Estimated energy purchase costs for Final Determination

Estimated energy purchase costs for use by the Queensland Competition Authority in its Final Determination on retail electricity tariffs for 2012/13

Prepared for the Queensland Competition Authority

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ACIL Tasman

Economics Policy Strategy

ACIL Tasman Pty Ltd

ABN 68 102 652 148
Internet www.aciltasman.com.au

Melbourne (Head Office)

Level 4, 114 William Street
Melbourne VIC 3000

Telephone (+61 3) 9604 4400
Facsimile (+61 3) 9604 4455
Email melbourne@aciltasman.com.au

Brisbane

Level 15, 127 Creek Street
Brisbane QLD 4000
GPO Box 32
Brisbane QLD 4001

Telephone (+61 7) 3009 8700
Facsimile (+61 7) 3009 8799
Email brisbane@aciltasman.com.au

Canberra

Level 1, 33 Ainslie Place
Canberra City ACT 2600
GPO Box 1322
Canberra ACT 2601

Telephone (+61 2) 6103 8200
Facsimile (+61 2) 6103 8233
Email canberra@aciltasman.com.au

Perth

Centa Building C2, 118 Railway Street
West Perth WA 6005

Telephone (+61 8) 9449 9600
Facsimile (+61 8) 9322 3955
Email perth@aciltasman.com.au

Sydney

PO Box 1554
Double Bay NSW 1360

Telephone (+61 2) 9389 7842
Facsimile (+61 2) 8080 8142
Email sydney@aciltasman.com.au

For information on this report

Please contact:

Marcus Randell
Telephone (07) 3009 8709 or 3009 8700
Mobile 0404 822 319
Email m.randell @aciltasman.com.au

Contributing team members

Paul Breslin
Paul Hyslop
Richard Lenton
Martin Pavelka
Cara Chambers

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1 Background

This report has been prepared for the Queensland Competition Authority's (the Authority) Final Determination (Final Determination) on notified retail electricity tariffs for 2012/13. It provides estimates of expected energy purchase costs for each settlement class. The energy purchase cost estimates provided in this report represent updated estimates over our draft report incorporating the latest available data and also responding to the submissions to the Authority's Draft Determination (Draft Determination) on notified retail electricity tariffs for 2012/13. It also corrects for any anomalies identified by ACIL Tasman, the Authority or in the submissions.

Retail tariffs are made up of three components: network costs, retailing costs and energy purchase costs. This report is limited to the energy purchase costs component. In accordance with the Ministerial Delegation[1] and the brief provided by the Authority, the methodology developed by ACIL Tasman provides an estimate of energy purchase costs which reflect the actual cost of purchasing electricity. Energy purchase costs (EPC) comprise wholesale energy purchase costs (WEPC) and other energy purchase costs (OEPC) associated with renewable energy incentives and market fees.

As far as estimating the EPC is concerned, ACIL Tasman has been instructed by the Authority to provide our best estimate of energy purchase costs based on expected market conditions in 2012/13. In accordance with the brief and based on the Authority's interpretation of the Ministerial Delegation as advised to ACIL Tasman, the energy purchase costs presented in this report are based on estimates of the expected WEPC for National Electricity Market (NEM) based independent electricity retailers in 2012/13 along with the expected OEPC. In this sense our estimate of the WEPC is the market price that an independent retailer would expect to pay for energy purchased from the NEM in 2012/13.

WEPC estimates are based on expected market prices not generation costs. The market prices are those expected to prevail in 2012/13 and have been estimated by NEM simulation and by averaging of the quarterly future contracts prices from d-cyphaTrade and AFMA. These prices reflect the existing supply-demand balance and the existing level of competition both in the pool and contract markets.

[1] Ministerial Delegation - September 2011

Found at: http://www.qca.org.au/files/ER-NEP1213-QLDGovtDME-CertDeleg-0911.PDF

The markets in 2012/13 are expected to be characterised by an oversupply of generation which in turn can be expected to produce prices which are lower than the current long run marginal cost (LRMC) of generation.

ACIL Tasman's report for the Draft Determination presented estimates of WEPC using two methodologies, the price distribution approach and the contract hedging approach. The report for the Draft Determination favoured the use of the contract hedging approach as the alternative price distribution approach was shown to have much greater uncertainty. Following a review of submissions and further consideration by ACIL Tasman, this report has discarded the price distribution approach and Final Determination presents only the contract hedging approach.

A key theme of the retailer response was that the retail tariffs should be set at a level which allows adequate headroom for retail competition to prevail for small customers (<100MWh/year) in the Energex area. ACIL Tasman acknowledges that if the retail tariffs are set too low, competition would undoubtedly be stifled and incumbent retailers may also face undue financial pressure.

Retailers generally argued that the energy purchase costs used in the Draft Determination were too low and did not reflect the energy purchase costs faced by retailers. Notably all retailer submissions asserted that setting tariffs too low will stifle competition. Importantly the Ministerial Delegation to the Authority states that the Authority is to consider the effect of the determination on competition in the Queensland retail electricity market, consistent with the Government's policy objective that consumers, wherever possible, should have the opportunity to benefit from competition and efficiency in the marketplace. ACIL Tasman generally agrees that setting tariffs at a level which would likely lead to stifling of competition would contravene the Ministerial Delegation.

2 Changes since the Draft Determination

This sections discusses the changes that have been made to the WEPC methodology and estimate since the Draft Determination, which included consideration of matters raised in submissions to the Draft Determination.

2.1 Price distribution methodology

The submissions generally highlighted concerns about the proposed price distribution approach. In addition ACIL Tasman acknowledged difficulties in accurately estimating the appropriate level of risk premium to be applied to the approach, which materially affects the WEPC estimate under that proposed methodology. This led to ACIL Tasman discarding the proposed price distribution approach for the Final Determination.

ACIL Tasman considers that the approach is an effective methodology for estimating expected market prices for 2012/13. However, ACIL Tasman acknowledges that retailer risk profiles and prudent risk management practices may lead them to hedge at prices well above the expected (mean) price. While the methodology could easily incorporate these prudent risk management practices where they could be quantified, feedback from meetings and submissions indicate that such quantification is difficult and not easy to establish for a representative retailer. This means that an appropriate level of risk premium was not able to be determined to be applied under the price distribution methodology.

The choice of any level of risk premium is material under the price distribution methodology. In ACIL Tasman's opinion, the uncertainty around the appropriate level of risk premium to be applied reduced the value of the proposed price distribution methodology in determining the WEPC estimate, with the risk to competition and consumers of getting it wrong (especially on the low side) being an important consideration. The methodology also ignored market based contract prices which are an important point of reference for estimating the 2012/13 WEPC.

On this basis this report presents only the contract hedging approach of the Draft Determination. The submissions also raised a number of issues with the contract hedging approach which ACIL Tasman has considered and taken into account where appropriate.

2.2 Generation costs and LRMC

Not all proposed changes or modifications in submissions have been incorporated. In particular the proposal to consider the use of the long run marginal cost (LRMC) of generation is not incorporated in the estimation of WEPC. ACIL Tasman notes that the Ministerial Delegation states the following in relation to estimating energy costs:

> The energy cost component of each regulated retail tariff should include the cost of purchasing energy, environmental and renewable energy costs, energy losses and National Electricity Market fees

The Delegation quite clearly refers to the "cost of purchasing energy" which may be quite different to the cost of generating/producing energy. Energy is purchased from the NEM via the electricity pool at the prevailing spot price(the NEM is a compulsory gross pool arrangement). Spot prices are hedged through electricity contracts. The cost of purchasing energy clearly relates to the appropriate estimate of expected spot prices and the degree to which an efficient, representative retailer would reasonably acquire electricity hedge contracts to hedge those spot prices.

ACIL Tasman acknowledges that the LRMC of generation reflects a reasonable annualised cost associated with investing in electricity generation. However, the LRMC of generation implies nothing about the allocative or dynamic efficiency of electricity investment decisions. The history of deregulated electricity markets in Australia (since the mid 1990's) indicates that markets move through cycles where energy purchasing costs are both lower and higher than the estimated LRMC. Generally lower prices eventuate when additional supply enters the market (sometimes aggressively) and higher prices eventuate when the supply-demand balance tightens.

As the NEM is a deregulated market, generation investment decisions are entirely in the hands of investors which means that any losses that occur or rents that accrue remain with those investors. This includes the resulting performance of any over-optimistic or poorly timed investment – i.e. the NEM design ensures that the consequences of those decisions are borne by the investors, not the end-users of electricity.

This means that the inclusion of generation production costs in the calculation of WEPC potentially imposes the consequences of inefficient investment decisions on end-users despite the NEM being designed to pass on the benefits of the competitive market to those end-users. This would appear to also run counter to the Ministerial Delegation which stated that the tariff setting is to be "...consistent with the Government's policy objective that consumers, wherever possible, have the opportunity to benefit from competition and efficiency in the marketplace.".

This is particularly pertinent for 2012/13 where the combination of electricity contract prices (as indicated by futures prices) and expected spot prices may not be sufficient for some generators to cover their LRMC. However, ACIL Tasman also acknowledges and accepts the notion put forward by many if not all retailers in their submissions that retail prices should not be set so low as to stifle competition and possibly impose undue financial stress on incumbent retailers.

2.3 Summary of changes

The main changes to the contract hedging results for the Final Determination could be summarised as:

- correction of an error of peak and off-peak periods used in the hedging model
- adjustment to the methodology to calculate the WEPC for the controlled loads which involves hedging
- update of distribution loss factors from 2011/12 to 2012/13 as published by AEMO
- a change to the calculation method used to account for losses
- update of the contract prices to incorporate the latest d-cyphaTrade contract prices up to 23 April 2012
- detailed modelling of the WEPC without carbon pricing
- updated estimates of market and ancillary service fees based on the latest AEMO information
- updated renewable power percentage and small target percentage (RPP and STP) released on 1 May 2012 by the Clean Energy Regulator (CER)
- applied losses from the reference node to the customer terminal for all Other EPCs (i.e. renewables and market fees)
- change in losses to apply to the Ergon Energy ICC, CAC, SAC and street lighting customers

The effect of these changes are summarised in Table 1.

Table 1 **Comparison of EPC estimates for Draft and Final Determinations**

Settlement classes	Draft Determination				Final Determination				Overall change in EPC
	Wholesale energy purchase cost at the regional reference node ($/MWh)	Renewable energy and market fees ($/MWh)	Allowance for transmission and distribution losses	Total energy purchase costs at the customer terminal ($/MWh)	Wholesale energy purchase cost at the regional reference node ($/MWh)	Renewable energy and market fees ($/MWh)	Allowance for transmission and distribution losses	Total energy purchase costs at the customer terminal ($/MWh)	
Prices including carbon pricing									
Energex - NSLP - residential and small business	$61.60	$12.10	7.4%	**$78.23**	$61.49	$12.18	7.2%	**$79.41**	**$1.19**
Energex - Control tariff 9000	$41.86	$12.10	7.5%	**$57.09**	$41.63	$12.18	7.3%	**$58.07**	**$0.98**
Energex - Control tariff 9100	$49.15	$12.10	7.5%	**$64.92**	$48.93	$12.18	7.3%	**$65.95**	**$1.03**
Energex - unmetered supply	$42.58	$12.10	7.5%	**$57.86**	$61.49	$12.18	7.2%	**$79.41**	**$21.55**
Ergon Energy - NSLP - SAC HV, CAC and ICC	$55.16	$12.10	8.0%	**$71.67**	$55.93	$12.18	8.6%	**$74.50**	**$2.83**
Ergon Energy - NSLP - SAC demand and street lighting	$55.16	$12.10	8.0%	**$71.67**	$55.93	$12.18	12.8%	**$78.08**	**$6.41**
Prices without carbon pricing									
Energex - NSLP - residential and small business and unmetered supply	$41.60	$12.10	7.4%	**$56.75**	$41.59	$12.18	7.2%	**$57.96**	**$1.21**
Energex - Control tariff 9000	$21.63	$12.10	7.5%	**$35.35**	$20.54	$12.18	7.3%	**$35.31**	**($0.04)**
Energex - Control tariff 9100	$28.92	$12.10	7.5%	**$43.18**	$28.86	$12.18	7.3%	**$44.29**	**$1.11**
Energex - unmetered supply	$22.34	$12.10	7.5%	**$36.12**	$41.59	$12.18	7.2%	**$57.96**	**$21.84**
Ergon Energy - NSLP - SAC HV, CAC and ICC	$35.15	$12.10	8.0%	**$50.07**	$35.64	$12.18	8.6%	**$52.31**	**$2.24**
Ergon Energy - NSLP - SAC demand and street lighting	$35.15	$12.10	8.0%	**$50.07**	$35.64	$12.18	12.8%	**$54.82**	**$4.75**

Data source: ACIL Tasman modelling and analysis based on a variety of data sources

3 Response to the submissions

In response to the Draft Determination the Authority received 36 submissions. The submissions are from electricity retailers and consumer groups and representative bodies and individual consumers. In this section we provide responses to concerns and suggestions raised in the submissions.

A number of submissions commented on elements in the price distribution approach which, because it is no longer being pursued as a methodology for the Final Determination, have not been addressed in this report.

In general retailers favoured incorporating an LRMC approach in the calculation of the EPC to reflect the cost of purchasing energy. ACIL Tasman has considered these proposals and has concluded that even if a sizeable portion of a retailers energy purchases are through Power Purchase Agreements (PPA) and reliable pricing information was available (which it is not) that it would not be appropriate to incorporate these PPAs in the calculation of the EPC.

PPAs are long term instruments usually running across several years or over the expected life of a generating asset with the PPA price designed to provide a stable long term return to the asset owner. In this sense the PPA price would generally be expected to reflect costs to a retailer no higher than purchasing through a combination of the electricity pool and electricity hedges over the life of the PPA. Therefore the market price over the term of the PPA would be expected to provide a ceiling to a well priced PPA.

This does not mean that a well priced PPA would be expected to be lower than the market price every year but would be expected to be lower in some years and on average no higher than the market price over the term of the PPA. This of course assumes that PPA prices are efficient. Separately in section 2.2 we considered the issue of inefficient generation investments. PPA prices linked to inefficient generation investments may always be higher than the expected market price over the life of the PPA, but there is no merit in attempting to pass these inefficiencies through to end-users.[2]

The 2012/13 year in Queensland is in ACIL Tasman's opinion, supported by modelling, characterised by an oversupply of generation. This implies that it might be expected that the expected market price will be lower than even efficiently priced PPAs.

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2 The NEM design ensures that to the extent that any PPA costs reflect inefficient investments that these costs remain with the counterparty to the PPA or are shared/passed back to the generation asset investor through facilities the reopen the PPA to renegotiation

ACIL Tasman has not taken the cost of PPAs or the LRMC of generation into account in calculating the EPC. This is because the market price for energy in 2012/13 is determined through the competitive NEM processes over that period, not by the cost of PPAs or the LRMC of generation.

Some submissions have also claimed that generation development would be stifled unless the EPC in retail tariffs takes account of generation costs through the application of an LRMC approach. ACIL Tasman does not accept this argument on the basis that, as generation and load move to balance with load growth, NEM market prices (combination of expected spot and contract) would be expected to increase to a level which will encourage new generation. This is inherent in the NEM design, as supply-demand tightens, prices rise and new generation investment occurs. This means that if applied in future years, the EPC in reflecting market prices would be expected to reflect price rises associated with a tighter supply-demand balance.

Importantly, the Authority's brief to ACIL Tasman based on the Ministerial Delegation was that the calculation of the EPC should be market based. As already noted above the relevant statement in the Ministerial Delegation which led to this position in that the "energy cost component of each regulated retail tariff should include the cost of purchasing energy".

3.1 Hedging Strategy

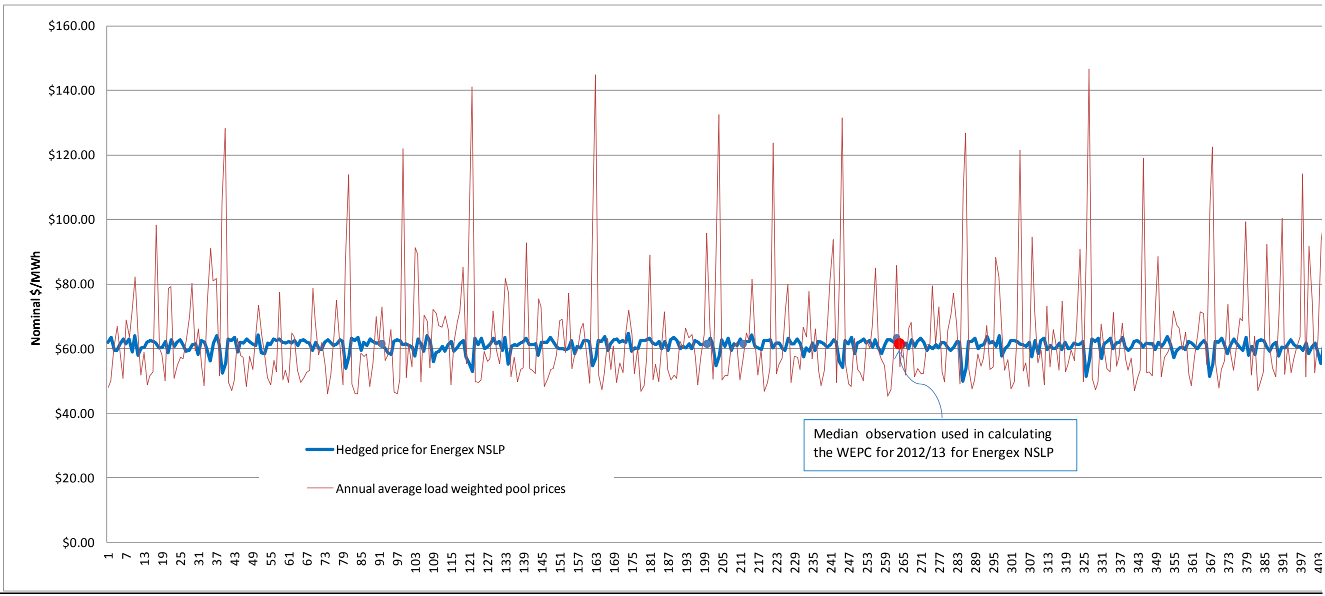
The hedging approach has been adopted for the estimation of the WEPC for the Final Determination. The hedging strategy is meant to represent a reasonable strategy that an efficient representative retailer would undertake to hedge against price risk in the pool market in a given year. A representative retailer would not attempt to cover 100% of all expected energy purchases, because of the very high cost involved.

Origin calculated that the cost of contracts in $/MWh terms exceeds the $/MWh wholesale energy costs and claims this is not correct. However, ACIL Tasman considers that there is no error in the calculation because there is a quantity of energy that is not hedged under the strategy employed for the EPC calculation. In particular this is in the off-peak periods which has a lower pool price than the flat contract price and so pulls down the average purchase price of energy because the hedging strategy covers only to the 80th percentile of the off-peak load. There would also be times in the peak periods when the load is not fully covered and when the pool price is less than the contract price.

TRUenergy noted that hedging, on average, provides a lower cost than if a retailer faced the spot price and Origin found that the expected return for cap contracts was higher than the premium. ACIL Tasman considers that both of these submissions are incorrect.

TRUenergy is correct in observing that the price distribution methodology produced generally higher prices than the hedging approach. We would agree that this seems inconsistent but suggests that the contract market is anticipating lower prices than our pool modelling. One factor could be the difference in view with respect to the load forecast used in the modelling. A lower load forecast would, for example, result in lower pool prices. We consider that the use of contract prices is appropriate as these are based on actual traded prices applying to the respective quarters even though the trading for some products for Q1 and Q2 2013 is relatively thin. As shown in Figure 1, when applying the hedging strategy, the volatility in pool prices across the 410 observations for 2012/13 is substantially removed and the EPC is relatively stable. This is consistent with the main purpose of entering electricity hedge contracts – to limit volatility and stabilise prices within an acceptable level of variation.

Figure 1 **Load weighted pool prices and hedged price for Energex NSLP 2012/13**



ᵅ Data source: *ACIL Tasman modelling using d-cyphaTrade prices*

In response to Origin's concern with regard to cap contract payments versus premiums, we note that our modelling shows that in those representations of 2012/13 where the pool price is expected to be high then the return to the cap contract exceeds the cap premium, which we would expect. In those representations where the pool price is low the opposite is the case. In the median case, used in calculating the WEPC for 2012/13, the market based contract premium is somewhat higher than the estimated cap payments. Furthermore the estimated swap difference payments are also positive which means that for the median year, the contract premium over the pool price was 13% or in other words the cost of contract hedging was 13% higher than if all the energy was purchased out of the pool. Table 2 sets this out in detail for the

Energex NSLP. This analysis appears to be in line with Origin Energy's understanding of the usual position with hedging costs.

Table 2 **Median observation used in calculating the WEPC for the Energex NSLP in 2012/13**

Item	Cost
Total MWh	10,322,425
Total estimated pool costs	$561,106,074
Estimated swap difference payments	$52,195,683
Market based cap premiums	$48,426,705
Estimated cap payments	-$26,921,409
Total estimated energy purchase cost	$634,807,053
Total estimated energy purchase cost $/MWh (at the RRN)	$61.50
Percentage premium for energy purchase cost over estimated pool cost	13%

Note: The estimated EPC of $61.50/MWh in the table is for one of the years on the high side of median of the 410 representative years. The actual median value is $61.49/MW as seen in Table 1which is the average of the 205 and 206representative years.

Data source: The median of the 410 observations for 2012/13 from the ACIL Tasman hedge and pool modelling

3.2 Use of LRMC to estimate WEPC

Generally retailers proposed the use of LRMC of generation in the estimation of WEPC. The use of LRMC of generation was rejected as an approach by ACIL Tasman and the Authority in both the Draft Methodology Paper and the Draft Determination. This was on the basis that market prices were a more efficient and cost reflective measure of the cost of purchasing energy. Furthermore the Ministerial Delegation stated that:

> The energy cost component of each regulated retail tariff should include the cost of purchasing energy,

As highlighted earlier in this report, the NEM is a compulsory gross pool market with all energy (with the exception of embedded and exempt generators) purchased through the pool. Importantly, the Delegation did not make reference to the cost of making or producing electricity.

Origin claims that the by failing to have regard to the actual cost of supplying electricity the Authority did not correctly interpret or apply section 90 (5) (a)(i) of the Electricity Act 1994 which states:

> (5) In making a price determination, the pricing entity—
>
> (a) must have regard to all of the following—
>
> (i) the actual costs of making, producing or supplying the goods or services;

From the wording in the Act and Delegation and discussions with the Government representatives the Authority has interpreted the Act and

Delegation to mean that WEPC estimates are to be based on prices expected to prevail in the National Electricity Market (NEM) and has briefed ACIL Tasman to provide estimates of WEPC on that basis.

At no stage has the Authority suggested to ACIL Tasman that the estimate of WEPC should be adequate to cover long run generation costs. The detailed analysis shows that the 2012/13 market is expected to be oversupplied resulting in subdued market prices which would generally be expected to be lower than the LRMC of generation.

3.2.1 Market contracts give only partial cover of costs

Origin and AGL commented that the hedging approach only covers a proportion of the actual energy volumes and that the remainder are covered through a variety of contractual and other arrangements including PPAs with generators. This has been cited as a reason for favouring the LRMC approach which would more reliably reflect the costs involved in these other arrangements assuming that they have been priced efficiently.

The ACIL Tasman analysis is based on the contention that the combination of expected spot and contract prices using the hedging contract approach represents an appropriate estimate of the market price for energy in that period regardless of how it is produced or acquired. The fact that a retailer may use other instruments such as PPAs to secure energy does not mean that the hedge contract approach is not an appropriate estimate of the prevailing the market cost of energy purchases.

ACIL Tasman accepts that PPAs involve a long term price which may be higher than the market price in some years and less than the market price in other years. In addition there may be PPAs which, for whatever reason, have generally higher costs than those that would be expected to be achieved in the contract market over the same period. ACIL Tasman contends that under the NEM arrangements such out-of-the-money arrangements would never be expected to be fully recovered over the life of those arrangements. ACIL Tasman notes that entities holding such out-of-the-money arrangements may be compelled under accounting standards to write them down using the NEM based market value to determine the level of write-off. Hence, ACIL Tasman has not attempted to value the alternative arrangements on the basis that the expected market value as determined by the appropriate combination of expected spot and contract prices for each year over the life of such arrangements provides a ceiling for a soundly priced the PPA.

3.3 Peak and off peak energy costs

A number of submissions observed that there was a sizeable difference between peak and off peak prices and questioned why the WEPC in the retail tariffs did not reflect this difference. Sunwater, for example, observed that there was the large differential between peak and off-peak rates in market contracts.

ACIL Tasman acknowledges that differentiating between peak and off peak using the hourly price series would be reasonable if the retailer energy purchase costs reflected this. However, AEMO charges for the energy supplied to the <100MWh customers at the average price weighted by the NSLP with no differentiation between the peak and off-peak periods. We considered using separate peak, off peak and shoulder prices for energy costs under the new residential time of use (TOU) tariff. However, these customers will not have interval metres and as such will still be included in the NSLP and the energy cost to a retailer is the same for all energy purchased.

Furthermore to differentiate between peak, shoulder and off-peak periods for the WEPC we would need to adopt an assumed or averaged load profile for the TOU customers which would not fit individual cases. This introduces uncertainty and increases the risk to retailers which may not earn sufficient revenue from the TOU tariff to cover the cost of purchasing the NSLP. Customers with more energy in the low priced off peak period, for example, would not cover the NSLP cost.

Structuring the tariff so the pass through network portion incorporates the price variations, as has occurred for the residential TOU tariff, removes the retailer risk while still maintaining some of the desired incentives for consumers to move more energy from peak to off-peak periods.

3.4 Calculation of contract prices

QCOSS suggested that all trading in d-cyphaTrade should be included; i.e. not exclude trading from prior to 8 November 2011 for Q1 and Q2 2013.

Prior to the 8 November 2013 there are very few trades by d-cyphaTrade for Q1 and Q2 2013. ACIL Tasman uses trade weighted average and so these earlier trades would have little influence on the price. More importantly ACIL Tasman was aware through analysis of TFS trading data that almost all trades prior to 8 November 2011 for the 2013 period were for the whole year, not the quarters, and were for contracts without carbon. ACIL Tasman noted that the price of these contracts had not changed noticeably. On the other hand d-cyphaTrade do not include a futures product that excludes carbon and given the uncertainty at that time over the future for carbon pricing there was virtually no trading of these futures.

AGL suggested that TFS carbon exclusive trades be used for base contract price estimates. TFS is an electricity broker from which ACIL Tasman purchased trading information to assist in its evaluation of the contract prices. Where the futures market is sufficiently liquid[3], the trade weighted average of daily settlement prices from d-cyphaTrade has been used, because it is a transparent source of market data. Furthermore in our report for the Draft Determination we showed that the d-cyphaTrade numbers from 8 November 2011 when the carbon tax legislation was passed, include an appropriate allowance for carbon as they align almost precisely with the TFS data with carbon and without carbon plus the AFMA carbon allowance.

In its submission on the Draft Determination, Origin strongly recommended a consistent approach for base and peak contracts of the trade-weighted average of d-cyphaTrade daily settlement prices and trades since 8 November 2011. Where there are no trades post 8 November 2011, the latest trade price should be used.

ACIL Tasman has used a consistent approach for base and peak contracts. Where the futures market is sufficiently liquid, we have used the trade weighted average of d-cyphaTrade daily settlement prices since they first traded. However, as explained in our report for the Draft Determination, the d-cyphaTrade base and peak contracts for Q1 2013 and Q2 2013 have been relatively thinly traded, particularly prior to the legislation being passed. Therefore, we have used the trade weighted average of d-cyphaTrade daily settlement prices since 8 November 2011, because TFS "with AFMA" prices plus the carbon pass-through are virtually the same as d-cyphaTrade prices from 8 November 2011. We considered that there was no reason to depart from using d-cypha Trade prices, because TFS "with AFMA" prices plus the carbon pass-through are virtually the same as d-cyphaTrade prices from 8 November 2011.

3.5 Carbon tax cost

QCOSS/ETROG, AGL and Origin questioned the robustness of the carbon cost estimates. Some indicated that the estimate was too high while others say it was too low.

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3 ACIL Tasman has shown this to be the case for d-cypha Trade base and peak Q3 2012 and Q4 2012 contracts and cap contracts.

The carbon costs have been based on the AFMA methodology of applying the NEM emissions factor to the carbon price. The emissions factor of 0.87 used in the report for the Draft Determination was taken from the PowerMark modelling for 2012/13 but was incorrectly based on generated energy and combustion emissions. The AFMA formula uses the AEMO published emissions factor which is based on sent out energy and total emissions (combustion and fugitive). This explains why the estimate was lower than expected in a number of submissions.

For this report we have used emissions factors based on sent out energy and other emissions (in accordance with the AEMO methodology). We have also undertaken detailed pool and hedge modelling of prices and WEPC for 2012/13 without carbon. The quarterly NEM emissions factors based on the median year representing 2012/13 used in the detailed modelling were 0.89,0.89,0.91 and 0.90 tCO_2-e/MWh sent-out respectively.

3.6 Peak and off-peak error

A number of submissions correctly identified an error in the classification of peak and off peak periods in the hedging model.

This error in the analysis for the Draft Determination has been corrected in this report for the Final Determination. Because of the error in identifying peak and off-peak periods, the estimated WEPC for the Energex NSLP at the regional reference node in the Draft Determination was $0.53/MWh (0.9%) lower than it should have been.

3.7 Controlled and unmetered loads revised approach

Several retailer submissions questioned the use of the price distribution methodology to estimate the controlled and un-metered loads with some suggesting that hedging might be a better approach.

For the Final Determination, ACIL Tasman has revisited the methodology for the controlled loads and has adopted a revised method. The resultant wholesale energy purchase costs for these settlement classes are, however, very similar in the Final Determination to the estimates in the Draft Determination. The new method involves calculating the total cost of supplying the Energex NSLP with and without the selected control load using the hedge approach. The difference in costs is taken as the cost of supplying the selected controlled load and the cost per unit for the selected controlled load to found by dividing the cost by the energy taken.

The cost of supplying the unmetered loads in Energex and street lighting in the Ergon Energy area are now taken as the respective NSLPs as the unmetered and street lighting loads are included in the respective NSLPs. The resultant wholesale energy purchase costs for the unmetered supply is higher in the Final Determination than in the Draft Determination.

3.8 AEMC Report

3.8.1 Background

AGL, Origin compared the ACIL Tasman report for the Draft Determination with a report prepared by ACIL Tasman for the Australian Energy Market Commission (AEMC) and on the basis of the differences in the reports questioned the efficacy of the ACIL Tasman PowerMark modelling and the overall approach to the estimation of the WEPC for the Draft Determination.

The AEMC Report provides estimates of the cost of supplying the residential customers and the estimates for 2012/13 for Queensland which were higher than estimates in the report for the Draft Determination.

Origin make a number of comments regarding ACIL Tasman's estimation of the energy purchase cost in relation to the spot price modelling. In particular:

> Origin is greatly concerned with ACIL's estimation of the energy purchase cost for 2012-13 as even cursory examination indicates that the outcome is well below market expectations (page 7, Origin submission).
>
> Origin has compared ACIL's current modelling results with the results it published in its report of October 2011 [to the AEMC], *Wholesale energy cost forecast for serving residential users*.... It is immediately apparent that the 2012-13 energy purchase cost of $41.60 (excluding losses and carbon) produced for the QCA is significantly lower ($15/MWh) than that reported by ACIL in its previous report(page 7, Origin submission).

To simplify our response to the above concerns, the following discussion relates to the time weighted wholesale electricity price for Queensland (or the flat price).

The report ACIL Tasman provided to the AEMC (released in October 2011) was based on modelling completed in July 2011. The modelling ACIL Tasman has undertaken for the Authority was completed in March 2012. Both sets of modelling were based on ACIL Tasman's latest off-the-shelf projection of the NEM (at the time). That is, in neither case did the client have input or influence into the modelling assumptions or projected outcomes.

It is worth noting that ACIL Tasman produces projections of the NEM using PowerMark, not predictions, based on a set of well thought through assumptions.

3.8.2 Assumption changes

ACIL Tasman, like any other industry consultant, or indeed any industry participant, routinely revises the assumptions that underpin its modelling. During the eight month period between the two sets of modelling a number of routine updates were made to the PowerMark assumptions. These updates are made usually on a quarterly basis when new information which comes to hand (during that quarter) is assessed internally within ACIL Tasman and if accepted is included in the model.

The table below identifies the key assumption changes made between the two sets of modelling as well as an estimate of the impact on the Queensland spot price.

Load Forecast

The pool price modelling for the AEMC project was undertaken in mid 2011 and was based on the load forecast in the AEMO 2011 ESOO while the pool price modelling for the Draft Determination was based on the Powerlink's updated 2100APR released in January 2012. Consideration was given to using the AEMO Updated 2011 ESOO but as only peak demand changes in three regions, energy was not revised and no 10% POE forecast provided it was decided not to use AEMO's partially updated forecast. The peak demand was some 358MW lower in the Updated 2011 APR than in the 2011 ESOO. The Updated 2011 APR load forecast for Queensland used by ACIL Tasman in modelling for the Draft Determination, reduced the annual energy by 3008GWh in 2012/13 or by an average of about 343MW, when compared with the AEMO 2011 ESOO load forecast used in the AEMC modelling. ACIL Tasman has not undertaken a specific sensitivity analysis within PowerMark of this assumption change, but based on previous modelling exercises and indeed the implied price impact of a 300MW demand reduction from AEMO's price sensitivity market re-runs in a setting of oversupply, ACIL Tasman estimates the impact of this assumption change to sit somewhere between a reduction of $2.00/MWh to $5.00/MWh to the time weighted price.

Ramp Gas

The impact of ramp gas (associated with LNG) on the NEM is a challenging consideration. And the extent to which ramp gas impacts the NEM depends largely on the volume of gas available to be used in generation and the extent to which this results in power stations being dispatched out of merit order.

ACIL Tasman acknowledges that the volume of ramp gas is somewhat of a moving target - with project proponents finding innovative ways to reduce the need for ramp gas to be consumed by out of merit order generation. Indeed, it is fair to say that even project proponents do not know exactly the extent of ramp gas.

Nevertheless, in January 2012, ACIL Tasman analysed the dispatch patterns of gas fired generators in Queensland and made the observation that the previous projections of generation volumes of selected gas-fired generators were lower than what had been actually observed and that this was likely due to greater ramp gas use than had been anticipated at that time. It is assumed in the modelling of the WEPC that the volume of generation observed from these gas fired generators would continue in 2012/13.

ACIL Tasman estimates that the impact of the increase generation from certain gas-fired generators in Queensland has reduced the spot price by about $1.00/MWh to $2.00/MWh.

Hydro generation

The final major change made to the assumptions relates to the generation volume of the major hydro plant at Snowy and in Tasmania. Although the modelling used for the AEMC had taken the breaking of the drought into account, it was unclear at that stage as to how quickly reservoir levels would recover on a consistent basis to allow the hydro plant to return to their long term average output levels.

However, reservoir levels improved significantly post winter 2011, and therefore ACIL Tasman made the decision to return the output of the hydro plant to normal levels from 2012 onwards in its modelling. Naturally, the increased generation volumes assumed for the hydro plant are estimated to have more of an impact on the price outcomes in the southern states, but this has flow on effects into Queensland, albeit at a somewhat diminished level.

Therefore, the AEMC modelling assumed a lower level of hydro generation than that assumed in the modelling for the Draft Determination, which meant that there was less plant available to meet the load resulting in higher prices.

3.8.3 Summary

Table 3 **Assumption updates and estimated impact on the Queensland time weighted average wholesale electricity price ($/MWh)**

Assumption updates applicable to 2012/13	Estimate of lower bound	Estimate of upper bound	Midpoint of bounds
Queensland demand projection revised downwards by about 350MW on average	-$2.00	-$5.00	-$3.50
Increased 100MW on average of dispatch from gas plant due to ramp gas	-$1.00	-$3.00	-$2.00
Increased 180MW on average dispatch from Snowy Hydro	-$1.00	-$2.00	-$1.50
Increased 150MW on average dispatch from Tas Hydro	-$0.00	-$1.00	-$0.50

Note: The values are estimates based on past modelling experience. The specific impact of each assumption change has not been modelled by ACIL Tasman.

Data source: ACIL Tasman

Taking the above considerations it is estimated that the main assumption changes between the two sets of modelling result in Queensland spot prices decreasing by about $7.00-$8.00/MWh on a time weighted basis for 2012/13. This largely explains the $9.00/MWh decrease in the modelled time weighted price between the AEMC report and the report for the Draft Determination.

The graph below plots the annual time weighted price from the modelling undertaken for the Authority's Draft Determination. Actual historical annual prices, and the current futures price for 2012/13 are included for reference.

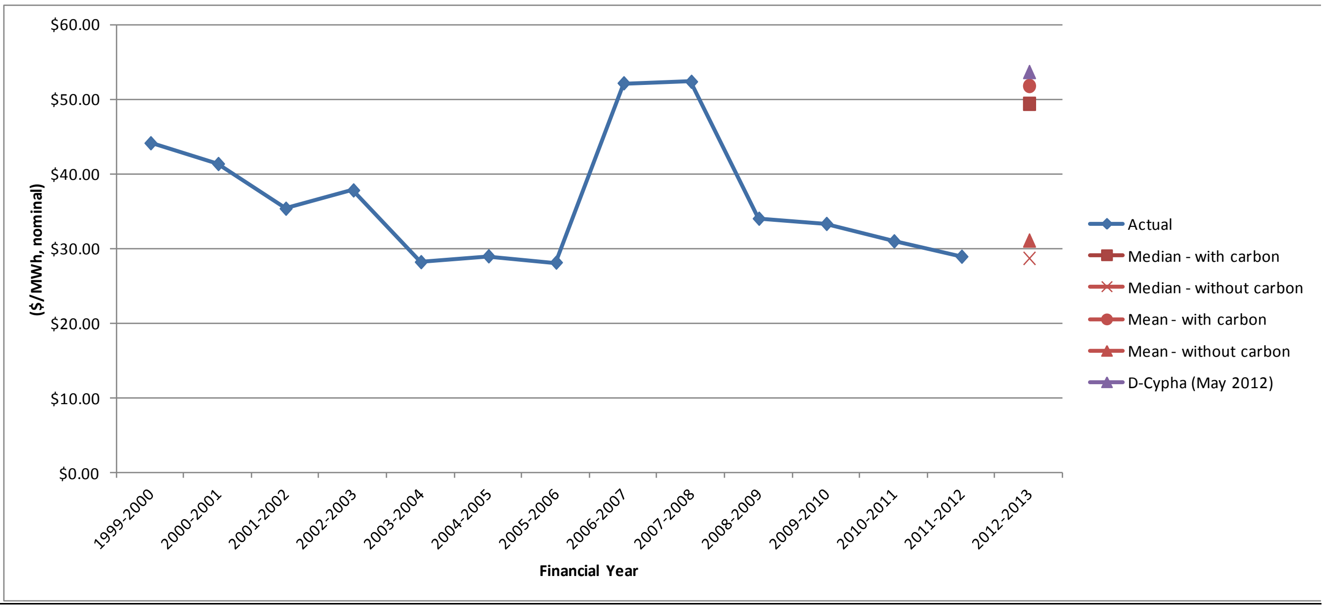
A number of modelled annual prices are included in the graphs, they are:

- the median annual time weighted price from the 410 simulations for 2012/13 - assuming a price on carbon
- the mean annual time weighted price from the 410 simulations for 2012/13 - assuming a price on carbon
- the implied median and mean time weighted price assuming a notional 90% pass-through of the $23 carbon price.

Compared with the recent past, the projected prices do not seem unreasonable. The modelling suggests an increase in price of about $3/MWh in 2012/13 over the 2011/12 price (when assuming no price on carbon). ACIL Tasman acknowledges that 2011/12 was a mild year - but when taking into account a large material outage at Millmerran for August to December 2011 and the prospect of more ramp gas in 2012-13, coupled with an increase in generation from hydro plant in the southern states (returning to normal generation volumes) an increase of $3/MWh does not seem implausible.

Further, the mean modelled outcome of the 410 simulations of 2012/13 sits very close to the latest d-cyphaTrade data again suggesting that the projection is not unreasonable, and not dissimilar to the view held more broadly by market participants.

Figure 2 **Comparison of annual time weighted wholesale electricity price ($/MWh, nominal) for Queensland used in the Draft Determination**



Note: "Without carbon" values are estimated from the "with carbon" values assuming a 90% pass-through of the $23 carbon price.
Data source: ACIL Tasman modelling, AEMO data, and D-Cypha data

ACIL Tasman readily acknowledges the challenge of modelling a market as complex as the NEM. Changes to input assumptions invariably have consequences on price outcomes. ACIL Tasman has provided the QCA with its latest projection of the NEM and it is fair to say that the prices are different to our projection from July 2011. However, we consider that this is for well explained reasons.

3.9 Creation of load data

Origin Energy suggested that ACIL should remove the 2008 load from its calculations because it was considerably lower than 2009, 2010 and 2011. TRUenergy, on the other hand, suggested that 4 years of data was not enough because there had been fewer days over 32 degrees in recent years.

Days are selected from the four years of actual data to populate the remaining 37 synthetic years with load data. The use of four years provides a good sized sample from which to select the days to populate the 37 synthetic years. It is important not to go too far back in history as load profiles change with load mix, end-user behaviour and other factors. ACIL Tasman accepts that the past four years were affected by mild summers which means that the sample of mild days will be larger than the sample of extreme temperature days for those four years. However the remaining 37 years are populated based on historical temperature data, which provides a robust data set of load years.

The 41 years of load traces (4 actual and 37 synthetic) as a whole are also adjusted to match the annual energy and 10% POE peak demand forecast to give 41 load representations for 2012/13. This means that the mildness or otherwise of the four actual years are not likely to have any effect on the final result.

AGL requested more explanation of about how the historic load has been manipulated. Our explanation follows.

Firstly the four years of data are adjusted to the same level as the final actual year (in this case 2010/11) by removing growth on a quarterly basis. The selections of days are then performed by matching day type season and temperature profile of each historic day with a day from the four years of growth adjusted actual load data. The selection of each day is based on the best match across all NEM regions[4] using temperature matching based on least squares approach.

Once all the 37 years have been populated, the 41 years are all grown to the 2012/13 load forecast using a linear transformation of the 41 years load traces, so that the peak of the 41 years matches the 10% POE summer peak forecast for 2012/13 and the energy of the 41 years matches 41 times the forecast annual energy for 2012/13. In other words the whole 41 years are adjusted together. To be strictly correct a 2.5% POE peak demand forecast should be used (i.e. 1 in 41 chance). ACIL Tasman analysis shows that there is little difference between a 2.5% and 10% POE forecast as with a 10% POE forecast air-conditioning is very close to its maximum practical utilisation. Furthermore it is likely that more than one hour will reach the 10% POE forecast as the peak day from the four years of actual data may be repeated a number of times in the 41 year constructed data set.

Ergon Energy queried why the 10% POE demand forecasts were used rather than a weighted average of the 90%, 50% and 10% POE.

As described in the previous paragraph The 10% POE peak demand forecast was used to transform the 41 years of load data. The median price year used as the estimate of the wholesale energy price for a particular settlement class is chosen from 410 alternative weather and outage years based on the price only and is not chosen for its demand or energy characteristics. This process avoids

4 Note that the NEM wide matching process is important to maintain consistency and reflect the interconnectedness of the NEM regions and the consequential influence across regions on prices.

the necessity of having to use the concept of a weighting separate 90%, 50% and 10% POE forecasts like that followed for the former BRCI as the whole of the price distribution is available.

3.10 Allowance for losses

In the Draft Determination ACIL Tasman used an energy weighted DLF to represent the distribution losses associated with the Ergon NSLP. ACIL Tasman understands that this is not cost reflective for individual customers. QCA requested that ACIL Tasman publish two loss factors associated with the Ergon Energy NLSP, one to cover the SAC demand and street lighting customers and the other to cover the HV SAC, CAC and ICC customers.

Origin suggested that loss factors should be applied to other energy costs (i.e. Large-scale Renewable Energy Target scheme (LRET) and Small-scale Renewable Energy Scheme (SRES) and market fees), Origin also suggested additional loss factors to account for loss between generators and the regional reference node. ACIL Tasman has considered these suggestions and accepts that transmission and distribution losses between the reference node and customer terminal should have been applied to other energy costs in the Draft Determination. However we do not accept that transmission losses between the generator and the regional reference node should be applied to other energy costs as these are also assessed at the regional reference node.

ACIL Tasman has also adjusted the calculation method used to account for losses. For the Draft Determination the WEPC at the customer terminal were calculated multiplying the WEPC at the node by one plus the percentage losses. This was not strictly correct and now the losses are accounted for by dividing the WEPC at the node by one minus the percentage losses.

The Renewable Power Percentage (RPP) and Small -scale Technology Percentage (STP) used in the estimate of the cost of LRET and SRES, respectively, are based on wholesale acquisitions from AEMO (i.e. at the node), therefore, only losses between the reference node and the customer terminal should be applied to cost of SRES and LRET. These losses are to be applied to the cost of LRET and SRES for the Final Determination.

3.11 Transmission constraints

Origin asked whether transmission constraints need to be taken into account.

The PowerMark modelling does not explicitly account for intra regional transmission constraints but calibration of the model ensures that it can replicate price outcomes under normal market circumstances. The situation at Calvale-Wurdong referred to by Origin is not a normal market characteristic.

3.12 Queensland Gas Scheme

QCOSS, CCCL and Stanwell disagreed with estimating gas electricity certificate (GEC) prices using a longer time series of market data (4 years) and preferred an estimate based on a 2-year average.

Given that GECs have been acquired by various means including via the short term market and via long term contracts and the fact that the GEC market is now oversupplied with low prices and very thin trading, the AFMA weekly GEC prices have been averaged over an extended period of 209 weeks or 4 years. This approach accepts that existing retailers have prudently entered arrangements to acquire GEC's which have legitimately added to the EPC.

3.13 Large-scale Generation Certificate (LGC) prices

AGL disagreed with using the market data based approach to estimating LGC prices, but instead supported using the LRMC approach.

Origin and QEnergy also questioned ACIL's approach of calculating LGC prices using an average of 106 weeks for 2012 as this includes REC prices that had been heavily influenced by the oversupply of certificates (between between April - Dec 2010). It suggested that only data for 2011 be used to calculate 2012 and 2013 LGC prices to account for the "start" date of the scheme (2011) and to exclude those prices that have been heavily influenced by the oversupply of certificates.

The average price of RECs using the AFMA data of around \$42/MWh aligns with ACIL Tasman's modelling of the renewable energy market (*RECMark*), which is a model based on the LRMC of renewable generation, a carbon price projection, a black energy price projection and the LRET penalty price and expiry date. In essence the model develops new renewable projects on a least cost basis across Australia and projects the marginal REC price required to ensure projects are commercially viable. A more detailed description of REC Mark is provided in Appendix A.1.

3.14 Small-scale Technology Certificate (STC) prices

QCOSS, CCCL, Stanwell and Ergon disagreed with calculating STCs based on the \$40/tCO2-e Clearing House (CH) price given that the STC market is currently oversupplied and there is an expectation that this trend would continue in 2013, and therefore using the CH price would over estimate the price of STCs paid by retailers. Submissions disagreed with ACIL's reasoning that it was unable to estimate the proportion of STCs likely to be traded in the open market. Submissions suggested that ACIL look into other sources such as ICAP, CEC and etc.

We have recently approached ICAP with regards to obtaining prices and trades for the electricity market, but ICAP does not sell this data to third parties. Sunwiz provided the QCA and ACIL Tasman with data containing historical STC prices and STC purchases and sales. It would be risky to use this data to determine the STC price in 2012/13 because:

1. the data is historical - there are no futures prices. The market for STCs was largely oversupplied in the first year, due to unprecedented demand. Going forward, we are likely to see a better match of supply with demand (via carrying over the surplus from last period into the current STP). Therefore, the historical data is not necessarily a good indicator of what will happen to the price of STCs in 2012/13.
2. the excess STC creation from last year has been brought forward and included in the 2012 target. This is likely to result in clearance of the excess STCs through the increase in demand via the higher target set for 2012 and therefore push the price closer towards $40
3. the purchase and sales data provided to us contains activity for only one retailer, and so doesn't represent broader retailer activity with respect to STCs

Origin and AGL submitted concerns on using ORER’s non-binding STP for 2013.

The non-binding STP for 2013 is the most transparent and publically available estimate for the STP for 2013. In 2011, The Clean Energy Regulator (CER) - previously, Office of the Renewable Energy Regulator (ORER) – engaged three companies (one of which was ACIL Tasman), to provide forward estimates of the number of small-scale technology certificates (STCs) likely to be created in the 2011, 2012 and 2013 calendar years – with the results available on the CER website. The results of the modelling assist the Minister in determining the binding and non-binding estimates of STP. Therefore, ACIL Tasman would not propose to move away from this source for the estimate of the 2013 STP, because it is the most transparent and available source.

4 Estimation of WEPC

In response to the criticisms of the price distribution approach it has not been pursued as a methodology for the Final Determination. Instead we have opted to use the contract hedging approach which still uses the 410 pool price profiles representing 2012/13 but then is overlayed by a hedging model with the loads and pool prices from the price distribution and contract prices from d-cyphaTrade.

The more widely used and understood methodology of developing a hedge book and using market contract prices similar to that used for estimating the Benchmark Retail Cost Index (BRCI), was seen as the more desirable methodology used by the Authority's for its Draft Determination and was generally supported by respondents as the preferred methodology. However, the low contracts trading volumes for the first half of 2013, most probably because of the impending introduction of a carbon tax, meant that there were concerns about the reliability of the contract price data. However, given the concerns over the price distribution methodology and given that trade volumes have increased since the Draft Determination, ACIL Tasman has adopted the contract hedge approach and developed estimates using that approach.

Apart from problems arising from the thinly traded market for the first half of 2013, the hedging methodology also requires the determination of an appropriate hedging strategy. ACIL Tasman has tested strategies by applying the contract strategy in a wide variety of potential load and pool price outcomes. This is achieved by setting the contract volumes against a median weather/price year then running the model against the 410 weather/outage years used in the price distribution approach.

Using the median price of 410 possible annual prices from the hedging approach as the estimate for the WEPC, as presented in this report, is considered superior to weighting the 50 percent, 10 percent and 90 percent POE price forecasts as used previously in the BRCI.

4.1 Outline of hedging approach

The hedging approach is a market based approach used to estimate wholesale energy market costs, not unlike the method used in calculating the energy costs for the BRCI. The contract hedging approach was described in detail in ACIL Tasman' report for the Draft Determination and has not changed for the Final Determination.

The approach is designed to simulate the wholesale energy market from a retailing perspective, where retailers hedge the pool price risk by entering into forward electricity contracts. It involves using 410 years of hourly pool prices and load profiles to provide the full range of possible outcomes for 2012/13 as input to a contracting model to estimate 410 annual hedged prices representing the possible range of WEPC for 2012/13.

The approach is a simplification of the actual contract market in that it is based on base, peak and cap contracts only with pricing determined by historical trading through d-cyphaTrade. It does not include other instruments available to retailers such as PPAs, purchase of exotic load profiles or load following instruments and use of own generation. We consider the more complex hedging approach followed by retailers is unlikely to generally result in higher overall energy purchase costs than the estimates from the simplified contract model – otherwise the simpler model would be preferred.

The hedging approach includes the following steps:

Step 1. Develop 41 years of load traces for each NEM region and each settlement class representing 2012/13 - Create a 41 year load trace data set: Populate 37 years (1971/72 to 2006/07)with load trace data for each NEM region, the Energex NSLP, control tariff and the Ergon Energy NSLP. These profiles are selected day by day from four years of load data (2007/08 to 2010/11) by matching the daily temperature profile and day type (season and working non-working days) for each day over the past 37 years across the NEM to a day of the four years of actual load data .

The resultant regional load traces are then adjusted to the 2012/13 level by adjusting them to match the 2012/13 demand and energy forecasts for Queensland from the Updated 2011Annual Planning Report (APR) and for other NEM regions from the AEMO 2011 ESOO. The adjustment to match the load forecast for 2012/13 is across the 41 years. Total energy under the load trace is forced to equal 41 times the forecast annual energy in each NEM region and peak demand for the 41 years is made to match the 10 percent probability of exceedence (POE) summer demand forecasts in each region.

These load traces have not been changed between the Draft and Final Determinations.

Step 2. Develop 10 plant outage scenarios for the NEM - Using binomial probability theory ACIL Tasman has simulated 10 sets of forced outages. These outage scenarios have not been changed between the Draft and Final Determinations

Step 3. Estimate hourly pool prices across the 410 data years each representing a possible outcome for 2012/13: Estimate 410 years (41 years of load in combination with 10 outage scenarios) of hourly prices for Queensland using *PowerMark,* ACIL Tasman's proprietary model of the NEM. These pool price estimates have not been changed between the Draft and Final Determinations

Step 4. Select the median pool price year - From the 410 years, select the year which delivers the median of the annual average load weighted price.

Step 5. Determine hedging strategy - Determine an appropriate hedging strategy which a reasonable representative retailer would use. The hedging strategy involves setting the parameters to calculate the base, peak and cap contract volumes based on the median year. For the Final Determination the hedging strategy chosen is the same as that used in the previous BRCI calculations. The Hedging strategy has not been changed between the Draft and Final Determination

Step 6. Determine contract volumes - Contract volumes are calculated by applying the hedging strategy to the load profile for the median year selected in Step 4. These contract volumes based on the median year profile are then fixed across all 410 years when calculating the wholesale energy purchase costs.

Step 7. Estimate forward contract prices - Estimate forward quarterly contract prices for base, peak and cap contracts for 2012/13 using forward contract price data from d-cyphaTrade. For the Final Determination these prices are based on trades to 23 April 2012.

Step 8. Estimate energy purchase costs for each of the 410 years - Bring together the contract volumes from Step 6 and contract prices from Step 7 for the median price year with the projected hourly pool prices from Step 3for each of the 410 years in a contract model and calculate the WEPC for each of the 410 years.

Step 9. Calculate the energy purchase costs for 2012/13 - Estimated energy purchase costs for 2012/13 is taken as the median of the 410 annual prices from Step 8.

Step 10. Estimate energy purchase costs for each settlement class - This is achieved by repeating Step 8 and Step 9 using the same hourly pool prices and contract strategy as in Step 3 and Step 5 but with load profiles from Step 1 and contract volumes for each settlement class. For tariffs for all customers <100MWh annual consumption the Energex NSLP profile is used. This means that the estimated energy purchase costs are the same for all of these customers.

Step 11. Apply a transmission/distribution loss factor - The estimated WEPC is at the Queensland regional reference node and an allowance for losses needs to be applied to bring the WEPC to the customer terminal.

4.2 More detail on hedging approach

This section provides more detail on the hedging approach.

4.2.1 Developing 41 years of load traces each representing 2012/13

Development of 41 annual load traces for the total of NEM region and associated settlement classes in the Energex and Ergon Energy areas is based on 41 years of capital city temperature data from 1970/71 to 2010/11 and half-hourly load traces for the NEM regions and settlement classes in the Energex and Ergon Energy areas for the four years 2007/08 to 2010/11. Under this approach each day in each of the 41 years would be populated by load traces selected from the four years of actual data set of the same day type and season with the closest matching temperature conditions. The three years of data 2007/08 to 2009/10 is uplifted to the 2010/11 level by applying a percentage growth per quarter.

Matching the temperature is achieved by finding the closest least squares match between the temperature profile for that day and the temperature profile for a day in the four years of load data from 2007/08 to 2010/11 across all NEM regions. Once the day with the same day type and season in four years from 2007/08 to 2010/11 that best matches the temperature profile of the day in question is identified, then all the associated NEM regional and settlement class load traces for that day are selected for the day in question. Data is chosen on a daily basis in this way because we wish to preserve the relationship between the NEM regional loads traces and settlement class load traces.

This procedure produces 41 years of load traces which represent 2010/11 with 37 developed from past temperature data and the actual load traces for the four years 2007/08 to 2010/11.

Using a non-linear transformation the 41 years of load data are adjusted to match the AEMO 2011 ESOO forecast for 2012/13 for each NEM region except Queensland. For Queensland the load forecast for 2012/13 from the Updated 2011 APR is used. This involves adjusting the load profiles for the NEM regions to match the 10 percent POE peak demand for 2012/13 across the whole 41 years and to ensure the energy under the 41 years load trace is 41 times the annual forecast for 2012/13. In other words for each NEM region the 41 years are considered as one continuous load trace, the maximum of which is adjusted to equal the 10% POE load forecast for the region and the area under the continuous load trace equals 41 times the forecast annual energy volume for the region.

The matching 41 years of load traces for the settlement classes are also adjusted by the same amounts to provide consistent load traces to represent 2012/13.

Since the Draft Determination the Australian Energy Regulator (AER) released its Final Determination on Powerlink's regulatory reset for five years to

2012/13 to 2016/17. The peak demand forecast for 2012/13 used by the AER was noticeably less than that published by Powerlink in its Updated 2011 APR and used in the Draft Determination. However the AER did not provide a forecast of annual energy for 2012/13 and as such AER's revised peak demand forecast for Queensland could not be used to adjust the 410 years of load data to the 2013/13 level.

4.2.2 Developing 10 plant outage scenarios for the NEM

There is some price volatility associated with power station forced outages which needs to be accounted for in calculating the cost of energy. Plant availability (outage) can have a significant bearing on pool prices with outages of larger plant or combinations of smaller plant or larger plant generally resulting in higher prices.

In *PowerMark* modelling the timing and duration of planned outages are fixed and pose little or no price volatility whereas the timing and duration of forced or unplanned outages are random and introduce price volatility. *PowerMark* allows random forced outages for each generator up to a predetermined level. This forced outage level is drawn from published documents and NEM data. In constructing the *PowerMark* data base we randomly assign to each generator unit a set of half-hourly forced outages, which reflect that unit's observed forced outage rate (with any anomalies removed). Each power station has different forced outage characteristics and this is also reflected in the *PowerMark* modelling.

Using binomial probability theory ACIL Tasman has simulated 10 sets of forced outages. This process has allowed a range of outage outcomes to be produced. The most important factor in outages is coincidence – if a number of units are forced out at the same time, volatile prices usually result. The process used to simulate the outage sets allows these sorts of coincidences to be represented appropriately in the sample.

4.2.3 Application of transmission and distribution losses

Prices from the Queensland regional reference node must be adjusted for losses to the end-users. Distribution loss factors (DLF) for Energex and Ergon Energy east zone and load weighted Marginal Loss Factors (MLF) for transmission losses from the node to major supply points in the distribution networks are applied.

The MLF for each of the Energex and Ergon Energy's east zone area is based on the average energy-weighted marginal loss factor for the Energex and Ergon Energy east zone TNI's. This analysis resulted in a loss factor of 0.98 percent for Energex and 4.61 percent for the Ergon Energy east zone.

The distribution loss factor by settlement class for the Energex area and the Ergon energy east zone are taken from the AEMO Distribution Loss factors for 2012/13.

The estimated transmission and distribution loss factors for the settlement classes are shown in Table 4.

Table 4 **Estimated transmission and distribution loss factors for Energex and Ergon Energy's east zone**

Settlement classes	Distribution losses	Transmission losses	Total losses
Energex - NSLP - residential and small business and unmetered supply	6.2%	1.0%	**7.2%**
Energex - Control tariff 9000	6.3%	1.0%	**7.3%**
Energex - Control tariff 9100	6.3%	1.0%	**7.3%**
Ergon Energy - NSLP - SAC HV, CAC and ICC	3.8%	4.6%	**8.6%**
Ergon Energy - NSLP - SAC demand and street lighting	7.8%	4.6%	**12.8%**

Data source: ACIL Tasman analysis on each of the Queensland TNIs, Queensland MLFs and Energex and Ergon Energy east zone DLFs for 2012/13 from AEMO.

ACIL Tasman has amended the calculation method used to account for losses. For the Draft Determination the WEPC at the end-user terminals were calculated multiplying the WEPC at the node by one plus the percentage losses. This was not strictly correct and now the losses are accounted for by dividing the WEPC at the node by one minus the percentage loss.

4.3 Data sources

The methodology uses data from a range of sources including those that are in the public domain and those that are not. Where possible the data sources will be available to stakeholders for review.

4.3.1 Generation cost and other data

The generator information used in the market modelling covers fuel and variable O&M costs, installed capacities, efficiencies, emission factors, planned and forced outage rates, auxiliary use, portfolio ownership structure, contract cover and minimum generation levels.

These data are contained in the generator data base used in the *PowerMark* modelling of pool prices. The estimates contained in this data base have been developed over the past 15 years and have been scrutinised by a wide variety of clients over this period. The sources of this data are many and include:

- annual reports
- gas price modelling using *GasMark*
- announced contractual arrangements for fuel
- ACIL Tasman estimates
- Non-sensitive information provided by clients
- AEMO reports

Summary data for Queensland power stations is provided in Table 5.

Table 5 Details of Queensland generators used in pool price modelling for 2012/13

Portfolio	Generator	Gen Type	Fuel	Capacity (MW)	Min Gen (MW)	Auxiliaries (%)	Thermal efficiency HHV (%) sent-out	Combustion emission factor (kg CO2-e/GJ of fuel)	VOM ($/MWh sent-out, 2011 $)	FOM ($/MW/year, 2011 $)
AGL	Oakey	Gas turbine	Natural gas	141	0	1.5%	32.6%	0.0513	$9.50	$13,000
AGL	Oakey	Gas turbine	Natural gas	141	0	1.5%	32.6%	0.0513	$9.50	$13,000
AGL	Townsville	cycle	Coal seam methane	160	133	3.0%	46.0%	0.0513	$1.04	$31,000
AGL	Townsville	cycle	Coal seam methane	80	67	3.0%	46.0%	0.0513	$1.04	$31,000
BBP	Braemar 1	Gas turbine	Natural gas	168	90	1.5%	30.0%	0.0513	$7.83	$13,000
BBP	Braemar 1	Gas turbine	Natural gas	168	90	1.5%	30.0%	0.0513	$7.83	$13,000
BBP	Braemar 1	Gas turbine	Natural gas	168	90	1.5%	30.0%	0.0513	$7.83	$13,000
CS Energy	Barron Gorge	Hydro	Hydro	30	15	1.0%	100.0%	0	$11.28	$52,000
CS Energy	Barron Gorge	Hydro	Hydro	30	15	1.0%	100.0%	0	$11.28	$52,000
CS Energy	Callide B	Steam turbine	Black coal	350	200	7.0%	36.1%	0.095	$1.19	$49,500
CS Energy	Callide B	Steam turbine	Black coal	350	200	7.0%	36.1%	0.095	$1.19	$49,500
CS Energy	Callide C	Steam turbine	Black coal	405	200	4.8%	36.5%	0.095	$2.70	$49,500
CS Energy	Gladstone	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	$1.18	$52,000
CS Energy	Gladstone	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	$1.18	$52,000
CS Energy	Gladstone	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	$1.18	$52,000
CS Energy	Gladstone	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	$1.18	$52,000
CS Energy	Gladstone	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	$1.18	$52,000
CS Energy	Gladstone	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	$1.18	$52,000
CS Energy	Kareeya	Hydro	Hydro	21	8	1.0%	100.0%	0	$6.15	$52,000
CS Energy	Kareeya	Hydro	Hydro	21	8	1.0%	100.0%	0	$6.15	$52,000
CS Energy	Kareeya	Hydro	Hydro	18	8	1.0%	100.0%	0	$6.15	$52,000
CS Energy	Kareeya	Hydro	Hydro	21	8	1.0%	100.0%	0	$6.15	$52,000
CS Energy	Kogan Creek	Steam turbine	Black coal	750	350	8.0%	37.5%	0.094	$1.25	$48,000
CS Energy	Mackay GT	Gas turbine	Fuel oil	34	0	3.0%	28.0%	0.0697	$8.94	$13,000
CS Energy	Wivenhoe	Hydro	Hydro	250	0	1.0%	100.0%	0	$0.00	$52,000
CS Energy	Wivenhoe	Hydro	Hydro	250	0	1.0%	100.0%	0	$0.00	$52,000
Ergon	Barcaldine	Gas turbine	Natural gas	55	27	3.0%	40.0%	0.0513	$2.37	$25,000
ERM	Braemar 2	Gas turbine	Natural gas	153	150	1.5%	30.0%	0.0513	$7.83	$13,000
ERM	Braemar 2	Gas turbine	Natural gas	153	0	1.5%	30.0%	0.0513	$7.83	$13,000
ERM	Braemar 2	Gas turbine	Natural gas	153	0	1.5%	30.0%	0.0513	$7.83	$13,000
InterGen	Callide C	Steam turbine	Black coal	405	200	4.8%	36.5%	0.095	$1.19	$49,500
InterGen	Millmerran	Steam turbine	Black coal	425.5	130	4.7%	36.9%	0.092	$2.81	$48,000
InterGen	Millmerran	Steam turbine	Black coal	425.5	130	4.7%	37.5%	0.092	$2.81	$48,000
Electricity Limited	Darling Downs	cycle	Natural gas	630	270	6.0%	46.0%	0.0513	$1.04	$31,000
Electricity Limited	Mt Stuart	Gas turbine	Liquid Fuel	146	0	3.0%	30.0%	0.0697	$8.94	$13,000
Electricity Limited	Mt Stuart	Gas turbine	Liquid Fuel	146	0	3.0%	30.0%	0.0697	$8.94	$13,000
Electricity Limited	Mt Stuart	Gas turbine	Liquid Fuel	126	0	3.0%	30.0%	0.0697	$8.94	$13,000
Electricity Limited	Roma	Gas turbine	Natural gas	40	0	3.0%	30.0%	0.0513	$9.50	$13,000
Electricity Limited	Roma	Gas turbine	Natural gas	40	0	3.0%	30.0%	0.0513	$9.50	$13,000
QGC	Condamine	cycle	Natural gas	140	0	3.0%	48.0%	0.0513	$1.04	$31,000
Rio Tinto	Yarwun	Gas turbine	Natural gas	168	143	2.0%	34.0%	0.0513	$0.00	$25,000
Stanwell - Tarong	Collinsville	Steam turbine	Black coal	31	20	8.0%	27.7%	0.0894	$1.31	$65,000
Stanwell - Tarong	Collinsville	Steam turbine	Black coal	31	20	8.0%	27.7%	0.0894	$1.31	$65,000
Stanwell - Tarong	Collinsville	Steam turbine	Black coal	31	20	8.0%	27.7%	0.0894	$1.31	$65,000
Stanwell - Tarong	Collinsville	Steam turbine	Black coal	31	20	8.0%	27.7%	0.0894	$1.31	$65,000
Stanwell - Tarong	Collinsville	Steam turbine	Black coal	31	20	8.0%	27.7%	0.0894	$1.31	$65,000
Stanwell - Tarong	Stanwell	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	$3.18	$49,000
Stanwell - Tarong	Stanwell	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	$3.18	$49,000
Stanwell - Tarong	Stanwell	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	$3.18	$49,000
Stanwell - Tarong	Stanwell	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	$3.18	$49,000
Stanwell - Tarong	Swanbank E	cycle	Coal seam methane	385	150	3.0%	47.0%	0.0513	$1.04	$31,000
Stanwell - Tarong	Tarong	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	$7.42	$49,500
Stanwell - Tarong	Tarong	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	$7.42	$49,500
Stanwell - Tarong	Tarong	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	$7.42	$49,500
Stanwell - Tarong	Tarong	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	$7.42	$49,500
Stanwell - Tarong	Tarong North	Steam turbine	Black coal	443	175	5.0%	39.2%	0.0921	$1.42	$48,000

Data source: *ACIL Tasman's* PowerMark *generator data base*

4.3.2 Fuel Prices

Fuel prices assumed for the Queensland generators is shown in Table 6

Table 6 **Fuel prices assumed for Queensland power stations (nominal $/GJ)**

Generator	Fuel	2012	2013
Barcaldine	Natural gas	$6.96	$7.11
Braemar 1	Natural gas	$2.80	$2.87
Braemar 2	Natural gas	$3.04	$3.11
Callide B	Black coal	$1.41	$1.44
Callide C	Black coal	$1.41	$1.44
Collinsville	Black coal	$2.25	$2.30
Condamine	Natural gas	$1.78	$2.22
Darling Downs	Natural gas	$3.96	$4.27
Gladstone	Black coal	$1.67	$1.71
Kogan Creek	Black coal	$0.80	$0.82
Mackay GT	Liquid Fuel	$32.27	$33.07
Millmerran	Black coal	$0.91	$0.93
Mt Stuart	Liquid Fuel	$32.27	$33.07
Oakey	Natural gas	$4.43	$4.53
Roma	Natural gas	$5.18	$5.66
Stanwell	Black coal	$1.49	$1.53
Swanbank E	Natural gas	$3.64	$3.80
Tarong	Black coal	$1.08	$1.10
Tarong North	Black coal	$1.08	$1.10
Townsville	Natural gas	$4.24	$4.33
Yarwun	Natural gas	$3.73	$3.80

Data source: ACIL Tasman research based on a wide variety of data sources and fuel market modelling

4.3.1 Plant outages

Planned and forced outages assumed for the Queensland plant are shown in Table 7.

Table 7 **Planned and forced outages for Queensland power stations**

Power station	Planned outage		Forced outage rate		Availability	
	2012	2013	2012	2013	2012	2013
Barcaldine	0.0%	8.2%	2.5%	2.5%	98%	89%
Barron Gorge	4.1%	4.1%	1.8%	1.8%	94%	94%
Braemar 1	0.0%	5.3%	1.3%	1.3%	99%	93%
Braemar 2	2.6%	0.0%	0.5%	0.5%	97%	100%
Callide B	7.7%	0.0%	4.2%	4.2%	88%	96%
Collinsville	1.6%	3.3%	3.9%	3.9%	94%	93%
Callide C	5.2%	5.2%	6.9%	6.9%	88%	88%
Condamine	3.6%	3.6%	1.4%	1.4%	95%	95%
Darling Downs	0.0%	8.2%	3.2%	3.2%	97%	89%
Gladstone	4.1%	4.1%	4.0%	4.0%	92%	92%
Kareeya	2.1%	2.1%	1.9%	1.9%	96%	96%
Kogan Creek	0.0%	8.2%	4.4%	4.4%	96%	87%
Millmerran	4.1%	4.1%	6.0%	6.0%	90%	90%
Mt Stuart	0.0%	5.3%	2.4%	2.4%	98%	92%
Stanwell	2.1%	2.1%	2.6%	2.6%	95%	95%
Swanbank B	4.0%	4.0%	6.9%	6.9%	89%	89%
Swanbank E	8.2%	0.0%	3.1%	3.1%	89%	97%
Tarong	2.0%	2.0%	3.0%	3.0%	95%	95%
Tarong North	0.0%	7.9%	2.9%	2.9%	97%	89%
Townsville	8.2%	0.0%	3.0%	3.0%	89%	97%
Yarwun	0.0%	8.2%	2.9%	2.9%	97%	89%

Data source: ACIL Tasman research based on a wide variety of data sources including AEMO

4.3.2 Load data

In the modelling for the Final Determination ACIL Tasman has used a number of data sources to estimate the WEPC for the settlement classes applying in the Energex and Ergon Energy areas.

The data sources include:

- Half hour load traces for each NEM region for the four years 2007/08 to 2010/11 published by the Australian Energy Market Operator (AEMO)on its website, used in the pool price modelling
- Half hour load traces for each Transmission Node Identity (TNI) for Energex area from AEMO via the Authority to provide a basis for estimating transmission losses from the regional reference node to the bulk supply points in the Energex and Ergon Energy supply areas
- Net System Load Profile (NSLP) for Energex for the four years 2007/08 to 2010/11 from the AEMO website to be used for estimation of costs for all Queensland franchise customers <100MWh per annum and Ergon Energy NSLP to be used for customers >100MWh per annum in the Ergon Energy area. Use of the NSLP to estimate wholesale EPC for large Ergon Energy customers was based on advice from Ergon Energy that large customers (SAC, CAC and ICC) on regulated tariffs in its area were included in the NSLP and thus the wholesale EPC for these customers should be based on the NSLP.

- Controlled load traces for the Energex area from the AEMO website for use in estimating the cost of supplying these tariffs
- Load forecast of summer and winter peak demands and annual energy for each NEM region published by AEMO in its 2011 Electricity Statement of Opportunities (ESOO) to be used as a basis for estimating the load trace for 2012/13 for all regions except Queensland
- Load forecast of summer and winter peak demands and annual energy for Queensland published by Powerlink in its Updated 2011 Annual Planning report (APR) used as a basis for estimating the load trace for 2012/13 for Queensland. ACIL Tasman considered using the lower load forecast used by AER in its final Powerlink determination for the period 2012/13 to 2016/17. However the AER provided only a peak demand forecast and not an annual energy forecast and as such this forecast was not suitable for use in the calculation of the WEPC for the Final Determination.

4.3.3 Other data

In addition to load and generator data the following are required:

- 40 years of three hourly temperature data for capital cities to be used in selecting the40 years of load traces used in the pool price modelling
- Proprietary information on prospective renewable energy developments including their type, location, capacity and costs for use in ACIL Tasman's *RECMark* to determine renewable energy capacity to be used in the 2012/13 pool price modelling.

4.4 Estimated contract prices used in the hedging approach

In the Final Determination, contract prices for Q3 2012 and Q4 2012 were calculated by using trading volume weighted d-cyphaTrade daily settlement prices for all trades up until 23 April 2012, the cut-off date for contract market data for the Final Determination.

On the other hand, Q1 2013 and Q2 2013 d-cyphaTrade futures have traded relatively thinly, while TFS OTC contracts excluding carbon for calendar year 2013 have traded relatively well. ACIL considered using TFS data but was unable to because data was only available for calendar year 2013 and not quarterly.

To address this issue, Q1 2013 and Q2 2013 base and peak futures have been estimated by using trading volume weighted d-cypha Trade daily settlement prices from 8 November 2011.[5]

This method of only using traded prices from 8 November 2011 to estimate Q1 2013 and Q2 2013 contract prices recognises that:

- d-cyphaTrade Q1 2013 and Q2 2013 futures have traded very thinly
- OTC contracts excluding carbon for calendar year 2013 have traded well

Since OTC contracts excluding carbon for calendar year 2013 (plus the carbon pass-through) are virtually the same as d-cyphaTrade futures for the implied calendar year 2013 from 8 November 2011, ACIL Tasman is satisfied that d-cyphaTrade prices from 8 November 2011 align well with the OTC carbon-exclusive contracts.

In a submission to the Draft Determination, QCOSS suggested that all trades in d-cypha be used, and to not exclude trades from prior to 8 November 2011.

ACIL Tasman's view is that the more heavily traded contract (that is, the OTC contract excluding carbon for calendar year 2013) better represents market prices. Therefore, using d-cyphaTrade prices from 8 November 2011 allows us to estimate quarterly contract prices (for Q1 2013 and Q2 2013) using d-cypha Trade data, given that there is no data for quarterly TFS OTC contracts excluding carbon.

In a submission to the Draft Determination, Origin recommended a consistent approach for base and peak contracts of the trade-weighted average of d-cypha Trade daily settlement prices and trades since 8 November 2011.

ACIL Tasman is satisfied that the approach used is consistent because it uses contracts that have been actively traded, or a proxy for contracts that have been actively traded (in the case of Q1 2013 and Q2 2013), and therefore, are the best representation of the market contract price.

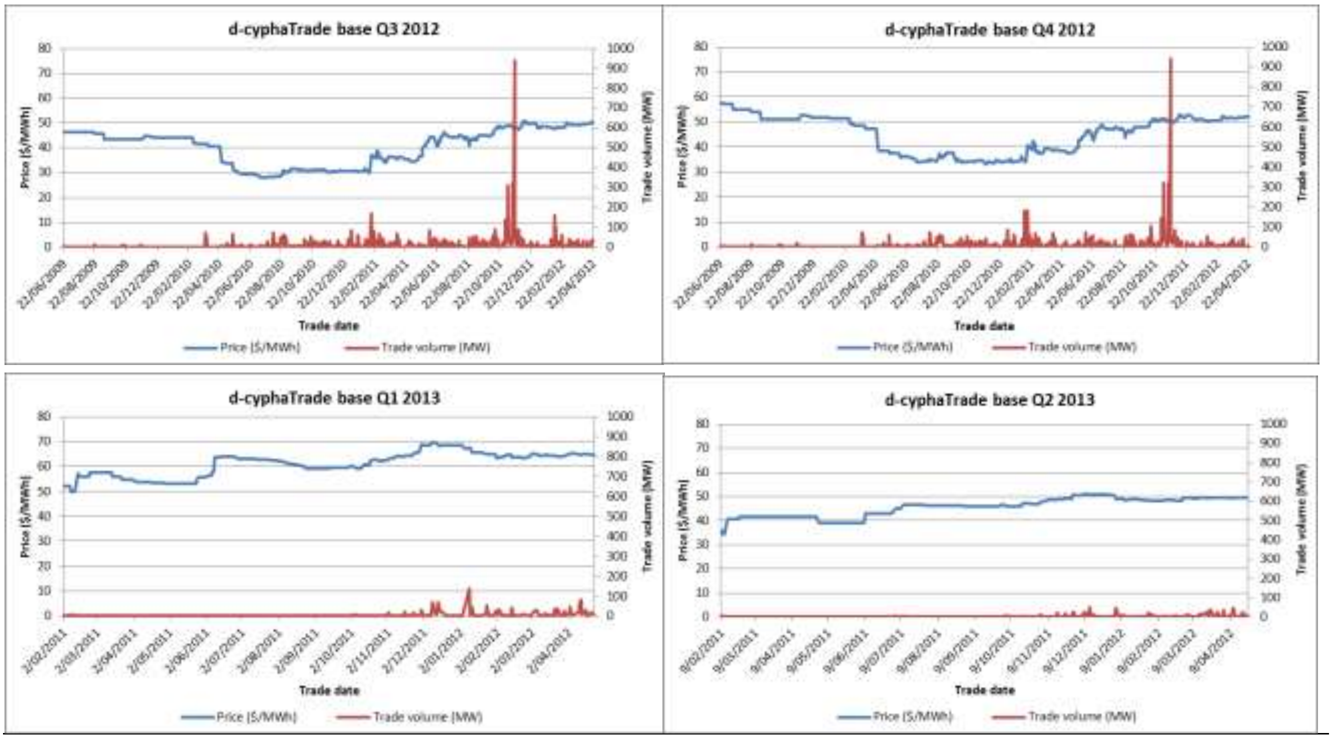
In a submission to the Draft Determination, AGL suggested the use of TFS carbon-exclusive trades for base contract price estimates.

ACIL Tasman is satisfied that there is no reason to depart from using d-cypha Trade prices, because TFS contracts excluding carbon for calendar year 2013 (plus the carbon pass-through) are virtually the same as d-cypha Trade prices from 8 November 2011.

[5] This method is not used for Peak Q2 2013 futures, which have not traded since 8th November 2011 (the latest trade for both d-cypha Trade and TFS was on 11 July 2011). The July 2011 price is used as the estimate of the contract price.

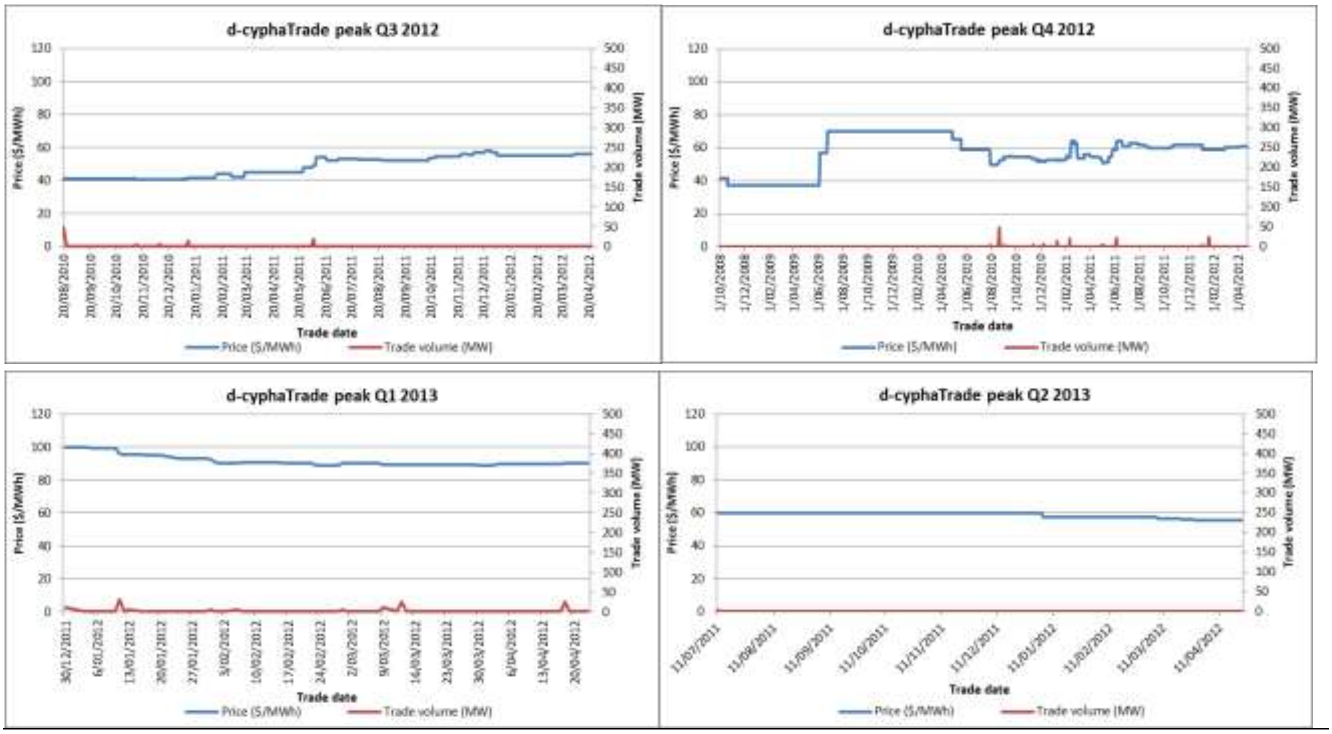
Figure 3, Figure 4 and Figure 5 show prices and trades for d-cyphaTrade base, peak and caps, respectively, since the contracts began to actively trade.

Figure 3 **Time series of trade volume and price – d-cypha Trade base futures for Q3 2012, Q4 2012, Q1 2013 and Q2 2013**



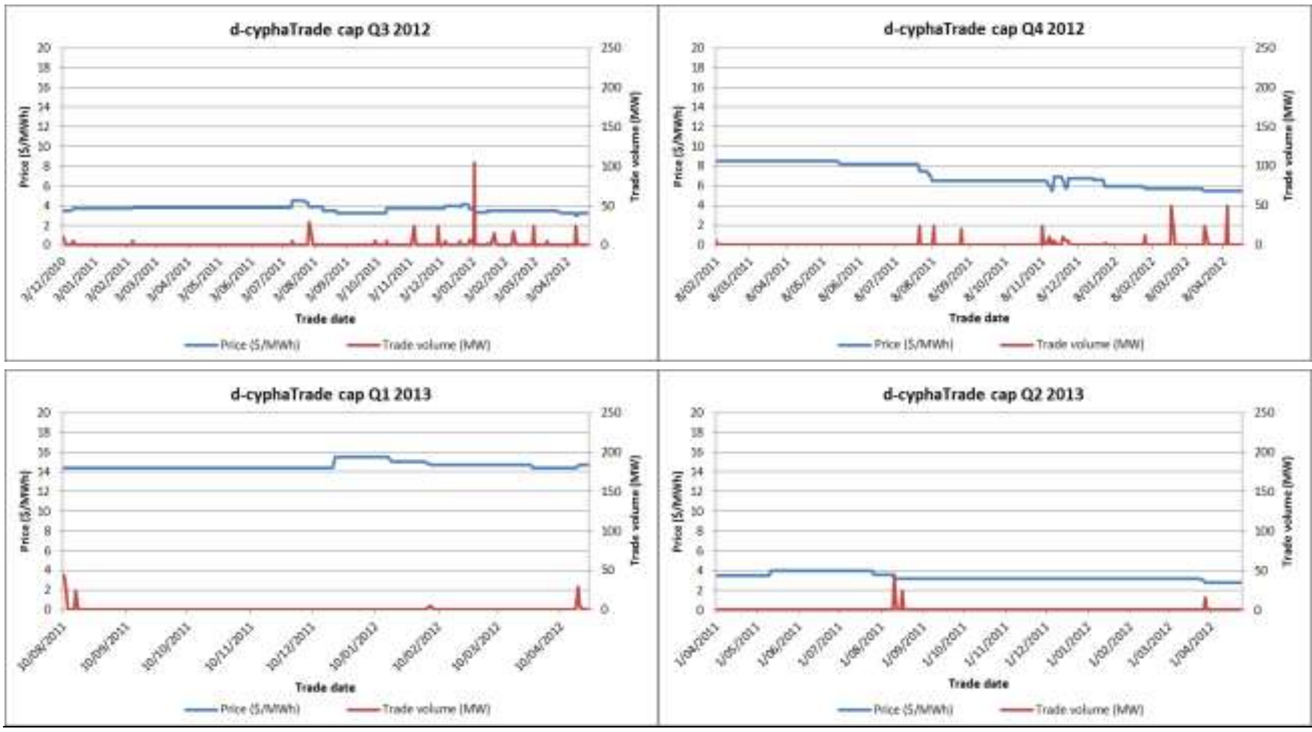
Data source: d-cypha Trade

Figure 4 **Time series of trade volume and price – d-cypha Trade peak futures for Q3 2012, Q4 2012, Q1 2013 and Q2 2013**



Data source: d-cypha Trade

Figure 5 **Time series of trade volume and price – d-cypha Trade caps for Q3 2012, Q4 2012, Q1 2013 and Q2 2013**



Data source: d-cypha Trade

Table 8 summarises the data source and method, including the time frame, for estimating quarterly contract prices.

Table 8 **Data source and method of estimating contract price**

	2012/13		
	Base contract price	**Peak contract price**	**Cap contract price**
Q3 2012	Trade-weighted average of d-cypha Trade daily settlement prices and trades since trading commenced (mid-2009)	Trade-weighted average of d-cypha Trade daily settlement prices and trades since trading commenced (mid-2010)	Trade-weighted average of d-cypha Trade daily settlement prices and trades since trading commenced (late-2010)
Q4 2012	Trade-weighted average of d-cypha Trade daily settlement prices and trades since trading commenced (mid-2009)	Trade-weighted average of d-cypha Trade daily settlement prices and trades since trading commenced (mid-2010)	Trade-weighted average of d-cypha Trade daily settlement prices and trades since trading commenced (late-2010)
Q1 2013	Trade-weighted average of d-cypha Trade daily settlement prices and trades since 8 November 2011	Trade-weighted average of d-cypha Trade daily settlement prices and trades since 8 November 2011	Trade-weighted average of d-cypha Trade daily settlement prices and trades since trading commenced (early-2011)
Q2 2013	Trade-weighted average of d-cypha Trade daily settlement prices and trades since 8 November 2011	Latest traded price (11 July 2011) on d-cypha Trade	Trade-weighted average of d-cypha Trade daily settlement prices and trades since trading commenced (early-2011)

Key:

= trade-weighted average of all trades

= trade-weighted average since the Senate passed CEF legislation on 8 Nov 2011

= latest traded price (11 July 2011) as there have been no trades since 8th November 2011

Table 9 shows the estimated quarterly swap and cap contract prices for the Final Determination and the Draft Determination for 2012/13 using the methods summarised in Table 8. Prices have not changed considerably since the Draft Determination, with the change in prices on average around $0.40/MWh.

Table 9 **Quarterly base, peak and cap estimated contract prices – 2012/13 Final Determination and Draft Determination ($/MWh)**

	2012/13 Final Determination		
	Base contract price	Peak contract price	Cap contract price
Q3	$42.30	$42.91	$3.53
Q4	$44.40	$54.27	$6.15
Q1	$66.02	$92.51	$14.47
Q2	$49.62	$60.00	$3.14
	2012/13 Draft Determination		
	Base contract price	**Peak contract price**	**Cap contract price**
Q3	$41.42	$42.91	$3.59
Q4	$43.97	$53.47	$6.65
Q1	$67.68	$96.81	$14.40
Q2	$50.03	$60.00	$3.20

Key:

= trading-weighted average covering all trades

= trading-weighted average since the Senate passed CEF legislation on 8 Nov 2011

= latest traded price (11 July 2011) as there have been no trades between 8th November 2011 and 23 April 2012

Data source: ACIL Tasman analysis using d-cyphaTrade data

4.5 Results for WEPC

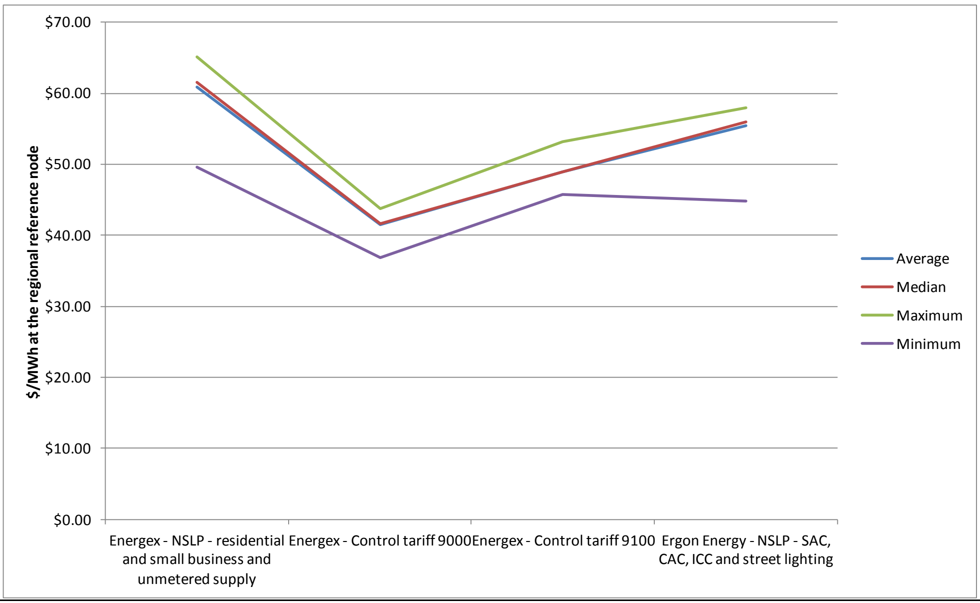
In the contract hedge model settlement process, the hourly prices are brought together with the hourly loads, the contract prices and the contract quantities for each hour of the year to provide an estimate of the cost of purchasing energy using the hedging approach.

This settlement process was run for each of the 410 years of pool price and load data from the price distribution approach, and then repeated for each of the individual settlement class load profiles. In each of these settlement classes studied, the load profile and the contract volumes, which are based on the particular load profile characteristics are varied. The 410 years of hourly pool prices for Queensland and quarterly flat, peak and cap contract prices for Queensland from Table 9 remain unchanged across each of the studies. The contract volumes are determined on the basis of the median year of the 410 data years load traces for the particular tariff class and held constant for that tariff class study when the hedging model is run against the 410 data years, representing possible EPC variations for 2012/13 for that tariff.

Figure 6 demonstrates that there is limited variation in the WEPC across the 410 years, which suggests that the hedge strategy is represents a reasonable approach by an efficient retailer. It is also interesting that the median and mean of each settlement class are very close suggesting a non skewed distribution of hedged prices across the 410 representations of 2012/13. The small variation across the 410 observations for the Energex NSLP hedged price can also be seen in Figure 1 which shows the effectiveness of the hedging strategy to remove price volatility.

For the control load tariffs ACIL Tasman used the hedge model to calculate the cost of supplying the NSLP with and without the control loads and the difference costs was taken as the cost for the controlled loads. The price per MWh for controlled loads is then calculated by dividing the cost difference by estimated energy under the controlled load.

Figure 6 **Variation in price across the 410 years - hedging approach**



Source: ACIL Tasman hedging analysis

ACIL Tasman favours the median price from the 410 annual prices as representing the best estimate of the energy purchase costs for each settlement class. Unlike the average of the 410 prices, the median is the point where there is an equal chance of the hedged load being lower as there is of being higher than the actual outcome. Also the median is not affected by any highs or lows which may be regarded as outliers whereas the average may be affected by these potential outliers. In any case the median and mean are almost identical as indicated in Figure 6.

Table 10 shows the results for the WEPC modelling for the Draft and Final Determinations. It includes an allowance for the transmission and distribution losses and the estimate of the cost at the customer terminals.

The main changes since the Draft Determination are in the unmetered supply and Ergon Energy estimates. The change in the estimated WEPC for controlled load in the Final Determination was minor even though the Draft Determination was based on the price distribution approach and not the hedging approach used for the Final Determination. The change in the WEPC for Ergon Energy loads is mainly associated with the change in the losses used to calculate the WEPC at the customer terminal. The change in the unmetered supply was because it was realised that this load in incorporated in the NSLP and thus should carry the same WEPC as the other loads in the NSLP. In the Draft Determination the WEPC for unmetered loads were incorrectly based on an assumed profile using the price distribution approach which understandably resulted in a low estimate than using the NSLP and the hedging approach.

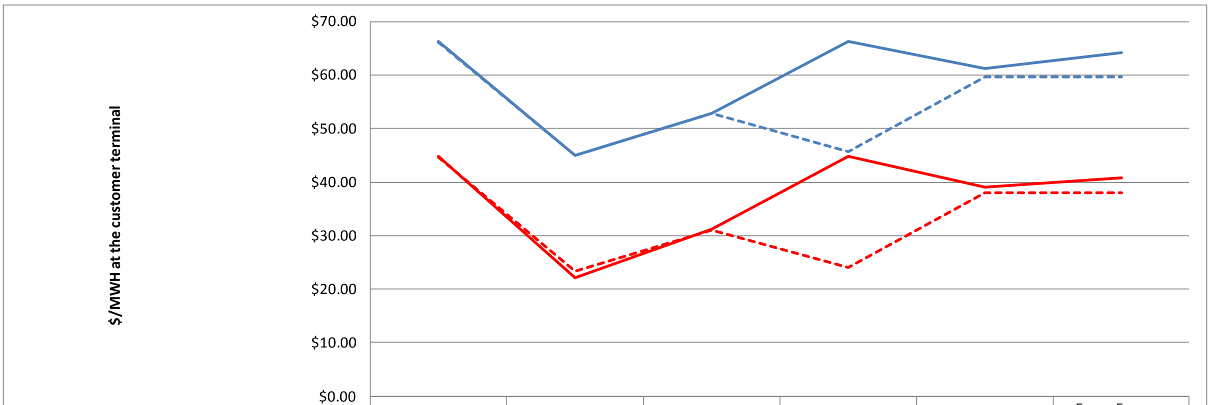
As noted above, ACIL Tasman has also adjusted the calculation method used to account for losses. For the Draft Determination the WEPC at the customer terminal were calculated multiplying the WEPC at the node by one plus the percentage losses. This was not strictly correct so for the Final Determination the losses are accounted for by dividing the WEPC at the node by one minus the percentage losses. This change accounts for an increase of between $0.30 and $0.40/MWh in the WEPC in Final Determination compared with the Draft Determination.

Table 10 **Estimated WEPC using the median price from hedging approach ($/MWh)**

Settlement classes	Draft Determination			Final Determination			Change in WEPC at the customer terminal between Draft and Final Determinations
	Estimated median cost at the Queensland regional reference node	Allowance for transmission and distribution losses	Estimated wholesale energy purchase costs at the customer terminal	Estimated median cost at the Queensland regional reference node	Allowance for transmission and distribution losses	Estimated wholesale energy purchase costs at the customer terminal	
Prices including carbon pricing							
Energex - NSLP - residential and small business	$61.60	7.4%	$66.13	$61.49	7.2%	**$66.28**	**$0.16**
Energex - Control tariff 9000	$41.86	7.5%	$44.99	$41.63	7.3%	**$44.93**	**($0.06)**
Energex - Control tariff 9100	$49.15	7.5%	$52.82	$48.93	7.3%	**$52.81**	**($0.01)**
Energex - NSLP - unmetered supply	$42.58	7.5%	$45.76	$61.49	7.2%	**$66.28**	**$20.52**
Ergon Energy - NSLP - SAC HV, CAC and ICC	$55.16	8.0%	$59.57	$55.93	8.6%	**$61.18**	**$1.61**
Ergon Energy - NSLP - SAC demand and street lighting	$55.16	8.0%	$59.57	$55.93	12.8%	**$64.11**	**$4.54**
Prices without carbon pricing							
Energex - NSLP - residential and small business	$41.60	7.4%	$44.65	$41.59	7.2%	**$44.83**	**$0.18**
Energex - Control tariff 9000	$21.63	7.5%	$23.25	$20.54	7.3%	**$22.16**	**($1.09)**
Energex - Control tariff 9100	$28.92	7.5%	$31.08	$28.86	7.3%	**$31.14**	**$0.06**
Energex - NSLP - unmetered supply	$22.34	7.5%	$24.01	$41.59	7.2%	**$44.83**	**$20.82**
Ergon Energy - NSLP - SAC HV, CAC and ICC	$35.15	8.0%	$37.97	$35.64	8.6%	**$38.99**	**$1.02**
Ergon Energy - NSLP - SAC demand and street lighting	$35.15	8.0%	$37.97	$35.64	12.8%	**$40.86**	**$2.89**

The WEPC results by settlement class with and without carbon pricing for the Draft and Final Determinations are summarised in Figure 7. It shows that, apart from the unmetered supply and the Ergon Energy loads there was very little change between the Draft and Final Determinations. The two Ergon Energy classes are higher mainly because of revised losses. For the Final Determination the unmetered supply has been based on the NSLP cost using the hedging approach not its own load profile using the price distribution approach as used in the Draft Determination.

Figure 7 **Energy purchase costs at the customer terminals – Draft and Final Determinations with and without carbon**



	Energex - NSLP - residential and small business	Energex - Control tariff 9000	Energex - Control tariff 9100	Energex - NSLP - unmetered supply	Ergon Energy - NSLP - SAC HV, CAC and ICC	Ergon Energy - NSLP - SAC demand and street lighting
With carbon pricing - Final Determination	$66.28	$44.93	$52.81	$66.28	$61.18	$64.11
With carbon pricing - Draft Determination	$66.13	$44.99	$52.82	$45.76	$59.57	$59.57
Without carbon pricing - Final Determination	$44.83	$22.16	$31.14	$44.83	$38.99	$40.86
Without carbon pricing - Draft Determination	$44.65	$23.25	$31.08	$24.02	$37.97	$37.97

Data source: ACIL Tasman analysis

5 Other energy purchase costs

The OEPC estimates shown in this section are as follows.

- Renewable energy costs associated with the Renewable Energy Target (RET) encompassing:
  - Large-scale Renewable Energy Target (LRET)
  - Small-scale Renewable Energy Scheme (SRES)
- Queensland Gas Scheme
- Market fees including:
  - NEM management fees
  - Ancillary services costs

5.1 Renewable Energy Target scheme

On 1 January 2011, the Renewable Energy Target (RET) has two elements: the Large-scale Renewable Energy Target (LRET), and the Small-scale Renewable Energy Scheme (SRES). Liable parties (i.e. all electricity users apart from those wholly or partially exempted for one reason or another such as Emissions Intensive Trade Exposed (EITE) industries such as aluminium) are now 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, ACIL Tasman has used in its calculation:

- Large-scale Generation Certificate (LGC) market prices from AFMA[6]
- Adjusted LRET targets for 2012 and 2013 of 16,763GWh and 19,088GWh respectively, as published by the Clean Energy Regulator (CER) – formerly known as Office of the Renewable Energy Regulator (ORER)
- CER binding estimate for 2012 RPP of 9.15 percent[7]
- CER binding estimate for 2012 STP of 23.96 percent[8]
- CER non-binding estimate for 2013 STP of 7.94 percent[9]
- CER default estimate for 2013 RPP of 10.42 percent[10]

[6] AFMA data includes weekly settlement prices to 23 April 2012, which is the cut-off date for all relevant market-based data used in the Final Decision for 2012/13 tariffs.

[7] Published on 24 February 2012

[8] Published on 24 February 2012

[9] Published on 30 March 2012

[10] Published on 1 May 2012

- CER clearing house price for 2012 and 2013 for Small-scale Technology Certificates (STCs) of $40/MWh.

5.1.1 LRET

The estimated cost of the LRET scheme is found by applying the Renewable Power Percentage (RPP) to the LGC price to establish the cost per MWh supplied to customers. Spreading the cost to the various tariffs is a relatively simple matter as the cost will be expressed as a cost per MWh.

There is little uncertainty over the Renewable Power Percentage (RPP) component of the calculation as this is estimated using data published by CER. The methodology for determining the price for LGCs is not as straight forward.

ACIL Tasman understands that the vast majority of LGCs are acquired by retailers through long term contracts with wind farms or through wind farm ownership. However, the prices in these contracts are not available for use in estimating the cost of the LRET scheme.

We also note that retailer submissions indicate the volume of LGC acquired through the traded market is small by comparison and that the market price may not a reliable indicator of costs and that it would be more appropriate to base the estimation of the cost of LRET by using the long run marginal cost (LRMC) of wind generation.

However, a low volume of trading does not necessarily mean that the traded prices are an unreliable source on which to base the estimation of the cost of the scheme. ACIL Tasman has examined the market price over recent years and has observed that the market price has reacted, as one would expect, to prevailing market conditions.

For example, between April and December 2010 the AFMA REC (now LGC) price for the year ahead fell from $46.41 to $29.29 in a period of significant and growing over supply. Since then with the split of the scheme into LRET and SRES on 1 January 2011 and an adjustment to the target, the LGC price for the year ahead has recovered to $40.53 in October 2011.

ACIL Tasman has used weekly market prices for LGCs published by AFMA to calculate the price of average LGCs. The average LGC prices calculated from the AFMA data are **$40.62/MWh for 2012** and **$42.97/MWh for 2013.**

In a submission to the Draft Determination, AGL disagreed with using the market data based approach to estimating LGC prices, but instead proposed using the LRMC approach to estimate LGC prices.

Furthermore, Origin Energy and QEnergy suggested that LGC prices that had been heavily influenced by the oversupply of certificates (between April and December 2010) should be excluded from the calculation of 2012 and 2013 LGC prices.

ACIL Tasman is satisfied that the current method of calculating the average price of LGCs results in a sound estimate of the cost of a retailer meeting the LRET in 2012/13. The average price of LGCs using the AFMA data of around $42/MWh aligns with our RECMark modelling, which is based on the LRMC of renewable generation, a carbon price projection, a black energy price projection and the LGC penalty price and expiry date. In essence the model develops new renewable projects on a least cost basis across Australia and projects the marginal REC price required to ensure projects are commercially viable. A more detailed description of REC Mark is provided in Appendix A.1.

The AFMA weekly LGC prices have been averaged over the following periods:

- 2012 is based on prices from 7 January 2010 to 23 April 2012 (120 weeks)
- 2013 is based on prices from 6 January 2011 to 23 April 2012 (68 weeks)

ACIL Tasman has used the CER binding estimate for 2012 RPP of 9.15 percent and the CER default estimate for 2013 RPP of 10.42 percent.

The default RPP is defined in Section 39 (2) (b) of the Renewable Energy (Electricity) Act 2000, and is calculated using the following formula:

> RPP for previous year * (required GWh of renewable sourced electricity for the year / required GWh of renewable sourced electricity for the previous year)

That is for 2013

> 9.15 percent * (19,088 / 16,763) = 10.42 percent

Table 11 shows the published binding CER estimate of the 2012 RPP and the CER default estimate of the 2013 RPP for the LRET scheme.

Table 11 **Elements of the 2012 and 2013 RPP estimates for the LRET scheme used in Final Determination**

Calendar Year	Required GWh of renewable source electricity	Renewable Power Percentage (RPP)
2012	**16,763**	**9.15%**
2013	**19,088**	**10.42%**

Data source: CER

Based on this approach, we estimate the cost of complying with the LRET scheme to be $4.10/MWh in 2012/13 as shown in Table 12.

Table 12 **Estimated cost of LRET – Final Determination 2012/13**

	2012	2013	Cost of LRET Final Determination 2012/13
RPP %	9.15%	10.42%	
Adjusted target GWh	16,763	19,088	
Average LGC price $/MWh	$40.62	$42.97	
Cost of LRET	**$3.72**	**$4.48**	**$4.10**

Data source: CER, AFMA, ACIL Tasman analysis

5.1.2 SRES

The cost of SRES is found by applying the STP to the STC price to estimate the cost per MWh for 2012 and 2013. The estimate used for the Final Determination for 2012/13 tariffs is then taken as the average of the 2012 and 2013 results.

In February 2012 CER has published the binding estimate for the 2012 STP, which is 23.96 percent, equivalent to 44.786 million STCs as a proportion of total estimated liable electricity for the 2012 year. In March 2012, CER published a non-binding estimate for 2013 of 7.94 percent, which was revised upwards from the December 2011 CER non-binding estimate of 7.87 percent, due to a downward revision in estimated total liable energy from 191,487 GWh to 189,798 GWh. The non-binding STC for 2013 is equivalent to 15.07 million STCs as a proportion of total estimated liable electricity for the 2013 year. ACIL Tasman has used these STPs for purpose of calculating the cost of the SRES component of the EPC for the 2012/13 retail tariffs.

In submissions to the Draft Determination, Origin and AGL expressed concerns about using CER's non-binding STP for 2013.

In response, ACIL Tasman is satisfied with the use of the CER non-binding estimate of STP for 2013 as it is based on extensive modelling and analysis of the 2013 STP and because it is a relatively transparent and publically available estimate. In 2011, CER engaged three companies (one of which was ACIL Tasman), to provide forward estimates of the number of small-scale technology certificates (STCs) likely to be created in the 2011, 2012 and 2013 calendar years, with all three reports publically available on the CER website. The results of the modelling assist the Minister in determining the binding and non-binding estimates of STP.

The current official clearing house price for STCs is $40/STC and STCs are available to retailers from the CER clearing house for this price. The clearing house price can be changed at any time by the Minister and as such the expected prevailing price for 2012/13 would need to be considered. However the clearing house works on a first in first out basis which has meant that because of the substantial oversupply the installers of solar photovoltaic systems have experienced significant delays in receiving payment for STCs which has been caused by significant oversupply and caused cash flow problems for some. As a result an active market for STCs has developed outside the clearing house to allow installers to gain quicker access to payment for STCs from retailers. The current market price (as at April 2012) for STCs is around $29.

This raises the question whether ACIL Tasman should take both clearing house price and market price into consideration when determining the price for STCs. To use the market price would pose a difficulty because of the need to forecast the proportion of STC likely to be traded in the tariff year. Furthermore, while AFMA quotes a market price for STCs, the volume traded at this price is unknown.

ACIL Tasman proposes to continue to use the clearing house price of $40/MWh as the price for STCs in determining the EPC.

Based on this approach, we estimate the cost of complying with the SRES to be $6.38/MWh in 2012/13.

Table 13 **Estimated cost of SRES – Final Determination 2012/13**

	2012	2013	Cost of SRES Final Determination 2012/13
STP %	23.96%	7.94%	
CER estimated STCs (millions)	44.786	15.07	
STC clearing house price $/MWh	$40.00	$40.00	
Cost of SRES	**$9.58**	**$3.18**	**$6.38**

Data source: CER, ACIL Tasman analysis

Combining the LRET and SRES costs for each year and taking the average of costs in 2012 and 2013 results in a total cost of both schemes of $10.48/MWh.

Table 14 compares the estimated cost of RET for the 2012/13 tariffs for the Draft and Final Determinations.

Table 14 **Comparison of the Draft and Final Determinations - cost of LRET and SRES ($/MWh)**

	Draft Determination			Final Determination		
	2012	2013	Cost of RET Draft Determination 2012/13	2012	2013	Cost of RET Final Determination 2012/13
RPP %	9.15%	9.97%		9.15%	10.42%	
Average LGC price $/MWh	$40.62	$42.89		$40.62	$42.97	
Cost of LRET	**$3.72**	**$4.28**	**$4.00**	**$3.72**	**$4.48**	**$4.10**
STP %	23.96%	7.87%		23.96%	7.94%	
STC clearing house price $/MWh	$40.00	$40.00		$40.00	$40.00	
Cost of SRES	**$9.58**	**$3.15**	**$6.37**	**$9.58**	**$3.18**	**$6.38**
Cost of RET	**$13.30**	**$7.42**	**$10.36**	**$13.30**	**$7.65**	**$10.48**

Data sources: ACIL Tasman analysis based on data from CER and AFMA

5.2 Queensland Gas Scheme

For the 2011/12 BRCI the cost of compliance with the Queensland GEC scheme was based on a two year average of the AFMA prices for GECs.

Retailers have generally stated that this methodology of relying entirely on the AFMA market prices underestimates the cost of the GEC scheme to retailers who have entered long term supply contracts or invested in generation to secure these certificates at prices which are much higher than those currently in the market. However, information on these contractual arrangements is not available and market price information is the only available source of GEC costs.

In submissions to the Draft Determination, QCOSS, CCCL and Stanwell disagreed with estimating GEC prices using a longer time series of market data (4 years) and preferred an estimate based on a 2-year average.

In response, ACIL Tasman's view is that where a market price for inputs to the calculation of retailers' EPC can be sourced reliably and consistently it should provide the best guide to the cost of compliance with the scheme. However given that GECs have been acquired by various means including long term contracts and the fact that the GEC market is now oversupplied with low prices and very thin trading, the AFMA weekly GEC prices have been averaged over an extended period of 209 weeks or 4 years as follows:

- for 2012 - from 1 Dec 2007 to 31 Dec 2011
- for 2013 - from 1 March 2008 to 23 April 2012

The cut-off date for the AFMA data used for the Final Determination for 2012/13 tariffs is 23 April 2012.

The average GEC prices calculated from the AFMA data are $6.11/MWh for 2012 and $5.18/MWh for 2013. By taking the average of GEC prices in 2012 and 2013, results in a GEC price of $5.64/MWh for 2012/13.

Table 15 **Estimated cost of Queensland Gas Scheme using AFMA data, $/MWh**

	Draft Determination 2012/13	Final Determination 2012/13
Price of GECs from AFMA data	$5.77	$5.64
Prescribed percentage	15%	15%
Total cost of Queensland Gas Scheme	**$0.86**	**$0.85**

Data sources: ACIL Tasman analysis based on data from AFMA for prices and Queensland Department of Energy and Water Supply for the prescribed percentage.

5.3 NEM fees

NEM participant and FRC fees are payable by retailers to AEMO to cover operational expenditure. The fees also cover costs associated with the National Transmission Planner, National Smart Metering and the Electricity Consumer Advocacy Panel.

Using estimates in AEMO's *Electricity Draft Budget and Fees for 2012/13*, the estimated total NEM fees in the Final Determination for 2012/13 tariffs is $0.40/MWh, which is unchanged from the Draft Determination.

Table 16 **Estimated NEM fees ($/MWh)**

Cost category	Draft Determination 2012/13	Final Determination 2012/13
Market participant fees	$0.34	$0.34
FRC fees	$0.06	$0.06
Total NEM fees	**$0.40**	**$0.40**

Data source: AEMO Electricity Draft Budget and Fees for 2012/13

5.4 Ancillary services

Weekly aggregated settlements data for ancillary service payments in each interconnected region are provided by AEMO. Using the the average costs over the preceding 52 weeks of currently available NEM ancillary services data as a basis for 2012/13(up to the cut-off date of 23 April 2012 for this report for the Final Determination), it is estimated that the cost of ancillary services will be $0.46/MWh for 2012/13.

Table 17 **Estimated ancillary services charges ($/MWh)**

	Draft Determination 2012/13	Final Determination 2012/13
Ancillary services	$0.47	$0.46

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

5.5 Summary of renewable energy costs and market fees

In summary, other energy costs for the Final Determination for 2012/13 tariffs are estimated to be $12.18/MWh, which is slightly higher than the estimated other energy costs of $12.10/MWh for the Draft Determination. The increase can be attributed to the higher estimates of STP and RPP for 2013 that have been published on the CER website since the Draft Determination.

In a submission to the Draft Determination, Origin suggested that loss factors be applied to SRES and LRET.

ACIL Tasman agrees that loss factors should be applied to the cost of LRET and SRES, because the relevant electricity acquisition used in the calculation of the STP and RPP is defined as a wholesale acquisition from AEMO, in other words, at the regional reference node. The costs of GECs, NEM fees and Ancillary services should be treated in a similar way.

The costs presented in Table 18 are at the regional reference node.

Table 18 **Summary of OEPC – at the regional reference node ($/MWh)**

Cost category	Draft Determination 2012/13	Final Determination 2012/13
Renewable Energy Target	$10.36	$10.48
Queensland Gas Scheme	$0.86	$0.85
NEM fees	$0.40	$0.40
Ancillary services	$0.47	$0.46
Total other energy costs	**$12.10**	**$12.18**

6 Summary of energy purchase costs (EPC)

Estimated EPC for the Draft and Final Determinations for the settlement classes in the Energex area and Ergon Energy are presented in Table 19. The estimated costs in the table include both the WEPC and the OEPC. The results with and without carbon are shown as is the estimated carbon pass through.

The main changes are the increase in the estimated EPC for the unmetered supply a change in approach and an increase in Ergon Energy large customers due to changed approach to estimating losses.

Apart from the Energex NSLP the carbon pass through is higher in the Final Determination than in the Draft Determination. The change occurred because of a change in the estimation approach with the Final Determination estimates without carbon pricing based on detailed pool price and hedge modelling and analysis. The Draft Determination was based on a pass through using the AFMA approach incorporating an NEM emissions factor of 0.87.

Table 19 **Estimated wholesale energy purchase costs for Energex and Ergon Energy settlement classes**

Settlement classes	Draft Determination				Final Determination				Overall change in EPC
	Wholesale energy purchase cost at the regional reference node ($/MWh)	Renewable energy and market fees ($/MWh)	Allowance for transmission and distribution losses	Total energy purchase costs at the customer terminal ($/MWh)	Wholesale energy purchase cost at the regional reference node ($/MWh)	Renewable energy and market fees ($/MWh)	Allowance for transmission and distribution losses	Total energy purchase costs at the customer terminal ($/MWh)	
Prices including carbon pricing									
Energex - NSLP - residential and small business	$61.60	$12.10	7.4%	**$78.23**	$61.49	$12.18	7.2%	**$79.41**	**$1.19**
Energex - Control tariff 9000	$41.86	$12.10	7.5%	**$57.09**	$41.63	$12.18	7.3%	**$58.07**	**$0.98**
Energex - Control tariff 9100	$49.15	$12.10	7.5%	**$64.92**	$48.93	$12.18	7.3%	**$65.95**	**$1.03**
Energex - unmetered supply	$42.58	$12.10	7.5%	**$57.86**	$61.49	$12.18	7.2%	**$79.41**	**$21.55**
Ergon Energy - NSLP - SAC HV, CAC and ICC	$55.16	$12.10	8.0%	**$71.67**	$55.93	$12.18	8.6%	**$74.50**	**$2.83**
Ergon Energy - NSLP - SAC demand and street lighting	$55.16	$12.10	8.0%	**$71.67**	$55.93	$12.18	12.8%	**$78.08**	**$6.41**
Prices without carbon pricing									
Energex - NSLP - residential and small business and unmetered supply	$41.60	$12.10	7.4%	**$56.75**	$41.59	$12.18	7.2%	**$57.96**	**$1.21**
Energex - Control tariff 9000	$21.63	$12.10	7.5%	**$35.35**	$20.54	$12.18	7.3%	**$35.31**	**($0.04)**
Energex - Control tariff 9100	$28.92	$12.10	7.5%	**$43.18**	$28.86	$12.18	7.3%	**$44.29**	**$1.11**
Energex - unmetered supply	$22.34	$12.10	7.5%	**$36.12**	$41.59	$12.18	7.2%	**$57.96**	**$21.84**
Ergon Energy - NSLP - SAC HV, CAC and ICC	$35.15	$12.10	8.0%	**$50.07**	$35.64	$12.18	8.6%	**$52.31**	**$2.24**
Ergon Energy - NSLP - SAC demand and street lighting	$35.15	$12.10	8.0%	**$50.07**	$35.64	$12.18	12.8%	**$54.82**	**$4.75**
Carbon Pass through									
	At the reference node		**At the customer terminal**		**At the reference node**		**At the customer terminal**		**Change**
Energex - NSLP - residential and small business	$20.00	87%	**$21.47**	**93%**	$19.90	87%	**$21.45**	**93%**	**-0.1%**
Energex - Control tariff 9000	$20.23	88%	**$21.74**	**95%**	$21.10	92%	**$22.77**	**99%**	**4.5%**
Energex - Control tariff 9100	$20.23	88%	**$21.74**	**95%**	$20.08	87%	**$21.67**	**94%**	**-0.3%**
Energex - unmetered supply	$20.24	88%	**$21.74**	**95%**	$19.90	87%	**$21.45**	**93%**	**-1.3%**
Ergon Energy - NSLP - SAC HV, CAC and ICC	$20.00	87%	**$21.60**	**94%**	$20.29	88%	**$22.19**	**96%**	**2.6%**
Ergon Energy - NSLP - SAC demand and street lighting	$20.00	87%	**$21.60**	**94%**	$20.29	88%	**$23.26**	**101%**	**7.2%**

Note: The pass through means the percent of the carbon price in $/tCO2-e is passes through to the electricity price in $/MWh.

Data source: ACIL Tasman modelling and analysis

6.1 Application of energy purchase cost to the individual retail tariffs

Energy purchase costs for the individual retail tariffs or groups of retail tariffs (ie cost to supply NSLP) should be applied to all energy usage. Any differences in peak and off peak prices for the new residential TOU tariff and business time of use should be built into the network tariff not the cost of energy so as to remove any unmanageable risks to retailers.

A ACIL Tasman modelling capability

A.1 RECMark

RECMark is ACIL Tasman's model of the Federal Large-scale Renewable Energy Target (LRET). The model utilises a large scale linear programming solver with an objective function to meet the LRET in a rational least cost manner. It operates on an inter-temporal least cost basis, under the assumption of perfect certainty.

The model horizon is typically set to the period from 2010 to 2060. This time horizon extends well beyond the end of the LRET (2030) in order to account for the economics of renewable plant installed within the period of the scheme but beyond the end of the subsidy.

In essence the model develops new renewable projects on a least cost basis across Australia and projects the marginal REC price required to ensure projects are commercially viable.

RET implementation

This section provides an overview of how the features of the enhanced Renewable Energy Target (RET) are modelled within RECMark. It should be noted that with the legislated split of the scheme into the Small-scale Renewable Energy Scheme (SRES) and the Large-scale Renewable Energy Target (LRET), the models focus is only on the LRET post 2010.

Existing generators

RECs created from existing renewable generators is projected outside of RECMark and feed to the model as an input. The projection is based upon historical REC creation, with assumptions made for new projects committed or under construction. REC creation estimates are based on actual data obtained from the REC registry at generator level.

Baselines

Baselines for existing renewable generators were set under the original MRET. These are dominated by the large hydro systems in the Snowy (NSW & VIC) and Tasmania. In total around 16,600 GWh of existing renewable generation is baselined. Above baseline output (particularly relevant for hydro) is sourced from PowerMark modelling.

Shortfall penalty

The shortfall charge as specified within the regulation is $65 per REC not-indexed (constant in nominal terms over the life of the scheme). This represents a significant increase over the $40/MWh shortfall charge under the old MRET scheme.

As penalties paid are not deductible business expenses (they are treated as fines), the effective after tax penalty is therefore $92.86/REC ($65 / (1-30%) assuming a 30% marginal tax rate). The penalty is not indexed so it declines in real terms over the period to 2030.

Any shortfall penalties paid by liable parties can be refunded in subsequent years if the required certificates are surrendered (see Section 95 of the legislation). The allowable refund period is three years from the time the entity lodges its renewable energy shortfall statement. Shortfall charges are refunded in full (at the nominal penalty price of $65/REC) provided the required certificates are surrendered within the 3 year refund period.

Banking/borrowing

Unlimited banking of permits is allowed. That is, permits created can be created and withheld for surrender in later years. There are no restrictions on the amount of permits which may be banked for future surrender. RECMark allows an unlimited number of RECs to be banked throughout the scheme.

Note that all banked RECs up until the end of calendar year 2010 will only be eligible to be used against the LRET, regardless of how they were created.

Borrowing under the scheme is effectively limited to 10% of each liable entities liability as outlined within Section 36(2). This provision is provided because it is often difficult for a retailer to accurately predict what its REC liability will be. The 10% provides liable parties some leeway in estimating liabilities. Given the unpredictable nature of liabilities in reality, RECMark does not allow for any explicit borrowing of permits.

Existing Coal Mine Methane Generators

The revised RET scheme makes allowance for up to 850 GWh of existing Coal Mine Methane (CMM) production to generate RECs upon the commencement of the CPRS. While CMM is not a renewable source, its inclusion into the RET is a means of compensation for the removal of the NSW Greenhouse Gas Abatement Scheme under which a number of CMM projects were receiving NGAC revenues and also future costs under CPRS.

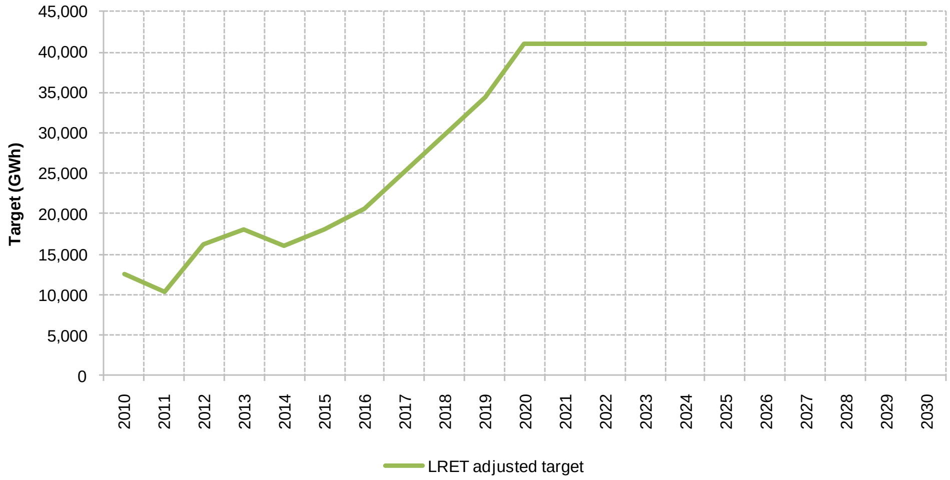
It is assumed that existing CMM generators produce RECs sufficient to fulfill the 850 GWh level through to the end of 2020 and therefore have no impact upon the REC market outcomes.

REC demand

Mandated target

The demand for RECs stem for liable party's obligation to surrender certificates to the CER, or alternatively, pay a shortfall penalty. With the announced split in the scheme into SRES/LRET, the revised aggregate target under the revised LRET is shown in Figure 8. The split in the scheme has resulted in the target reducing by around 4,000 GWh in all years from 2011 to 2030.

Figure 8 **Large-scale renewable energy target**



Note: Excludes existing CMM generation

Data source: Department of Climate Change, Enhanced Renewable Energy Target Factsheet, February 2010

Green power

Green Power is a national government renewable energy accreditation program which organises publicly available independent auditing of energy provider sales and purchase records. Accredited Green Power products are available from all Australian energy providers. Green Power is run by the NSW Government on behalf of Australian Capital Territory, New South Wales, Queensland, South Australia, Victoria and Western Australia Governments.

A provider's Green Power sales cannot be used by a provider to meet its RET target. To ensure that Green Power sales are additional to legislated renewable energy purchases through the RET, Green Power product providers are required to transfer and voluntarily surrender an eligible REC for each MWh sold as part of a Green Power product within a settlement period. Approximately 9 million LGCs have been voluntarily surrendered to offset GreenPower obligations since the MRET scheme commenced.

GreenPower demand is added to the mandated target to get the total REC demand.

REC supply

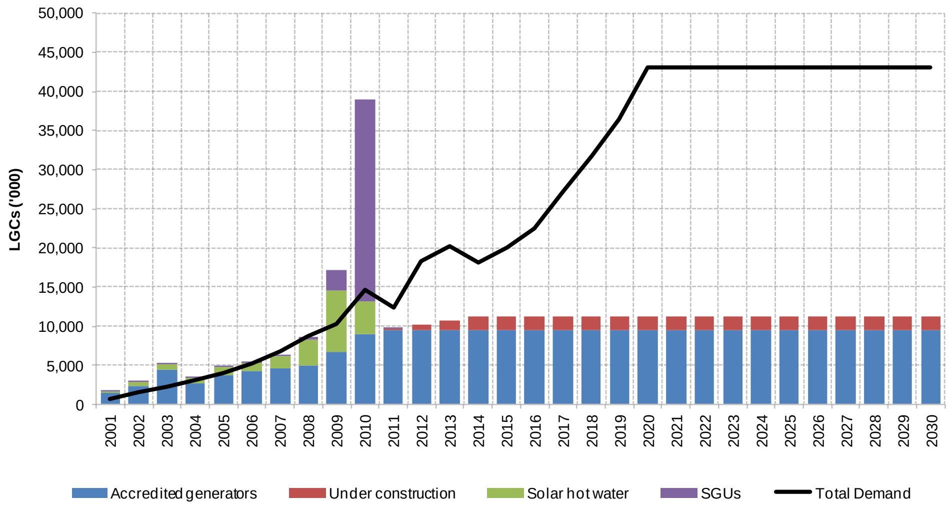
The means by which RECs are created under the RET scheme are categorised as follows:

- Accredited generators: these consist of the large renewable power stations and account for the bulk of LGC supply. Generators which were in existence prior to the commencement of the scheme are baselined.
- Small Generating Units (SGUs): relate to small scale generating units which generally sell RECs through an agent. SGUs installed to-date have generally been rooftop solar photovoltaic units, but a number of small scale wind and hydro units. RECs are created through deeming, either annually or for up to 15 years at a time. SGUs receive a REC multiplier under the Solar Credits Scheme commencing at 5 RECs per MWh, which is scaled back over time.
- Solar Hot Water (SHW): SHW units are generally residential units either traditional rooftop units of free standing heat pumps. Ten years worth of RECs are deemed to have been created upon installation of the unit.

With the split of the RET into the SRES and LRET, SGU and SHW installations will receive a fixed clearing house price of $40/STC and will be separated from the LRET from 1 January 2011. As such SGU and SHW installations after 1 January 2011 will have no bearing upon the outlook for LGC prices.

Figure 9 shows the LGC demand against actual and projected contributions from existing generators and SGU/SHW. The commencement of SRES in 2011 removes SGU/SHW from the supply mix from 1 January 2011. The gap between the assumed output from existing generators and the target from 2011 onwards represents the supply gap RECMark attempts to fill on a least cost basis.

Figure 9 **RET and assumed contribution from existing generators and SGU/SHW**



Note: Based on announced LRET target. Excludes CMM volumes.
Data source: ACIL Tasman, CER for historical data

Accredited generator new entrant database

ACIL Tasman maintains a comprehensive database of proposed renewable developments and assumed costs. The database comprises of around 230 specific and generic renewable projects across Australia. Projects include:

- Wind (approximately 130 sites comprising of 14,300 MW)
- Small-scale hydro
- Bagasse/biomass
- Geothermal
- Solar: PV, parabolic trough, linear Fresnel, parabolic dish).

Generic renewable costs have been developed as inputs to the model. For remote projects additional costs are assumed for transmission connection to the network.

Black energy prices

Black energy prices are an exogenous input into RECMark. These are taken from ACIL Tasman's *PowerMark* model. ACIL Tasman uses values for Western Australian and the Northern Territory derived from separate modelling of these systems.

Model Results

RECMark produces a number of useful results. The model produces a REC price projection to 2030 taking into account all inputs and constraints. It also estimates the range of plant that is likely to enter by technology type including any shortfall against the target, and the likely fuel mix in producing RECs.

Results can be easily produced for various policy and technology scenarios to consider the impact on REC prices.

The following reports are produced by RECMark:

- Overall scheme summary:
  - REC demand and supply, annual RECs created, surrendered and banked, REC shortfalls and penalties paid
  - REC price projection
- RECs created by fuel type: nationally and by State each year
- RECs created by individual generator: existing and new entrants each year
- New entrant capacity installed by generator by State each year
- Aggregate renewable capacity installed (existing and new entrant) by fuel type, by State each year
- Detailed new entrant project discounted cash flows detailing:
  - Project timing projected by the model
  - Costs: capital, fixed O&M, variable O&M
  - Revenues: black energy, REC and net revenues
  - Project NPV
- New entrant project NPV summary.