Calculation of energy costs for the 2011-12 BRCI

Includes the calculation of energy purchase costs, LRMC, and other energy costs

Prepared for the Queensland Competition Authority

Draft Report of 16 December 2010

ACIL Tasman

Economics Policy Strategy

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1 Introduction

ACIL Tasman has been engaged by the Queensland Competition Authority (QCA) to assist in the calculation of the energy cost components of the Benchmark Retail Cost Index (BRCI) for the year 2011-12.

This report is a draft prepared with data concerning energy input costs, contracts and other charges which is the latest available at the time of completing the draft and will be updated where later data is available for the final report.

For this draft report the load data for both the long run marginal cost (LRMC) and energy purchase cost (EPC) covers the 12 months to the end of September 2010. In the final report the load used in the calculation of LRMC will be based on load for the 2010 calendar year and for the EPC the latest available load data will be used, which will be the 12 months up to end March 2011.

The parts of the 2011-12 BRCI calculation that ACIL Tasman is providing assistance on are:

- The long run marginal cost (LRMC) of electricity in Queensland. This calculation applies a least cost planning model to develop the lowest cost mix of new plant to provide incremental supply in Queensland.
- The energy purchase cost (EPC), involving a projection of regional reference prices (RRPs) in Queensland using a market simulation model and combining these RRPs with an assumed retailer contracting strategy and contract price projections for the 2011-12 year.
- Other energy costs that apply to electricity generators and retailers in Queensland, comprising;
  - Retailer costs associated with complying with the Commonwealth government's Renewable Energy Target (RET) scheme, this year including for both the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES),
  - Retailer costs associated with complying with the Queensland government's Gas Scheme,
  - National Electricity Market (NEM) retailer fees, paid by all market participants,
  - Ancillary Service Fees, paid by all retailers to cover ancillary services provided on the network.

The methodology, assumptions, data and forecasts used in each of these calculations along with the results are set out in that part of this report which describes the calculation of each component.

In determining the methodology to be used in the above calculations ACIL Tasman has been conscious of the provisions of the Electricity Act 1994 and the Electricity Regulations 2006. The latter states in Section 107:

> S107 Consistency of framework with previous tariff years
>
> (1) The theoretical framework must be the same, or substantially the same, from tariff year to tariff year unless—
>
> (a) the pricing entity considers that there is a clear reason to change it; and
>
> (b) the pricing entity has, under section 99, published draft decision material about the reason for the change.

We have interpreted this with the help of the judgment in the case *AGL Energy v QCA & Anor; Origin Energy Retail Ltd v QCA & Anor* [2009] QSC 90 to mean that the methodology for calculating the LRMC and EPC should be consistent between successive year calculations unless there is a good reason for change. If the QCA considers a change in methodology is justified, a similar change needs to be made in the previous year's BRCI calculation so that the year on year change in the BRCI is not distorted.

ACIL Tasman has adopted the methodology used to calculate energy costs for the 2010-11 BRCI and set out in the report;

> Calculation of energy costs for the 2010-11 BRCI Final Decision, ACIL Tasman, dated 13 May 2010.

The methodology described in the 2010-11 report was based in turn on the methodology set out in the previous year's BRCI produced by CRA International:

> Calculation of the Benchmark Retail Cost Index 2009-10, Final Report, CRA International, dated 8 June 2009.

Where differences in methodology have arisen between last year's report and this year's the reasons for the change are set out and the new methodology described. A similar methodology is then applied to the previous year's calculation so that the year on year change in the BRCI is based on the same methodology in both years.

The only change in methodology in this year's calculation concerns the calculation of the retailers' liability for payments under the Queensland Government's Gas Scheme. In previous years the penalty cost of not surrendering a Gas Electricity Certificate (GEC) has been used to estimate the retailers' liability. This year we have used the reported costs of GECs over a certain period of time. We believe this provides a better indicator of the costs to retailers associated with the Scheme than the penalty value. This is discussed further in Section 4.2.

Another difference has arisen in the way the retailers' costs associated with compliance of the Commonwealth government's Renewable Energy Target (RET). The RET Scheme has changed since the 2010-11 calculation and we have taken those changes into account in the 2011-12 calculation of liability. We have stayed as close as possible to the previous year's methodology while taking account of these program changes and do not consider the new calculation to be a change in methodology. The calculation is set out in Section 4.1.

The data sources and forecasts used in the calculation are the latest available data updated in a number of cases where we believe this is necessary. The LRMC calculation and the pool price modelling have relied upon the ACIL Tasman report[1] prepared for AEMO in April 2009, with updates of gas and coal prices and the price of imported capital equipment. The rationale for the updates and the data used are set out in Section 2.3.

Section 2 of this report describes the calculation of the LRMC, Section 3 the calculation of the EPC and Section 4 covers the other components of the cost of energy; costs arising from compliance with the SRET and LRET, the Queensland Gas Electricity Scheme, market fees paid to AEMO and ancillary service costs.

1.1 Summary of results

Table 1 below shows a summary of the cost of energy components of the 2011-12 draft report compared to our previous estimates for the 2010-11 final report. It shows that the LRMC has increased slightly in line with an increase in some input costs, such as fuel and operation and maintenance, the EPC has fallen $9.28/MWh, mainly due to the reduction in the cost of swap and hedge contracts and the cost of meeting renewable energy obligations has more than doubled mainly because of the change to the program, which has more than doubled the retailers' costs of compliance. The increase in the cost of meeting renewable energy obligations effectively cancels out the reduction in the EPC caused by falling contract prices and overall the measure Total Energy Costs increases by 1.5% between the final report for the 2010-11 BRCI and this draft report for the 2011-12 BRCI.

[1] ACIL Tasman, "Fuel resource, new entry and generation costs in the NEM", April 2009.

Table 1 **Summary of results for the energy cost components – draft report for the 2011-12 BRCI compared to 2010-11 final report**

	Final Report 2010-11	Draft Report 2011-12	% Change
NEM load (MWh)	37,832,394	37,811,724	
Energy costs ($/MWh)			
LRMC	$58.59	61.51	5%
Energy purchase costs (EPC)	$58.51	49.23	-15.9%
Energy - based on 50% weighting	$58.66	55.37	-5.6%
Renewable Energy Target	$3.05	7.53	146%
Queensland Gas Scheme a	$1.20	0.56	-53%
NEM fees	$0.34	0.42	24%
Ancillary services	$0.39	0.43	10%
Total energy costs ($MWh)	**$63.64**	$64.31	1.0%
Total energy costs ($ millions)	$2,408	$2,432	

a Queensland Gas Scheme estimate for the Final Report 2010-11 has been revised since the Final Report from $2.80 to $1.20 due to the change in methodology for estimating the cost of the gas scheme.

2 The calculation of LRMC

2.1 Introduction

The Electricity Regulation 2006, section 106, states the following with respect to the calculation of LRMC.

> The theoretical framework must comply with the following principles—
>
> (a) it is generally recognised and understood in economic theory;
>
> (b) the application of the theoretical framework should result in a cost per unit of electricity, expressed in dollars per megawatt hour, that constitutes the cost of energy;
>
> (c) the long run marginal cost 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;
>
> (d) there must not be double-counting of the cost of the schemes mentioned in section 92(2) of the Act.

The least cost modelling approach is similar in principle and application to that used in previous years and we believe it complies with 106(a) above. The model produces results consistent with 106(b) and (c) and we believe the approach, while taking into account the effects of schemes such as RECs and GECs on energy costs, does not double count the effects of these schemes.

In developing the LRMC component of the 2011-12 BRCI, ACIL Tasman has taken the following steps.

- Developed recent and reliable forecasts of fuel, capital and O & M costs for the range of power stations in use in the NEM,
- Taken into account state and Commonwealth programs that add or subtract to energy costs, such as the RET and GEC schemes,
- Used these inputs in a least cost supply model which minimizes both short run and long run marginal costs in meeting future market demand.

ACIL Tasman used its least cost optmising model, PowerMark LT, to calculate the LRMC for the Queensland region of the Australian NEM.

The LRMC assumptions for this draft report include a load trace based on the 12 month period to 30 September 2010. The load trace used for the LRMC calculation for the final report will be based on the 12 months to 31 December 2010 (calendar year 2010). Coal and gas prices have been adjusted to reflect recent price levels and industry developments and the components of the weighted average cost of capital (WACC) have been checked to make sure they remain current.

The significant appreciation of the Australian dollar against the US dollar in the past 12 months raises the question about whether imported capital items for power stations should be adjusted. Such an adjustment has not been included yet on the reasoning that the LRMC is a 10 year model and over this period we have assumed that it will trade within its usual historic range.

2.2 PowerMark LT

PowerMark LT is a long term planning and analysis tool. It is a dynamic least cost model, which optimises existing and new generation operation and new investments over the selected period; given assumptions concerning demand growth, plant costs, interconnectors, new development costs and government policy settings. PowerMark LT utilises a large scale commercial LP solver. The LP matrix itself is reasonably large with approximately 1 million variables, 1.4 million constraints and 2.5 million non-zero coefficients. PowerMark LT solves to provide the solution for a single long term scenario (technology, policy settings etc.).

PowerMark LT uses a sampled 50 point sequential representation of demand in each year, with each point weighted such that it provides a realistic representation of the demand population. The sampling utilises a tree clustering process with a weighted pair-group centroid distance measure.

The NEM is modelled on a regional basis with interconnectors represented as bidirectional linkages between regions with defined capacity limits and linear (as opposed to quadratic) loss equations.

In relation to new entry, PowerMark LT provides an optimal expansion program which takes into account all generation costs and constructs new generation facilities under the assumption of perfect foresight of future costs.

A range of new entrant technologies are available for deployment in each region, with defined fixed and variable costs. Fixed costs are in the form of an annual charge (specified in $/kW/year), covering capital, fixed O&M and tax. Variable costs (specified in $/MWh), represent fuel and variable O&M. For each technology constraints may be applied to construction limits in any one year or in aggregate.

The long-run is usually defined as a period of time in which all inputs can be varied. In the case of the generation sector the key difference in inputs that can be varied is the capacity of the generation fleet. Therefore, the LRMC is defined as the cost of an incremental unit of generation capacity, spread across each unit of electricity produced over the life of the station.

When calculating LRMC for new generation, the costs considered include all costs relevant to the investment decision. These costs are:

- The capital cost (including connection and other infrastructure)
- Other costs including legal and project management costs
- Fixed operating and maintenance costs
- Variable costs over the life of the station
- Tax costs (if using a post-tax discount rate).

ACIL Tasman estimates LRMC for plant based on a Discounted Cash Flow (DCF) new entrant model which is discussed in the following section.

2.3 Forecasts of capital, fuel and O & M costs

2.3.1 Capital costs

The capital cost projections presented here have been sourced from the document prepared by ACIL Tasman for the Inter regional Planning Committee of the (then) NEMMCO in April 2009

> ACIL Tasman, "Fuel resource, new entry and generation costs in the NEM". April 2009

The capital cost forecasts have been checked to ensure the underlying assumptions are still relevant. The estimates reflect a long-run equilibrium level around which shorter-term perturbations may occur.

The capital cost estimates include the following cost elements:

- engineering, procurement and construction (EPC)
- planning and approval
- professional services
- land acquisition
- infrastructure costs (incl. water)
- spares and workshop etc
- connection to the electricity network
- fuel connection, handling and storage.

Costs are expressed in A$/kW for each technology and where appropriate have been differentiated based on the method of cooling. The capital cost estimates exclude interest during construction (IDC) as costs relating to IDC are implicitly included within the new entrant model.

An international database of published capital costs for new entrant power plant has also been used to provide an informed view of capital costs for new plant in the NEM.

For the emerging technologies published research reports, which include estimates of capital costs as well as projections in the capital costs to account for the learning curve effect, have been relied upon.

Table 2 details a selection of key background assumptions that were used for this exercise and Table 3**Capital costs ($/kW, 2011-12 prices)**

	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
ACIL Tasman April 2009								
Black Coal	$2,348	$2,268	$2,228	$2,190	$2,176	$2,163	$2,160	$2,157
Brown Coal	$2,583	$2,495	$2,451	$2,409	$2,394	$2,379	$2,376	$2,372
CCGT	$1,402	$1,307	$1,305	$1,282	$1,266	$1,264	$1,260	$1,256
OCGT	$1,010	$941	$939	$923	$910	$908	$905	$902
Wind	$2,588	$2,406	$2,356	$2,279	$2,274	$2,268	$2,260	$2,249
Hydro	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773
Geothermal	$5,463	$5,503	$5,433	$5,363	$5,294	$5,226	$5,160	$5,093
Biomass	$5,131	$5,117	$5,097	$5,077	$5,057	$5,037	$5,017	$4,998

shows the capital cost projections for the range of technologies considered. The capital costs shown in Table 3**Capital costs ($/kW, 2011-12 prices)**

	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
ACIL Tasman April 2009								
Black Coal	$2,348	$2,268	$2,228	$2,190	$2,176	$2,163	$2,160	$2,157
Brown Coal	$2,583	$2,495	$2,451	$2,409	$2,394	$2,379	$2,376	$2,372
CCGT	$1,402	$1,307	$1,305	$1,282	$1,266	$1,264	$1,260	$1,256
OCGT	$1,010	$941	$939	$923	$910	$908	$905	$902
Wind	$2,588	$2,406	$2,356	$2,279	$2,274	$2,268	$2,260	$2,249
Hydro	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773
Geothermal	$5,463	$5,503	$5,433	$5,363	$5,294	$5,226	$5,160	$5,093
Biomass	$5,131	$5,117	$5,097	$5,077	$5,057	$5,037	$5,017	$4,998

are sourced from ACIL Tasman's April 2009 report to the IRPC of NEMMCO. We believe they still represent a reasonable view of current capital costs. They include the effects of the global financial crisis and the recovery during 2009 and 2010 on construction costs and the demand for new generation capacity.

Table 2 **Key assumptions used within the analysis**

Assumption	Value	Comments
Inflation (CPI)	2.50%	Long-term inflation rate at the mid-point of the RBA targeted inflation band. While near-term forecasts exist for CPI (Treasury, RBA etc) a single long-term value is preferable. 2.5% is in-line with Treasury's latest Mid-year Economic and Fiscal Outlook report for years 2010-11 and 2011-12 (p6)
Exchange rate (USD/AUD)	0.75	The estimated future average exchange rate is based on the average since the float of the Australian dollar in 1984 (0.73) and since 2000 (0.72) and the observation that the exchange rate has been close to 0.75 for between 20 and 25 per cent of the time during these periods.
International oil price (US$/bbl)	$70 increasing to $110 by 2020	EIA International Energy Outlook 2010 reference case forecast for oil prices over the period to 2020 (2010 dollars)
Internationally traded thermal coal price (A$/tonne)	$92.50	ACIL Tasman projection (in nominal dollars) for FOB Newcastle. Implies FOB price declining in real terms
LNG export facilities developed in Queensland	Total of 16 Mtpa capacity	Assumed two projects at Gladstone
Upstream gas developments	ACIL Tasman assumptions	Assumptions relating to level of CSG development and conventional exploration success
Discount rate for new entrants	6.77%	Post-tax real WACC

Table 3 **Capital costs ($/kW, 2011-12 prices)**

ACIL Tasman April 2009	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Black Coal	$2,348	$2,268	$2,228	$2,190	$2,176	$2,163	$2,160	$2,157	$2,153	$2,149
Brown Coal	$2,583	$2,495	$2,451	$2,409	$2,394	$2,379	$2,376	$2,372	$2,368	$2,364
CCGT	$1,402	$1,307	$1,305	$1,282	$1,266	$1,264	$1,260	$1,256	$1,252	$1,247
OCGT	$1,010	$941	$939	$923	$910	$908	$905	$902	$898	$895
Wind	$2,588	$2,406	$2,356	$2,279	$2,274	$2,268	$2,260	$2,249	$2,236	$2,222
Hydro	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773
Geothermal	$5,463	$5,503	$5,433	$5,363	$5,294	$5,226	$5,160	$5,093	$5,028	$4,963
Biomass	$5,131	$5,117	$5,097	$5,077	$5,057	$5,037	$5,017	$4,998	$4,977	$4,959

2.3.2 Operation and maintenance costs

Operating and maintenance (O&M) costs comprise of both fixed and variable components. Variable O&M (or VOM), is required for the estimation of SRMC, while Fixed O&M (FOM) costs are required for new entrant costs and decisions relating to retirements of incumbent plant.

Variable O&M

The additional operating and maintenance costs for an increment of electrical output depends on a number of factors, including the size of the increment in generation, the way in which wear and tear on the generation units is accrued between scheduled maintenance (hours running or a specific number of start-stop cycles) and whether operation is as a base load or peaking facility. Generally, VOM is a relatively small portion of overall SRMC.

For coal, VOM includes additional consumables such as water, chemicals and energy used in auxiliaries and incremental running costs such as ash handling.

For gas, in addition to consumables and additional operating costs, an allowance is also included for major maintenance. The reason for including an allowance for major maintenance in the VOM for gas turbines is because this maintenance is not periodic, as it is for coal plant, but rather is generally determined by hours of operation and specific events such as starts, stops, trips etc.

It is these additional starts that mean that an OCGT peaking plant has a higher VOM per MWh than either a CCGT base or intermediate load plant.

The VOM value is usually expressed in sent-out terms to account for internal usage by the station (see below) rather than in 'as generated' terms.

Table 4 **Variable operation and maintenance ($/MWh, 2011-12 prices)**

VOM (Real $/MWh)	2011-12
SC BLACK (AC)	$1.29
SC BROWN (AC)	$1.29
CCGT (AC)	$1.13
OCGT	$8.08
Wind	$1.89
Hydro	$7.69
Geothermal (HDR)	$2.15
Biomass	$5.05

Note: AC refers to air-cooled power stations

Data source: ACIL Tasman forecasts

Fixed O&M

FOM represents costs which are fixed and do not vary with station output, such as major periodic maintenance, wages, insurances and overheads. For stations that are vertically integrated with their fuel supply, fixed O&M costs can also include fixed costs associated with the coal mine/gas field. These costs are presented on a $/MW installed/year basis.

As major maintenance expenditure may not occur every year – major maintenance may only occur every second, third or fourth year – the estimated FOM values represent an annualised average for each station.

Table 5 **Fixed operation and maintenance costs ($/MW/year, 2011-12 prices)**

FOM (Real $/MW/year)	2011-12
SC BLACK (AC)	$51,691
SC BROWN (AC)	$59,229
CCGT (AC)	$33,384
OCGT	$14,000
Wind	$22,076
Hydro	$54,920
Geothermal (HDR)	$37,691
Biomass	$53,339

Note: AC refers to air-cooled power stations
Data source ACIL Tasman forecasts:

2.3.3 Thermal efficiencies

The thermal efficiency/heat rate for new plants has been estimated in both net and gross terms. These values are presented as a percentage (amount of energy converted from the fuel into electricity) and also in GJ/MWh.

Thermal efficiency is presented on Higher Heating Value (HHV) basis which includes the energy required to vaporize water produced as a result of the combustion of the fuel. Efficiencies presented on a HHV basis (as opposed to Lower Heating Value or LHV) are the appropriate measures to calculate fuel use and the marginal costs of generation.[2]

The starting thermal efficiency for new entrants is assumed to remain constant over the life of the station (i.e. no heat rate decay).

Table 6 **Thermal conversion efficiencies (HHV, sent-out values)**

	2011-12
SC BLACK (AC)	40.0%
SC BROWN (AC)	32.0%
CCGT (AC)	50.0%
OCGT	31.0%
Biomass	30.0%

Note: AC refers to air-cooled power stations
Data source: ACIL Tasman forecasts

[2] LHV values are often used by turbine manufacturers for comparison as these values are independent of the type of fuel used. Efficiencies in LHV terms are higher when quoted as a percentage (more efficient) than efficiencies in HHV terms.

2.3.4 Availability

Availability is the ratio of the potential output of a power station taking in to account downtime for maintenance (both planned and unplanned) and the availability of the primary energy source (such as wind or solar radiation in the case of wind turbines and solar generation) to the output of the power station operating at full capacity with no outages or stoppages over one year.

Availability is a measure of the power station's technical capability to generate over a year. It does not take into account reductions in output or stoppages for market or commercial reasons.

Table 7 **Availability %**

	2011-12
SC BLACK (AC)	90%
SC BROWN (AC)	90%
CCGT (AC)	92%
OCGT	97%
Wind	30%
Hydro	30%
Geothermal (HDR)	90%
Biomass	85%

Note: AC refers to air-cooled power stations

Data source: ACIL Tasman forecasts

2.3.5 Auxiliaries

Auxiliary load is used within a power station as part of the electricity generation process (also called a parasitic load). The usual way of expressing the station auxiliaries is as a percentage applied to the gross capacity of the station, providing a measure of the net capacity or sent-out capacity of the station.

Station auxiliaries also affect the sent-out or net thermal efficiency of the station, and therefore the station's SRMC.

Table 8 **Auxiliary use of energy (%)**

	2011-12
SC BLACK (AC)	7.5%
SC BROWN (AC)	9.5%
CCGT (AC)	2.4%
OCGT	2.0%
Wind	0%
Hydro	0%
Geothermal (HDR)	0%
Biomass	0%

Note: AC refers to air-cooled power stations

Data source: ACIL Tasman forecasts

2.3.6 Fuel costs

The supply of fuel into power stations in a greenfields modelling approach is assumed to mirror existing supplies to a certain extent in that lowest cost gas and coal supplies are used first. Coal is assumed to be supplied from a combination of tied and third party sources which, along with long term contractual arrangements, affects the pass through of international coal prices to domestic prices.

There is currently no liquid spot market for either coal or gas in Australia. Therefore, basing fuel costs on an opportunity cost basis (i.e. the current market price as distinct from actual contracted cost) is rarely appropriate.

The forecast of fuel costs prepared for the LRMC modelling is shown in Table 11. The forecasts are based on ACIL Tasman's April 2009 report to the IRPC of NEMMCO. The commentary on coal and gas prices below provides additional detail on how these forecasts were produced for specific fuels in the different NEM regions and how they were averaged in some cases for use in the greenfields LRMC model.

Coal

Coal prices have been reviewed in light of the continued strength in the price for thermal coal exports although this has been offset to an extent by the improvement in the $A/$US exchange rate. Coal prices into NSW power stations are most affected by the trend in the price of export thermal coal, with all power stations dependent on coal supply contracts which are increasingly being linked to export parity prices. The forecast for brown coal prices into Victorian power stations, which are not influenced by export prices, have not been changed in real terms from our estimates in the final report for the 2010-11 BRCI. The greenfields calculation of the LRMC results in no coal fired power in South Australia so coal prices in that NEM region are not necessary.

Export prices affect prices into power stations when they are supplied by third party suppliers with an export option and as coal contracts come up for renewal. We assume that as coal contracts are renewed the price in the new contract is set at between 80% and 85% of the netback export price. All power stations in NSW are affected by export coal prices with coal prices into Swanbank B and Gladstone power stations in Queensland influenced by prevailing export prices. This netback export price has changed from our estimates in the final report for the 2010-11 BRCI, partly because of a strengthening in export coal prices over the last 12 months and partly because of the appreciation of the Australian dollar against the currencies of Australia's major coal trading partners (which has tended to reduce prices in Australian dollars). The net effect of these changes is a slight increase in projected coal prices in 2011-12 compared to 2010-11, which in turn will tend to increase the 2011-12 LRMC estimate compared to the estimate provided the final report for the 2010-11 BRCI calculation.

In arriving at black coal costs in NSW and Queensland for use in the LRMC we have averaged the coal prices into existing stations. This has been done on the assumption that the existing domestic coal supply sources will be available to the new build coal stations in the calculation of LRMC. However Swanbank B, Collinsville and Tarong, which have largely exhausted their existing supply sources, have been excluded from the Queensland average. All power stations in NSW have been included.

The forecast coal prices into the NSW power stations are shown in Table 9. The average of these prices has been used for the NSW coal price in the calculation of LRMC.

Table 9 **Coal prices into NSW power stations (A$/GJ, 2011-12 prices)**

	Macquarie Generation	Eraring Energy	Delta Coastal	Delta Western	Redbank	Coal price used in LRMC modelling
2011/12	$1.42	$1.80	$2.04	$2.05	$1.08	$1.68
2012/13	$1.44	$1.81	$2.05	$2.05	$1.08	$1.69
2013/14	$1.37	$2.23	$2.12	$2.13	$1.07	$1.79
2014/15	$1.34	$2.23	$2.37	$2.14	$1.07	$1.83
2015/16	$1.40	$2.13	$2.21	$2.17	$1.07	$1.80
2016/17	$1.34	$2.10	$2.13	$2.19	$1.07	$1.77
2017/18	$1.40	$2.07	$2.03	$2.20	$1.06	$1.75
2018/19	$1.57	$2.25	$2.00	$2.31	$1.06	$1.84
2019/20	$1.63	$2.20	$1.98	$2.36	$1.06	$1.85

Data source: AXCIL Tasman analysis

The forecast coal prices for Queensland existing coal stations used in the LRMC modelling are shown in Table 10. The average of these prices has been used for the Queensland coal price in the calculation of LRMC.

Table 10 **Coal prices into Queensland power stations (A$/GJ, 2011-12 prices)**

	Gladstone	Stanwell	Callide B & C	Collinsville	Millmerran	Kogan Creek	Coal price used in LRMC modelling
2011/12	$1.67	$1.49	$1.41	$2.45	$0.91	$0.80	$1.26
2012/13	$1.67	$1.49	$1.41	$2.45	$0.91	$0.80	$1.25
2013/14	$1.66	$1.49	$1.40	$2.44	$0.90	$0.80	$1.25
2014/15	$1.66	$1.48	$1.40	$2.44	$0.90	$0.80	$1.25
2015/16	$1.81	$1.48	$1.40	$2.43	$0.90	$0.79	$1.28
2016/17	$1.81	$1.48	$1.39	$2.42	$0.90	$0.79	$1.27
2017/18	$1.80	$1.47	$1.39	$2.42	$0.90	$0.79	$1.27
2018/19	$1.80	$1.47	$1.39	$2.41	$0.89	$0.79	$1.27
2019/20	$1.79	$1.46	$1.38	$2.41	$0.89	$0.79	$1.26

Data source: ACIL Tasman analysis

Natural gas

Long-term price projections for gas included in Table 11 have been provided as output from our proprietary gas market model – *GasMark*. The *GasMark* model incorporates a complete input database containing data and assumptions for every gas producing field, transmission pipeline and major load/demand centre in Australia. It is used by ACIL Tasman internally, and is also licensed to a number of external gas market participants.

GasMark provides price projections for each defined node on the Eastern Australian gas grid.

The availability of gas to support generation in each NEM region is determined by a number of factors, namely:

- The reserves and production capability of various fields (locally and in an aggregate sense throughout Eastern Australia)
- Existing transmission capacity into the region (if the region does not have sufficient gas resources)
- The potential for new or additional transmission capacity.[3]

The assumptions used in this forecast include the development of two LNG export facilities each with two liquefaction trains of about 4 Mtpa capacity. This results in a total installed LNG capacity of 16 Mtpa, with assumed start-up over the period 2014 to 2016.

[3] The planning and development of additional pipeline capacity is generally shorter than the station itself and therefore does not impact upon the lead-time for gas plant development.

On the demand-side the outlook includes assumed growth in domestic demand, both through large industrial loads and general growth in reticulated gas to residential and commercial premises.

The supply assumptions include all existing and known, but undeveloped field developments and an assessment of undiscovered conventional and yet-to-be certified CSG resources.

Table 11 shows the projected delivered gas prices for new CCGT and OCGT plant in each NEM region in $/GJ at 2011-12 prices. For CCGT plant the delivered cost assumes a gas load factor of 80% (for transportation costs). Prices for OCGT plant are at a premium to CCGT costs, reflecting higher transportation and commodity costs for low gas load factor users.

Prices in the period to 2013–14 decline in real terms, particularly in Queensland and South Australia. This reflects the availability of short term ramp-up gas prior to the commencement of the LNG operations. After LNG operations commence, prices generally trend upward in real terms as domestic supply is sourced from higher cost production areas.

The appreciating A$ to US$ exchange rate over the past 12 months does not have the same significance for forecast gas prices as it does for the coal price forecast. Gas prices are determined mostly within the domestic market and the influence of east coast LNG exports is that it removes gas reserves from the domestic supply picture, thereby causing higher cost reserves to be called upon to meet the domestic market.

There are no changes proposed to existing gas supply contracts. However, the assumed gas prices for new entrants (and for existing stations upon expiry of existing contracts) have changed, and are shown for each region in the graphs below. The key changes when compared with the gas prices used in the final report for the calculation of the 2010-11 BRCI are:

- Gas prices in Queensland are lower at the front end of the projection reflecting excess short term gas due to the ramping up of the LNG developments.
- Prices in Victoria are slightly lower in the front end of the projection as a result of more wind farms entering the market in that region and hence delaying CCGT investment.
- However, gas prices are higher in the back end of the projection for Victoria (and South Australia) as a result of the updated capital costs for CCS and geothermal projects delaying the deployment of coal fired CCS and geothermal projects, and hence prolonging the reliance of CCGT investment.

Table 11 **Fuel costs (AUD/GJ, 2011-12 prices)**

	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Biomass	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78
Geothermal	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Hydro	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
New Black Coal NSW	$1.68	$1.69	$1.79	$1.83	$1.80	$1.77	$1.75	$1.84	$1.85	$1.85
New Black Coal QLD	$1.26	$1.26	$1.25	$1.25	$1.25	$1.28	$1.27	$1.27	$1.27	$1.26
New Brown Coal VIC	$0.61	$0.61	$0.61	$0.61	$0.60	$0.60	$0.60	$0.60	$0.60	$0.60
New CCGT NSW	$6.32	$5.86	$5.87	$5.58	$5.71	$5.70	$5.69	$5.56	$5.59	$5.84
New CCGT QLD	$4.51	$4.46	$4.24	$4.04	$4.40	$4.86	$5.21	$5.22	$5.50	$5.31
New CCGT SA	$5.34	$5.59	$5.64	$5.42	$5.63	$5.89	$5.88	$5.88	$6.10	$6.10
New CCGT TAS	$5.05	$5.31	$5.33	$5.05	$5.19	$5.19	$5.19	$5.19	$5.24	$5.58
New CCGT VIC	$4.19	$4.45	$4.48	$4.20	$4.34	$4.34	$4.34	$4.34	$4.39	$4.73
New OCGT NSW	$7.90	$7.32	$7.34	$6.98	$7.14	$7.13	$7.11	$6.95	$6.99	$7.30
New OCGT QLD	$5.63	$5.57	$5.30	$5.05	$5.50	$6.08	$6.51	$6.52	$6.87	$6.63
New OCGT SA	$6.67	$6.99	$7.05	$6.78	$7.03	$7.36	$7.35	$7.34	$7.63	$7.62
New OCGT TAS	$6.31	$6.63	$6.66	$6.31	$6.48	$6.48	$6.48	$6.48	$6.55	$6.98
New OCGT VIC	$5.24	$5.57	$5.61	$5.25	$5.42	$5.42	$5.42	$5.42	$5.49	$5.92
Wind	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Data source: ACIL Tasman forecasts

2.3.7 New entrant model

The new entrant model utilised by ACIL Tasman is a simplified DCF model for a greenfield generation project. It is significantly simpler than a DCF model which would be utilised to evaluate an actual investment decision for a specific project due to the fact that it is by definition generic and designed to be suitable for a range of projects and proponents.

Cash flows within the model are evaluated on an un-geared post-tax basis and include the effect of depreciation. A geared project post tax WACC is used as the project discount rate in effect incorporating gearing upstream. However, the cash flows do not directly include the effects of the interest tax shield and dividend imputation credits.

The model includes an estimate of build time for each of the new entrant technologies and capital expenditure is spread out over this period. The discounted cash flow calculation is started from year zero (before any construction begins) and the first years record negative cash flows incurred through project capital expenditure discounted each year by the WACC. When positive cash flows commence they begin to reduce this accumulation of negative cash flow. Spreading out construction costs in this way means that capital costs have effectively been increased by interest costs over the construction period.

2.3.8 WACC for new entrants

ACIL Tasman uses a calculated WACC as a conservative proxy for an investment decision hurdle rate in the new entrant financial model within the LRMC modelling.

The discount rate used within the new entrant model is a calculated post-tax real WACC. A post-tax WACC is used because of the importance of tax depreciation for capital intensive plant such as power stations.

When using a DCF a number of WACC derivations and cash flow models can be used. Choices need to be made as to whether the analysis is performed on a real or nominal, pre or post-tax basis. Once this has been decided, the model can either incorporate items such as the interest tax shield (recognition of the deductibility of interest payments for tax purposes) and imputation credits explicitly within the cash flows, or alternatively via adjustment to the WACC itself. The cash flows used in the greenfield new entrant cost calculations are designed to be consistent with the Officer WACC definition used. There are a number different expressions for post-tax WACC, the most common ones include:[4]

- Vanilla
- Monkhouse
- Officer.

The Officer formula is the most complex of these owing to the fact that it incorporates all tax effects in the WACC calculation itself and is applied to simple post-tax cash flows. The Officer WACC is the most widely cited as the target post-tax WACC because it is commonly used for asset valuation and project evaluation.

As the Officer WACC formula includes the interest tax shield and imputation credits there is potential for inaccuracies to exist as it is essentially a simplification. This is particularly so in the case of finite projects that have different amounts of depreciation and tax payable throughout the project life.

A more accurate means of accounting for these elements can be achieved by incorporating them explicitly into the cash flows and using a Vanilla WACC. However, assumptions then need to be made regarding the type, structure and tenure of debt finance for the project which does not lend itself to the generic analysis that is associated with the LRMC financial model.

[4] Each of these formulae is equivalent if the analysis is performed on a pre-tax basis.

In the new entrant model used here the post-tax real Officer WACC is applied to un-geared cash flows which, for consistency with the WACC, do not include the effects of the interest tax shield or dividend imputation credits.

The post-tax nominal Officer WACC used in the new entrant cost model for input to the LRMC modelling is expressed as:

$$WACC_{Officer\ (post-tax\ nominal)} = \frac{E}{V} \times R_e \left(\frac{(1-T_E)}{\left(1-T_E(1-G)\right)} \right) + \frac{D}{V} \times R_d (1-T_E)$$

Where:

- E/V is the proportion that is equity funded, 0.4
- D/V is the proportion that is debt funded, 0.6
- V is the total enterprise value (value of debt plus equity)
- R_e is the nominal post-tax cost of equity, 16.2%
- R_d is the nominal cost of debt, 8.38%
- T_E is the effective corporate tax rate, 22.5%
- G (Gamma), which is the value of imputation tax credits as a proportion of the tax credits paid, 0.5

This gives a post-tax nominal result of **9.48%.**

The nominal post-tax WACC is adjusted into real terms using the Fischer equation as follows:

$$WACC_{Officer\ (post-tax\ real)} = \left(\frac{\left(1 + WACC_{Officer\ (post-tax\ nominal)}\right)}{(1+F)} \right) - 1$$

Where: F is the relevant inflation rate, assumed at 2.5%.

The Officer WACC is applied to cash flows that do not include the effects of the interest tax shield and dividend imputation credits. That is, cash flows are un-geared and defined simply as:

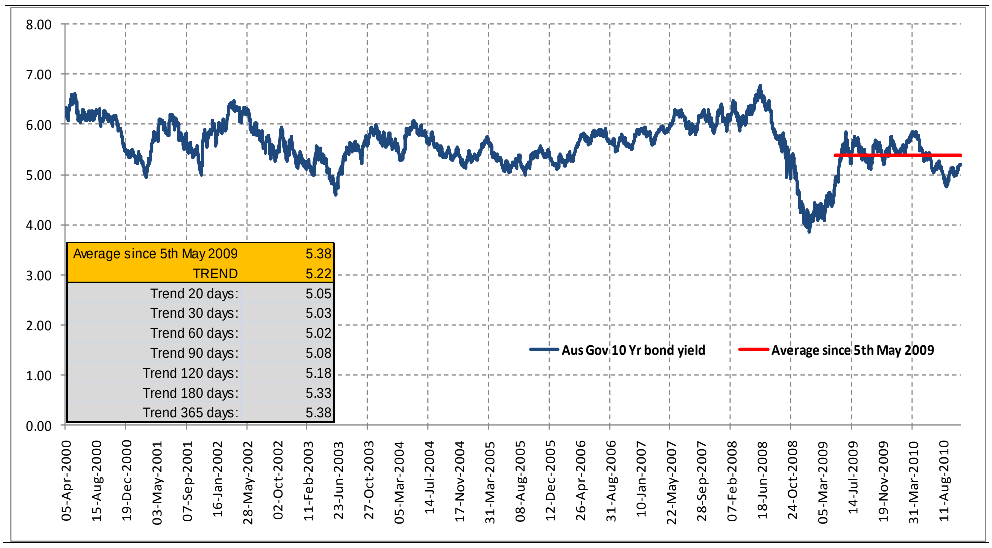
$$Cash\ Flows_{(Officer)} = X \times (1-T)$$

Where:

- X is the project cash flow
- T is the statutory corporate tax rate.

The risk free rate has been updated by taking the average daily yield after the 5th of May 2009 on 10 year commonwealth bonds. The 5th of May has been selected as it would appear the government 10 year bond rate settled to a new level from that point onward (see Figure 1). The yields were sourced from RBA data[5].

Figure 1 **Australian government 10 year bond rate since 2000**



Data source: RBA, "Indicative Mid Rates of Selected Commonwealth Government Securities", sourced on 29 October 2010

The updated debt basis point premium is usually estimated with reference to the number of basis points by which a group of representative company BBB+ rated bonds exceed the risk free rate. In a recently completed paper[6] the Independent Pricing and Regulatory Tribunal (IPART) of NSW indicate a debt basis point premium of about 280. In a recent decision (on gas distribution) the AER[7] selects a debt basis point premium of 335. ACIL Tasman has used a debt basis premium of 300 points in calculating the WACC for the calculations in this draft report for the 2011-12 BRCI, the same as the number used in the final report for the 2010-11 BRCI.

The above IPART and AER reports were also referred to when updating the market risk premium. The AER suggest a level of 6.5% for this parameter while IPART suggest a range of 5.5 to 6.5%. We have used 6.0% in this report.

Other parameters used for this draft report have been kept at the same levels as in the final report for the 2010-11 BRCI.

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5 RBA, "Capital Market Yields – Government Bonds - Daily", sourced on 29 October 2010.

6 "IPART's Weighted Average Cost of capital", IPART, April 2010.

7 AER, "Final Decision, access arrangement proposal; ACT, Queanbeyan and Palerang gas distribution network". Canberra, March 2010

Table 12 **WACC parameters**

	Parameter	2010-11 final report	2011-12 draft report
D+E	Funding	100%	100%
D	Debt	60%	60%
E	Equity	40%	40%
rf	Risk free RoR	5.43%	5.38%
MRP = (rm-rf)	Market risk premium	6.0%	6.0%
rm	Market RoR	11.43%	11.38%
T	Corporate tax rate	30%	30%
Te	Effective tax rate	22.5%	22.5%
	Debt basis point premium	300	300
rd	Cost of debt	8.0%	8.38%
G	Gamma	0.50	0.50
ba	Asset Beta	0.80	0.80
bd	Debt Beta	0.16	0.16
be	Equity Beta	1.75	1.75
re	Required return on equity	16.5%	15.9%
F	Inflation	2.50%	2.50%

These parameters give a post tax real WACC of 6.77%, which is 0.04% less than the WACC used in the final report for the 2010-11 BRCI.

2.3.9 The Average Loss Factor (ALF)

The electricity generated and sent out by power stations is paid for at the Regional Reference Node (RRN). The LRMC modelling needs to take into account the average transmission loss between the power station and the RRN. In the case of specific power stations operating at a particular location, the appropriate loss factor to use in taking account of transmission losses would be the Marginal Loss Factor (MLF) at the power station's node. The LRMC modelling undertaken here is modelling generic power stations within the Queensland (and other) regions and the appropriate transmission loss factor is the average for the Queensland region, the ALF.

The ALF has been calculated in a similar way to previous years. Powerlink's Annual Planning Report, 2010, on page 26 provides a medium growth forecast of 2011-12 Queensland transmission losses (2,009GWh) and sent-out energy (54,297GWh) and dividing the former by the latter gives a forecast ALF of 3.7%.

2.4 Methodology

In calculating the 2011-12 LRMC the PowerMark LT model has been run in so-called "greenfields" mode. This mode assumes that no plant already exists (that is, the existing plant in the NEM have been removed from the

PowerMark LT database) and the model builds from zero the most efficient (least cost) combination of plant to meet the demand duration curve. It builds a combination of base load, mid merit and peaking plant and uses the market's modelled price duration curve to govern the entry of different types and costs of new investment. The calculated RRPs for a given year are therefore the LRMC in each region of the market as they are the prices that support the least cost combination of new plant.

The model is multi-regional and temporal and therefore includes the effects of regional differences in input assumptions (such as different fuel costs in each state) and changes in the input assumptions during the model horizon. For example, the lower fuel costs in Queensland result in the model finding a solution which includes Queensland generators exporting electricity into NSW.

The long term model draws on the individual life cycle costs of the available generation technologies from the individual new entrant financial models for each technology, each year and each region to select the lowest cost technologies.

PowerMark LT is run for 2011-12 to 2019-20 inclusive (nine years). As we noted in last years' report, we believe that a 9 year horizon provides a more realistic outlook for the LRMC than a one or three year outlook in that it allows new generators to take into account reasonably foreseeable events, such as changes in gas and coal prices. Restricting the period over which the LRMC is calculated effectively cuts down the foresight of the hypothetical new entrants and maintains their costs and prices at present day levels.

Consistent with the assumptions used in the 2010-11 LRMC modelling, the 2011-12 LRMC modelling does not explicitly include any changes that might follow from the introduction of an emissions trading scheme (ETS) or any form of carbon pricing in Australia. The date of introduction and the price of emissions permits are both still uncertain and we have opted to exclude these effects on this basis.

2.4.1 Demand

For this draft report on the 2011-12 BRCI the demand duration curve for the model has been built from actual NEM regional half-hourly load traces for the 12 month period ending 30 September 2010.

This base load trace contains the abnormal weather conditions of November 2009, with an unexpected warm period in southern Queensland which caused electricity prices to spike to high levels a number of times throughout the month. This period causes the average annual average price for 2011-12 to be up to about $5/MWh higher than if we use the load trace from a more typical

November (the same month in 2008, for example). This atypical November load trace will not be included in the LRMC calculation for the final report as we move the trace to the 12 months ending 31 December 2010, which will then exclude November 2009.

These demands are on as "as generated" basis and include electricity delivered from the transmission system to the distribution system as well as demand of end-users directly connected to the transmission system, consistent with the Supreme Court decision on the Judicial Review of the 2008-09 BRCI.

For the LRMC modelling a sample of 50 regional demands was selected from the set of half-hourly demands to represent the entire year. This sample set is selected to best represent the distribution of demands in each region on an annual basis as well as to best represent the relationship between demands across the regions (that is, the coincidence of demands).

Each of the 50 regional demands in the sample set has a weighting and weightings sum to 8,760.

The sample demand set is then grown for each of the years between 2011-12 and 2019-20 inclusive based on the forecasts of annual regional maximum demand and regional energy use published in the 2010 AEMO Electricity Statement of Opportunities (ESOO). The selection of the 50 regional demands is not stratified by season and therefore the sample set does not explicitly distinguish between summer and winter. As a consequence the sample set is grown to a single peak demand in each region and not both the summer and winter peaks. The peak selected is the maximum of the two seasonal peaks published in the ESOO. This is the same as the approach taken for the 2010-11 BRCI calculation.

PowerMark LT uses "as-generated" demands, not "sent-out" (after internal usage has been deducted). Therefore, the energy parameter in the ESOO (which is reported on a sent-out basis) is increased to "as-generated" by using the scaling factors provided in the Powerlink 2010 Annual Planning Review.

2.4.2 Transmission

PowerMark LT includes the existing interconnectors and optimises their use. However, intraregional transmission is not modelled and all generation and consumption is assumed to be at the state regional reference nodes. Again, this is consistent with the approach taken in our report to the QCA for the calculation of the 2010-11 BRCI.

2.4.3 Other factors

The modelling assumes the Queensland Gas Electricity Certificate (GEC) Scheme continues with GEC prices fixed at the penalty and the GEC target set at 15% for 2011-12. PowerMark LT subtracts the GEC price from the LRMC of gas-fired plant in Queensland – this deduction increases the attractiveness of these plant which results in more CCGT/OCGTs being included in the optimal plant mix of Queensland. However, if there is an oversupply of GECs then only the proportion of GECs able to be sold is included in the revenue streams. This has the effect of decreasing the amount of the reduction to the LRMC due to the GECs. For example, if Queensland generators produce twice as many GECs as are required to meet the annual target then the model will only reduce the LRMC of the CCGTs/OCGTs by 50% of the GEC penalty. The model undertakes several iterations to find a stable solution of gas-fired penetration. This is similar to the approach taken in previous years.

The effects of the LRET scheme are included with the REC price fixed at the penalty. We assume the LRET scheme is satisfied at the recently adjusted targets and the REC price is taken off the LRMC of the renewable plant in all regions. The SRES is aimed at small scale home generation and it has not been taken into account in this calculation as it should not affect the LRMC of renewable generation.

2.5 Results

The results from the LRMC modelling for the 2011-12 draft report are compared to the final report calculation for the 2010-11 BRCI in Table 13. The main differences in Queensland can be summarised as:

- lower coal fired capacity and higher CCGT and OCGT capacity
- higher capacity factor for both OCGT and CCGT, unchanged for the coal fired stations.

These changes are mainly due to the changed base load trace.

Table 13 **ACIL Tasman LRMC results**

	SRMC ($/MWh)	LRMC ($/MWh)	Plant capacity (MW)	Dispatch (GWh)	Capacity factor (%)	Market share (%)	Capacity share (%)
2010-11 Final Report							
Coal	$12.09	$50.00	4,995	39,381	90.0%	66.5%	49.3%
CCGT	$29.97	$61.67	3,687	18,844	58.3%	31.8%	36.4%
OCGT	$77.78	$242.68	1,441	1,032	8.2%	1.7%	14.2%
Total			10,123	59,256		100.0%	100.0%
2011-12 Draft Report							
Coal	$12.61	$51.52	4,415	34,808	90.00%	55.68%	43.01%
CCGT	$28.36	$62.28	4,334	26,448	69.67%	42.31%	42.21%
OCGT	$72.76	$228.37	1,518	1,256	9.45%	2.01%	14.78%
Total			10,266	62,512		100.00%	100.00%
% change							
Coal	4.1%	3.0%	-13.1%	-13.1%	0.0%	-19.4%	-14.6%
CCGT	-5.7%	1.0%	14.9%	28.8%	16.3%	24.8%	13.8%
OCGT	-6.9%	-6.3%	5.0%	17.8%	13.2%	15.4%	3.9%
Total			1.4%	5.2%		0.0%	0.0%

Data source: ACIL Tasman modelling

The resultant LRMC of electricity in Queensland in 2011-12 for use in the 2011-12 BRCI is **$61.51/MWh**. This takes into account an allowance of 3.7% to cover average transmission losses in the Queensland region of the NEM.

This result is slightly higher than $58.59 presented in last year's final report. This change is mainly due to the change in the new load shape and the revised fuel prices.

3 Energy purchase costs (EPC)

In order to maintain consistency in the methodology applied to the EPC calculation ACIL Tasman has followed the methodology applied in the calculation of the 2010-11 BRCI, which was in turn based on the methodology applied by CRA for the 2009-10 BRCI.

The methodology is summarised briefly in the following steps.

- Develop a load trace for the NEM load for Queensland (the small load) which is total load at the Queensland TNIs (the large load) minus the load of directly connected customers.
- Prepare a forecast for the "as generated" load traces for the NEM regions based on the recorded half hour data to 30 September 2010 from the load forecast in the AEMO 2010 ESOO.
- Using the load traces for the NEM regions, carry out simulation market modelling for the 2011-12 financial year providing a projection of RRPs for each half hour of the year in each region of the NEM, including Queensland.
- Calculate swap and cap contracts contract volumes for each half hour of 2011-12 by applying the retailer's contracting strategy developed in previous in previous years to manage the risks in supplying the NEM load for Queensland (small load). The strategy includes the use of two-way (swap) and one-way (cap) contracts.
- Estimate swap and contract prices for each half hour period in 2011-12 using prices from the d-cypha Trade database of contract prices.
- Combine the half hourly RRPs, the load trace of the half-hourly small load and the half hourly contract volumes and prices in a spreadsheet model to produce the cost in each half hour for a retailer supplying the small load. The cost outcome reflects the payments made to AEMO for pool purchases at the projected RRP as well as difference payments paid by or to the retailer for swap contracts, premiums paid for cap contracts and any payments from cap contracts.

The remainder of this chapter provides more detail on each of these steps.

3.1 The load forecasts

ACIL Tasman has forecast the load traces for the total (large) load for Queensland and for the "as generated" load in each of the NEM regions using its load shape forecast program. The method involved transforming:

- the actual half hourly load traces for total (large) load for Queensland for the year to 30 September 2010 to match the Powerlink 2010 APR forecasts of winter and summer maximum demand and annual energy.

- the "as generated" load traces for each NEM region for the year to 30 September 2010 to match the AEMO 2010 ESOO forecasts for summer and winter peaks and annual energy for 2011-12.

The forecast load trace for the total (large) load for Queensland is measured at the point of delivery from the transmission network.

The NEM load (or small load) for Queensland is defined as the total load delivered from the transmission network to customers on distribution networks minus the load of customers that are directly connected to the transmission network. These loads do not include transmission losses or energy used in power station auxiliaries.

The "as generated" load in each NEM region is measured at the generator terminals and includes power station auxiliaries and transmission losses.

The forecast load trace for the total (large) load for Queensland is used in calculating the NEM (small) load for Queensland, which in turn is used in the calculation used to determine retail energy purchase costs.

The generated load in the NEM regions is used in modelling the 2011-12 half hour RRPs needed to calculate the cost of energy.

The total (large) Queensland load and the NEM regional load forecast for 2011-12 are lined up on a half hour basis to ensure the loads and prices are consistent with each other in the calculation of the cost of energy.

3.1.1 Half-hourly load trace data for Queensland

ACIL Tasman aggregated the half-hourly load data for each Queensland TNI for the year to 30 September, as supplied by QCA, into the total load for Queensland including directly connected customer load.

As was the case for the draft report for the 2010-11 BRCI, for this draft report the financial year load trace configurations for both total load for Queensland and the directly connected customer load is produced by moving the loads for December 2009, March 2010 and June 2010 from the beginning to the end of the load trace.

The load traces for both total NEM regional load for Queensland and the directly connected customers are adjusted in precisely the same way so that they remain exactly comparable with each other for every half hour.

Load traces of "as generated" load for each NEM region using data to 30 September were also constructed in this way. These load traces were extracted from the AEMO website.

3.1.2 Load forecasts for Queensland and NEM Regions

The forecasts of the following items for 2011-12 are then extracted from the Powerlink 2010 APR:

- **Annual scheduled energy delivered** from the transmission system based on the medium economic forecasts (i.e. Native Energy minus the Delivered Energy Adjustment to account for embedded non-scheduled generation)
- **Scheduled summer maximum demand delivered** from the transmission system under the medium economic forecasts at 10%, 50% and 90% probability of exceedence (POE).
- **Scheduled winter maximum demand delivered** from the transmission system under the medium economic forecast at 10%, 50% and 90% POE.
- **Coincident demand of directly connected customers in summer and winter** taken from the table showing Connection Point Native Demands Coincident with State.

The following forecasts for each NEM region were also extracted from the AEMO 2010 ESOO to produce the NEM regional load traces used in the modelling of 2011-12 RRPs:

- **Annual scheduled and semi scheduled energy sent-out from power stations** system based on the medium economic forecasts
- **Scheduled and semi scheduled generated summer maximum demand** under the medium economic forecasts at 10%, 50% and 90% POE.
- **Scheduled and semi scheduled generated winter maximum demand** under the medium economic forecasts at 10%, 50% and 90% POE.

3.1.3 Forecast of minimum demand for Queensland

A forecast of minimum demand is produced by ACIL Tasman by projecting the observed minimum half-hourly load from the actual load traces at the forecast growth in annual energy. The minimum load for both the total load for Queensland and the generated load for each NEM region was forecast in this way.

3.1.4 Forecast load traces for the total (large) load for Queensland and the generated load for each NEM region

The ACIL Tasman spreadsheet model is then used to grow the half-hourly load traces for:

- The total load for Queensland to match the medium growth forecasts of annual energy, minimum demand and summer and winter peak demands at 50%POE, 10%POE and 90%POE.

- The generated load in each NEM region to match the medium growth forecasts of annual energy, minimum demand and summer and winter peak demands at 50% POE, 10%POE and 90%POE..

The load trace forecasting model uses a non-linear transformation to adjust the recorded load trace to fit the forecast elements using a goal seek method similar to a linear programming solution.

The forecast half-hourly load trace for the total load in Queensland is produced for 2011-12 based on the load trace described above, and the medium growth 10%, 50% and 90% POE forecasts from the Powerlink 2010 APR.

10% and 90% POE load traces are then constructed by replacing the top 400 half hours in the 50% POE load trace with the values from the load traces based on the 10% and 90% POE load forecasts.

A similar approach is used to construct 50%POE, 10%POE and 90%POE as generated load traces for each NEM region used for modelling 50%POE, 10%POE and 90%POE RRPs for use in calculating the cost of energy.

3.1.5 Forecast load traces for directly connected customers for Queensland

The half-hourly load trace for directly connected customers is then increased or decreased by the percentage change in the contribution to summer and winter system demand of the directly connected customers as reported by Powerlink in the relevant APR.

3.1.6 Forecast load traces for NEM (small) load for Queensland

The forecast half-hourly demand trace for retail customers in Queensland (i.e. the NEM load or small load), is then calculated by subtracting the forecast half-hourly demand trace for directly connected customers from the forecast half-hourly demand trace for the total NEM load for Queensland. The resultant forecast is the one that has been used in the calculation of EPC for 2010-11 BRCI.

Table 14 presents the forecast minimum and maximum demand, energy and load factor from this load trace used in this draft report for the calculation of the 2011-12 BRCI.

Table 14 **Maximum and minimum demand (MW), energy (GWh) and load factor (%) – 2011-12 draft and 2010-11 final reports**

	Total Load (MW)			Directly Connected (DC) Load (MW)	NEM (small) load (MW)		
	10%POE	50%POE	90%POE		10%POE	50%POE	90%POE
2010-11 Final Report							
Maximum demand (MW)	9,330	8,866	8,583	1,320	8,192	7,730	7,448
Minimum demand (MW)	3,988	3,988	3,988	804	2,803	2,803	2,803
Energy (GWh)	50,751	50,682	50,641	10,869	39,882	39,813	39,772
Load factor (%)	62.1%	65.3%	67.4%	94.0%	55.6%	58.8%	61.0%
2011-12 Draft Report							
Maximum demand (MW)	9,577	9,104	8,816	1,402	8,400	7,929	7,643
Minimum demand (MW)	4,147	4,147	4,147	1,049	2,896	2,896	2,896
Energy (GWh)	52,359	52,289	52,248	11,299	41,059	40,990	40,949
Load factor (%)	62.4%	65.6%	67.7%	92.0%	55.8%	59.0%	61.2%
% Change							
Maximum demand	2.6%	2.7%	2.7%	6.2%	2.5%	2.6%	2.6%
Minimum demand	4.0%	4.0%	4.0%	30.5%	3.3%	3.3%	3.3%
Energy	3.2%	3.2%	3.2%	4.0%	3.0%	3.0%	3.0%
Load factor	0.5%	0.5%	0.4%	-2.1%	0.4%	0.3%	0.3%

Data source: ACIL Tasman analysis based on Powerlink data

As expected there are only minor differences between the key load trace parameters for 2011-12 draft report and the 2010-11 final report as they are based on the same load forecast from the 2010 Powerlink APR.

3.2 Simulation market modelling for 2011-12

The market simulation modelling used ACIL Tasman's model of the NEM, PowerMark, and was undertaken using nominal prices for the fuel and other costs so that the resulting RRPs are nominal (that is 2011-12 prices).

PowerMark is used extensively by ACIL Tasman in simulations and sensitivity analyses conducted on behalf of industry clients.

PowerMark effectively replicates the AEMO settlement engine — SPD engine (scheduling, pricing and dispatch). This is achieved through the use of a large-scale LP-based solution incorporating features such as quadratic interconnector loss functions, unit ramp rates, network constraints and dispatchable loads. The veracity of modelled outcomes relative to the AEMO SPD has been tested and exhibits an extremely close fit.

In accordance with the NEM's market design, the price at any one period is the cost of the next increment of generation in each region (the shadow or dual price within the LP). The LP seeks to minimise the aggregate cost of generation for the market as a whole, whilst meeting regional demand and other network constraints

One of the features of PowerMark is the inclusion of a portfolio optimisation module. This setting allows selected portfolios to seek to maximise net revenue positions (taking into consideration contracts for differences) for each period. These modified generator offers are then resubmitted to the settlement engine to determine prices and dispatch levels. Each period is iterated until a convergence point (based on Nash-Cournot equilibria theory) is found.

This feature results in modelled portfolios structuring their generation offers in an economically rational way.

The assumptions required in order to produce a year of half hourly RRPs are as follows.

- **Electricity consumption**, including energy and maximum demand projections which take into account existing energy conservation measures, distributed renewable generation.
- **New entrant costs**, which are based on new entrant financial models similar to those used in the LRMC modelling.
- **Market supply**, which covers the power stations available to generate in the market and includes assumptions about retirements and new entry as well as planned and unplanned outages over 2011-12.
- **Contract cover**, which sets out ACIL Tasman's assumptions concerning the proportion of energy generated in any period that is covered by swap contracts. This is an important input to the modelling as the proportion of generation that is uncontracted affects the way in which PowerMark models price outcomes. (This is not related to the calculation of contract difference payments undertaken for the small load).

The modelling for 2011-12 shows an outlook in which electricity prices have continued to decline over the past two years following the high prices reached in 2007 and 2008 during the extended drought in eastern Australia.

Hydro generation is now returning to long term average output levels and new capacity has been added to the NEM. Between 2009 and 2011 new capacity added or scheduled amounts to 4,500MW, including the commissioning of Colongra, Eraring expansion, Tallawarra, Uranquinty, Braemar Two, Condamine, Darling Downs, Yarwun, Quarantine expansion, Tamar Valley, Bogong and Mortlake between 2009 and 2011.

Table 15 shows the quarterly average (time weighted) RRPs from the market modelling for the 2011-12 draft report.

Table 15 **ACIL Tasman quarterly RRPs– 2011-12 draft report ($/MWh)**

	10%POE	50%POE	90%POE
Q3 2011	$45.58	$37.86	$33.22
Q4 2011	$105.28	$55.23	$35.49
Q1 2012	$69.32	$35.60	$29.97
Q2 2012	$29.68	$29.56	$27.87
Annual average	$62.52	$39.61	$31.66

Note, the annual RRP is not a simple average of the four quarters because of the variation in the number of days in each quarter.

Data source: ACIL Tasman PowerMark modelling

Settlement has been modelled for three load scenarios – the 10%POE, the 50%POE and the 90%POE.

The quarterly RRP changes between the final report for the 2010-11 BRCI and the draft report for the 2011-12 BRCI are shown in Table 16. It shows that the high annual average price in the 10% case is being driven mostly by the December quarter in 2011. This is based on the load trace from the December quarter 2009, which included a very hot period during November when prices reached very high levels in the NEM. This characteristic of the load trace has been brought through to the 2011-12 result and magnified to some extent as demand is higher through forecast demand growth.

As we have noted previously, this feature of the load trace will disappear in the modelling carried out for the final report as the load trace will be based on the 12 months to end of March 2011 rather than the 12 months to end of September 2010. Removing the effects of November 2009 (by replacing it with the load trace from November 2008) lowers the 50% POE annual average RRP by about $5/MWh. It will be replaced in the modelling done for the final report by the load trace for November 2010, which, at the time of writing, looks as if it may be a below-average November in terms of daily maximum temperatures and electricity demand. The load trace for the final report will also include the first quarter of 2011, which will also probably cause a difference between the Draft and Final annual average RRPs, although there is no way of knowing whether the difference will be positive or negative at this time.

Table 16 **Change in quarterly RRPs between 2010-11 final and the 2011-12 draft reports ($/MWh)**

	10%POE	50%POE	90%POE
Q3	$9.99	$3.42	$1.55
Q4	$35.21	$10.13	$0.85
Q1	$11.79	-$0.97	-$1.37
Q2	-$1.87	-$0.50	-$0.19
Annual average	$13.84	$3.05	$0.22

Data source: ACIL Tasman PowerMark modelling

3.3 Contracting strategy and prices

ACIL Tasman has followed the contracting methodology used in last year's calculation of the EPC for the 2010-11 BRCI, which was developed by CRA for QCA in previous calculations of the BRCI. The methodology has been discussed with stakeholders and appears to have become broadly agreed.

The strategy assumes that the retailer's objective is to purchase contracts that match its load as closely as possible so that it is not exposed to the spot market during peak periods and it is not over-contracted during off-peak periods.

The following criteria are used each quarter to purchase hedge contracts for the Queensland small load is

Flat swaps	80th percentile of off-peak load
Peak swaps	90th percentile of peak load
$300 caps	105% of maximum peak load

The strategy requires that a retailer represented in the calculation of the BRCI would spread 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. This results in contracts being purchased evenly over the period

We have assumed therefore, in common with previous years, that for calculation of the EPC contracts are purchased evenly over the period 1 July 2009 to 30 October 2010. For the final report we will assume the contracts are purchased evenly over the period 1 July 2009 to 31 March 2011[8].

[8] This timeline is slightly shorter for Q1 2012 and Q2 2012 cap contracts, which began trading from 1 April 2010.

Table 17 shows estimated quarterly swap and cap contract volumes purchased for 2011-12 under this strategy used for this draft report.

Table 17 **Quarterly swap and cap contract volumes – 2011-12 draft report compared to 2010-11 final report (MW)**

	2010-11 Final Report			2011-12 Draft Report			Percent change		
	Flat contract volume	Peak contract volume	Cap contract volume	Flat contract volume	Peak contract volume	Cap contract volume	Flat contract volume	Peak contract volume	Cap contract volume
Q3	4,276	1,172	1,331	4,403	1,273	1,086	3.0%	8.6%	-18.4%
Q4	4,646	1,854	1,413	4,724	1,922	1,472	1.7%	3.7%	4.2%
Q1	4,840	1,711	1,565	4,895	1,789	1,642	1.1%	4.5%	4.9%
Q2	4,275	1,379	1,244	4,464	1,403	994	4.4%	1.8%	-20.1%

The similarities and differences between the two sets of contract volumes for each quarter are due largely to the load traces used in the two calculations. The load trace used in this draft report for 2011-12 covers the 12 months to 30 September 2010 while the load trace used in the final report for the 2010-11 BRCI covered the 12 months to 31 March 2010. The load traces have two quarters in common, Q1 and Q4, while Q2 and Q3 are new load traces in the 2011-12 calculation. While the load traces are increased by the forecast increase in load, the contracting outcomes reflect the peakiness of the load shape and the 2010 load trace is proving to be less peaky than 2009. As a consequence cap contract volumes have fallen in Q2 and Q3 markedly, while Q1 and Q4 are very similar to those used in the final report for the 2010-11 BRCI.

3.3.1 Contract prices

The cost of the swap and cap contracts has been estimated under the assumption that the retailer spreads its purchases of contracts evenly over the period from 1 July 2009 to 30 October 2010.

Data from d-cypha Trade was used to estimate the cost of electricity swap and cap contracts. Contract prices were estimated using the average of daily settlement prices from 1 July 2009 up until 31 October 2010, which was the latest available data at the time of writing this report [9].

[9] This timeline is slightly shorter for Q1 2012 and Q2 2012 cap contracts, which began trading from 1 April 2010.

Table 18 shows estimated quarterly swap and cap contract prices for 2011-12 compared to those used in the final report for the 2010-11 BRCI. The flat and peak swap contracts used in this draft report for the 2011-12 BRCI are consistently lower than the corresponding contract prices used in the final report for the 2010-11 BRCI. Flat contract prices have fallen most and the contract prices in Q1, traditionally the high priced time of year in the NEM, have also fallen significantly.

Table 18 **Quarterly swap and cap contract prices – 2011-12 draft compared to the 2010-11 final report ($/MWh)**

	2010-11 Report			2011-12 Draft Report			Percent change		
	Flat contract price	Peak contract price	Cap contract price	Flat contract price	Peak contract price	Cap contract price	Flat contract price	Peak contract price	Cap contract price
Q3	$36.92	$50.47	$4.58	$32.13	$47.46	$4.29	-13.0%	-6.0%	-6.3%
Q4	$45.12	$66.18	$10.06	$37.83	$59.99	$9.90	-16.2%	-9.4%	-1.6%
Q1	$66.80	$110.39	$25.21	$53.46	$96.76	$20.06	-20.0%	-12.3%	-20.4%
Q2	$39.03	$47.59	$4.56	$35.89	$49.93	$3.17	-8.0%	4.9%	-30.5%

Data source: ACIL Tasman analysis using d-cyphaTrade data

3.4 Settlement

In the settlement process the half hourly prices from the 2011-12 market simulation are brought together with the half hourly loads for the small load and the contracting prices and quantities for each half hour of the year in a spreadsheet model to provide a projection of the cost of purchasing energy for the small load in 2011-12.

As described in Section 3.1 above the Queensland load data used to calculate the cost of purchasing energy is measured at the Transmission Node. In order to reflect transmission losses in the final energy purchase cost, the average loss factor (ALF) is applied to the cost estimate (in $/MWh).

From Table 2.7, page 26 of the Powerlink 2010 APR we took the transmission losses for 2011-12 (2,009GWh) and divided by the sent-out energy (54,297GWh), to get a loss factor of 3.7%. This is the same method as used in our calculation for the 2010-11 BRCI.

The results for 2011-12 are shown in Table 19. There are a number of changes between our calculation for the draft report for the 2011-12 BRCI and our final report for the 2010-11 BRCI. The key ones are:

- the RRPs are higher overall
- peak and flat contract volumes are slightly higher
- flat, peak and cap contract prices are noticeably lower.

This has resulted in:

- slightly higher pool costs
- reduced swap difference payments
- reduced cap payments
- a lower EPC in 2011-12.

Table 19 **Contract settlement for the 10%, 50% and 90% POE for 2011-12 draft and the 2010-11 final reports**

2011-12	10% POE	50% POE	90% POE
2011-12 Draft Report			
Total MWh	41,059,444	40,989,557	40,948,983
Total pool costs $	$3,481,150,362	$1,933,199,970	$1,450,776,766
Swap difference payments $	-$1,313,752,314	$11,132,855	$456,471,959
Cap premiums $	$120,493,263	$120,493,263	$120,493,263
Cap payments $	-$392,099,878	-$114,623,385	-$35,628,138
Total energy purchase cost $	$1,895,791,433	$1,950,202,703	$1,992,113,850
Total energy purchase cost $/MWh	$46.17	$47.58	$48.65
Total energy purchase cost (including ALF) $/MWh	$47.88	$49.34	$50.45
2010-11 Final Report			
Total MWh	39,881,858	39,812,567	39,771,882
Total pool costs $	$2,518,466,674	$1,711,618,772	$1,402,837,178
Swap difference payments $	-$196,627,841	$490,449,318	$772,597,454
Cap premiums $	$142,482,345	$142,482,345	$142,482,345
Cap payments $	-$238,222,156	-$100,752,308	-$46,127,321
Total energy purchase cost $	$2,226,099,022	$2,243,798,127	$2,271,789,655
Total energy purchase cost $/MWh	$55.82	$56.36	$57.12
Total energy purchase cost (including ALF) $/MWh	$57.88	$58.44	$59.23
Difference 2011-12 minus 2010-11			
Total MWh	1,177,586	1,176,991	1,177,101
Total pool costs $	$962,683,688	$221,581,198	$47,939,588
Swap difference payments $	-$1,117,124,473	-$479,316,463	-$316,125,494
Cap premiums $	-$21,989,082	-$21,989,082	-$21,989,082
Cap payments $	-$153,877,722	-$13,871,077	$10,499,183
Total energy purchase cost $	-$330,307,589	-$293,595,424	-$279,675,806
Total energy purchase cost $/MWh	-$9.65	-$8.78	-$8.47
Total energy purchase cost (including ALF) $/MWh	-$10.00	-$9.11	-$8.78

Table 20 shows the estimated cost of purchasing energy for the 2011-12 BRCI period.

The weighted energy purchase cost in 2011-12 is **$49.23/MWh**. This is $9.28/MWh less than the EPC estimated in our final report for the 2010-11 BRCI.

Table 20 **Energy purchase costs for 2011-12, scenario results, weightings and weighted values ($/MWh)**

	Scenario weighting	Draft Report 2011-12	Final Report 2010-11	Change
Energy purchase costs ($/MWh) - 10POE	30.40%	$47.88	$57.88	-$10.00
Energy purchase costs ($/MWh) - 50POE	39.20%	$49.34	$58.44	-$9.11
Energy purchase costs ($/MWh) - 90POE	30.40%	$50.45	$59.23	-$8.78
Energy purchase costs ($/MWh) - Weighted		$49.23	$58.51	**-$9.28**

Data source: ACIL Tasman analysis

The most significant factor causing the reduction in the EPC between the two years is the reduction in the price of contracts. Forward contracts have been falling since the high priced period from 2007 to 2009, which was caused by the prolonged drought in eastern Australia leading to shortages of water for cooling in some thermal power stations and generation water in hydro stations. The weather patterns in eastern Australia over this period tended to produce very high summer temperatures which also lead to high electricity prices.

Prices in the NEM are now falling with the passing of the drought, a change in weather with a La Nina event bringing wetter and cooler weather to eastern Australia and the commissioning of new plant which has helped to dampen price spikes. These factors are now showing through not only in pool prices but also in forward contract prices.

Contract prices and availability may also be showing the effects of the shelving of the Commonwealth Government's carbon pollution reduction scheme, which may have been influencing the price of longer term contracts and introducing enough uncertainty to affect the willingness of both sellers and buyers to contract for such terms.

4 Other energy costs

ACIL Tasman has also estimated other energy costs for the 2011-12 BRCI. The approach for estimating the cost of NEM fees and Ancillary Services has stayed as close as possible to the previous approach to these calculations given the need to maintain a consistent methodology combined with the fact that the approach has been canvassed with QCA and other stakeholders.

The approach to estimating the cost of the Renewable Energy Target (RET) has also remained the same, however, the analysis has been extended to incorporate the split of the scheme into two parts from 1 January 2011. More details of our methodology for estimating the costs of the modified RET scheme are provided in Section 4.1.

The estimated cost of the Queensland Gas Scheme has been approached in a different way to previous years. The new approach incorporates the market price of GECs rather than the use of the penalty price. As a result of this change, our previous estimate of the cost of GECs for 2010-11 as contained in our final report for the 2010-11 BRCI has been revised for consistency. More details of the revised approach are provided in Section 4.2.

4.1 Renewable Energy Target scheme

As of 1 January 2011, the enhanced Renewable Energy Target (RET) will be split into two parts: the Large-scale Renewable Energy Target (LRET), and the Small-scale Renewable Energy Scheme (SRES). From 1 January 2011, liable parties will be required to comply and surrender certificates for both SRES and LRET.

To determine the costs to retailers of complying with both the LRET and SRES, we have estimated the Renewable Power Percentage (RPP) and the Small-scale Technology Percentage (STP). The RPP has been estimated based on the adjusted targets under the LRET. The STP for 2011-12 has been estimated based on the published STP for 2011 of 14.8%[10] and the number of Small-scale Technology Certificates (STC) expected to be created in 2012.[11]

Certificates created from eligible renewable energy power stations after 1 January 2011 will be classified as LGCs. Certificates created from installations

[10] Published by ORER on 1st December 2010

[11] SRES covers small-scale renewable energy projects such as solar water heaters, air source heat pumps, and small-scale solar photovoltaic panels.

of eligible small-scale systems on or after 1 January 2011 will be classified STCs, unless they meet either of the following transitional arrangements:

- Certificates created for small-scale renewable energy systems installed before 1 January 2011 which are created on or after 1 January 2011 will be classified as LGCs. In this case certificates must be created within 12 months of installation.
- In certain circumstances, some of these STCs may apply to the Regulator to become LGCs if there is a contract entered into on or before 25 February 2010.

AGL's methodology for estimating the price of a large-scale generation certificate (LGC) is to examine the differential between the estimated LRMC for wind generation and a proxy for black energy prices.

The range for the LRMC of wind is suggested to be $110 to $155/MWh and they suggest a figure of $117/MWh, which is derived from the Hallett 4 wind farm sale in October 2009.

AGL then suggest a number of options for developing a proxy for black energy prices that the wind farm would earn. They conclude that the LRMC of a gas-fired CCGT running at 100% capacity factor should be used for this purpose. This estimate is discounted to reflect the fact that wind is non-firm and cannot guarantee a pure flat contract. The difference between these estimates represents the estimate of REC price.

The Renewable Power Percentage (RPP) is then estimated and the REC price applied to arrive at the cost of complying with LREC obligations.

4.1.1 The most appropriate approach to calculating the cost of the RET Scheme

AGL and Energy Australia in submissions to the QCA have suggested using an estimate of the price of a large-scale renewable energy certificate REC based on the difference between the LRMC of the lowest cost renewable new entrant (in this case wind energy) and the LRMC of a typical electricity market new entrant as a proxy for the black energy price. The difference between these two proxies then represents the additional price needed for wind to enter the market and should equal the price of the LGC.

In attempting to estimate the costs faced by retailers in purchasing electricity (and more importantly, the changes in the cost of purchasing electricity) through the BRCI, the most transparent approach is to use market data when it is available. This is more likely to reflect changes in the costs that retailers face in purchasing the components of the energy package they deliver to consumers, including the costs of various government schemes that require consumers to subsidise certain energy generation technologies.

If a reliable market based measure exists then it is difficult to justify the use of proxies. The use of two proxies is likely to miss the significant variations in both electricity market prices and certificate prices over time and it is unlikely to be representative of the actual costs of compliance with the LRET scheme. The markets for both electricity and LGCs are likely to be affected by periods of under and over supply, changing prices significantly and thereby affecting retailers' costs in purchasing their energy. Such changes would not be picked up through a calculation of proxies.

The calculation of two LRMCs to help arrive at an LGC estimate is also more complex than using consistent market data as it involves employing a number of assumptions. As a consequence it could be difficult to arrive at an accepted and objective set of input assumptions.

For example, the estimate of the LRMC of wind energy is very dependent upon the capacity factor assumed for the site. As the best sites are taken up, capacity factors are likely to reduce and the LRMC will increase over time. A range has been suggested for the wind energy LRMC, ($110 to $155/MWh) acknowledging this sensitivity to the particular site.

A proxy has also been suggested for the black energy price, which is calculated as the LRMC of a gas-fired CCGT running at 100% capacity factor. The gas price used for fuel cost will be an important assumption in this value (fuel cost comprises 40-50% of LRMC for a CCGT). As delivered gas prices vary region to region, it raises the question as to which price and region should be used. Using a proxy for the wholesale market price means that this component would not vary with market conditions of over or under supply. In other words there would be no attempt to include an assessment of market conditions in the calculation.

The submission also suggests an allowance be included to account for the non-firm nature of wind. The allowance is an estimate of the additional cost required to 'firm-up' intermittent wind output. It is clear that a discount needs to be applied in such a calculation but the magnitude of the discount is difficult to estimate.

Based on analysis of historical wind dispatch patterns, wind farms in general do not achieve the time-weighted average price for their dispatch. On average, dispatch-weighted prices for wind output is around 95% of the corresponding average pool price. This ratio is a function of weather and the level of wind penetration:

- Weather affects the value because it is usually less windy during hot summer peak periods when prices are high. Wind farms tend to miss many of the price spike events that occur in the NEM.

- As wind penetration increases, during windy periods, prices are likely to be low as a result of high levels of low cost wind output. Conversely, prices will be higher during periods of low wind. As a consequence the ratio between dispatch-weighted prices for wind output and the time-weighted average for a particular region is likely to decline over time as wind penetration increases.

In addition to the lower energy revenue from wind, its intermittent nature also incurs costs to 'firm-up'.

The approach suggested by AGL and Energy Australia only covers a short period which we believe would lead to distortions in the calculation of the renewable LRMC and black energy proxies:

- The ERET as legislated only applies to 2030. A wind farm which commences operation immediately will have to exist for the last 5 years of its life without any LGC subsidy. The longer the delay in construction of a renewable project, the fewer years of subsidy it will qualify for and the higher its threshold LRMC will be.
- Black energy prices are unlikely to remain flat in real terms over the next 25 years due to cost increases, regulatory changes and potential introduction of an ETS.
- LGC prices will not be flat in real terms. Forward REC prices exhibited a 5-8% premium for future years.
- LRMCs for renewable technologies are unlikely to remain static. Even if wind is the dominant technology throughout, capacity factors are likely to reduce as the best sites are developed first, resulting in increasing LRMCs.

Given these concerns with the calculation of a proxy for the price of a LGC we recommend an approach that continues the use of market based data as a basis for the estimation of these costs in the future.

4.1.2 LRET

For the estimation of the cost of LRET, we have used weekly market prices for RECs published by AFMA to calculate the price of average Large-scale Generation Certificates (LGCs). The average LGC prices calculated from the AFMA data are $43.34/MWh in 2011 and $42.51/MWh in 2012 using the averaging methodology set out in the CRA report[12]. The prices are then multiplied by the RPP to get the cost of compliance with the LRET in $/MWh.

[12] See page 111 of the CRA report, *Calculation of the Benchmark Retail Cost Index 2009-10* (1 December 2009).

The LRET target has been adjusted to account for the split of the scheme into two parts, with a reduction of around 4,000 GWh to the annual targets from 2011 onward. The legislated targets for 2011 and 2012 are 10,400 GWh and 12,300 GWh respectively. However, under the revised Act, section 40 (1A) allows for an increase to the annual targets for calendar year 2012 and 2013 if more than 34.5 million valid certificates exist at the end of 2010. Based on discussions with the Department of Climate Change and Energy Efficiency (DCCEE), ACIL Tasman understands that the 34.5 million figure was comprised of an allowance of 20 million banked RECs plus the 2010 target (12,500 GWh) and allowance for Greenpower of 2,000 GWh.

Based on RECs created to the end of September, ACIL Tasman projects that there will be around 42.2 million valid certificates at the end of 2010 (including banked RECs and those created through calendar year 2010). Therefore the excess of RECs referred to in section 40 (1A) is projected to be around 7.7 million (42.2 less 34.5), equivalent to 7,700 GWh. This means that the targets for 2012 and 2013 would be increased by 3,850 GWh, taking them to 16,150 GWh and 18,050 GWh respectively.

In the context of this review, this excess REC adjustment results in an increase to the projected RPP for calendar year 2012. In the absence of the adjustment the RPP is projected to be 6.07%. With the inclusion of the adjustment, the RPP is projected to be 7.97%. Note that the RPP estimate includes a 25% increase in the amount of partial exemption certificates for energy intensive trade exposed (EITE) customers.

Based on this approach, we presently estimate the cost of complying with the LRET scheme to be $2.80/MWh in 2011-12.

4.1.3 SRES

For the estimation of the cost of SRES, we have used the clearing house STC prices of $40/MWh in 2011 and 2012.[13] This price is then multiplied by the STP to get the cost of compliance with the SRES in $/MWh.

The STP has been estimated based on the published STP for 2011 of 14.8%[14], and based on ACIL Tasman's low case estimate for the number of STCs to be created in 2012 as detailed in Table 21. ACIL Tasman’s low case estimate is based on internal forecasting of STCs created from solar hot water and PV installations. We note that there is significant uncertainty regarding the number

13 STCs will be able to be sold to the online STC clearing house for a price of $40 (excl GST)

14 Published by ORER on 1st December 2010

of STCs created over this period (as highlighted by the size of the range) due to potential changes in rebates and feed-in tariffs over the period.[15]

Table 21 **Projection of STC creation for 2012 (million)**

Calendar year	ACIL Tasman High case	ACIL Tasman Low case	ACIL Tasman Mid case
2012	34.6	18.0	30.2

Data source: ACIL Tasman analysis

Based on this approach, we estimate the cost of complying with the SRES to be $4.73/MWh in 2011-12.

Table 22 summarises the estimated costs for the LRET and SRES for the 2011-12 BRCI.

Table 22 **Estimated cost of the LRET and SRES ($/MWh)**

	2011	2012	Cost of RET (Draft Report) 2011-12
RPP %	5.08%	7.97%	
Average LGC price $/MWh	$43.34	$42.51	
Cost of LRET	**$2.20**	**$3.39**	**$2.80**
STP %	14.80%	8.87%	
STC clearing house price $/MWh	$40.00	$40.00	
Cost of SRES	**$5.92**	**$3.55**	**$4.73**
Total cost ($/MWh)	**$8.12**	**$6.93**	**$7.53**

Data source: ACIL Tasman analysis based on AFMA price data and data from the REC Registry, and ORER for 2011 STP

Table 23 shows the estimated combined cost of LRET and SRES for this draft report for the 2011-12 BRCI compared with the estimated cost of RET in final report for the 2010-11 BRCI.

[15] The low case forecast takes into consideration the recently announced reduction in the solar credit multiplier from 5 to 4 from 1 July 2011, and the changes announced to the NSW feed-in tariff.

Table 23 **Estimated combined cost of LRET and SRES ($/MWh)**

	2010-11			2011-12		
	2010	2011	Cost of RET Final Report 2010-11	2011	2012	Cost of LRET and SRES Draft Report 2011-12
Cost of RET	$2.85	$3.25	**$3.05**	$8.12	$6.93	**$7.53**

Data sources: ACIL Tasman analysis based on AFMA price data, data from the REC Registry, and ORER for 2010 RPP and 2011 STP

4.2 Queensland Gas Scheme

In previous calculations of the energy cost component of the BRCI by CRA and in 2010-11 by ACIL Tasman, the change in the cost of complying with the Queensland Gas Scheme has been calculated as the product of the prescribed percentage (proportion of retail sales that must be covered by a Gas Electricity Certificate, GEC) and the tax adjusted level of the penalty.

The Queensland Government submission to the QCA, as well as submissions from consumer groups, suggests changing this approach and using market based data to price GECs instead of the penalty. In the past CRA noted in their report that the published data on GEC prices (obtained from the Australian Financial Markets Association, AFMA) might not be based on enough trades to be reliable.

Using the penalty method the allowance increases slightly between 2010-11 and 2011-12 but using AFMA data the allowance falls by approximately 53%. Table 24 shows the results based on the penalty price, while Table 25 shows the results based on the market price of GECs.

Table 24 **Estimated cost of Queensland Gas Scheme based on penalty, $/MWh**

	FINAL 2010-11	DRAFT 2011-12
Shortfall charge	$13.26	$13.67
Tax-effective shortfall charge	$18.94	$19.53
Prescribed percentage	15%	15%
Total cost of Queensland Gas Scheme	**$2.84**	**$2.93**

Table 25 **Estimated cost of Queensland Gas Scheme using AFMA data, $/MWh**

	2010-11	2011-12
Price of GECs from AFMA data	$7.99	$3.70
Prescribed percentage	15%	15%
Total cost of Queensland Gas Scheme	**$1.20**	**$0.56**

We have calculated average GEC market prices for 2010-11 and 2011-12 by averaging weekly settlement prices in the 24 months leading up to the commencement of the GEC liable year (calendar year). For example, the 2010 GEC price estimate is the average of weekly settlement prices from 1 January 2008 to 31 December 2009. This methodology reflects the requirement for liable parties (e.g. energy retailers) to surrender the prescribed amount of GECs on a calendar year basis.

The 2010-11 GEC market price estimate has been calculated as though it were for the final report for the 2010-11 BRCI. That is, we have used data up to the cut-off date for the 2010-11 final report of 31 March 2010. Correspondingly, the 2011-12 GEC market price estimate has been calculated using data up to the cut off date for this draft report (i.e. 30 October 2010).

The submission to the QCA from the Queensland Government points out that the costs faced by the retailers in complying with the Scheme are better reflected by the market price of GECs than by the penalty. The Scheme has a high rate of compliance and the penalty is rarely applied. Annual movements in the cost of complying with the Scheme will therefore be better reflected by year on year changes in the market price of GECs than by the penalty.

ACIL Tasman agrees with this proposition. If a market price for inputs to the calculation of retailers' Energy Purchase Costs can be sourced reliably and consistently each year it should provide the best guide for year on year changes in costs.

The AFMA data

AFMA produces weekly curves for environmental products (RECs, NGACs and GECs) based on weekly price data collected from various contributors (mostly retailers). In total, there are around 14 contributors to environmental products curves although not all of these contribute to the GEC price data.

The data is collected each week through a telephone interview with a nominated person in each of the retailers. There are a significant number of weeks when no price is provided because there have been very few or zero trades. Since November 2009, the maximum number of contributors to the GEC price curve has been 5 per week. The number of contributions in any given week is sometimes reduced due to the exclusion of price outliers (i.e. AFMA exclude prices that are outside one standard deviation from the mean).

AFMA have collected the data in the same way since the GEC liability arose and there are no indications that they will stop collecting the data or change the fairly simple survey approach they have now.

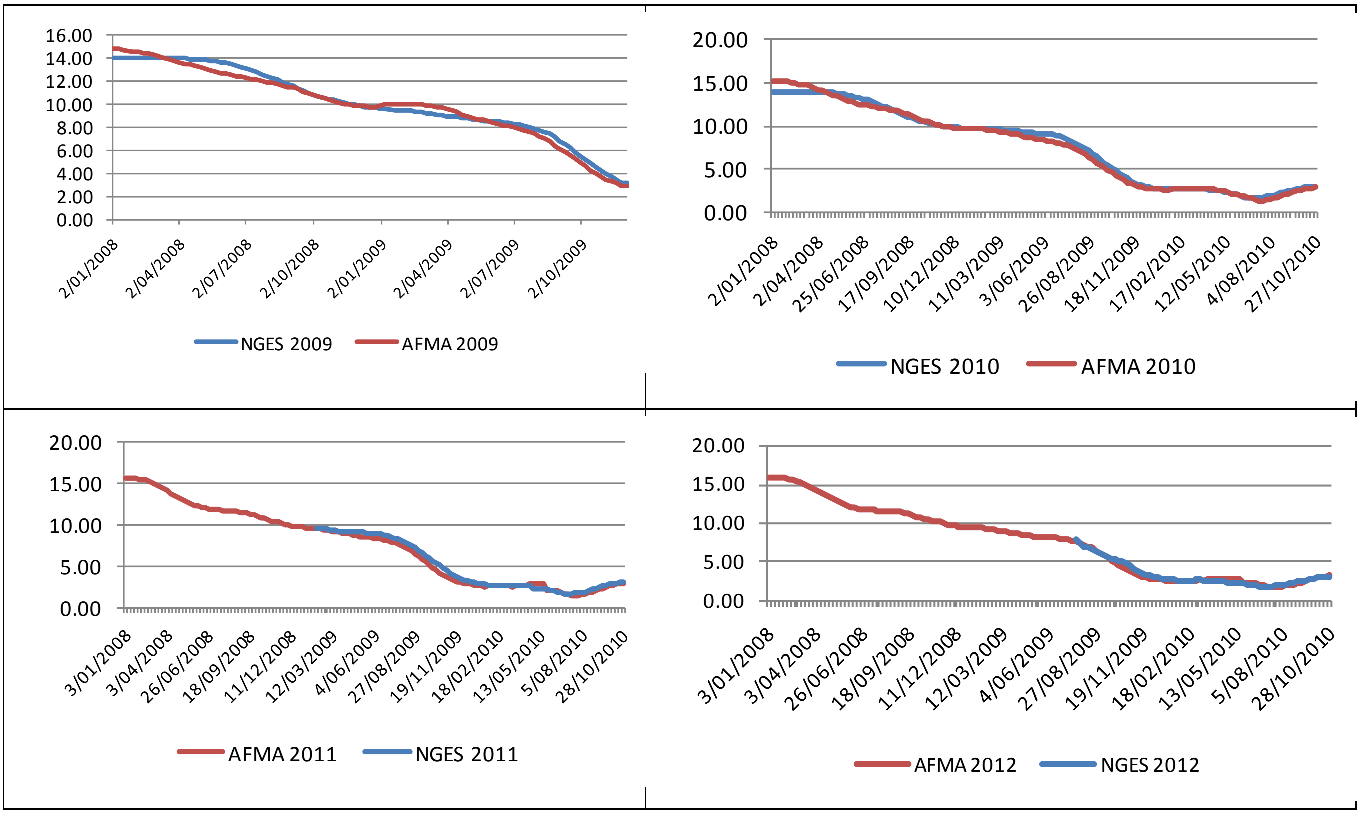
Concerns have been raised about using the AFMA data as a reliable guide to GEC market prices. AFMA present the data as the result of a telephone survey with a relatively small number of respondents.

In order to corroborate the AFMA data we have sought data on forward GEC prices from Nextgen, a broker providing energy products to wholesalers and retailers in the NEM, including so-called environmental products such as RECs and GECs.

AFMA data has been gathered on GEC forward prices over the period January 2008 to October 2010 and Nextgen data on GEC prices was also gathered over this period for comparison. Figure 2 shows the comparison between the 90 day moving average price of GEC prices for 2009, 2010, 2011 and 2012 from AFMA and Nextgen. Nextgen prices for 2011 are only available from February 2009 and for 2012 from July 2009.

The annual graphs of forward prices show a strong similarity between the two

Figure 2 **Comparison of 90 day moving average forward prices of GECs for 2009 to 2012 sourced from AFMA and Nextgen**



Data source: AFMA and Nextgen, shown as NGES in the figure.

data sources. They follow a similar path throughout each year and there is no indication that one has consistently higher or lower prices than the other. The average year on year differences between the two sources are also very similar and result in a similar estimate for the change in GEC costs between 2010-11 and 2011-12 (Table 25).

Table 26 **Comparison of estimated costs of Queensland Gas Scheme using AFMA and Nextgen data, $/MWh**

Using AFMA data	2010-11	2011-12	Change	%change
Price of GECs from AFMA data	$7.99	$3.70	-$4.29	-54%
Prescribed percentage	15%	15%		
Total cost of Qld Gas Scheme	**$1.20**	**$0.56**	**-$0.64**	**-54%**
Using Nextgen data				
Price of GECs from Nextgen data	$8.42	$3.74	-$4.68	-56%
Prescribed percentage	15%	15%		
Total cost of Qld Gas Scheme	**$1.26**	**$0.56**	**-$0.70**	**-56%**

The above provides a reasonable confirmation of AFMA data as a source of GEC prices and we believe that it would be reasonable to keep on using it as a source of GEC costs for Queensland retailers with periodic checks with alternative sources.

4.3 NEM fees

Participant and FRC fees are payable to AEMO to cover operational expenditure. The method used in the final report for the 2010-11 BRCI for estimating NEM fees was 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.

ACIL Tasman has referred to AEMO's final decision on NEM fees for 2010-11 and used the method above to calculate the estimate for 2011-12.

AEMO's published final NEM participant fees for 2010-11 are $0.33/MWh. Final FRC fees for 2010-11 are $0.07/MWh. Overall NEM fees in 2010-11 are higher than the estimated 2010-11 fees in the final report by about $0.06/MWh. This is due primarily to two new cost categories that are charged to market customers from July 2010 - costs associated with National Smart Metering (NSM) and National Transmission Planner (NTP) functions.

Table 27 compares the NEM fees estimates in the final report for the 2010-11 BRCI and the estimate in this draft report for the 2011-12 BRCI.

Estimated total NEM fees for 2011-12 have increased by $0.08/MWh or around 24%. This is due mostly to the recovery of costs associated with NSM and NTP functions from July 2010, as mentioned above.

Table 27 **Estimated NEM fees ($/MWh)**

Cost category	Final Report 2010-11	Draft Report 2011-12	% change
Market participant fees	$0.28	$0.35	25%
FRC fees	$0.06	$0.07	20%
Total NEM fees	**$0.34**	**$0.42**	24%

Data source: ACIL Tasman analysis based on he AEMO final decision on NEM fees for 2010-11

4.4 Ancillary services

Weekly aggregated settlements data for ancillary service payments in each interconnected region are provided by AEMO. Based on the average cost over the preceding 52 weeks of currently available ancillary services costs data for the NEM (up to the cut-off date of 30th October 2010 for this draft report), it is estimated that the cost of ancillary services will be $0.43/MWh for the 2011-

12 BRCI. This is 10% higher than the $0.39/MWh in the final report for 2010-11 BRCI due to the higher ancillary service costs in the new period.

Table 28 compares the Ancillary Services charges estimates included in the final report for the 2010-11 BRCI compared to the estimate in this draft report for the 2011-12 BRCI.

Table 28 **Estimated ancillary services charges ($/MWh)**

	Final Report 2010-11	Draft Report 2011-12	% change
Ancillary services	$0.39	$0.43	10%

Data source: ACIL Tasman analysis based on AEMO Ancillary Services payment data

4.5 Summary of other energy costs

In summary, other energy costs for our draft report for the 2011-12 BRCI are estimated to be $349 million or $9.24/MWh, an increase of 86% compared to the final report for the 2010-11 BRCI. Table 29 compares the other energy cost estimates to be used in this report with the estimates used in the final report for the 2010-11 BRCI. The cost of the Queensland Gas Scheme in the final report for 2010-11 has been calculated on the basis of the cost of GECs at the time of the final report so as to maintain a consistent methodology between the 2010-11 and 2011-12 BRCI calculations.

Table 29 **Summary of other energy costs ($/MWh)**

Cost category	Final Report 2010-11	Draft Report 2011-12	% change
Renewable Energy Target	$3.05	$7.53	146%
Queensland Gas Scheme	$1.20	$0.56	-53%
NEM fees	$0.34	$0.42	24%
Ancillary services	$0.39	$0.43	10%
Total other energy costs	**$4.98**	**$8.94**	**80%**

Data source: ACIL Tasman analysis based on AFMA and AEMO data.

A Electricity market modelling for 2011-12

This Appendix provides the input data and assumptions for the PowerMark electricity market modelling used to provide RRPs for each half hour in 2010-11. It begins by setting out the supply side inputs from ACIL Tasman's generator database, assumed additions and withdrawals of plant, short run marginal costs, heat rates, loss factors, offer strategies, contract cover assumptions and plant availability.

A.1 Supply

A.1.1 Introduction

When taken together with the electricity demand forecast, the assumptions regarding plant additions and retirements will determine the supply-demand balance and are critical to the modelling results.

A.1.2 Initial supply settings

Table 30 to Table 34 outline generator characteristics in terms of portfolio, generator type, capacity and on-off dates for existing and committed plant.

Table 30 **Initial setting for existing and committed plant, NSW**

Region	Generator	DUID	From Date	To Date	Gen Type	Fuel	Unit Size (MW)	Min Gen (MW)	Contract Cover (MW)	Aux (%)	Thermal efficiency (HHV sent-out, %)	Emission factor (t CO2/GJ)	Emission factor (t CO2/MWh)	Var O&M (2009 $/MWh, sent-out)
NSW1	Bayswater	BW01	1/01/2012		Steam turbine	Black coal	680	310	490	6.0%	35.9%	0.0902	0.9045	$1.18
NSW1	Bayswater	BW02	1/01/2012		Steam turbine	Black coal	680	310	330	6.0%	35.9%	0.0902	0.9045	$1.18
NSW1	Bayswater	BW03	1/01/2012		Steam turbine	Black coal	680	310	490	6.0%	35.9%	0.0902	0.9045	$1.18
NSW1	Bayswater	BW04	1/01/2012		Steam turbine	Black coal	680	310	330	6.0%	35.9%	0.0902	0.9045	$1.18
NSW1	Bendeela No. 1 Pump	SHPUMP	1/01/2012		Hydro	Hydro	240	0	0	1.0%	100.0%	0.0000	0.0000	$9.23
NSW1	Blowering 1x80MW	BLOWERNG	1/01/2009		Hydro	Hydro	80	20	20	1.0%	100.0%	0.0000	0.0000	$5.13
NSW1	Colongra	CG1	1/01/2012		Gas turbine	Na ural gas	166	0	10	3.0%	32.0%	0.0513	0.5771	$9.98
NSW1	Colongra	CG2	1/01/2012		Gas turbine	Na ural gas	166	0	10	3.0%	32.0%	0.0513	0.5771	$9.98
NSW1	Colongra	CG3	1/01/2012		Gas turbine	Na ural gas	166	0	10	3.0%	32.0%	0.0513	0.5771	$9.98
NSW1	Colongra	CG4	1/01/2012		Gas turbine	Na ural gas	166	0	10	3.0%	32.0%	0.0513	0.5771	$9.98
NSW1	Eraring Power Sta ion 330kv	ER01	1/01/2012		Steam turbine	Black coal	720	210	460	6.5%	35.4%	0.0895	0.9102	$1.18
NSW1	Eraring Power Sta ion 330kv	ER02	1/01/2012		Steam turbine	Black coal	720	210	460	6.5%	35.4%	0.0895	0.9102	$1.18
NSW1	Eraring Power Sta ion 500kv	ER03	1/01/2012		Steam turbine	Black coal	720	210	460	6.5%	35.4%	0.0895	0.9102	$1.18
NSW1	Eraring Power Sta ion 500kv	ER04	1/01/2012		Steam turbine	Black coal	720	210	460	6.5%	35.4%	0.0895	0.9102	$1.18
NSW1	Guthega 2x30MW NSW	GUTHEGANSW1	1/01/2009		Hydro	Hydro	60	0	27	1.0%	100.0%	0.0000	0.0000	$7.18
NSW1	Hume Power Station NSW	HUMENSW	1/01/2009		Hydro	Hydro	29	5	0	1.0%	100.0%	0.0000	0.0000	$6.15
NSW1	Hunter Valley Gas Turbine	HVGTS	1/01/2009		Gas turbine	Fuel oil	50	0	0	3.0%	28.0%	0.0697	0.8961	$9.50
NSW1	Liddell	LD01	1/01/2012		Steam turbine	Black coal	525	250	350	5.0%	33.8%	0.0928	0.9884	$1.18
NSW1	Mt Piper Power Sta ion	MP1	1/01/2012		Steam turbine	Black coal	660	280	280	5.0%	37.0%	0.0874	0.8504	$1.31
NSW1	Mt Piper Power Sta ion	MP2	1/01/2012		Steam turbine	Black coal	660	280	570	5.0%	37.0%	0.0874	0.8504	$1.31
NSW1	Munmorah Power Station	MM3	1/01/2012		Steam turbine	Black coal	300	150	150	7.3%	30.8%	0.0903	1.0555	$2.18
NSW1	NSW NE Wind	NSWNEWind	1/01/2012		Wind	Wind	180.5	63.175	63.175	1.0%	100.0%	0.0000	0.0000	$1.75
NSW1	Redbank Power Station	REDBANK1	1/01/2009		Steam turbine	Black coal	150	75	135	8.0%	29.3%	0.0900	1.1058	$1.18
NSW1	Shoalhaven Bendeela Power Station	SHGEN	1/01/2012		Hydro	Hydro	240	0	30	1.0%	100.0%	0.0000	0.0000	$9.23
NSW1	Smithfield Energy Facility	SITHE01	1/01/2009		Cogeneration	Na ural gas	176	140	165	5.0%	41.0%	0.0513	0.4504	$2.37
NSW1	Tallawarra	Tallawarra1	1/07/2010		Gas turbine combined cycle	Na ural gas	410	205	320	3.0%	50.0%	0.0513	0.3694	$1.04
NSW1	Tumut 1 4x82.4MW NSW	UPPTUMUTNSW1	1/01/2009		Hydro	Hydro	616	0	220	1.0%	100.0%	0.0000	0.0000	$7.18
NSW1	Tumut 3 6x250MW NSW	TUMUT3NSW1	1/01/2009		Hydro	Hydro	1500	0	220	1.0%	100.0%	0.0000	0.0000	$11.28
NSW1	Unranquinty	Uran1	15/01/2009		Gas turbine	Na ural gas	166	0	10	3.0%	32.0%	0.0513	0.5771	$9.98
NSW1	Unranquinty	Uran2	15/01/2009		Gas turbine	Na ural gas	166	0	10	3.0%	32.0%	0.0513	0.5771	$9.98
NSW1	Unranquinty	Uran3	15/01/2009		Gas turbine	Na ural gas	166	0	10	3.0%	32.0%	0.0513	0.5771	$9.98
NSW1	Unranquinty	Uran4	15/01/2009		Gas turbine	Na ural gas	166	0	10	3.0%	32.0%	0.0513	0.5771	$9.98
NSW1	Vales Point B Power Station	VP5	1/01/2012		Steam turbine	Black coal	660	250	460	4.6%	35.4%	0.0898	0.9132	$1.18
NSW1	Vales Point B Power Station	VP6	1/01/2012		Steam turbine	Black coal	660	250	390	4.6%	35.4%	0.0898	0.9132	$1.18
NSW1	Wa lerawang C Power Station	WW7	1/01/2012		Steam turbine	Black coal	500	250	250	7.3%	33.1%	0.0874	0.9506	$1.31
NSW1	Wa lerawang C Power Station	WW8	1/01/2012		Steam turbine	Black coal	500	250	250	7.3%	33.1%	0.0874	0.9506	$1.31

Data source: ACIL Tasman

Table 31 Initial setting for existing and committed plant, Qld

Region	Generator	DUID	From Date	To Date	Gen Type	Fuel	Unit Size (MW)	Min Gen (MW)	Contract Cover (MW)	Aux (%)	Thermal efficiency (HHV sent-out, %)	Emission factor (t CO2/GJ)	Emission factor (t CO2/MWh)	Var O&M (2009 $/MWh, sent-out)
QLD1	Barcaldine Power Sta ion	BARCALDN	1/01/2009		Gas turbine	Natural gas	55	27	20	3.0%	40.0%	0.0513	0.4617	$2.37
QLD1	Barron Gorge	BARRON-1	1/01/2009		Hydro	Hydro	30	1	14	1.0%	100.0%	0.0000	0.0000	$11.28
QLD1	Barron Gorge	BARRON-2	1/01/2009		Hydro	Hydro	30	2	14	1.0%	100.0%	0.0000	0.0000	$11.28
QLD1	Braemar	BRAEMAR1	1/01/2010		Gas turbine	Natural gas	168	0	150	2.5%	30.0%	0.0513	0.6156	$7.83
QLD1	Braemar	BRAEMAR1	1/01/2010		Gas turbine	Natural gas	168	150	150	2.5%	30.0%	0.0513	0.6156	$7.83
QLD1	Braemar	BRAEMAR2	1/01/2010		Gas turbine	Natural gas	168	150	150	2.5%	30.0%	0.0513	0.6156	$7.83
QLD1	Braemar	BRAEMAR3	1/01/2010		Gas turbine	Natural gas	168	150	150	2.5%	30.0%	0.0513	0.6156	$7.83
QLD1	Braemar_Two	BRAEMAR5	1/07/2009		Gas turbine	Natural gas	153	150	150	2.5%	30.0%	0.0513	0.6156	$7.83
QLD1	Braemar_Two	BRAEMAR6	1/07/2009		Gas turbine	Natural gas	153	0	150	2.5%	30.0%	0.0513	0.6156	$7.83
QLD1	Braemar_Two	BRAEMAR7	1/07/2009		Gas turbine	Natural gas	153	0	0	2.5%	30.0%	0.0513	0.6156	$7.83
QLD1	Callide B Power Station	CALL_B_1	1/01/2009		Steam turbine	Black coal	350	220	250	7.0%	36.1%	0.0950	0.9474	$1.19
QLD1	Callide B Power Station	CALL_B_2	1/01/2009		Steam turbine	Black coal	350	220	220	7.0%	36.1%	0.0950	0.9474	$1.19
QLD1	Callide Power Plant	CPP_3	1/01/2012		Steam turbine	Black coal	450	200	325	4.8%	36.5%	0.0950	0.9370	$2.70
QLD1	Callide Power Plant	CPP_4	1/01/2012		Steam turbine	Black coal	450	200	325	4.8%	36.5%	0.0950	0.9370	$2.70
QLD1	Collinsv lle Power Station	COLNSV_1	1/01/2009		Steam turbine	Black coal	31	12	8	8.0%	27.7%	0.0894	1.1619	$1.31
QLD1	Collinsv lle Power Station	COLNSV_2	1/01/2009		Steam turbine	Black coal	31	0	0	8.0%	27.7%	0.0894	1.1619	$1.31
QLD1	Collinsv lle Power Station	COLNSV_3	1/01/2009		Steam turbine	Black coal	31	0	0	8.0%	27.7%	0.0894	1.1619	$1.31
QLD1	Collinsv lle Power Station	COLNSV_4	1/01/2009		Steam turbine	Black coal	31	0	0	8.0%	27.7%	0.0894	1.1619	$1.31
QLD1	Collinsv lle Power Station	COLNSV_5	1/01/2009		Steam turbine	Black coal	66	0	0	8.0%	27.7%	0.0894	1.1619	$1.31
QLD1	Condamine Power Station	CONDAMINE1	1/01/2012		Gas turbine combined cycle	Natural gas	140	135	90	3.0%	48.0%	0.0513	0.3848	$1.04
QLD1	Darling Downs ATR	DDATR1	1/04/2010		Gas turbine combined cycle	Natural gas	630	0	500	6.0%	46.0%	0.0513	0.4015	$1.04
QLD1	Gladstone	GSTONE1	1/01/2012		Steam turbine	Black coal	280	110	200	5.0%	35.2%	0.0921	0.9419	$1.18
QLD1	Gladstone	GSTONE2	1/01/2012		Steam turbine	Black coal	280	110	200	5.0%	35.2%	0.0921	0.9419	$1.18
QLD1	Gladstone	GSTONE3	1/01/2012		Steam turbine	Black coal	280	110	160	5.0%	35.2%	0.0921	0.9419	$1.18
QLD1	Gladstone	GSTONE4	1/01/2012		Steam turbine	Black coal	280	110	160	5.0%	35.2%	0.0921	0.9419	$1.18
QLD1	Gladstone	GSTONE5	1/01/2012		Steam turbine	Black coal	280	110	160	5.0%	35.2%	0.0921	0.9419	$1.18
QLD1	Gladstone	GSTONE6	1/01/2012		Steam turbine	Black coal	280	110	160	5.0%	35.2%	0.0921	0.9419	$1.18
QLD1	Kareeya	KAREEYA1	1/01/2009		Hydro	Hydro	21	8	10	1.0%	100.0%	0.0000	0.0000	$6.15
QLD1	Kareeya	KAREEYA2	1/01/2009		Hydro	Hydro	21	8	10	1.0%	100.0%	0.0000	0.0000	$6.15
QLD1	Kareeya	KAREEYA3	1/01/2009		Hydro	Hydro	18	8	10	1.0%	100.0%	0.0000	0.0000	$6.15
QLD1	Kareeya	KAREEYA4	1/01/2009		Hydro	Hydro	21	8	10	1.0%	100.0%	0.0000	0.0000	$6.15
QLD1	Kogan Creek	KPP_1	1/01/2011		Steam turbine	Black coal	750	350	572	8.0%	37.5%	0.0940	0.9024	$1.25
QLD1	Mackay Gas Turbine	MACKAYGT	1/01/2009		Gas turbine	Fuel o l	34	0	5	3.0%	28.0%	0.0697	0.8961	$8.94
QLD1	M llmerran Power Plant	MPP_1	1/01/2009		Steam turbine	Black coal	425.5	100	350	4.7%	36.9%	0.0920	0.8976	$2.81
QLD1	M llmerran Power Plant	MPP_2	1/01/2009		Steam turbine	Black coal	425.5	100	350	4.7%	36.9%	0.0920	0.8976	$2.81
QLD1	Mt Stuart Gas Turbine	MSTUART1	1/01/2009		Gas turbine	Liquid Fuel	146	0	30	3.0%	30.0%	0.0697	0.8364	$8.94
QLD1	Mt Stuart Gas Turbine	MSTUART2	1/01/2009		Gas turbine	Liquid Fuel	146	0	30	3.0%	30.0%	0.0697	0.8364	$8.94
QLD1	Mt Stuart Gas Turbine	MSTUART3	1/07/2009		Gas turbine	Liquid Fuel	126	0	30	3.0%	30.0%	0.0697	0.8364	$8.94
QLD1	Oakey Power Station	OAKEY1	1/01/2010		Gas turbine	Natural gas	141	40	5	3.0%	32.6%	0.0513	0.5665	$9.50
QLD1	Oakey Power Station	OAKEY2	1/01/2010		Gas turbine	Natural gas	141	40	5	3.0%	32.6%	0.0513	0.5665	$9.50
QLD1	Roma Gas Turbine Station	ROMA_7	1/01/2010		Gas turbine	Natural gas	40	38	32	3.0%	30.0%	0.0513	0.6156	$9.50
QLD1	Roma Gas Turbine Station	ROMA_8	1/01/2010		Gas turbine	Natural gas	40	38	32	3.0%	30.0%	0.0513	0.6156	$9.50
QLD1	Stanwell Power Station	STAN-1	1/01/2009		Steam turbine	Black coal	360	190	230	7.0%	36.4%	0.0904	0.8941	$3.18
QLD1	Stanwell Power Station	STAN-2	1/01/2009		Steam turbine	Black coal	360	190	230	7.0%	36.4%	0.0904	0.8941	$3.18
QLD1	Stanwell Power Station	STAN-3	1/01/2009		Steam turbine	Black coal	360	190	190	7.0%	36.4%	0.0904	0.8941	$3.18
QLD1	Stanwell Power Station	STAN-4	1/01/2009		Steam turbine	Black coal	360	190	230	7.0%	36.4%	0.0904	0.8941	$3.18
QLD1	Swanbank E Gas Turbine	SWAN_E	1/07/2010		Gas turbine combined cycle	Coal seam	385	150	180	3.0%	47.0%	0.0513	0.3929	$1.04
QLD1	Tarong North Power Station	TNPS1	1/01/2009		Steam turbine	Black coal	443	175	250	5.0%	39.2%	0.0921	0.8458	$1.42
QLD1	Tarong Power Station	TARONG#1	1/01/2010		Steam turbine	Black coal	350	140	240	8.0%	36.2%	0.0921	0.9159	$7.42
QLD1	Tarong Power Station	TARONG#2	1/10/2009		Steam turbine	Black coal	350	140	200	8.0%	36.2%	0.0921	0.9159	$7.42
QLD1	Tarong Power Station	TARONG#3	1/10/2009		Steam turbine	Black coal	350	140	200	8.0%	36.2%	0.0921	0.9159	$7.42
QLD1	Tarong Power Station	TARONG#4	1/10/2009		Steam turbine	Black coal	350	140	200	8.0%	36.2%	0.0921	0.9159	$7.42
QLD1	Townsville Power Station	YABULU	1/07/2010		Gas turbine combined cycle	Coal seam	240	113	113	3.0%	46.0%	0.0513	0.4015	$1.04
QLD1	Wivenhoe Power Station	W/HOE#1	1/01/2009		Hydro	Hydro	250	0	40	1.0%	100.0%	0.0000	0.0000	$0.00
QLD1	Wivenhoe Power Station	W/HOE#2	1/07/2009		Hydro	Hydro	250	0	20	1.0%	100.0%	0.0000	0.0000	$0.00
QLD1	Yarwun Cogen	YARWUN	1/01/2011		Gas turbine	Natural gas	168	143	143	2.0%	34.0%	0.0513	0.5432	$0.00

Data source: ACIL Tasman

Table 32 Initial setting for existing and committed plant, SA

Region	Generator	DUID	From Date	To Date	Gen Type	Fuel	Unit Size (MW)	Min Gen (MW)	Contract Cover (MW)	Aux (%)	Thermal efficiency (HHV sent-out, %)	Emission factor (t CO2/GJ)	Emission factor (t CO2/MWh)	Var O&M (2009 $/MWh, sent-out)
SA1	Angaston	ANGAS1	1/01/2009		Gas turbine	Distillate	30	0	0	2.5%	26.0%	0.0679	0.9402	$9.50
SA1	Dry Creek Gas Turbine Station	DRYCGT1	1/01/2009		Gas turbine	Natural gas	52	0	0	3.0%	26.0%	0.0513	0.7103	$9.50
SA1	Dry Creek Gas Turbine Station	DRYCGT2	1/01/2009		Gas turbine	Natural gas	52	0	0	3.0%	26.0%	0.0513	0.7103	$9.50
SA1	Dry Creek Gas Turbine Station	DRYCGT3	1/01/2009		Gas turbine	Natural gas	52	0	0	3.0%	26.0%	0.0513	0.7103	$9.50
SA1	Hallett Power Station	AGLHAL	1/01/2009		Gas turbine	Natural gas	180	0	10	2.5%	24.0%	0.0513	0.7695	$9.50
SA1	Ladbroke Grove Power Station	LADBROK1	1/01/2009		Gas turbine	Natural gas	40	0	35	3.0%	30.0%	0.0513	0.6156	$3.55
SA1	Ladbroke Grove Power Station	LADBROK2	1/01/2009		Gas turbine	Natural gas	40	0	35	3.0%	30.0%	0.0513	0.6156	$3.55
SA1	Mintaro Gas Turbine Station	M NTARO	1/01/2009		Gas turbine	Natural gas	90	0	0	3.0%	28.0%	0.0513	0.6596	$9.50
SA1	Nor hern Power Station	NPS1	1/07/2010		Steam turbine	Black coal	265	190	240	5.0%	34.9%	0.0910	0.9387	$1.18
SA1	Nor hern Power Station	NPS2	1/07/2010		Steam turbine	Black coal	265	190	240	5.0%	34.9%	0.0910	0.9387	$1.18
SA1	Osborne Power Station	OSB-AG	1/01/2009		Cogenera ion	Natural gas	180	125	132	5.0%	42.0%	0.0513	0.4397	$5.03
SA1	Pelican Point Power Station	PPCCGT	1/07/2010		Gas turbine combined cycle	Natural gas	485	370	440	2.0%	48.0%	0.0513	0.3848	$1.04
SA1	Playford B Power Station	PLAYB-AG	1/01/2009		Steam turbine	Black coal	240	0	0	8.0%	21.9%	0.0910	1.4959	$2.97
SA1	Port Lincoln Gas Turbine	POR01	1/01/2009		Gas turbine	Distillate	50	0	50	8.0%	26.0%	0.0679	0.9402	$9.50
SA1	Quarantine Power Station	QPS1	1/01/2009		Gas turbine	Natural gas	24	0	10	5.0%	32.0%	0.0513	0.5771	$9.50
SA1	Quarantine Power Station	QPS2	1/01/2009		Gas turbine	Natural gas	24	0	10	5.0%	32.0%	0.0513	0.5771	$9.50
SA1	Quarantine Power Station	QPS3	1/01/2009		Gas turbine	Natural gas	24	0	10	5.0%	32.0%	0.0513	0.5771	$9.50
SA1	Quarantine Power Station	QPS4	1/01/2009		Gas turbine	Natural gas	24	0	10	5.0%	32.0%	0.0513	0.5771	$9.50
SA1	Quarantine Power Station	QPS5	1/01/2009		Gas turbine	Natural gas	120	0	60	5.0%	32.0%	0.0513	0.5771	$9.50
SA1	SA NE Wind	SANEWind1	1/01/2012		Wind	Wind	172	172	172	1.0%	100.0%	0.0000	0.0000	$1.75
SA1	Snuggery Power Station	SNUG1	1/01/2009		Gas turbine	Distillate	63	0	20	3.0%	26.0%	0.0679	0.9402	$9.50
SA1	Torrens Island Power Station A	TORRA1	1/01/2010		Steam turbine	Natural gas	120	2	2	5.0%	30.0%	0.0513	0.6156	$2.23
SA1	Torrens Island Power Station A	TORRA2	1/01/2010		Steam turbine	Natural gas	120	2	2	5.0%	30.0%	0.0513	0.6156	$2.23
SA1	Torrens Island Power Station A	TORRA3	1/01/2010		Steam turbine	Natural gas	120	2	2	5.0%	30.0%	0.0513	0.6156	$2.23
SA1	Torrens Island Power Station A	TORRA4	1/01/2010		Steam turbine	Natural gas	120	2	2	5.0%	30.0%	0.0513	0.6156	$2.23
SA1	Torrens Island Power Station B	TORRB1	1/01/2012		Steam turbine	Natural gas	200	40	110	5.0%	32.0%	0.0513	0.5771	$2.23
SA1	Torrens Island Power Station B	TORRB2	1/01/2012		Steam turbine	Natural gas	200	40	110	5.0%	32.0%	0.0513	0.5771	$2.23
SA1	Torrens Island Power Station B	TORRB3	1/01/2012		Steam turbine	Natural gas	200	40	110	5.0%	32.0%	0.0513	0.5771	$2.23
SA1	Torrens Island Power Station B	TORRB4	1/01/2012		Steam turbine	Natural gas	200	40	75	5.0%	32.0%	0.0513	0.5771	$2.23

Data source: ACIL Tasman

Table 33 Initial setting for existing and committed plant, Tas

Region	Generator	DUID	From Date	To Date	Gen Type	Fuel	Unit Size (MW)	Min Gen (MW)	Contract Cover (MW)	Aux (%)	Thermal efficiency (HHV sent-out, %)	Emission factor (t CO2/GJ)	Emission factor (t CO2/MWh)	Var O&M (2009 $/MWh, sent-out)
TAS1	Bastyan	BASTYAN1	1/01/2009		Hydro	Hydro	79.9	14	42	5.0%	100.0%	0.0000	0.0000	$6.15
TAS1	Bell Bay Three	BELLBAYTHREE1	1/07/2009		Gas turbine	Natural gas	60	0	30	2.5%	29.0%	0.0513	0.6368	$7.83
TAS1	Bell Bay Three	BELLBAYTHREE2	1/07/2009		Gas turbine	Natural gas	60	0	30	2.5%	29.0%	0.0513	0.6368	$7.83
TAS1	Bell Bay Three	BELLBAYTHREE3	1/07/2009		Gas turbine	Natural gas	60	0	30	2.5%	29.0%	0.0513	0.6368	$7.83
TAS1	Cethana	CETHANA1	1/01/2009		Hydro	Hydro	85	21	63	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Devils Gate	DEVILS1	1/01/2009		Hydro	Hydro	60	32	60	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Fisher	FISHER1	1/01/2009		Hydro	Hydro	43.2	10	30	0.5%	100.0%	0.0000	0.0000	$5.13
TAS1	Gordon	GORDON1	1/01/2012		Hydro	Hydro	432	0	125	0.5%	100.0%	0.0000	0.0000	$5.13
TAS1	John Bu ters	BUTTERS1	1/01/2009		Hydro	Hydro	144	0	50	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Lake Echo	ECHO1	1/01/2009		Hydro	Hydro	32.4	0	0	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Lemonthyme_Wilmot	LEMONTHYME1	1/01/2009		Hydro	Hydro	51	5	15	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Lemonthyme_Wilmot	WLMOT1	1/01/2009		Hydro	Hydro	30.6	8	24	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Liapootah_Wayatinah_Catagunya	CATAGUNYA1	1/01/2009		Hydro	Hydro	48	3	9	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Liapootah_Wayatinah_Catagunya	LIAPOOTAH1	1/01/2009		Hydro	Hydro	83.7	14	42	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Liapootah_Wayatinah_Catagunya	WAYAT NAH1	1/01/2009		Hydro	Hydro	38.3	10	30	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Mackintosh	MAKC NTOSH1	1/01/2009		Hydro	Hydro	79.9	20	60	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Meadowbank	MEADOWBANK1	1/01/2009		Hydro	Hydro	40	24	40	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Poatina	POATINA1	1/01/2012		Hydro	Hydro	300	0	50	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Reece	REECE1	1/01/2009		Hydro	Hydro	231.2	93	231.2	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Tamar Va ley Power Station CCGT1	TVPSCCGT1U1	1/01/2012		Gas turbine combined cycle	Natural gas	200	125	180	3.0%	48.0%	0.0513	0.3848	$1.05
TAS1	Tarraleah	TARRALEAH	1/01/2009		Hydro	Hydro	90	36	90	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Trevallyn	TREVALLYN	1/01/2009		Hydro	Hydro	80	38	80	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Tribute	TR BUTE1	1/01/2009		Hydro	Hydro	82.8	20	60	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Tungatinah	TUNGAT NAH1	1/01/2009		Hydro	Hydro	125	20	60	0.5%	100.0%	0.0000	0.0000	$6.15

Data source: ACIL Tasman

Table 34 **Initial setting for existing and committed plant, Vic**

Region	Generator	DUID	From Date	To Date	Gen Type	Fuel	Unit Size (MW)	Min Gen (MW)	Contract Cover (MW)	Aux (%)	Thermal efficiency (HHV sent-out, %)	Emission factor (t CO2/GJ)	Emission factor (t CO2/MWh)	Var O&M (2009 $/MWh, sent-out)
VIC1	Anglesea Power Station	APS	1/01/2009		Steam turbine	Brown coal	160	150	160	10.0%	27.2%	0.0910	1.2044	$1.18
VIC1	Bairnsdale Power Station	BDL01	1/01/2009		Gas turbine	Natural gas	46	0	20	3.0%	34.0%	0.0513	0.5432	$2.23
VIC1	Bairnsdale Power Station	BDL02	1/01/2009		Gas turbine	Natural gas	46	10	20	3.0%	34.0%	0.0513	0.5432	$2.23
VIC1	Bogong	BOGONG1	1/10/2009		Hydro	Hydro	140	4	20	1.0%	100.0%	0.0000	0.0000	$7.18
VIC1	Dartmouth Power Station	DARTM1	1/01/2012		Hydro	Hydro	158	0	35	1.0%	100.0%	0.0000	0.0000	$6.15
VIC1	Eildon Power Station	EILDON1	1/01/2009		Hydro	Hydro	60	0	20	1.0%	100.0%	0.0000	0.0000	$9.23
VIC1	Eildon Power Station	EILDON2	1/10/2009		Hydro	Hydro	60	0	20	1.0%	100.0%	0.0000	0.0000	$9.23
VIC1	Energy Brix Complex	MOR1	1/01/2009		Steam turbine	Brown coal	90	50	55	15.0%	24.0%	0.0990	1.4850	$2.18
VIC1	Energy Brix Complex	MOR2	1/01/2009		Steam turbine	Brown coal	30	14	14	15.0%	24.0%	0.0990	1.4850	$2.18
VIC1	Energy Brix Complex	MOR3	1/01/2009		Steam turbine	Brown coal	75	37	37	15.0%	24.0%	0.0990	1.4850	$2.18
VIC1	Hazelwood Power Station	HWPS1	1/01/2012		Steam turbine	Brown coal	205	130	150	10.0%	22.0%	0.0930	1.5218	$1.18
VIC1	Hazelwood Power Station	HWPS2	1/01/2012		Steam turbine	Brown coal	205	130	150	10.0%	22.0%	0.0930	1.5218	$1.18
VIC1	Hazelwood Power Station	HWPS3	1/01/2012		Steam turbine	Brown coal	205	130	150	10.0%	22.0%	0.0930	1.5218	$1.18
VIC1	Hazelwood Power Station	HWPS4	1/01/2012		Steam turbine	Brown coal	205	130	150	10.0%	22.0%	0.0930	1.5218	$1.18
VIC1	Hazelwood Power Station	HWPS5	1/01/2012		Steam turbine	Brown coal	205	130	150	10.0%	22.0%	0.0930	1.5218	$1.18
VIC1	Hazelwood Power Station	HWPS6	1/01/2012		Steam turbine	Brown coal	205	130	150	10.0%	22.0%	0.0930	1.5218	$1.18
VIC1	Hazelwood Power Station	HWPS7	1/01/2012		Steam turbine	Brown coal	205	130	150	10.0%	22.0%	0.0930	1.5218	$1.18
VIC1	Hazelwood Power Station	HWPS8	1/01/2012		Steam turbine	Brown coal	205	130	180	10.0%	22.0%	0.0930	1.5218	$1.18
VIC1	Hume Power Station Vic	HUMEV	1/01/2009		Hydro	Hydro	29	12	0	1.0%	100.0%	0.0000	0.0000	$6.15
VIC1	Jeeralang A Power Sta ion	JLA01	1/01/2009		Gas turbine	Natural gas	57	0	20	3.0%	22.9%	0.0513	0.8065	$8.94
VIC1	Jeeralang A Power Sta ion	JLA02	1/01/2009		Gas turbine	Natural gas	57	0	20	3.0%	22.9%	0.0513	0.8065	$8.94
VIC1	Jeeralang A Power Sta ion	JLA03	1/01/2009		Gas turbine	Natural gas	57	0	20	3.0%	22.9%	0.0513	0.8065	$8.94
VIC1	Jeeralang A Power Sta ion	JLA04	1/01/2009		Gas turbine	Natural gas	57	0	20	3.0%	22.9%	0.0513	0.8065	$8.94
VIC1	Jeeralang B Power Sta ion	JLB01	1/01/2009		Gas turbine	Natural gas	85	0	40	3.0%	22.9%	0.0513	0.8065	$8.94
VIC1	Jeeralang B Power Sta ion	JLB02	1/01/2009		Gas turbine	Natural gas	85	0	40	3.0%	22.9%	0.0513	0.8065	$8.94
VIC1	Jeeralang B Power Sta ion	JLB03	1/01/2009		Gas turbine	Natural gas	85	0	40	3.0%	22.9%	0.0513	0.8065	$8.94
VIC1	Laverton North Power Sta ion	LAVNORTH	1/01/2009		Gas turbine	Natural gas	312	0	0	2.5%	30.4%	0.0513	0.6075	$7.83
VIC1	Loy Yang A Power Station	LYA1	1/01/2009		Steam turbine	Brown coal	560	400	450	9.0%	27.2%	0.0915	1.2110	$1.18
VIC1	Loy Yang A Power Station	LYA2	1/01/2009		Steam turbine	Brown coal	520	400	450	9.0%	27.2%	0.0915	1.2110	$1.18
VIC1	Loy Yang A Power Station	LYA3	1/01/2009		Steam turbine	Brown coal	560	400	485	9.0%	27.2%	0.0915	1.2110	$1.18
VIC1	Loy Yang A Power Station	LYA4	1/01/2009		Steam turbine	Brown coal	540	400	450	9.0%	27.2%	0.0915	1.2110	$1.18
VIC1	Loy Yang B Power Station	LOYYB1	1/01/2009		Steam turbine	Brown coal	525	200	450	7.5%	26.6%	0.0915	1.2383	$1.18
VIC1	Loy Yang B Power Station	LOYYB1	1/01/2009		Steam turbine	Brown coal	525	200	400	7.5%	26.6%	0.0915	1.2383	$1.18
VIC1	Loy Yang B Power Station	LOYYB2	1/01/2009		Steam turbine	Brown coal	525	200	450	7.5%	26.6%	0.0915	1.2383	$1.18
VIC1	Loy Yang B Power Station	LOYYB2	1/01/2009		Steam turbine	Brown coal	525	200	400	7.5%	26.6%	0.0915	1.2383	$1.18
VIC1	McKay Power Station	MCKAY1	1/01/2009		Hydro	Hydro	100	0	0	1.0%	100.0%	0.0000	0.0000	$7.18
VIC1	McKay Power Station	MCKAY2	1/10/2009		Hydro	Hydro	60	0	0	1.0%	100.0%	0.0000	0.0000	$7.18
VIC1	Mortlake OCGT	MORTLAKE_OCG	1/01/2011		Gas turbine	Natural gas	275	0	0	3.0%	32.0%	0.0513	0.5771	$8.22
VIC1	Mortlake OCGT	MORTLAKE_OCG	1/01/2011		Gas turbine	Natural gas	275	0	0	3.0%	32.0%	0.0513	0.5771	$8.22
VIC1	Murray 1 10x95MW Vic	MURRAYVIC1	1/01/2009		Hydro	Hydro	1500	0	440	1.0%	100.0%	0.0000	0.0000	$6.15
VIC1	Newport Power Sta ion	NPS	1/01/2012		Steam turbine	Natural gas	500	0	100	5.0%	33.3%	0.0513	0.5546	$2.23
VIC1	Somerton Power Station	AGLSOM	1/01/2009		Gas turbine	Natural gas	160	0	5	2.5%	24.0%	0.0513	0.7695	$9.50
VIC1	Valley Power Peaking Facility	VPGS1	1/01/2009		Gas turbine	Natural gas	50	0	5	3.0%	24.0%	0.0513	0.7695	$9.50
VIC1	Valley Power Peaking Facility	VPGS2	1/01/2009		Gas turbine	Natural gas	50	0	5	3.0%	24.0%	0.0513	0.7695	$9.50
VIC1	Valley Power Peaking Facility	VPGS3	1/01/2009		Gas turbine	Natural gas	50	0	5	3.0%	24.0%	0.0513	0.7695	$9.50
VIC1	Valley Power Peaking Facility	VPGS4	1/01/2009		Gas turbine	Natural gas	50	0	5	3.0%	24.0%	0.0513	0.7695	$9.50
VIC1	Valley Power Peaking Facility	VPGS5	1/01/2009		Gas turbine	Natural gas	50	0	5	3.0%	24.0%	0.0513	0.7695	$9.50
VIC1	Valley Power Peaking Facility	VPGS6	1/01/2009		Gas turbine	Natural gas	50	0	5	3.0%	24.0%	0.0513	0.7695	$9.50
VIC1	VIC NE Wind	VICNEWind	1/08/2011	30/09/2011	Wind	Wind	67.2	20.16	20.16	1.0%	100.0%	0.0000	0.0000	$1.75
VIC1	VIC NE Wind	VICNEWind	1/10/2011	28/02/2012	Wind	Wind	207.2	76.66	76.66	1.0%	100.0%	0.0000	0.0000	$1.75
VIC1	VIC NE Wind	VICNEWind	1/03/2012		Wind	Wind	347.2	128.46	128.46	1.0%	100.0%	0.0000	0.0000	$1.75
VIC1	West Kiewa Power Station	WKEWA1	1/01/2009		Hydro	Hydro	31	2	0	1.0%	100.0%	0.0000	0.0000	$7.18
VIC1	West Kiewa Power Station	WKEWA2	1/01/2009		Hydro	Hydro	31	2	8	1.0%	100.0%	0.0000	0.0000	$7.18
VIC1	Yallourn W Power Station	YWPS1	1/01/2009		Steam turbine	Brown coal	360	220	280	8.9%	23.5%	0.0925	1.4170	$1.18
VIC1	Yallourn W Power Station	YWPS2	1/01/2009		Steam turbine	Brown coal	360	220	280	8.9%	23.5%	0.0925	1.4170	$1.18
VIC1	Yallourn W Power Station	YWPS3	1/01/2009		Steam turbine	Brown coal	380	220	323	8.9%	23.5%	0.0925	1.4170	$1.18
VIC1	Yallourn W Power Station	YWPS4	1/01/2009		Steam turbine	Brown coal	380	220	280	8.9%	23.5%	0.0925	1.417	$1.18

Data source: ACIL Tasman

A.1.3 Near term supply changes assumed

Table 35 below outlines the committed or advanced withdrawals and additions of plant assumed to be common in each of the scenarios.

In Queensland, it is assumed that drought conditions which have lowered the generation from Tarong Power Station and Swanbank B during 2007/08 have subsided, allowing the stations to return to full service by 2009. The modelling shows a decrease in Swanbank B's dispatch when Kogan Creek was commissioned in November 2007 - due to Swanbank B being the most expensive coal fired plant in the CS portfolio.

Table 35 **Near-term additions to and withdrawals from generation capacity, by region**

Portfolio	Generator	Type	Nameplate capacity (MW)	Date-on	Date-off
			Victoria		
AGL Energy	Bogong	Hydro	140	Oct 2009	
Origin Energy	Mortlake	OCGT	550	Jan 2011	
Oaklands Hill	NE	Wind	67.2	Aug 2011	
Macarthur	NE	Wind	140	Oct 2011	
Macarthur	NE	Wind	140	March 2012	
			New South Wales		
TRUenergy	Tallawarra	CCGT/Gas	410	Jul 2008	
Origin Energy	Uranquinty	GT/Gas	664	From Feb 2009	
Delta	Colongra	GT/Gas	664	Dec 2009	
Delta	Munmorah	Black Coal	-600		Jul 2014
Delta	Mt Piper U1-U2	Black coal	+90MW per unit	Assumed not to proceed	
Eraring	Eraring	Black coal	+60MW per unit	2010	
			South Australia		
Origin Energy	Quarantine	OCGT	+120	Dec 2008	
AGL Energy	Hallett wind farm	Wind	95	April 2008	
Infigen	Lake Bonney Stage 2	Wind	159	July 2008	
Trust Power	Snowtown	Wind	99	July 2008	
AGL Energy	Hallett 2 wind farm	Wind	71	Nov 2009	
Infigen	Lake Bonney Stage 3	Wind	39	2010	
Pacific Hydro	Clements Gap	Wind	57	2010	
AGL Energy	Hallet Stage 4	Wind	132	2011	
AGL Energy	Oaklands Hill	Wind	63	2011	
Roaring 40s	Waterloo	Wind	111	2011	
			Queensland		
Queensland Gas Co	Condamine	CCGT/Gas	80/140	Feb 2009 80MW OCGT, 140MW CCGT by Aug 2009	
ERM	Braemar 2	OCGT/Gas	460	July 2009	
CS Energy	Swanbank B	Black coal	-440		April 2012
Origin Energy	Darling Downs	CCGT	630	January 2010	
Origin Energy	Mt Stuart	OCGT	126	October 2009	
Rio Tinto	Yarwun	CCGT/Cogen	168	January 2011	
			Tasmania		
Alinta	Tamar Valley PS	CCGT/Gas	200 + 40 (OCGT)	Jul 2009	
Bell Bay Power	Bell Bay PS	Gas	-240		October 2009

Data source: AEMO ESOO and ACIL Tasman

A.1.4 Short run marginal costs of plant

The NEM is modelled on a nominal basis and we assume that variable operating and maintenance costs and fuel costs escalate over time, relative to an assumed CPI of 2.5%.

Fuel prices

Fuel costs are more complex, in that they escalate at different rates and, the escalation in some cases is not smooth – reflecting step changes in the demand/supply balance of gas as well as changes (expiry and renewal) in coal contracts.

Gas

There are two key factors that are likely to affect gas demand on the East Coast of Australia over coming years:

- Increased reliance on gas for power generation.
- Expansion of LNG production, including proposed development of an East Coast LNG industry based on CSG.

Our modelling for gas assumes two 4 million tonne per annum LNG facilities constructed in 2014 and 2018. This has a demand for gas feed of 220 PJ/a commencing in 2014 and increasing to 440 PJ/a in 2018.

Ramp-up gas associated with LNG production is a significant matter for the gas market over the next decade. We conclude that the ramp-up gas can be dealt with through a number of mitigating measures and we do not anticipate the ramp-up gas having a material influence on price.

Gas prices for base/intermediate load plant are determined either:

- on a cost plus basis for gas fired power stations sited on dedicated resources (e.g. Darling Downs and Condamine)
- from estimated contract prices where information is available
- from estimated market based nodal prices (GasMark Global projection) incorporating transportation costs when contracts expire or for new entrants sited remotely from gas fields
- Where existing power stations contracts expire over time, a blended average of existing contract and estimated market prices is used.

Peaking plant gas prices are set in the same way as the base/intermediate load except that a 50% premium is added to reflect the optional value and intermittent nature of the gas supply. While many peaking plants store distillate as an emergency reserve, we assume that in the normal course of business that this reserve is not used.

Coal

We determine coal fuel costs based on ACIL Tasman's internal projections. We consider the prices and duration of existing coal contracts. Upon expiry of existing contracts these plants are assumed to move to market-based rates. We assume that power stations are able to negotiate contracts at either a ROM cost plus rate (allowing a return on capital employed in the mine) or 80% of the ROM netback price whichever is the higher. For power stations that are not mine mouth, we include the efficient cost of transportation - either rail or road.

Queensland black coal

In Qld there are four types of coal supply arrangement:

- mine mouth - own mine: Tarong, Kogan Creek, Millmerran
- mine mouth - captive third party mine: Callide B, Callide Power, Collinsville
- transported from captive third party mine: Stanwell
- transported from third party mine: Gladstone, Swanbank B

Power stations in Queensland relying on their own mine mouth coal supply are least likely to be affected by the high export prices and it has been assumed that they will offer marginal fuel costs into the market which are currently less than A$1.00/GJ. However they will be affected by mining cost increases which have increased rapidly in recent years in response to strong demand and high oil and tyre prices.

Power stations with a mine mouth operation with a third party supplier are likely to be under pressure to accept prices more in line with export parity particularly with price reviews and contract renewal. However the arrangements for the larger Callide power stations have two decades to run and have limited if any price reopeners.

In 2004 Stanwell entered a 16 year arrangement with the Curragh mine which is not linked to export prices. We expect that Stanwell will be actively seeking advantageous alternative arrangements when these current arrangements expire.

Gladstone and Swanbank which rely on transported coal from third party mines are at greatest risk of pass through of export prices. However Gladstone has a long term arrangement with Rolleston to take lower quality coal. Swanbank is likely to continue on similar arrangements beyond the current three year contract with the New Acland mine near Oakey as alternative markets are limited by the export infrastructure in the Brisbane region; which is at capacity with no prospect of an increase in the medium term.

NSW black coal

In NSW all coal is supplied to the power stations by third party coal mines under a variety of contractual arrangements with varying terms, prices and transport arrangements. These contracts vary from relatively short term (1 to 2 years) to very long term (20 years or more). Generally these contracts were written before the surge in export coal prices from early 2004 and carry contract prices which are generally well below the export parity value being experienced in today's export market.

New tonnage however will need to be sourced in a setting of higher export coal prices. There are a number of strategies which local power stations will employ to keep prices of new tonnage lower than export parity price and these include:

- gaining access to undeveloped resources and employing a contract miner to produce the coal. (there are many unallocated resources available in NSW for this purpose)
- offering firm contracts to potential new developments in order to achieve discounted prices by lowering the market and infrastructure risks associated new developments
- entering into long term contractual arrangements with mines aimed at achieving cost related pricing
- offering to take non-exportable high ash coal, oxidised coal and washery rejects and middlings.

We expect these purchase strategies to result in reductions of around 20% on the export parity price of coal at most locations.

Victorian brown coal

Extensive deposits of brown coal occur in the tertiary sedimentary basins of Latrobe Valley coalfield which contains some of the thickest brown coal seams in the world. The coal is up to 330 m thick and is made up of 4 main seams, separated by thin sand and clay beds. The total brown coal resource in the Latrobe Valley is estimated to be 394,000 million tonnes, with an estimated useable brown coal reserve of 50,000 million tonnes.

Anglesea's brown coal reserves are estimated at around 120 million tonnes. Average coal thickness is 27 metres. The coal is a high quality brown coal, with a heat value of just over 15MJ/kg.

Mine mouth dedicated coalmines supply all the power stations. The coalmines are owned by the same entities that own the power stations with two exceptions. The exceptions are the Loy Yang B power station, where the mine, which is in close proximity to the power station, is owned and operated by Loy Yang Power, the owners and operators of the Loy Yang A power station and Energy Brix which is supplied by Morwell mine.

The marginal price of coal for the Victorian power stations is generally taken as the cash costs for mining the coal.

Table 36 details the estimated marginal costs for coal at each power station. The marginal costs for coal are based on the cost of electricity required to produce the marginal tonne and the royalty charges.

Table 36 **Estimated coal costs for Victorian generators in 2009/10**

Power Station / Mine	Total Cash Cost $/t	Variable Cost $/t	Energy Content GJ/t	Variable Cost $/GJ
Yallourn/Yallourn	$3.24	$0.62	6.8	$0.10
Loy Yang A - directly form Loy Yang mine	$3.00	$0.65	8.2	$0.08
Loy Yang B - purchased from Loy Yang mine	$3.00	$3.00	8.2	$0.37
Hazelwood/Morwell	$4.19	$0.60	7.0	$0.08
Anglesea/Anglesea	$5.99	$5.99	15.0	$0.40
Energy Brix/Morwell	$4.19	$4.19	7.0	$0.60

Data source: ACIL Tasman analysis

The variable cost of coal as calculated in Table 36 is used to calculate the marginal costs for the Victorian Power stations operating in the NEM. In the cases where the coal mine is owned by the power station (Yallourn, Hazelwood and Loy Yang A) the short run marginal costs mainly consist of the additional electricity and royalty costs involved in mining the marginal tonne of coal. For Anglesea the marginal cost of coal is taken to be the cost of extraction using trucks and shovels. The marginal price of coal for the two stations that purchase coal from nearby mines (Loy Yang B and Energy Brix) is taken to be the estimated cost per unit of production.

South Australia black coal

The only currently producing coalfield in South Australia is near Leigh Creek based on low-grade sub-bituminous black coal. The mining operation involves drilling, blasting and removal of overburden and coal by shovels and trucks. After mining, the crushed coal is railed to the Port Augusta power stations. Due to the steeply dipping seams, it is likely that economic recovery of coal will be limited to between 70 and 100 Mt at depths of 150–200 m.

The Leigh Creek mine is about 250kms from the Northern power station. A long-term freight contract is in place with Pacific National. The delivered cost of coal is estimated at $1.40/GJ. The marginal cost of coal in South Australia is taken as the average cash costs of production and transport. The life of the

Leigh Creek mine is constantly under review and will depend on the cost of mining and transport.

Table 37 **Assumed fuel costs (2011-12 $/GJ) by station by year**

Region	Generator	Fuel	2011-12
NSW1	Bayswater	Black coal	$1.42
NSW1	Colongra	Natural gas	$7.24
NSW1	Eraring Power Station 330kv	Black coal	$2.05
NSW1	Eraring Power Station 500kv	Black coal	$2.05
NSW1	Hunter Valley Gas Turbine	Fuel oil	$31.87
NSW1	Liddell	Black coal	$1.42
NSW1	Mt Piper Power Station	Black coal	$2.12
NSW1	Munmorah Power Station	Black coal	$2.11
NSW1	Redbank Power Station	Black coal	$1.09
NSW1	Smithfield Energy Facility	Natural gas	$4.34
NSW1	Tallawarra	Natural gas	$3.94
NSW1	Unranquinty	Natural gas	$6.31
NSW1	Vales Point B Power Station	Black coal	$2.11
NSW1	Wallerawang C Power Station	Black coal	$2.12
QLD1	Barcaldine Power Station	Natural gas	$6.88
QLD1	Braemar	Natural gas	$3.15
QLD1	Braemar_Two	Natural gas	$3.00
QLD1	Callide B Power Station	Black coal	$1.43
QLD1	Callide Power Plant	Black coal	$1.43
QLD1	Collinsville Power Station	Black coal	$2.48
QLD1	Condamine Power Station	Natural gas	$0.98
QLD1	Darling Downs ATR	Natural gas	$3.54
QLD1	Gladstone	Black coal	$1.69
QLD1	Kogan Creek	Black coal	$0.81
QLD1	Mackay Gas Turbine	Fuel oil	$31.87
QLD1	Millmerran Power Plant	Black coal	$0.92
QLD1	Mt Stuart Gas Turbine	Liquid Fuel	$31.87
QLD1	Oakey Power Station	Natural gas	$4.38
QLD1	Roma Gas Turbine Station	Natural gas	$5.02
QLD1	Stanwell Peaking Facility	Fuel oil	$31.87
QLD1	Stanwell Power Station	Black coal	$1.51
QLD1	Swanbank B Power Station	Black coal	$2.69
QLD1	Swanbank E Gas Turbine	Coal seam methane	$3.45
QLD1	Tarong North Power Station	Black coal	$1.09
QLD1	Tarong Power Station	Black coal	$1.09
QLD1	Townsville Power Station	Coal seam methane	$4.19
QLD1	Yarwun Cogen	Natural gas	$3.69
SA1	Angaston	Distillate	$31.87
SA1	Dry Creek Gas Turbine Station	Natural gas	$4.88
SA1	Hallett Power Station	Natural gas	$6.73
SA1	Ladbroke Grove Power Station	Natural gas	$5.55
SA1	Mintaro Gas Turbine Station	Natural gas	$6.73
SA1	Northern Power Station	Black coal	$1.62
SA1	Osborne Power Station	Natural gas	$4.28
SA1	Pelican Point Power Station	Natural gas	$4.11
SA1	Playford B Power Station	Black coal	$1.62
SA1	Port Lincoln Gas Turbine	Distillate	$31.87
SA1	Quarantine Power Station	Natural gas	$5.92
SA1	Snuggery Power Station	Distillate	$31.87
SA1	Torrens Island Power Station A	Natural gas	$4.18
SA1	Torrens Island Power Station B	Natural gas	$4.18
TAS1	Bell Bay	Natural gas	$5.88
TAS1	Bell Bay Three	Natural gas	$5.63
TAS1	Tamar Valley Power Station CCGT1	Natural gas	$5.63
VIC1	Anglesea Power Station	Brown coal	$0.42
VIC1	Bairnsdale Power Station	Natural gas	$4.45
VIC1	Energy Brix Complex	Brown coal	$0.63
VIC1	Hazelwood Power Station	Brown coal	$0.09
VIC1	Jeeralang A Power Station	Natural gas	$4.28
VIC1	Jeeralang B Power Station	Natural gas	$4.28
VIC1	Laverton North Power Station	Natural gas	$4.26
VIC1	Loy Yang A Power Station	Brown coal	$0.09
VIC1	Loy Yang B Power Station	Brown coal	$0.39
VIC1	Mortlake OCGT	Natural gas	$5.52
VIC1	Newport Power Station	Natural gas	$4.23
VIC1	Somerton Power Station	Natural gas	$4.27
VIC1	Valley Power Peaking Facility	Natural gas	$4.02
VIC1	Yallourn W Power Station	Brown coal	$0.10

Note: These values are applied to the HHV heat rates to give a fuel cost in $/MWh.

Data source: *ACIL Tasman*

A.1.1 Thermal efficiency

The thermal efficiencies of all plant are shown above. The thermal efficiency values tabulated are measured as sent-out. Even though the model settles the market on a 'as generated' basis it uses a 'sent-out' SRMC for the purpose of formulating the offer curves as well as calculating the portfolio net revenue in the optimisation routine. As part of the settlement process, NEMMCO pays the generators based on their dispatch measured at the regional reference node (RRN) – which is the sent-out dispatch corrected for the MLF.

A.1.2 Marginal loss factors

The marginal loss factors (MLFs) assumed in the scenarios are taken directly from the latest NEMMCO report – "List of Regional Boundaries and Marginal Loss Factors for the 2008/09 Financial Year". The MLFs are used in the settlement routine to adjust the offers of the generators. The generators themselves do not make this alteration to their offer curves – hence the short run marginal costs tabulated in the following section have not been adjusted for MLF.

A.1.3 Short run marginal costs

Taken together, the fuel costs, thermal efficiency and variable O&M costs determine the short run marginal cost (SRMC) for each station. Table 38 summarises the nominal SRMC assumed for each station.

Table 38 **Station SRMC (2011-12 $/MWh) for existing or committed plant**

Region	Generator	Fuel	2011-12
NSW1	Bayswater	Black coal	$15.60
NSW1	Colongra	Natural gas	$89.70
NSW1	Eraring Power Station 330kv	Black coal	$19.65
NSW1	Eraring Power Station 500kv	Black coal	$19.65
NSW1	Hunter Valley Gas Turbine	Fuel oil	$414.47
NSW1	Liddell	Black coal	$16.50
NSW1	Mt Piper Power Station	Black coal	$21.31
NSW1	Munmorah Power Station	Black coal	$26.21
NSW1	Redbank Power Station	Black coal	$14.44
NSW1	Smithfield Energy Facility	Natural gas	$40.07
NSW1	Tallawarra	Natural gas	$27.14
NSW1	Uranquinty	Natural gas	$78.99
NSW1	Vales Point B Power Station	Black coal	$22.07
NSW1	Wallerawang C Power Station	Black coal	$23.67
QLD1	Barcaldine Power Station	Natural gas	$58.08
QLD1	Braemar	Natural gas	$51.18
QLD1	Braemar_Two	Natural gas	$36.61
QLD1	Callide B Power Station	Black coal	$15.28
QLD1	Callide Power Plant	Black coal	$16.67
QLD1	Collinsville Power Station	Black coal	$33.24
QLD1	Condamine Power Station	Natural gas	$2.45
QLD1	Darling Downs ATR	Natural gas	$22.81
QLD1	Gladstone	Black coal	$18.32
QLD1	Kogan Creek	Black coal	$8.98
QLD1	Mackay Gas Turbine	Fuel oil	$413.90
QLD1	Millmerran Power Plant	Black coal	$11.75
QLD1	Mt Stuart Gas Turbine	Liquid Fuel	$386.92
QLD1	Oakey Power Station	Natural gas	$51.89
QLD1	Roma Gas Turbine Station	Natural gas	$52.93
QLD1	Stanwell Peaking Facility	Fuel oil	$0.00
QLD1	Stanwell Power Station	Black coal	$18.03
QLD1	Swanbank B Power Station	Black coal	$32.59
QLD1	Swanbank E Gas Turbine	Coal seam methane	$21.43
QLD1	Tarong North Power Station	Black coal	$10.99
QLD1	Tarong Power Station	Black coal	$18.30
QLD1	Townsville Power Station	Coal seam methane	$27.62
QLD1	Yarwun Cogen	Natural gas	$31.57
SA1	Angaston	Distillate	$445.61
SA1	Dry Creek Gas Turbine Station	Natural gas	$76.52
SA1	Hallett Power Station	Natural gas	$111.60
SA1	Ladbroke Grove Power Station	Natural gas	$69.08
SA1	Mintaro Gas Turbine Station	Natural gas	$97.05
SA1	Northern Power Station	Black coal	$17.70
SA1	Osborne Power Station	Natural gas	$41.41
SA1	Pelican Point Power Station	Natural gas	$31.58
SA1	Playford B Power Station	Black coal	$29.32
SA1	Port Lincoln Gas Turbine	Distillate	$445.61
SA1	Quarantine Power Station	Natural gas	$74.51
SA1	Snuggery Power Station	Distillate	$445.61
SA1	Torrens Island Power Station A	Natural gas	$34.58
SA1	Torrens Island Power Station B	Natural gas	$34.58
TAS1	Bell Bay	Natural gas	$0.00
TAS1	Bell Bay Three	Natural gas	$75.88
TAS1	Tamar Valley Power Station CCGT1	Natural gas	$40.53
VIC1	Anglesea Power Station	Brown coal	$6.64
VIC1	Bairnsdale Power Station	Natural gas	$48.86
VIC1	Energy Brix Complex	Brown coal	$11.56
VIC1	Hazelwood Power Station	Brown coal	$2.63
VIC1	Jeeralang A Power Station	Natural gas	$73.12
VIC1	Jeeralang B Power Station	Natural gas	$73.12
VIC1	Laverton North Power Station	Natural gas	$56.75
VIC1	Loy Yang A Power Station	Brown coal	$2.36
VIC1	Loy Yang B Power Station	Brown coal	$6.43
VIC1	Mortlake OCGT	Natural gas	$68.26
VIC1	Newport Power Station	Natural gas	$47.47
VIC1	Somerton Power Station	Natural gas	$73.00
VIC1	Valley Power Peaking Facility	Natural gas	$69.25
VIC1	Yallourn W Power Station	Brown coal	$2.73

Note: The SRMCs reported are as at 1 January for the given year. An SRMC of zero indicates the station is not available. The SRMCs for CCGTs in Queensland are reduced by an assumed GEC price; the SRMCs for CCGTs in o her regions are reduced by an assumed NGAC price.

Data source: *ACIL Tasman generator database*

A.2 Offer strategies

Generation portfolios enter into electricity derivative contracts to hedge pool revenues in order to reduce earnings risk and avoid insolvency. In entering into these contracts generators are indifferent to RRP movements across the volume of these contracts except where RRP fall below the SRMC. Hence a short term optimal strategy is to offer all generation that is contracted at SRMC. However if all generators contract heavily and then offer all generation that is contracted at a price of SRMC, the RRP will tend to spiral downwards and future contracts will tend to reflect lower RRP expectations. Hence long term optimal strategies require some generation to be bid above SRMC to maintain underlying RRPs and by implication contract prices.

PowerMark provides a range of options with regard to the offer strategy used by each portfolio. Offer strategies include:

- Maximising dispatch, so that each portfolio attempts to maximise its output in each period – typically for price takers
- Maximising net uncontracted revenue – for price makers.

Net pool revenue is dispatch weighted pool revenue in each period less fuel costs. Only uncontracted revenue is maximised as the portfolio is assumed to be indifferent in the short term to the price it receives from the pool for that volume of its dispatch, which is contracted. It will only attempt to maximise its revenue for that proportion of its output, which is not under contract.

In order to avoid the downward price spiral noted above, the contract volume setting in PowerMark is not designed to fit exactly with actual contract volumes. Rather it is a setting that allows accurate simulation of the way in which portfolio generators bid in the market – i.e. large portions of volume at SRMC to guarantee a minimum volume with smaller portions of volume at multiples of SRMC to reflect the total cost of supply.

In the scenarios, for the most part, we have assumed the second optimising strategy (as we do in nearly all runs of PowerMark) that each portfolio will offer energy in order to attempt to maximise the returns from uncontracted revenue, reflecting an objective of maximising the returns from contracted and uncontracted revenues over the long term.

A.2.1 Hydro plant

Hydro plant have very low SRMCs so if PowerMark were to 'start' their bid curves at their true SRMC, in a manner similar to a thermal plant, then they would over the course of a year generate well beyond their energy constraints. Instead the model uses the notion of an opportunity cost for the water which attempts to maximise the net revenue of the plant but not break the energy constraint.

PowerMark allows the hydro plant to offer their capacity strategically – that is, they attempt to optimise their net pool revenue but at the same time satisfying their energy (water availability and storage) constraints. As a consequence, the offer curves may vary by season, day of week and time-of-day to reflect the energy constraints and profit maximising behaviour. Rather than using their true SRMC as a starting point, the hydro plant are assigned an opportunity cost which will change year on year depending on the demand/supply balance in the market.

We assume an annual energy constraint equal to the long term annual generation of the plant (which is equal to the long term average inflows).

A.2.2 Wind and geothermal plant

Wind and geothermal plant are assumed to offer their available capacity at a zero price to maximise the chance of dispatch.

In general, wind plants are assumed to achieve a capacity factor of 30%.

Geothermal plant will be assumed to achieve an 85% capacity factor. The implicit assumption here is that additional wells are drilled to offset the natural decline in performance of the existing wells, so that the capacity factor remains reasonably constant throughout the projection.

A.2.3 Offer curve construction

Regardless of offer strategy, for each plant, ACIL Tasman sets the first two tranches of the offer curve according to:

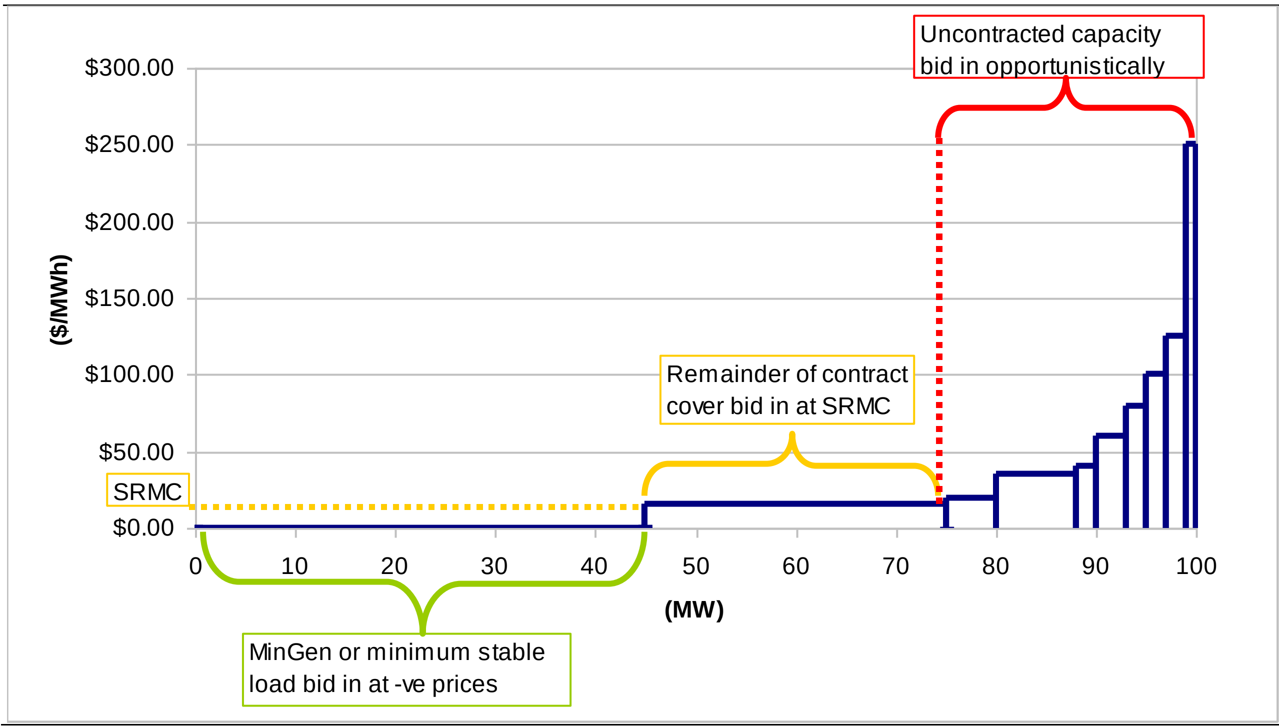
- the assumed level of MinGen, which is offered between -$1000/MWh and $0/MWh; and
- the assumed level of contract cover, which is offered at the SRMC of the plant.

In addition to the MinGen and contract cover settings; for some plant, tranches of the offer curve may be fixed to account for assumed cap contracts. This setting is mainly used for peaking plant and typically set to rounded dollar values between $100/MWh and $250/MWh.

A number of assumptions are made when setting the fixed part of the offer curve for each station. ACIL Tasman invests a great deal of time collating analysis of historical offer curves and separate market intelligence to formulate what it considers to be reasonable long term assumptions about the MinGen, contract cover and cap contract settings for each generator.

Finally, the projection assumes that the cap on price offers (or VoLL) is set at AUD10,000/MWh and rises to $12,500/MWh in July 2010. The offer curves of all plant are capped at this value. Although VoLL may be revised further, we assume that it does not otherwise change throughout the projection period.

Figure 3 **Example offer curve of a generator**



Data source: ACIL Tasman

A.3 Contract cover

Contract cover measures the extent to which generators have their RRP exposure covered by financial swap contracts (two-way hedges)[16]. In modelling pool markets, the level of swap contract cover is a key factor in price and dispatch outcomes. Based solely on short-run analysis, a generator would typically offer contracted capacity at marginal cost (save for below marginal cost bids in respect of 'MinGen' and ramp-up needs[17]), and will bid to maximise net revenues from the remaining uncontracted capacity.

However, this short run optimal strategy is not optimal in the long run as it drives RRPs down well below contract prices leading to lower contract prices in the future with an ongoing spiral downwards of pool and contract prices. Hence in practice at least some generators (generally the bigger portfolios with the most to gain and lose) are willing to sacrifice some contract revenue to avoid this downward spiral.

While swap contract levels are not publicly known, portfolio bid stacks do allow the level of capacity bid at marginal cost to be inferred. While this probably underestimates the total volume of contracts in place, it reflects the volume of contracts that each generator is willing to protect rather than sacrifice in the interests of long run profitability.

Within PowerMark, specification of swap contract levels means specification of the amount of capacity to be offered at or below marginal cost. It is estimated by reference to recent market experience and adjusted over time on the basis of an analysis of contracting incentives.

ACIL Tasman's analysis to date indicates that the lowest of the off-peak hours are heavily contracted as a proportion of load, whereas caps and other more exotic options are added to swaps in the peak periods to provide cost effective risk management.

ACIL Tasman establishes proxy values of swap contract cover for recent historical periods by 'reverse engineering' the swap contract cover and swap contract target assumptions such that they replicate actual power station dispatch and RRPs when actual demand data and outage data are substituted

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[16] Caps impact on generator offering behaviour only to the extent that they relate to plant capacity that would normally be off-line.

[17] 'MinGen' (for minimum generation) is the estimated minimum level at which a plant can be technically and economically operated (for flame control and damage limitation). Generators usually offer this level of capacity at near zero or substantially negative prices in order to avoid being offloaded by the central dispatcher. It is rare — but does occur — for the RRP to settle at a negative "offload" price. Generators also tend to offer capacity at below marginal cost for periods when they are intent on 'ramping-up' in order to have the ability to offer greater amounts of capacity in a subsequent period, when RRPs are expected to be higher.

for projected demand and outages. The estimates derived in that way are plausible numbers in the opinion of market participants familiar with them. **We expect the level of contract cover in the market to stabilise, on a long term basis, at about 85-90% of all demand. Based on our modelling, this allows new entrants a reasonable level of contract cover as well as maintaining the contract levels of existing baseload plant.**

It is important to note that the levels of contract cover in the market assumed in the scenarios are expressed in terms of load, not in capacity.

A.4 Plant availability

A.4.1 Introduction

PowerMark includes in it for each generator a planned maintenance schedule and a set of random unplanned outages.

In 2005, ACIL Taman undertook an availability analysis of coal fired plant in the NEM spanning 1999 to 2004 using published NEMMCO data. The availability analysis grouped planned maintenance and forced outages together.

The analysis found that in Queensland the average outage days per year across all coal plant was 41 and the median was 37 – this equates to an availability of 88% and 90% respectively. The median was reported in an attempt to remove anomalous outages – such as the well recognised difficulties experienced by Millmerran – although it gave only a slightly lower result than the average.

The 75th percentile of the outage distribution was 60 days, which equates to 84% availability.

ACIL Tasman proposes to use an availability of 90% for coal plant.

There is not as much long term data available on CCGT plant in Queensland, but ACIL Tasman in its market modelling of the NEM and Singapore routinely assumes CCGTs experience 15 days per year of planned maintenance (which equates to 4%) and a 3% forced outage rate. **Therefore, ACIL Tasman uses an availability of 92% for CCGT plant**.

We assume a 1.5% forced outage rate for peaking plant. Although peaking plant undergo planned maintenance, we assume that this maintenance is scheduled during the off-peak months when the plant are rarely used. Given these plants typically have annual capacity factors of less than 5%, it appears reasonable to assume that their planned maintenance can be scheduled during periods when there is a very low probability of high priced outcomes in the NEM.

Therefore, ACIL Tasman proposes to use an availability of 98.5% for OCGT plant.

Hydro plants are assumed to have an overall availability of 95% per year.

Geothermal plants are assumed to have an overall availability of 90% per year.

A.4.2 Forced outage rates

Table 39 summarises the assumed annual forced outage rate by station.

A.4.3 Planned maintenance

Water-cooled black coal plant are generally assumed to have planned maintenance schedules that equate to about one month every two years.

Air-cooled black coal plant tend to have a schedule that equates to one month every year

The newer brown coal plant tend to have a schedule that equates to one month every four years and the older brown coal plant a schedule that equates to one month every year.

New entrant CCGTs and coal plant are assumed to be off-line one month every four years for planned maintenance.

Table 39 **Annual forced outage rate, by station**

Region	Generator	Fuel	UPO
NSW1	Bayswater	Black coal	3.0%
NSW1	Colongra	Natural gas	1.5%
NSW1	Eraring Power Station 330kv	Black coal	3.0%
NSW1	Eraring Power Station 500kv	Black coal	3.0%
NSW1	Hunter Valley Gas Turbine	Fuel oil	2.5%
NSW1	Liddell	Black coal	3.0%
NSW1	Mt Piper Power Station	Black coal	3.0%
NSW1	Munmorah Power Station	Black coal	7.0%
NSW1	Redbank Power Station	Black coal	4.0%
NSW1	Smithfield Energy Facility	Natural gas	2.5%
NSW1	Tallawarra	Natural gas	3.0%
NSW1	Unranquinty	Natural gas	1.5%
NSW1	Vales Point B Power Station	Black coal	3.0%
NSW1	Wallerawang C Power Station	Black coal	3.0%
QLD1	Barcaldine Power Station	Natural gas	2.5%
QLD1	Braemar	Natural gas	1.5%
QLD1	Braemar_Two	Natural gas	1.5%
QLD1	Callide B Power Station	Black coal	4.0%
QLD1	Callide Power Plant	Black coal	6.0%
QLD1	Collinsville Power Station	Black coal	4.0%
QLD1	Condamine Power Station	Natural gas	1.5%
QLD1	Darling Downs ATR	Natural gas	3.0%
QLD1	Gladstone	Black coal	4.0%
QLD1	Kogan Creek	Black coal	4.0%
QLD1	Mackay Gas Turbine	Fuel oil	1.5%
QLD1	Millmerran Power Plant	Black coal	5.0%
QLD1	Mt Stuart Gas Turbine	Liquid Fuel	2.5%
QLD1	Oakey Power Station	Natural gas	2.0%
QLD1	Roma Gas Turbine Station	Natural gas	3.0%
QLD1	Stanwell Power Station	Black coal	2.5%
QLD1	Swanbank B Power Station	Black coal	7.0%
QLD1	Swanbank E Gas Turbine	Coal seam methane	3.0%
QLD1	Tarong North Power Station	Black coal	3.0%
QLD1	Tarong Power Station	Black coal	3.0%
QLD1	Townsville Power Station	Coal seam methane	3.0%
QLD1	Yarwun Cogen	Natural gas	3.0%
SA1	Angaston	Distillate	1.5%
SA1	Dry Creek Gas Turbine Station	Natural gas	3.0%
SA1	Hallett Power Station	Natural gas	1.5%
SA1	Ladbroke Grove Power Station	Natural gas	3.0%
SA1	Mintaro Gas Turbine Station	Natural gas	1.5%
SA1	Northern Power Station	Black coal	5.0%
SA1	Osborne Power Station	Natural gas	3.0%
SA1	Pelican Point Power Station	Natural gas	3.0%
SA1	Playford B Power Station	Black coal	10.0%
SA1	Port Lincoln Gas Turbine	Distillate	1.5%
SA1	Quarantine Power Station	Natural gas	2.5%
SA1	Snuggery Power Station	Distillate	2.0%
SA1	Torrens Island Power Station A	Natural gas	4.5%
SA1	Torrens Island Power Station B	Natural gas	4.5%
TAS1	Bell Bay	Natural gas	3.0%
TAS1	Bell Bay Three	Natural gas	3.0%
TAS1	Tamar Valley Power Station CCGT1	Natural gas	3.0%
VIC1	Anglesea Power Station	Brown coal	3.0%
VIC1	Bairnsdale Power Station	Natural gas	2.5%
VIC1	Energy Brix Complex	Brown coal	2.5%
VIC1	Hazelwood Power Station	Brown coal	3.5%
VIC1	Jeeralang A Power Station	Natural gas	2.5%
VIC1	Jeeralang B Power Station	Natural gas	2.5%
VIC1	Laverton North Power Station	Natural gas	1.5%
VIC1	Loy Yang A Power Station	Brown coal	3.0%
VIC1	Loy Yang B Power Station	Brown coal	4.0%
VIC1	Mortlake OCGT	Natural gas	1.5%
VIC1	Newport Power Station	Natural gas	2.0%
VIC1	Somerton Power Station	Natural gas	1.5%
VIC1	Valley Power Peaking Facility	Natural gas	1.5%
VIC1	Yallourn W Power Station	Brown coal	4.0%

Data source: ACIL Tasman assumptions