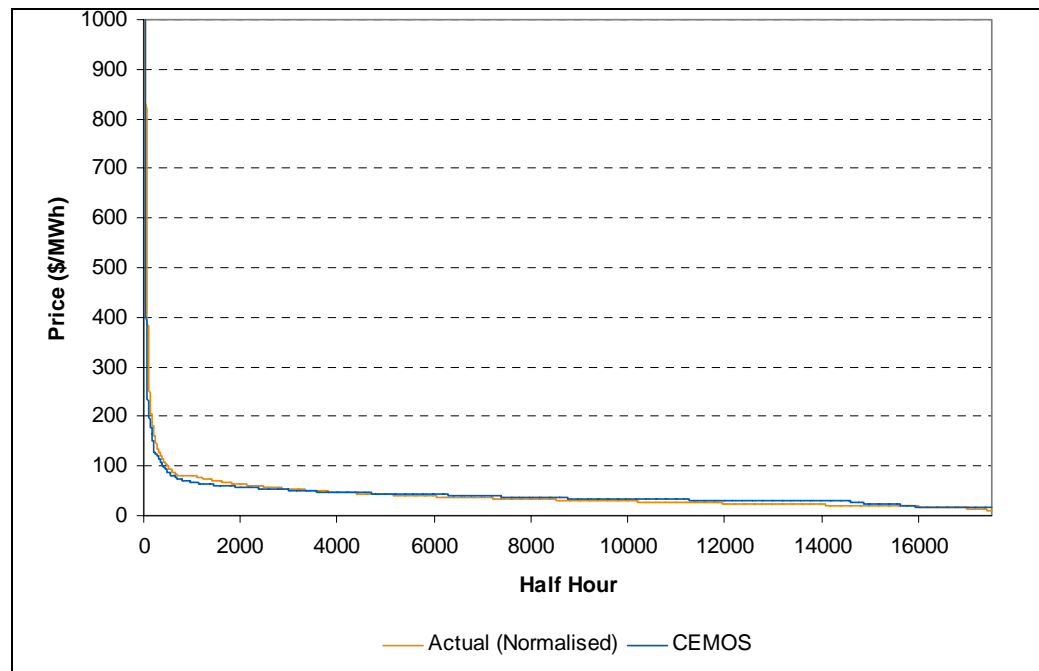
The results of the calibration are shown in Figure 6 and Figure 7, which compares actual prices from 2007/08 with the model results from CEMOS.

**Figure 6: Time-Weighted Average prices 2007/08 (\$/MWh)**



Source: NEMMCO actual data and CEMOS modelled data.

**Figure 7: CEMOS vs. actual NEM spot price duration curve for Queensland**



Source: NEMMCO actual data and CEMOS modelled data.

Notes: The price duration curve describes how frequently (in number of half-hours in the year) certain price outcomes occur.

### C.3 TRANSMISSION SYSTEM AND SCALING FACTORS

This section discusses various aspects of the transmission system modelling in the BRCI calculations for 2009-10, as follows:

- A brief overview discussion of how the CEMOS model used by CRA models the transmission system;
- Whether the generation system is built on a pre-transmission or post-transmission loss level;
- Implications of new generation siting on transmission system costs;
- How new transmission requirements are addressed in the model;
- Whether transmission loss factors can be changed over the analysis horizon; and
- Consistency of scaling factors used in the modelling.

#### *How the transmission system is modelled in CEMOS*

In the CEMOS model, the transmission capacity **between the connected NEM regions** is the current transmission system, i.e. CEMOS represents the regions of the NEM including the transmission interconnections between them. Committed but not yet commissioned transmission projects are added to the transmission capacity at their respective expected commissioning dates – these are obtained from the latest SOO<sup>86</sup> published by NEMMCO. This is not a greenfield approach to interconnection between NEM regions. Further economic or reliability augmentations are assessed manually. In order to ensure that the overall system energy balance is correct when scheduling transfers of energy between NEM regions, CEMOS applies a loss factor based on a calculation of the average of the losses implied by the inter-regional loss equations as published in NEMMCO's "List of Regional Boundaries and Marginal Loss Factors for the 2008/09 Financial Year".

**Within a NEM region**, the loss factor that applies to each generator in CEMOS which is modelled under the greenfield approach to generation is an average of the marginal losses for generators in the region, as published in NEMMCO's "List of Regional Boundaries and Marginal Loss Factors for the 2008/09 Financial Year".

CEMOS has two groups of transmission **constraints**:

- **Governing the flow of power in a transmission line:** Flow in either direction along a line must not exceed the line capacity, as specified in the latest SOO; and

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<sup>86</sup> NEMMCO's 2007 Statement of Opportunities is currently used; the 2008 Statement of Opportunities will be used when it is available.

8 June 2009

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- **Balancing of flows into and out of a node:** Total line flows into and out of each regional reference node must equal the difference between the generation flowing into the node and the off-takes. Thus, the nodal balance constraints equate demand, generation, losses, electricity flows to/from the node.

*Whether the generation system is built on a pre-transmission or post-transmission loss level*

CEMOS operates to meet the demand forecast in the SOO which is on a **post-transmission loss basis** within each region. Accordingly, the model then uses a lossless intra-regional representation and average loss representation between regions to build the generation portfolio with the order of scheduling of generation determined by generator offer prices scaled by MLFs.

*Whether the implications of new generation siting on transmission system costs can be addressed, perhaps by adding a representative capital charge to each generation plant type that is likely to have material impacts on transmission system costs (e.g. geothermal plant which will be located far from the grid and will require substantial investment in transmission extension)*

As stated above, within a NEM region, the loss factor that applies to each generator in CEMOS which is modelled under the greenfield approach to generation is an average of the marginal losses for generators in the region, as published in NEMMCO's "List of Regional Boundaries and Marginal Loss Factors for the 2008/09 Financial Year". In the BRCI greenfield approach, we do not know where new generation will be sited, and therefore have little choice but to continue to adopt the average loss factor that exists in the current transmission network. We are open to adopting an alternative approach if one can be developed in the time available.

Consistent with the greenfield approach, we do not make allowances for additional transmission costs that will be incurred due to new generation technologies. New generation capacity is assumed to be connected to the transmission system without reference to transmission costs. Additional costs could be added to the capital cost of those generators where it is believed that they will have a material impact on transmission system costs. However, adding a specific transmission charge to the cost of a new plant would imply that this was the charge that the particular plant would face. If installation of that plant was of system-wide economic benefit then under the shallow connection regime in the NEM, the plant would not face the full cost of additional transmission – although it would be borne by participants through transmission charges. This is at the heart of debate about the future transmission planning regime and allocation of costs.

8 June 2009

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*How new transmission requirements are addressed in the model, and whether that characterisation could be improved*

As mentioned above, the transmission system in CEMOS is based on transmission capacity that is currently in place, and new transmission lines (or expansions to current lines) that have been committed, as per the latest SOO. This means that our model is based on actual current and planned transmission capacity. There is currently no function to optimise expansions or new builds in the transmission system, which in practice may or may not be built in the timeframe under consideration. We note in this regard that the BRCI is undertaken for a nine-year period, which is a relatively short period from the perspective of transmission system planning. However, we do monitor the level of flow and price differences between the regions to consider if it is appropriate to add additional transmission.

As the greenfield generation system solution gets less like the existing planting, it becomes less likely that the nature and location of the existing transmission system would be the transmission required by the greenfield generation system. We need to recognise that the philosophy of the BRCI – and particularly the LRMC section of it – is not necessarily trying to quantify the costs that a retailer will face, but rather the change in the optimised costs that retailers would face from year to year. This makes the relativities in costs more important than the actual values.

*Whether transmission loss factors can be changed over the analysis horizon in reaction to where and how much generation is added*

Transmission loss factors can be changed over the analysis horizon in response to where and how much generation is added. However, as discussed above, there is no basis for knowing what the meshed network would look like if we construct a full greenfield network, and hence no basis for knowing what the loss factors would be.

*Ensure the transmission loss factors used in the modelling are internally consistent*

There are two types of scaling factors used in our modelling:

- Scaling factors are used to convert between generation terminal basis and sent-out basis (i.e. to account for the house load of generators) in the LRMC calculations; and
- In the energy purchase cost calculation, a scaling factor for Queensland is used in order to adjust settlement prices for the effect of transmission losses between the Queensland reference nodes and the transmission nodes where energy is supplied.

These are very different scaling factors, and are discussed in turn below.

8 June 2009

The **LRMC** is calculated using CRA's CEMOS model, which simulates investment and dispatch over the nine-year time horizon. NEMMCO's jurisdictional scheduled maximum demand (MW) projections are on a generator terminal basis while the energy (GWh) projections are on a sent-out basis. CEMOS models on a sent-out basis so a scaling factor for each jurisdiction is used to convert between generator terminal basis and sent-out basis. The factor varies between jurisdictions because the average house load varies with the technology type. A single factor is used for each jurisdiction because the demand estimates are provided on that basis.

The source for the factors to apply to the CEMOS modelling is the 2008 ANTS Consultation: Final Report (Table 8, page 41). These scaling factors are reproduced in Table 34 below. We note that these values are unchanged from the previous 2007 values.

**Table 34: Scaling factors to convert sent-out energy to generator terminal basis**

Region	ANTS 2008 consultation paper scaling factor
QLD	1.060
NSW	1.060
VIC	1.100
SA	1.041
TAS	1.000

Source: ANTS 2008

In the **energy purchase cost calculations**, the scaling factor for Queensland is used in order to adjust settlement prices to account for transmission losses between the Queensland reference node and the transmission nodes where energy is supplied. It is calculated from data provided by Powerlink in the 2008 Annual Planning Report (Table 3.8, page 34).

#### C.4 RECENT MAJOR APPLICATIONS OF CEMOS

CEMOS has been applied to undertake modelling analyses on a wide range of energy issues in several countries and in different market structures, including Australia, Hong Kong, Korea, Malaysia, New Zealand, Saudi Arabia, Singapore and Thailand. Table 35 provides an overview of recent applications of CEMOS.

8 June 2009

**Table 35: Selected applications of CEMOS**

Country	Applications	Client
Australia	Impact on future investment and profitability of existing generators under a range of carbon constraint scenarios and policy mechanisms	Australian National Generators Forum and the Electricity Supply Association of Australia
Australia	Projections of spot and market outcomes for 2007-2030 to support a bid for the Basslink interconnector, including hydrology and carbon price scenarios	Commercial-in-confidence
Australia	Valuation of demand side response measures (fuel cost savings, reliability improvement and capacity deferral benefits) for 2006-2025	International Energy Agency (IEA)
Singapore	Fuel competition impact on the Electricity Market of Singapore (NEMS) of the potential introduction of LNG, given existing contract structures and LNG pricing scenarios	Gas Supply Pte
Singapore	Forward pool price projections and modelling of vesting contracts to be implemented for the Singapore Electricity Market	Mirant Singapore
New Zealand	Valuation of economic benefit of 400 kV transmission alternative in the North Island of New Zealand	Transpower New Zealand
South Korea	Development of electricity market arrangements in Korea, including impact of alternative vesting arrangements, pool price projections, market power mitigation, transmission constraints, new entry optimisation	Korea Electric Power Corporation (KEPCO)
Malaysia	Review efficiency of generation dispatch process	Tenaga Nasional Berhad
Saudi Arabia	Valuation of electricity power project investment	Commercial-in-confidence
Malaysia	Model of the integrated Thailand and electricity system to provide forward electricity projections and break-even gas prices for different entry and macroeconomic scenarios	Amerada Hess
South Korea	Valuation and risk assessment for two merchant IPP investments	Commercial-in-confidence

8 June 2009

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Some of the recent modelling reports where CEMOS has been used are listed below:

- Analysis of the need for additional zones in the Australian market for the Ministerial Council on Energy  
([www.mce.gov.au/assets/documents/mceinternet/ModellingReport20041123171152.pdf](http://www.mce.gov.au/assets/documents/mceinternet/ModellingReport20041123171152.pdf))
- Analysis of transmission investment options in New Zealand conducted for Transpower New Zealand  
([www.electricitycommission.govt.nz/pdfs/submissions/pdfstransmission/draft-decision/Transpower-vo3-CRAI-transpower-modelling.pdf](http://www.electricitycommission.govt.nz/pdfs/submissions/pdfstransmission/draft-decision/Transpower-vo3-CRAI-transpower-modelling.pdf))
- Evaluation of the impact of alternative greenhouse gas policy scenarios on the electricity sector in Australia for the National Generators Forum  
([www.ngf.com.au/html/index.php?option=com\\_remository&Itemid=32&func=fileinfo&id=99](http://www.ngf.com.au/html/index.php?option=com_remository&Itemid=32&func=fileinfo&id=99))
- Review of reliability standard for the Australian Energy Market Commission  
([www.aemc.gov.au/pdfs/reviews/Comprehensive%20Reliability%20Review/aemcdocs/003CRR%20Interim%20Report%20-%20Appendix%205.pdf](http://www.aemc.gov.au/pdfs/reviews/Comprehensive%20Reliability%20Review/aemcdocs/003CRR%20Interim%20Report%20-%20Appendix%205.pdf))
- Valuation of demand side resources in Australia for the International Energy Agency  
([www.demandresponseresources.com/Portals/0/Australia/Australia\\_CRA%20Report%20on%20Demand%20Response%20Dec%2006.pdf](http://www.demandresponseresources.com/Portals/0/Australia/Australia_CRA%20Report%20on%20Demand%20Response%20Dec%2006.pdf))

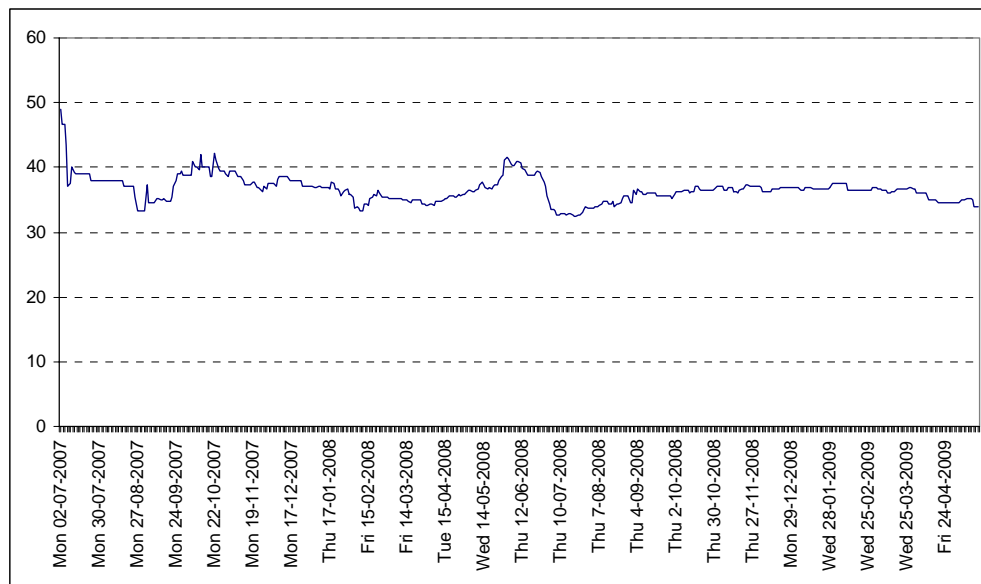
## APPENDIX D: GRAPHS OF D-CYPHA TRADE PRICES USED IN ESTIMATING THE COST OF PURCHASING ENERGY IN 2009-10

All the prices in the graphs in this appendix are in nominal \$/MWh.

### D.1 FLAT SWAP CONTRACT PRICES

#### D.1.1 Q3 2009 – July to September 2009

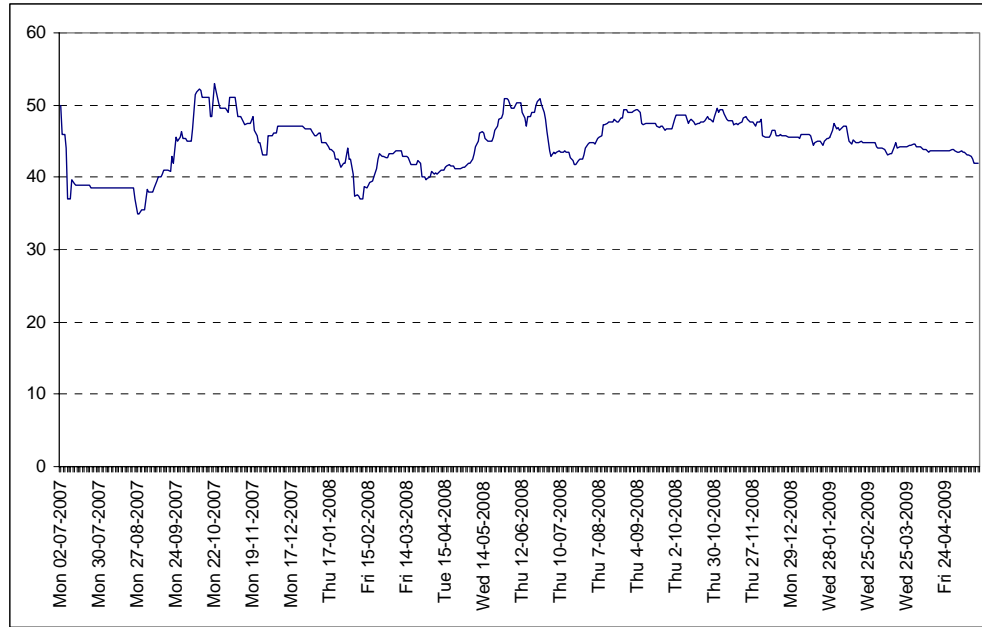
**Figure 8: d-cypha Trade prices for Queensland flat swap contracts for Q3 2009 – July to September 2009**



Source: d-Cypha Trade data

**D.1.2 Q4 2009 – October to December 2009**

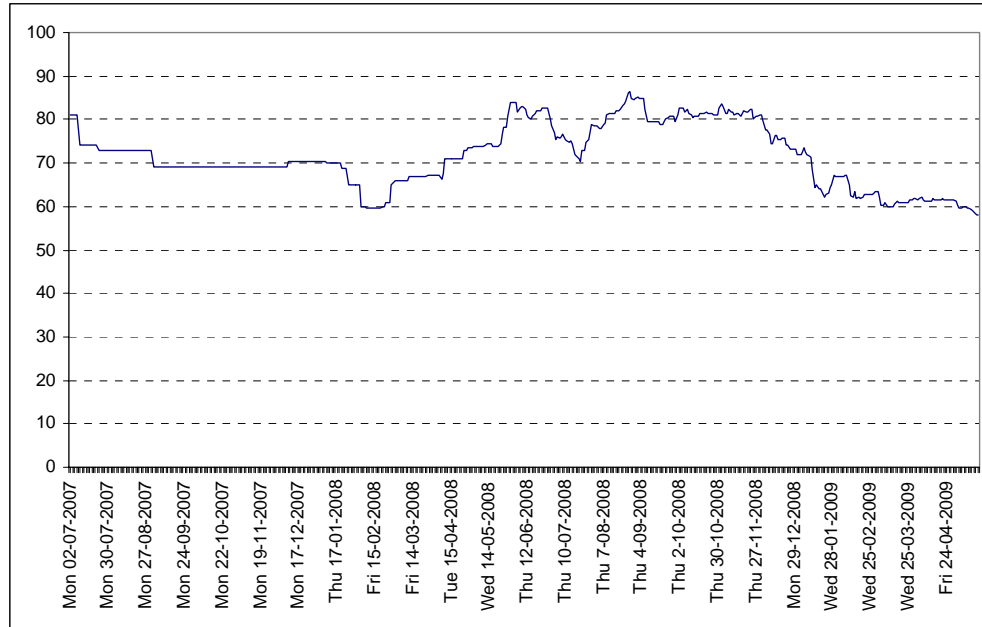
**Figure 9: d-cypha Trade prices for Queensland flat swap contracts for Q4 2009 – October to December 2009**



Source: d-Cypha Trade data

**D.1.3 Q1 2010 – January to March 2010**

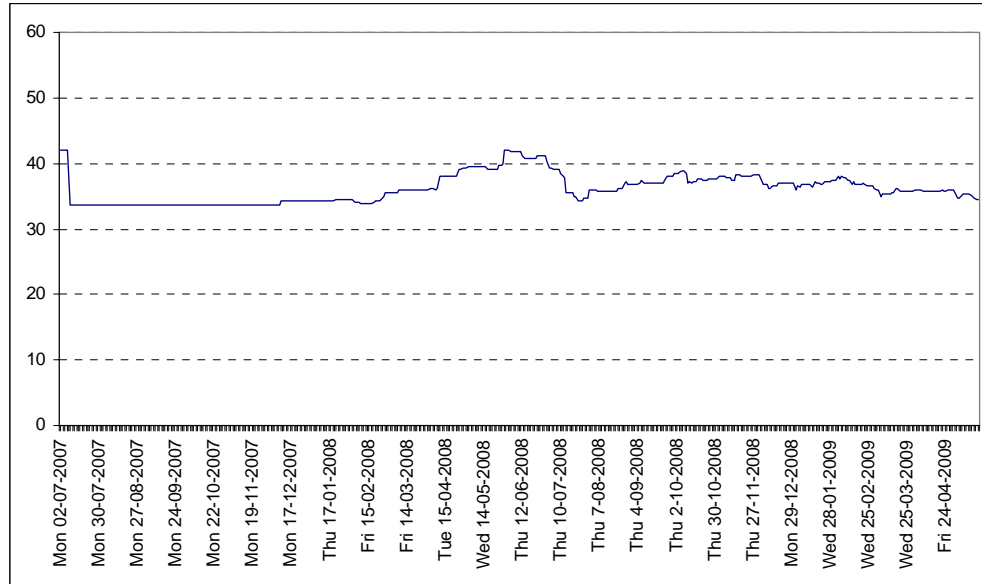
**Figure 10: d-cypha Trade prices for Queensland flat swap contracts for Q1 2010 – January to March 2010**



Source: d-Cypha Trade data

**D.1.4 Q2 2010 – April to June 2010**

**Figure 11: d-cypha Trade prices for Queensland flat swap contracts for Q2 2010 – April to June 2010**

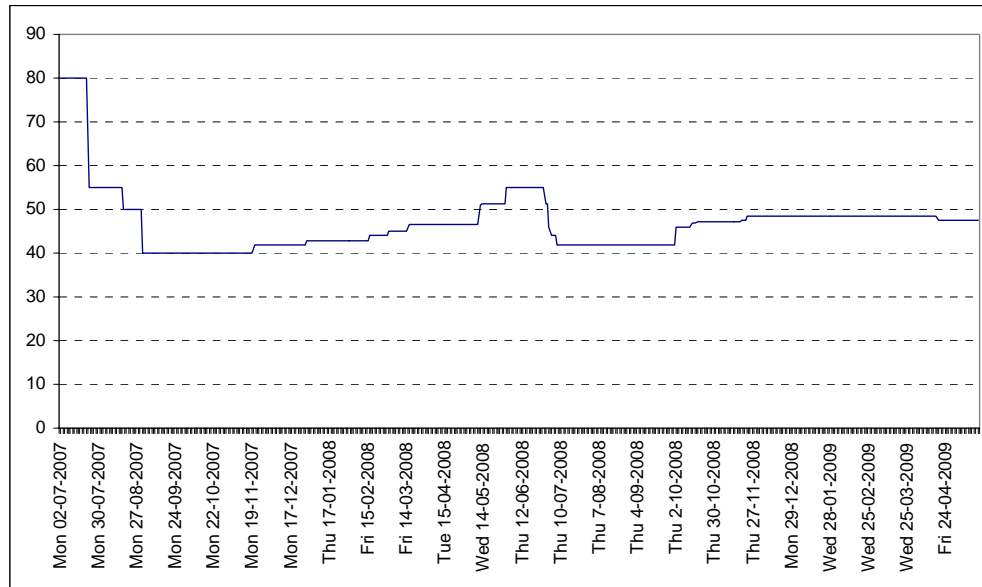


Source: d-Cypha Trade data

## D.2 PEAK SWAP CONTRACT PRICES

### D.2.1 Q3 2009 – July to September 2009

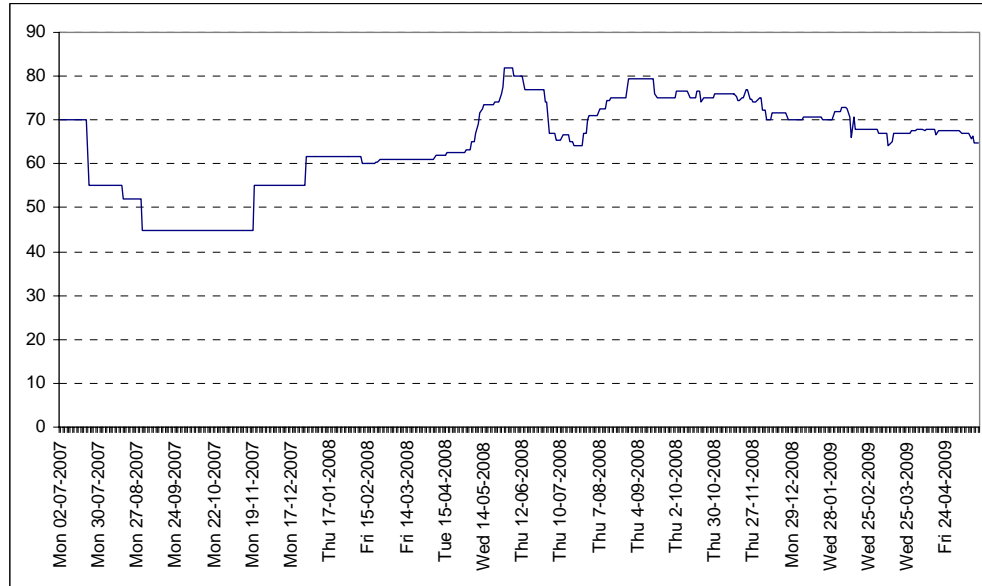
**Figure 12: d-cypha Trade prices for Queensland peak swap contracts for Q3 2009 – July to September 2009**



Source: d-Cypha Trade data

**D.2.2 Q4 2009 – October to December 2009**

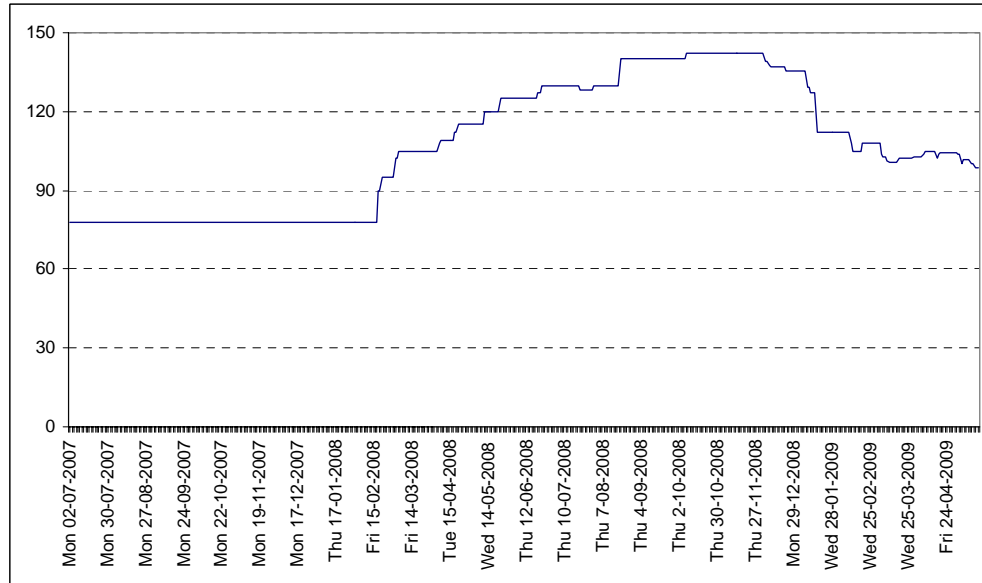
**Figure 13: d-cypha Trade prices for Queensland peak swap contracts for Q4 2009 – October to December 2009**



Source: d-Cypha Trade data

**D.2.3 Q1 2010 – January to March 2010**

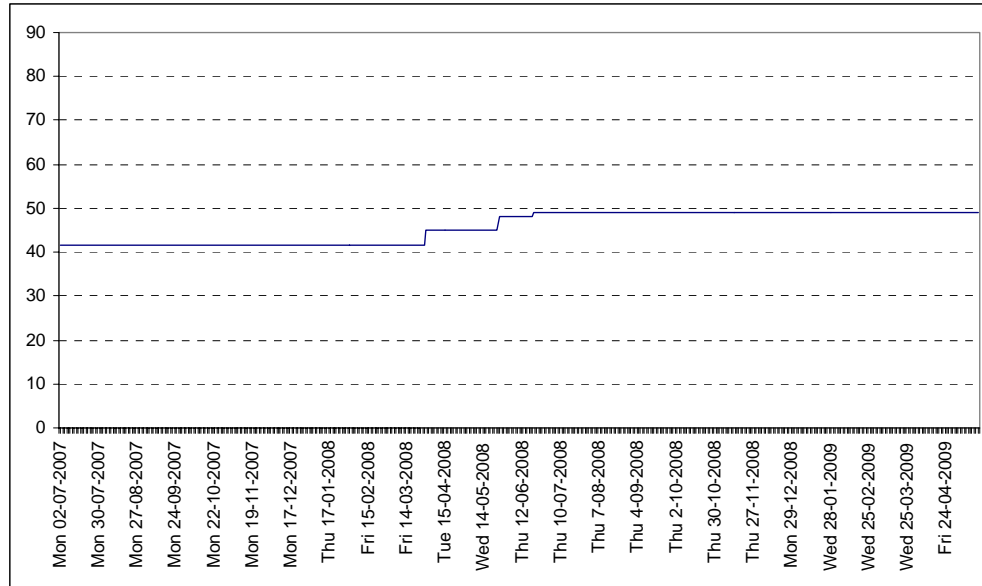
**Figure 14: d-cypha Trade prices for Queensland peak swap contracts for Q1 2010 – January to March 2010**



Source: d-Cypha Trade data

**D.2.4 Q2 2010 – April to June 2010**

**Figure 15: d-cypha Trade prices for Queensland peak swap contracts for Q2 2010 – April to June 2010**

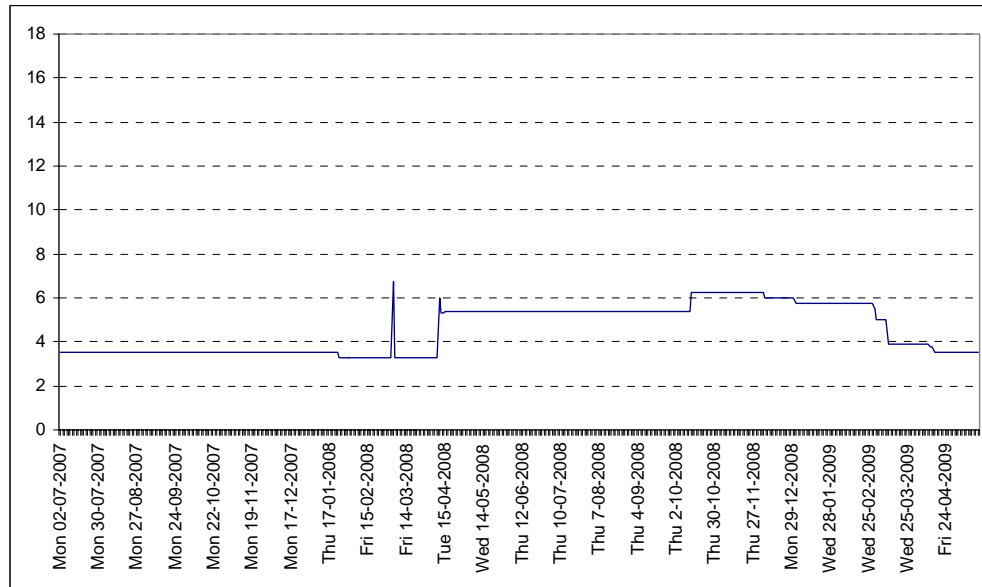


Source: d-Cypha Trade data

### D.3 CAP CONTRACT PRICES (AT \$300 CAP)

#### D.3.1 Q3 2009 – July to September 2009

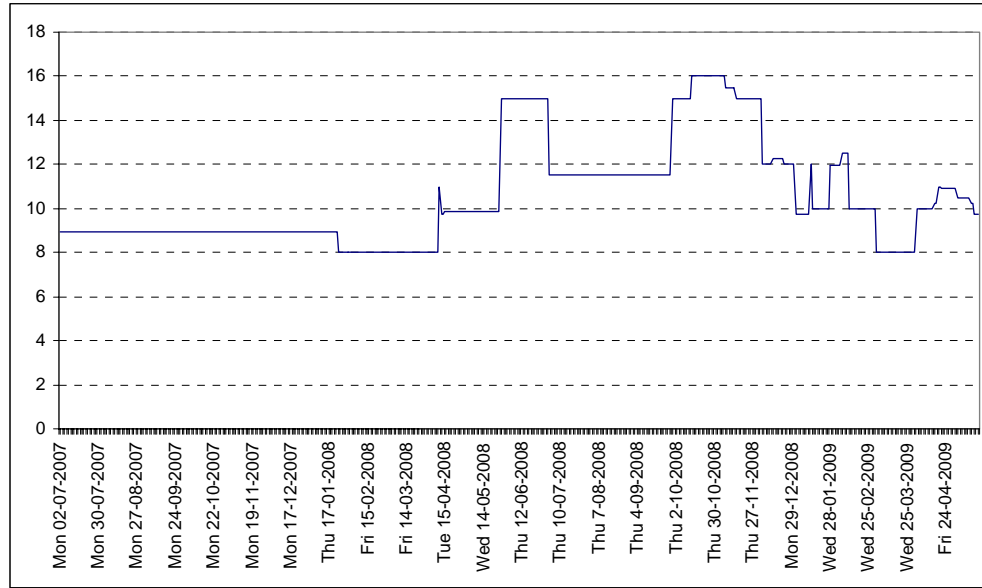
**Figure 16: d-cypha Trade prices for Queensland \$300 cap contracts for Q3 2009 – July to September 2009**



Source: d-Cypha Trade data

**D.3.2 Q4 2009 – October to December 2009**

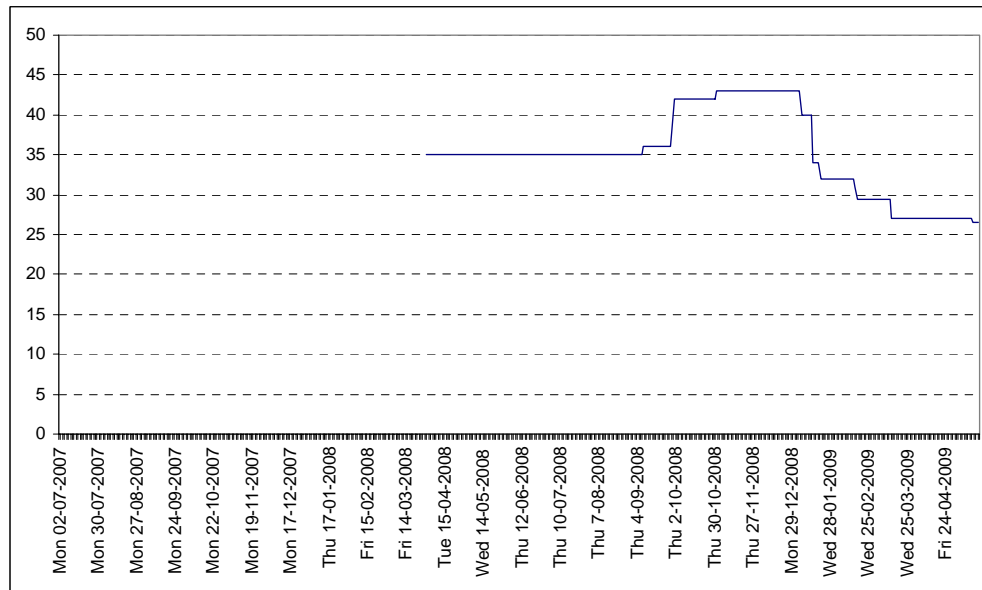
**Figure 17: d-cypha Trade prices for Queensland \$300 cap contracts for Q4 2009 – October to December 2009**



Source: d-Cypha Trade data

**D.3.3 Q1 2010 – January to March 2010**

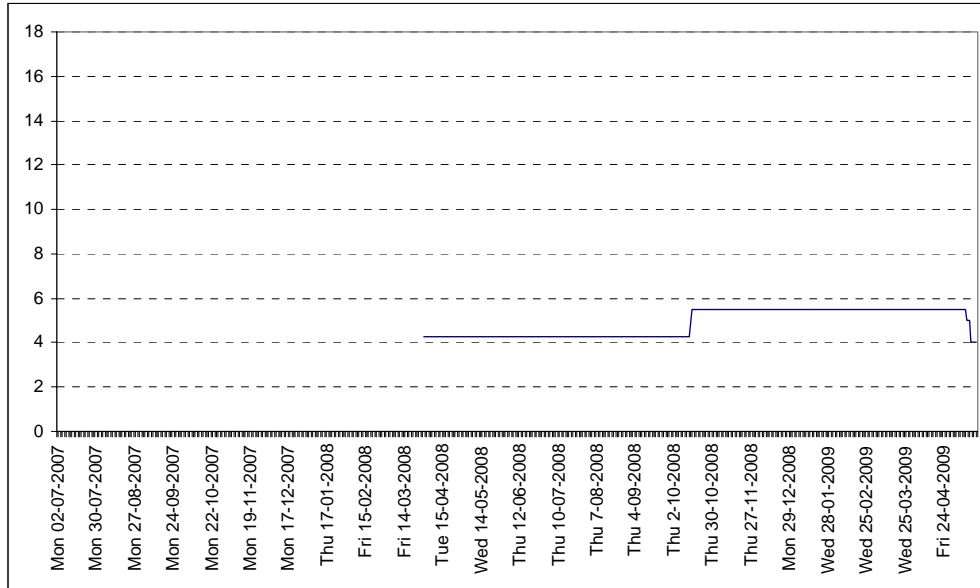
**Figure 18: d-cypha Trade prices for Queensland \$300 cap contracts for Q1 2010 – January to March 2010**



Source: d-Cypha Trade data

**D.3.4 Q2 2010 – April to June 2010**

**Figure 19: d-cypha Trade prices for Queensland \$300 cap contracts for Q2 2010 – April to June 2010**



Source: d-Cypha Trade data

## APPENDIX E: INPUT ASSUMPTIONS FOR THE LOAD DATA USED IN THE LRMC CALCULATION

### E.1 PEAK AND ENERGY PROJECTIONS

Peak and energy projections are used along with the 2008 calendar year load to forecast a Load Duration Curve (LDC) for each jurisdiction in each year over the duration of the model run. These projections come from NEMMCO's report "2008 Energy and maximum Demand Projections" which was released in July 2008. Peak projections for Queensland have been updated since the draft First Report to take into account the updated peak projections that were released by NEMMCO in August as a result of Powerlink revising its projections for Queensland. The LRMC calculation assumes a medium economic growth scenario and a 50POE temperature scenario.

### E.2 40 LOAD BLOCK LDC FOR QUEENSLAND IN THE 2009-10 TARIFF YEAR

As discussed in the body of the report, CEMOS uses a 40 load block approach when solving for the LRMC. Table 36 outlines the details of the 40 load blocks that were generated for Queensland in the 2009-10 LRMC calculation, namely the load that each block represents and the number of hours in the year that the block represents. The corresponding LDC is shown in Figure 20 which also compares this to the LDC used for the previous 2008-09 tariff year LDC calculation.

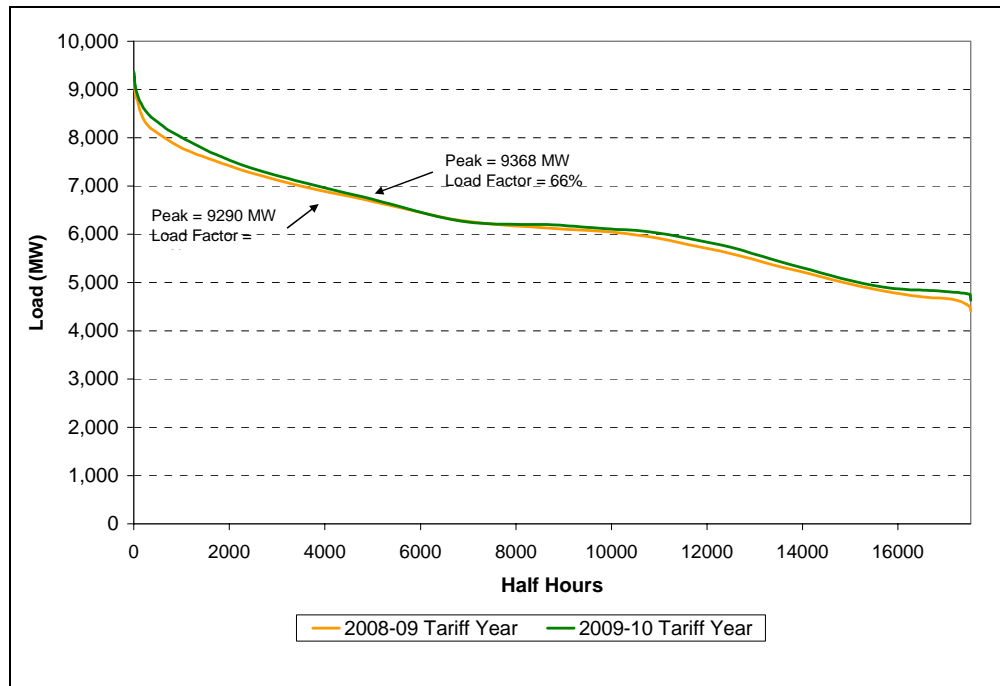
8 June 2009

**Table 36: Details of the 40 load blocks for Queensland in the 2009-10 tariff year LRM calculation**

Block	Load (MW)	Hours in year	Block	Load (MW)	Hours in year
1	9367.92	1	21	7668.21	215
2	9328.52	1	22	7375.62	382
3	9291.95	2	23	7077.24	542
4	9251.25	2	24	6734.28	719
5	9187.23	3	25	6266.30	949
6	9083.03	6	26	6195.15	939
7	9007.61	8	27	6117.21	554
8	8939.36	6	28	6057.89	445
9	8880.99	10	29	5910.38	442
10	8822.16	12	30	5732.76	435
11	8762.78	13	31	5472.45	451
12	8700.26	17	32	5264.38	386
13	8625.66	19	33	5032.96	427
14	8558.87	24	34	4879.47	432
15	8468.57	37	35	4839.68	353
16	8415.23	31	36	4812.07	216
17	8315.82	63	37	4789.69	127
18	8169.20	100	38	4769.11	80
19	8028.30	123	39	4744.82	30
20	7876.52	149	40	4630.46	9

Source: CRA analysis

**Figure 20: Queensland's 2009-10 tariff year LDC compared to the 2008-09 tariff year LDC**



8 June 2009

## APPENDIX F: CONSISTENCY CHECKS PERFORMED ON CEMOS MODELLING OUTPUTS

### F.1 CONSISTENCY CHECKS PERFORMED ON LRMC OUTPUTS

In addition to confirming the mechanics of the model operate correctly, several broad “sanity” checks are applied to the output of LRMC model runs in CEMOS. These are part of the consistency and validation process. The checks applied to the greenfield LRMC modelling outputs are described below in Table 37.

**Table 37: Output checks for LRMC modelling in CEMOS**

Output Item	Check performed	Outcome
Average price in each region	Observed prices should be reasonable and prices should react in as expected for changes in inputs	Prices are reasonable with a mix of some increases and decreases due to the mix of plant types and fuel costs across the different regions.
Difference in average price between adjoining regions	Prices for adjoining regions should be similar unless there is interconnector congestion between the regions.	Prices in Queensland, Victoria and New South Wales are similar to each other. South Australia and Tasmania were slightly higher than the other states, but still comparable.
Unserviced energy (USE)	Magnitude should be benchmarked against the NEM 0.002% reliability standard.	USE was assessed each year in the modelling horizon. The highest observed USE in any year was 0.0027%. The fact that USE is greater than 0.002% means that it is more economic to have unserved energy. This was expected due to tougher RET target compared to last year.
Reserve margin	Values should compare reasonably to typical actual values – noting that greenfield reserve margin may not be the same as for actual system	The reserve margin was calculated each year in the modelling. Values ranged from 3.53% and 11.15%, with an average value of 6.65%. No reserve margin is enforced in the LRMC modelling so the resulting average level is considered reasonably comparable to typical market values.
Profitability of each generator unit – Comparing market revenue to fixed and operating costs of installed generators	This is a key demonstration of commercial viability of investment profile. Profit ratio of 1 represents a commercial investment.	All non-renewable generators achieve an average profitability ratio of at least 1. Renewable generators which enter the plant mix in order to achieve RET targets achieve average profitability ratio less than 1. Sale of RECs is assumed to make up the difference

Source: CRA analysis

These checks combined with the input data updates give us confidence to support the LRMC modelling results for this Final report.

## **F.2 CONSISTENCY CHECKS PERFORMED ON STEMM OUTPUTS**

The STEMM module in CEMOS is used to calculate the half hour prices that are used in the Energy Purchase Cost calculations. A set of prices for the 2009-10 tariff year is calculated for each set of load forecasts, namely 10POE, 50POE and 90POE. Table 38 outlines the checks applied to the STEMM price outputs.

8 June 2009

**Table 38: Output checks for STEMM modelling in CEMOS**

Output Item	Check performed	Outcome
Cumulative Price Threshold (CPT)	Confirm as reasonable	Half hour prices forecasts for 2009-10 from the STEMM module of CEMOS are used in the Energy Purchase Cost calculation. The results showed no CPT breaches in either the 50POE or 90POE demand scenarios. CPT breaches that were shown in the 10POE demand scenario were adjusted. <sup>87</sup>

87 The initial 10POE scenario pool price trace contained CPT breaches that affected eight half hours in one event. These occurrences are likely to be the result of two simplifying approximations within the modeling as it was undertaken.

First, in the methodology used in this work, the forced outage rate and the maintenance outage rate are combined into a single averaged outage rate and applied equally to every half hour. Clearly, maintenance outages would not be planned for peak periods, and the inclusion of the maintenance outage rate in a general outage rate increases the probability of outages occurring in peak periods and creating high demand high price events.

Second, ACIL created the 10POE demand trace by increasing each of the top 400 half hours of the load duration curve in the 50POE demand scenario. The top half hour was increased to reach the peak demand forecast for the 10POE scenario. The remaining 399 half hours were increased in decreasing amount to allow the 401<sup>st</sup> half hour of the 10POE scenario to occur at the same demand level as the 401<sup>st</sup> half hour in the 50POE scenario. This results in quite a high number of half hours with high demand. Given that price can be quite sensitive to demand at the top end of the availability curve, this, particularly in combination with the outage rate issue cited above, makes it highly likely that the number of CPT breaches observed is an artifact of the modeling.

It is also the case that (a) CPT breaches are seldom observed in actual NEM practice, and (b) the 10POE scenario is used in the modeling as an input to a probabilistic outcome; we are not trying to model an actual 10POE year. In this regard it is important to note that a 10POE year is defined by a peak demand only: there is no model of the energy consumption or load shape of a 10POE year as compared to its 50POE counterpart. The approach used by ACIL (and the approach used previously by CRA) for constructing the 10POE demand scenario is logical but is by no means the only way in which a 10POE load would look.

Given these factors, the decision was made to cap the pool price forecast of the 10POE demand scenario to avoid CPT breaches but to do so as conservatively as possible. This was accomplished by calculating the cumulative price (CP) on a half hour basis over the course of the run and identifying any half hour in which the CP exceeded \$140,000 (to provide a pragmatic margin for error from the actual threshold of \$150,000). In every such case, the price in the subsequent half hour was adjusted to ensure that the CPT was not breached. The adjusted price was determined by calculating the maximum price that could be bid without causing a CPT breach. However, a minimum price of \$300 was imposed because it was assumed that the actual price in times of stress would not be below this level and because it is the administered price that would apply if the CPT were to be breached in fact.