Estimated energy costs for 2013-14 retail tariffs

Estimated energy costs for use by the Queensland Competition Authority in its Final Determination on retail electricity tariffs for 2013-14

Prepared for the Queensland Competition Authority

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ACIL Tasman

Economics Policy Strategy

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1 Introduction

This report provides estimates of expected energy costs for use by the Queensland Competition Authority (the Authority) in its Final Determination on retail electricity tariffs for 2013-14.

The report considers the submissions made by stakeholders following the Authority's Draft Determination, *Draft Determination on Regulated Electricity Tariffs for 2013-14, February 2013* and a subsequent workshop where those submissions refer to the cost of energy in regulated retail electricity prices.

Retail prices generically consist of three components:

- network costs
- energy costs
- costs associated with retailing to end users.

This report is concerned with the energy costs component only. In accordance with the Ministerial Delegation (the Delegation) which is attached as Appendix A and the Consultancy Terms of Reference (TOR) provided by the Authority and which is attached as Appendix B, the methodology developed by ACIL Tasman provides an estimate of energy costs to be incurred by a retailer to supply customers on notified prices for 2013-14; i.e. non-market customers. Energy costs comprise wholesale energy costs, other energy costs associated with renewable energy incentives, market fees and ancillary services charges and transmission and distribution losses.

1.1 Background

In accordance with the Delegation and the TOR, ACIL Tasman is to provide expert advice to the Authority on the energy costs to be incurred by a retailer to supply customers on notified prices for 2013-14. We are required to have regard to the actual costs of making, producing or supplying the goods or services which in this case are the customer retail services to be supplied to non-market customers for the tariff year 1 July 2013 to 30 June 2014. In establishing the most appropriate methodology for undertaking this task, we have considered a range of approaches which might be used to estimate the wholesale energy cost component.

In the interest of clarity, in undertaking the task, ACIL Tasman has not been tasked to provide expert advice on:

- the effect that the price determination might have on competition in the Queensland retail market
- the Queensland Government uniform tariff policy

- time of use pricing
- any transitional arrangements that might be considered or required.

ACIL Tasman understands that these matters will be considered by the Authority when making its Determination.

In determining the question as to what constitutes the actual cost of making, producing or supplying customer retail services to customers supplied on notified prices, ACIL Tasman has taken a consistent approach with advice it provided to the Authority for the 2012-13 Determination, which was tested in the Supreme Court of Queensland and found to meet the requirements of the Act and Delegation.

1.2 Methodology

ACIL Tasman has considered the responses in written submissions to the Draft Determination and has decided to retain the same methodology for the 2013-14 Final Determination as was used for the Draft Determination. This methodology was also the methodology applied in 2012-13 with some refinements. These refinements to the methodology incorporate changes in response to some of the matters that have been raised by stakeholders and have been made as part of ACIL Tasman's ongoing development of the underlying methodology.

The approach adopted by ACIL Tasman simulates the wholesale energy market from a retailing perspective with retailers hedging the pool price risk by entering into electricity contracts with contract prices represented by the observable futures market data. Other energy costs are added to the hedged wholesale energy costs and the total is then adjusted for estimated network losses.

1.2.1 Pool modelling/price distribution

The pool price modelling involves developing hourly pool prices for 462 simulations of 2013-14 (42 historical weather years and 11 outage scenarios), using ACIL Tasman's electricity market simulator, *PowerMark*. These are used in conjunction with the retailer contracting model (also referred to as the hedge model) to estimate the annual wholesale energy costs (WEC) for each of the 462 simulations.

1.2.2 Electricity Hedging

The retailer contracting model is a simplified model of the actual contract market based on observable prices for base, peak and cap contracts. These building block contracts are used to develop a standardised contract strategy which is then used in conjunction with the 462 simulations of 2013-14 to estimate the WEC.

1.2.3 Other energy costs

Other costs are based on a building block approach as follows:

- Renewable Energy costs are based on legislated targets for the large-scale renewable energy target (LRET) and the most recently published data for the small-scale renewable energy scheme (SRES).
- Queensland Gas Scheme
- National Electricity Market (NEM) fees as published by AEMO
- Ancillary services based on recent historical costs
- A prudential cost allowance associated with obligations to AEMO.

2 Response to the submissions on the Draft Determination

2.1 Introduction

This section of the report responds to issues raised with respect to energy cost elements in submissions to the Draft Determination for 2013-14. Submissions raised a number of queries and made a number of suggestions for improvement of the methodology used for estimating energy costs. Most concerned the estimation of the WEC of which there were two major themes.

The first major theme related to questions with respect to the methodology for constructing the 42 simulated demand sets used in the modelling and WEC estimates (Queensland and Energex NSLP). A number of submissions attempted to demonstrate that the simulated demand sets did not cover the full range of possible outcomes for 2013-14 as was intended and in particular, under represented the number of high demand outcomes associated with extreme weather and plant outage events. The main thrust of this criticism was to demonstrate that extreme demands were under represented and thereby modelled spot prices were lower than they should be.

The second major theme was that a wider range of hedging instruments should be used in estimating the WEC. The arguments in favour of a wider range of instruments considered basing the WEC estimates on one type of market hedging instrument did not fully capture the actual cost of energy borne by retailers. It was argued that other forms of hedging including power purchase agreements (PPAs) and retailer owned generation were legitimate hedging instruments and their actual costs should also be included.

Following a full and careful consideration of the various criticisms and suggestions provided in the submissions, ACIL Tasman has not been persuaded to change the method for estimating hedging costs that was used in the Draft Determination.

2.2 General comments on the submissions

Before considering specific matters raised in the submissions, we have provided a number of general comments on the results derived by applying the ACIL Tasman methodology. These results demonstrate that there is a wide range of pool price simulated outcomes which we are satisfied covers the expected range of outcomes over the period 2013-14. Clearly demand is a critical input to the modelling and we take great care in establishing appropriate demand sets. These general comments show that the demand sets used in the analysis, along with the other key assumptions, have produced what we regard as a satisfactory range of pool price simulated outcomes.

In addition to the pool price simulation results, the effect of hedging on the WEC is also considered. The benefits of hedging (buying) are inversely correlated with pool prices. The hedge strategy employed in the methodology ensures that in most periods, the NSLP demand is fully covered by hedges. In general, higher pool prices are linked to periods of higher Queensland demand, all other things being equal. In hedging the NSLP, the critical factors are the correlation between the Queensland and NSLP demand traces. The maximum NSLP demand, which has been the focus of a number of submissions, generally occurs outside the periods of extreme simulated Queensland demand/price. Given the lack of correlation between extreme prices in Queensland and the NSLP peak demand, the absolute estimate of the NSLP peak demand has negligible effect on the WEC estimate.

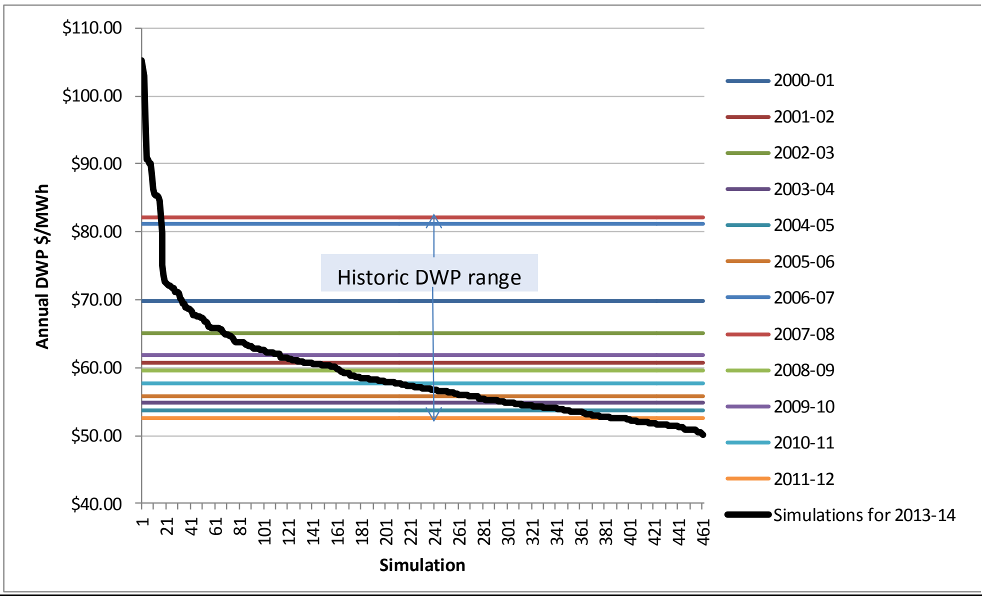
These matters are covered in some detail in the following sub-sections.

2.2.1 Queensland pool prices

The annual demand weighted pool prices (DWP) for Queensland from the 462 simulations range from a low of $50.20/MWh to a high of $105.20/MWh. This compares with the lowest recorded Queensland DWP in the last 12 years of $52.54/MWh in 2011-12 to the highest during the drought year of 2007-08 of $82.19/MWh (includes an assumed carbon pass through of 90%).

Figure 1 compares the Queensland DWP for the 462 simulations for 2013-14 with the Queensland DWPs from the past 12 years. Although there have been changes to both the supply and demand side of the market, it clearly shows that the simulations cover a noticeably wider range in potential prices for 2013-14 than has occurred in the past 12 years of history. In fact the top 16 simulations (3.5% of all simulations) exceed the highest DWP yet recorded - keeping in mind the annual DWP of 2007-08 was partly the result of the millennium drought conditions. ACIL Tasman is satisfied that in an aggregate sense the distribution of the 462 simulations for 2013-14 cover an adequately wide range of possible pool price outcomes for 2013-14.

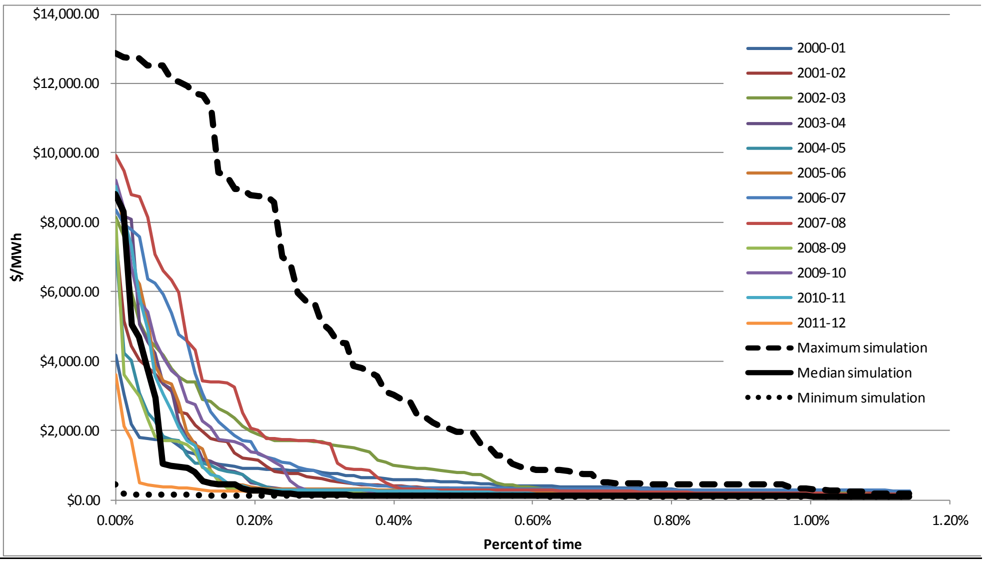
Figure 1 **Annual DWP for Queensland for the 462 simulations for 2013-14 compared with the annual DWP recorded in past years**



Note: The historic DWPs assume a 90% pass through of the carbon price of $24.15/tCO2-e.
Source: AEMO historic pool price data and ACIL Tasman results from PowerMark modelling

Comparing the upper 1% of hourly prices in the simulations with historical spot prices shows the spread of the prices from the simulations also easily covers the spread of spot prices historically. For this upper tail we have not made any adjustment to the historic prices for carbon pricing (the effect would be expected to be negligible). The comparison is illustrated in Figure 2 which clearly demonstrates that range of upper 1% of prices from the 462 simulations for 2013-14 easily encompasses the range of historic prices. It is also notable, that as would be expected, the distribution of simulated price outcomes demonstrates a strong positive skewness.

Figure 2 **Comparison of the upper tail of the price duration curve for the past 12 years compared with the spread from the 462 simulations of 2013-14**



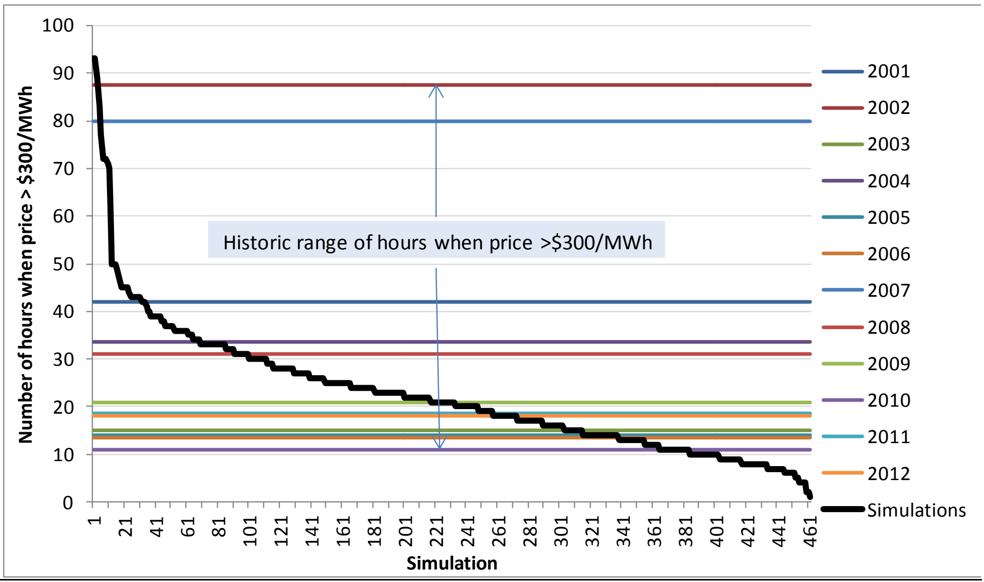
Source: AEMO historic pool price data and ACIL Tasman results from PowerMark modelling

ACIL Tasman is satisfied the Queensland pool prices from the 462 simulations cover the range of expected price outcomes for 2013-14 both on average and in the upper tail. These comparisons clearly show that the 42 simulated demand traces combined with the 11 plant outage scenarios provide a sound basis for modelling the expected future outcomes for 2013-14.

2.2.2 Prices over $300/MWh

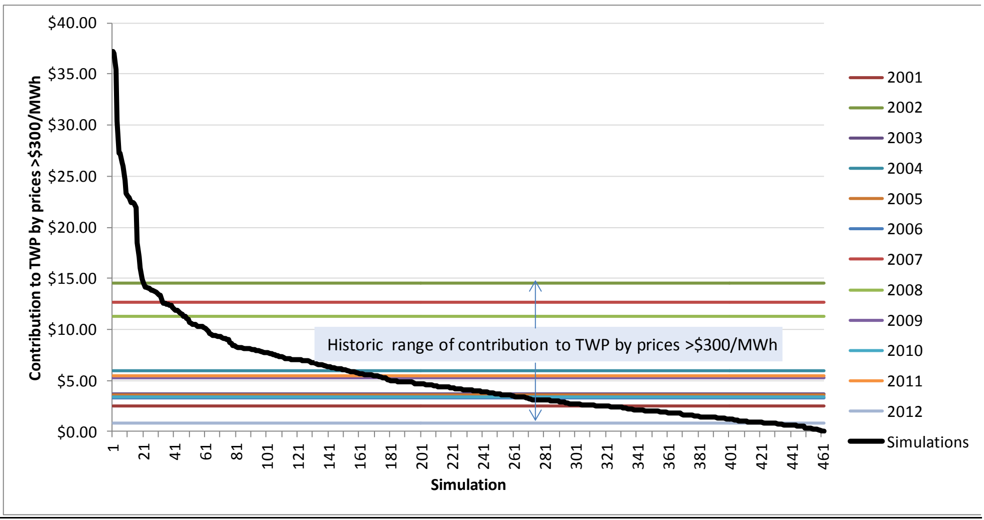
ACIL Tasman is also satisfied that its proprietary market model *PowerMark* has performed adequately in capturing the extent and level of the high price events based on the demand and outage inputs for the 462 simulations. Figure 3 shows that the number of hours when the price is above $300/MWh captured in the modelling of the 462 simulations compares favourably with history. Furthermore, the range in annual average contribution to TWP of prices above $300/MWh for the 462 simulations is consistent with those recorded in history as shown in Figure 4.

Figure 3 **Number of hours when prices are above $300/MWh in the modelled simulations and recorded in the past**



Source: AEMO historic pool price data and ACIL Tasman results from PowerMark modelling

Figure 4 **Annual average contribution to the TWP by prices above $300/MWh in the modelled simulations and recorded in the past**



Source: AEMO historic pool price data and ACIL Tasman results from PowerMark modelling

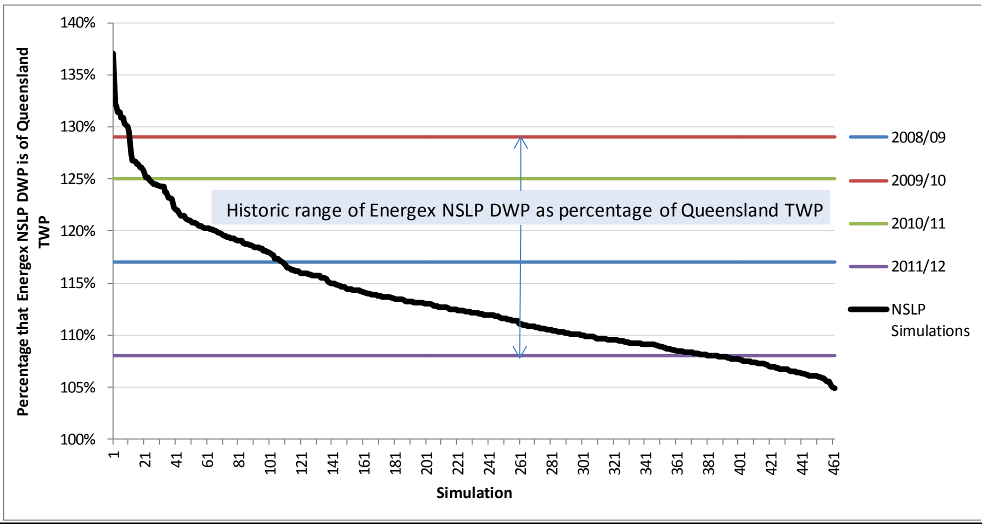
2.2.3 Cost of supplying the Energex NSLP

There have been suggestions in a number of retailer submissions that the Energex NSLP peak demand is too low which in turn is presumed to lead to a lower cost to supply the NSLP. However, the maximum demand of the NSLP is not in isolation a critical feature in determining the cost of supply. As discussed at the beginning of Section 2.2 above, it is the shape of the NSLP demand trace and its relationship to the shape of the Queensland demand trace which is critical to the cost of supplying the NSLP demand. The summer maximum demand for the NSLP occurs in the evening while the Queensland summer demand peaks occur earlier in the afternoon. This means that the peak of the NSLP is unlikely to be coincident with extreme price events due to the afternoon Queensland peak. Furthermore, using past data as a guide, the annual peak of the NSLP could well be in winter which has a different set of characteristics and relationship to price.

A test of the appropriateness of the NSLP demand shape and its relationship with the Queensland demand shape can be undertaken by comparing the annual DWP for the Energex NSLP with the Queensland time weighted pool price (TWP). Figure 5 shows that, for the past four financial years, the DWP for the Energex NSLP as a percentage of the Queensland TWP has varied from a low of 108% in 2012/13 to a high of 129% in 2009-10. In the 462 simulations for 2013-14 this percentage varies from 105% to 137% which more than covers the recorded range. The higher simulated percentages are associated with simulations where there is a higher correlation between the Queensland pool price and the Energex NSLP demand.

The comparison with actual outcomes over the past four years in Figure 5 demonstrates that the relationship between the Energex NSLP demand and Queensland pool prices in the 462 simulations is sound. Further, the cost of supplying the Energex NSLP in the simulations relates well to the Queensland pool price and covers the full range of possible outcomes for 2013-14. It also provides a sound cross check on the shape of the NSLP demand and its relationship with the Queensland demand.

Figure 5 **Annual DWP for the NSLP as a percentage of the annual TWP for Queensland for each of the 462 simulations and as recorded in the past four years**



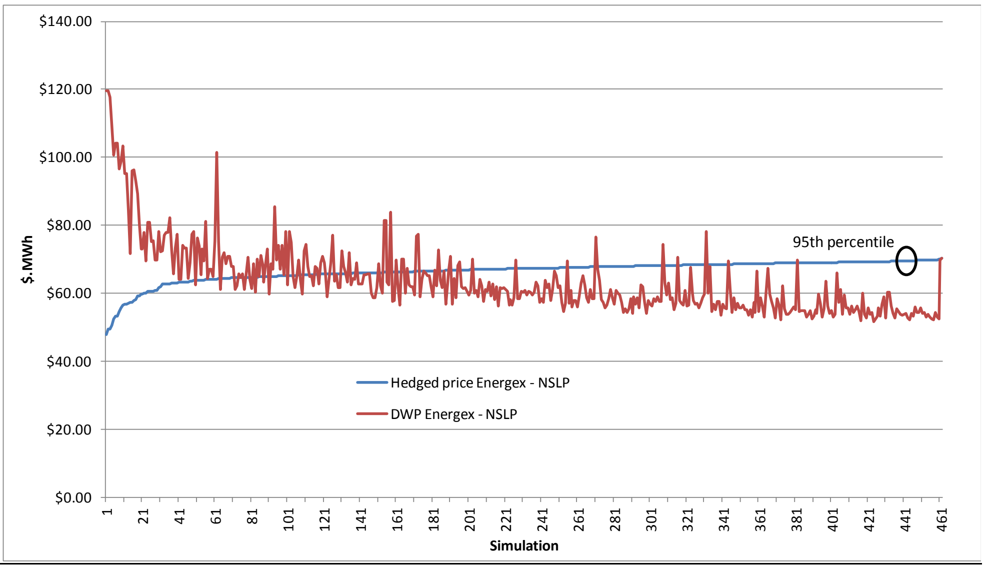
Source: AEMO historic pool price data and ACIL Tasman results from PowerMark modelling

2.2.4 The effects of hedging

The ACIL Tasman methodology used a simple hedge book approach based on standard quarterly base and peak swaps and caps. The prices for these hedging instruments are from the futures market and supplied by d-cypha Trade.

As hedge benefits are inversely related to pool prices, in general, simulations with higher demand weighted pool prices, produce lower hedged prices. Figure 6shows that, under the ACIL Tasman methodology, the higher estimates of supply costs including hedge effects are not associated with high demand and high pool price years. This is because, the benefits from the hedge strategy used in the methodology dominate the pool prices such that the higher hedged prices are generally related to the lower pool price simulations and vice versa.

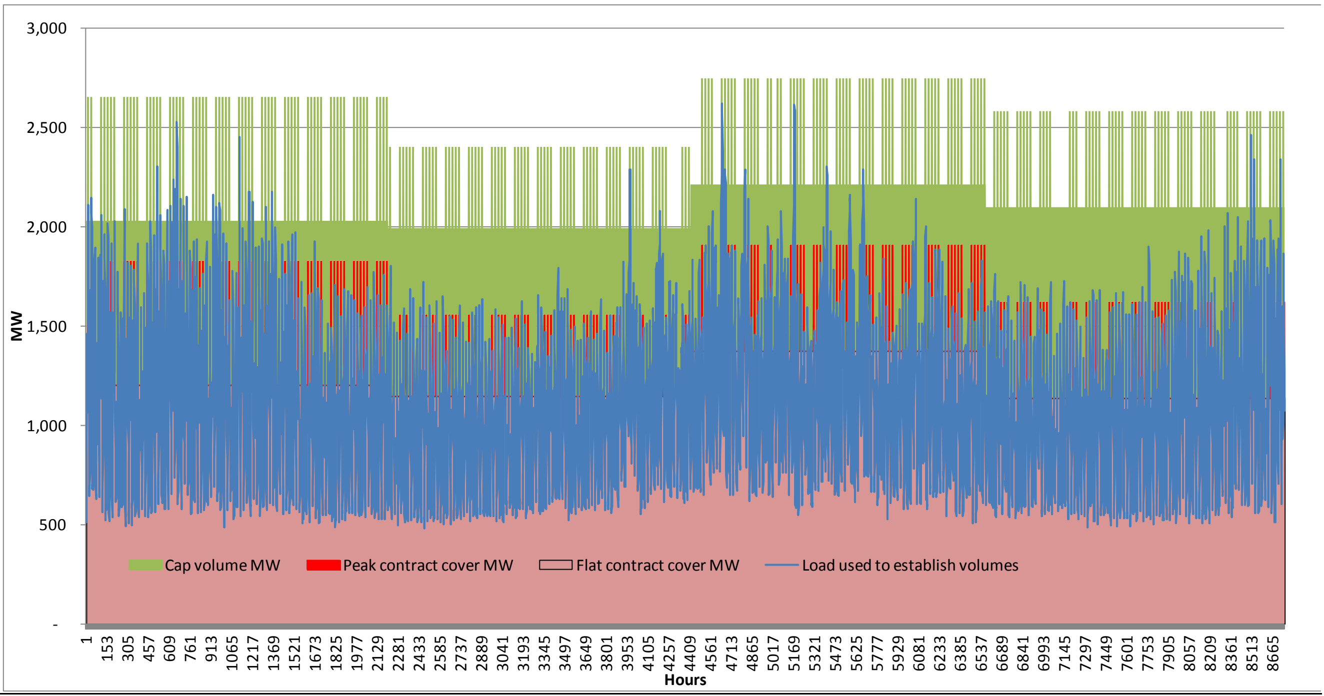
Figure 6 **Annual hedged and DWP for Energex NSLP for the 462 simulations ($/MWh)**



Data source: ACIL Tasman modelling

Contract volumes are calculated by applying the hedging strategy to a simulated demand trace which has a peak demand and annual energy very close to the 50% POE peak demand and energy forecast and has an annual demand weighted price for Queensland very close to the median demand weighted price across all 462 simulations. Once established, these contract volumes are then fixed across all 462 simulations when calculating the wholesale energy cost. The contract volumes used are shown in Figure 7. These contract volumes are available from the Authority's website as part of the Draft Determination.

Figure 7 **Contract volumes used in the hedge modelling of the 462 simulated years for 2013-14**



Source: ACIL Tasman

Contract volumes are calculated for each settlement class by assuming the following for each quarter:

- Base contract volume is set to equal the 80th percentile of the off-peak hourly demands for the quarter.
- Peak period contract volume is set to equal the 90th percentile of quarterly peak period demands minus the base contract volume.
- Cap contract volume set at 105 per cent of the quarterly peak demand minus the base and peak contract volumes.

Detailed results of the hedged modelling for three of the 462 simulations using the contract volumes shown in Figure 7 are shown in Table 1. The three simulations are intentionally chosen to demonstrate the inverse rrelationship between pool prices and hedge price outcomes.

Table 1 **Hedge modelling results for highest and lowest DWPs and for the 95 percentile of hedged prices for the Energex NSLP**

Description	Units	Selected simulations for Energex NSLP for 2013-14		
		Highest NSLP demand weighted pool price	Lowest NSLP demand weighted pool price	95th percentile of NSLP hedged prices
Queensland				
Peak demand	MW	9,054	9,020	8,868
Annual energy	GWh	54,171	53,298	53,242
Load factor	%	68.30%	67.45%	68.54%
Time weighted pool price	$/MWh	$91.08	$49.17	$50.53
Demand weighted pool price	$/MWh	$105.20	$50.20	$51.99
Number of hours above $300/MWh	Number	89	1	14
Average price for hours above $300/MWh	$/MWh	$3,960.54	$446.51	$811.65
Energex NSLP				
Summer peak demand	MW	2,515	2,430	2,323
Annual energy	GWh	9,656	9,492	9,502
Load factor	%	43.84%	44.59%	46.69%
Demand weighted pool price	$/MWh	$119.68	$51.56	$54.56
Total pool costs	$m	$1,155.62	$489.38	$518.45
Hedging of Energex NSLP				
Volume flat swaps	GWh	10,655		
Volume peak swaps	GWh	1,956		
Average caps	MW	868		
Cost of flat swaps	$m	$616.52		
Cost of peak swaps	$m	$135.37		
Cap premiums	$m	$47.43		
Swap difference payments	$m	-$464.81	$120.85	$99.86
Cap payments	$m	-$275.57	-$0.12	-$6.01
Total cost after hedging	$m	$462.67	$657.54	$659.73
Cost of hedging	$/MWh	$47.92	$69.27	$69.43

Data source: ACIL Tasman assessments and modelling

From Table 1 it can be seen that the hedged volumes and cost of hedges are the same for all three simulations as the contract strategy is based on the same volumes and contract prices for all simulations.

There are a number of important observation which can be made about the information provided in Table 1:

- The simulation with the highest DWP is associated with highest peak demand and annual energy of the three simulations.
- The simulation which produces the 95th percentile of NSLP hedged prices is not a particularly high year for demand and energy at both Queensland and Energex NSLP levels and hence has a lower DWP.
- As expected the "Total pool costs" are very high for the simulation with the highest DWP ($1,155.6m) and lowest for the lowest DWP ($489.4m). For the simulation which produced the 95th percentile of the hedged prices the total pool costs were $518.4m - that is, towards the lower end of the simulated pool outcomes.
- After applying the hedging strategy the costs are very different with the simulation with the highest DWP having the lowest "Total cost after hedging " of $462.7 m (or $47.92/MWh) and the 95th percentile having the highest cost after hedging of the three of $659.7m (or $69.43/MWh) . This occurs because:
  - simulations with higher pool prices will have pool prices that are likely to be closer to, or to exceed, swap contract prices such that costs associated with over-contracting are less and payments on both the swap contracts are expected to be more favourable to the retailer
  - simulations with higher pool prices are generally associated with higher demands thereby lowering the level of over contracting in the simulations which again means that costs associated with over-contracting are less and payments on swap contracts are expected to be more favourable to the retailer
  - simulations with higher pool prices generally have a greater number and more extreme price spikes above $300/MWh which generally results in higher cap payments to the retailer.
- payments on swap contracts under the highest DWP simulation lead to a substantial reduction in pool costs (minus $464.8m) while payments under the other two simulations added to the pool costs (plus $120.8m and $99.9m).
- "Cap payments" under the highest DWP simulation reduce pool costs by a significant $275.6m compared with only $0.1m under the lowest DWP simulation and $6.0 in the 95th percentile of hedged costs simulation.

It is this interplay between contract prices and pool prices and contract volumes and estimated demands which explains why the 95th percentile of hedged prices is not correlated with the 95th percentile of pool prices. More specifically, this addresses the concern expressed in some retailer submissions as to the nature of pool prices and why there were so few pool prices greater than $300/MWh in the 95th percentile of hedged NSLP price simulations.

2.3 Inclusion of PPA and/or owned generation costs

A number of retailer submissions proposed changes to the methodology to take account of actual prices paid for long dated power purchase agreements (PPA) and/or to incorporate costs incurred in owning generation assets.

In our paper, provided in December 2012 in support of the QCA consultation process, ACIL Tasman recognised that retailers enter into a variety of hedging arrangements including PPA and physical generation options. The usefulness of considering generation options as hedging costs was considered in some detail with the conclusion being that using the face-value costs of these instruments had little merit. This is because generation investments are typically long dated and may have been committed some time ago. The nominal price in a PPA or the annualised historical cost of generation would reflect the value of the generation anticipated at the time of commitment, when the investor was faced with a variety of uncertain futures. Once an investment is committed, the costs are sunk. As time proceeds, the value of the generation asset is determined by the actual future that eventuates and may be quite different to the value expected at the time of commitment.

There are also usually additional benefits to a retailer owning a PPA or physical generation beyond any hedge benefits. These are likely to include some or all of the following:

- the right to dispatch the associated plant (the ability to vary the volume and price at which it is offered and by implication the ability to have some influence on the market price outcome including benefiting from price rises)
- the ability to profit from market price rises when there are substantial rises in new entrant capital costs (PPA costs are typically linked to the associated plant's sunk capital costs with or without indexing usually in some way linked to inflation) – as an example capital costs rose between 50% and 100% between 2004 and 2008 as commodity prices and labour costs rose significantly
- the ability to profit when rises in alternative fossil fuel costs occur – i.e. a gas fired plant benefits when rises in coal prices occur driving up electricity prices in the future and similarly a coal fired plant benefits when rises in gas prices occur
- in the case of gas fired plant which has much lower carbon intensities than coal fired plant, benefiting when carbon prices are introduced or rise as NEM price rises linked to carbon are expected to be dominated by coal fired plant over that period
- the bringing forward of the monetisation of own fuel resources that otherwise may have taken many years to market and sell.

As a consequence, ACIL Tasman considers that the likelihood of these historical costs reasonably representing the actual costs of supplying customer retail services to the premises of non-market customers would be largely a matter of coincidence.

ACIL Tasman recognises that retailers may choose to enter into non-standard hedging arrangements including bespoke hedges, PPAs and owned generation. However, the sunk cost of these arrangements does not, in ACIL Tasman's opinion, reflect the actual costs of making, producing or supplying customer retail services for the reasons summarised below.

- Electricity retailers supply customer retail services with electricity purchased through the NEM, and it is the cost of acquiring electricity through the NEM that is relevant in estimating retailer costs.
- PPAs and/or owned generation usually incorporate benefits to the owner beyond electricity price hedging which may explain some of the substantial differences in price compared with standardised hedging arrangements.
- Notwithstanding the other benefits that are likely to accrue to owners, PPAs and/or owned generation smooth the variation in prices over the investment cycle and it would be largely a matter of coincidence if the prices specified in PPAs or the annualised costs of owned generation reflected the market value of hedges in any particular year.
- As PPAs and/or owned generation are invested *ex ante* over long time frames and are subject to the risk of alternative futures, the PPA price or annualised cost of generation may be a poor indicators for the plant's current market value and once other benefits are considered is unlikely to reflect the cost of hedging electricity in a particular year when engaged in supplying customer retail services.
- Some PPAs and/or owned generation may be inefficient investments and in such cases the PPA price or annualised cost of generation is likely to be an even poorer indicator for the plant's market value and once other benefits are considered is even more unlikely to reflect the cost of hedging electricity in a particular year when engaged in supplying customer retail services.

2.4 Futures contracts representing hedging costs

Origin Energy again noted that that not all electricity contracts are traded through the futures market and if they were, that substantially higher price outcomes are likely to eventuate because of the increased demand.

As stated in our report accompanying the Draft Determination, ACIL Tasman does not agree with this contention. If more contracts were purchased through the futures market, then this implies existing supply that is meeting that demand currently through bilateral[1] or over-the-counter (OTC)[2] trading would move to provide supply through the futures market. The increased supply would offset the increased demand and all other things being equal, price would be expected to largely be the same.

2.4.1 Contract liquidity

Origin energy has stated that there is insufficient liquidity in elements of the Queensland the futures market to provide a robust and accurate estimate of contract prices.

Our response remains the same as in our report for the Draft Determination where we noted that liquidity is an issue in all of the electricity contract markets. However, based on the volumes traded in the futures market for the year in question, we are satisfied that sufficient liquidity exists to promote efficient arbitrage should prices move significantly out of kilter in each of the contract markets.

2.4.2 Inconsistency between hedging and pool price modelling

Some submissions suggest that using only futures contracts in the hedging model but including the volumes associated with PPAs in the pool modelling demonstrates an inconsistency in our approach (and specifically results in lower pool prices). It has been suggested that either the costs of the PPAs be included in the hedge model or that the volumes associated with PPAs be ignored within our pool modelling so as to ensure consistency between the two modelling aspects of our methodology.

ACIL Tasman disagrees with the conclusion that there is an inconsistency between the two models. The pool modelling incorporates all contract volumes as they have a material effect on the behaviour of generators in the spot market. The contract market does not ignore the PPA volume, rather it quite appropriately values the hedging benefits of PPAs and owned generation at the observable market price, i.e. the price at which hedges backed by PPA or owned generation would be expected to be transacted if they were offered to the market.

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1 Between individual parties and may be bespoke in nature.

2 Normally relatively standard products traded through brokers.

2.5 Development of State and NSLP demand traces

A number of suggestions regarding the estimation of the various demand traces has been made by retailers. The general thrust of the comments are that the demand traces are too low and under represent the upper tail of demands.

As discussed in Section 2.2 and shown in Figure 1 to Figure 5 the pool price outcomes from the demand traces developed by ACIL Tasman when modelled with the 11 outage scenarios, provides a wide range of possible pool price outcomes for 2013-14. The distribution of these price outcomes is shown to be consistent with past experience and provides a good representation of the potential upper tail of possible pool price outcomes for 2013-14. This information has been presented to demonstrate that while the simulated demand traces for the State and NSLP are important, the price formation process is also affected by other important considerations such as outages and other factors.

Were demands to be increased then, all other things being equal, pool prices would be higher and price spikes above $300/MWh more frequent. However, given the negative correlation between pool prices and hedged benefits in the ACIL Tasman methodology, higher demands and pool prices are likely to result in lower overall hedged prices (see Section 2.2.4).

The comments on development of the demand traces for 2013-14 covered a variety of aspects including that:

- peak demands for Queensland from simulations do not match the AEMO demand forecast
- extreme demand events are not covered
- peak demands for the Energex NSLP are lower than in 2009-10
- consecutive hot days are not well enough accounted for in the demand traces
- the three base years used to construct the other 39 demand traces are subdued demand profiles which means they do not incorporate sufficient variation and under represent high demands
- overall peak demand across the 42 simulated demand traces for Queensland should exceed the AEMO 10% POE demand forecast which is a 1 in 10 year peak demand not a 1 in 42 years
- peak demand for the NSLP is not affected by the installation of PVs or economic growth

- greater weighting should be given to Brisbane and Sydney temperatures when undertaking the matching process to derive the simulated demand traces.

While many of these issues were raised following the initial workshop in December 2012 and were addressed in our report for the Draft Determination, each in turn are briefly discussed in the following sub-sections.

2.5.1 Peak demands for Queensland from simulations do not match the AEMO demand forecast

In its submission AGL noted that the 10%POE, 50%POE and 90%POE peak summer demands for the Queensland system peak in 2013-14 used in our analysis are not identical to the corresponding peak demand parameters for the low growth forecast published by AEMO in the 2012 National Electricity Forecast Report (NEFR).

The following explains the reason for this difference:

- AEMO develop the peak demand forecasts as if there was no impact (reduction) due rooftop solar PV and then estimate the penetration of rooftop solar PV and make an assumption about the amount of output from rooftop solar PV that is then deducted from the peak demand forecasts.
- AEMO in their document titled, *Rooftop PV Information Paper 2012*, note the peak demand in summer in Queensland occurs between 12:30pm and 17:30pm.
- During this time of day, AEMO estimate that solar PV output is between 3% and 62% of capacity (62% near midday and 3% at 5:30pm).
- AEMO state in the same paper they assume the peak demand occurs that 4pm and that the output from the installed rooftop solar capacity is 28%.
- For summer 2013-14 AEMO assume 600MW of solar PV is installed, which at 4pm equates to 168MW of output (0.28 * 600) which is deducted from their peak demand forecasts for summer. AEMO assume the same output from rooftop solar PV (and hence the same reduction to demand) when estimating each of the 90%POE, 50%POE and 10%POE peak summer demands for 2013-14[3].
- In the 42 Queensland demand sets generated using the ACIL Tasman methodology, the annual peak summer demands also occur between 12:30pm and 17:30pm - consistent with AEMO's finding. However, as we use historical weather years to generate the 42 demand sets, there is nothing

[3] It should be noted that the AEMO solar PV installed projection is lower than QCA's own projection but ACIL Tasman has retained the AEMO solar PV installed projection to ensure consistency.

in our methodology to force the 10%POE, 50%POE and 90%POE peak demands (or any of the annual peak demands for that matter) to occur at 4pm.

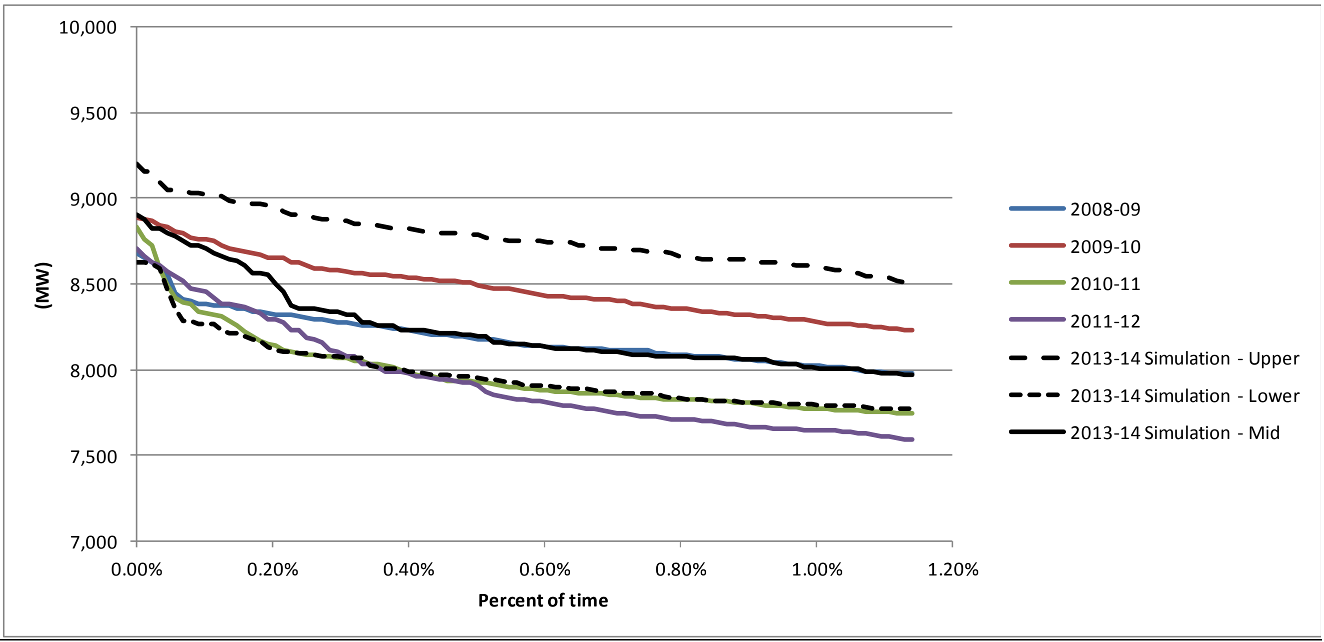
- Therefore, the amount of solar PV output deducted from each peak demand depends on the time of day that the peak demand occurs. For example, a peak demand at 2:00pm would experience a reduction due to solar PV output of around 300MW - about a 50% reduction rather than 28% (or 168MW) reduction simply due to a difference in timing of the peak.

2.5.2 Coverage of extreme demand events

Some submissions expressed concern that the methodology results in an under representation of extreme demand events. Given that the ACIL Tasman methodology uses the AEMO peak demand forecast as its basis, we are satisfied that extreme demand events are represented for the Queensland demand sets.

Figure 8 plots the upper 100 hour segment of the demand duration curves for three of the 42 simulated Queensland demand sets resulting from the methodology. The three demand sets in the graph represent the upper, lower and middle of the range of demand duration curves across all 42 simulated sets. Included for reference are the demand duration curves for the actual demands for 2008-09 to 2011-12. It can be seen that the demand duration curves of the simulated demand sets for 2013-14 not only envelope the recent historic demand duration curves, but demonstrate that the difference between the maximum and minimum of the envelope is about 700MW across the top 100 hours - that is, the variation between the simulated demand sets does not just occur at the single peak annual demand but across a reasonable portion of the demands within the given simulation. This variation in demand contributes to the variation in modelled pool price outcomes already discussed in Section 2.2.

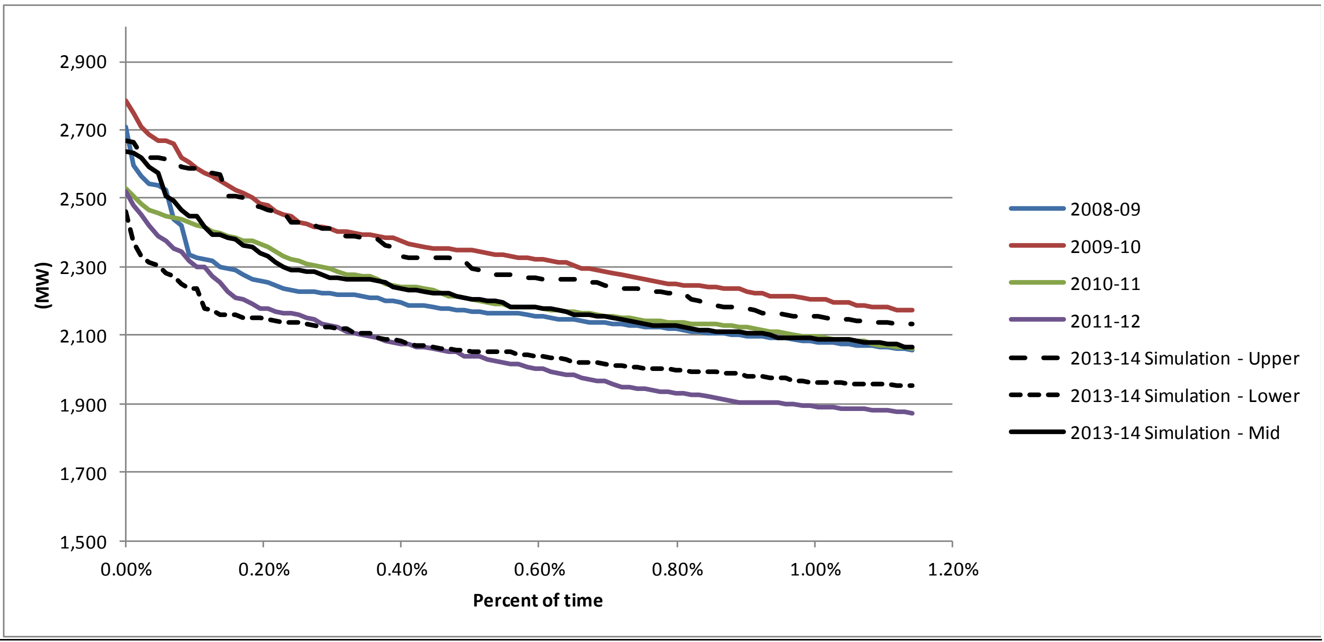
Figure 8 **Top 100 hourly demands - Queensland**



Note: Data for 2008-09 to 2011-12 includes top 200 half hourly demands.
Source: ACIL Tasman analysis and AEMO data

Similarly, Figure 9, shows the variation in the simulated Energex NSLP demand sets envelopes recent outcomes and covers a range of about 250MW across the top 100 hours.

Figure 9 **Top 100 hourly demands - Energex NSLP**



Note: Data for 2008-09 to 2011-12 includes top 200 half hourly demands.

Source: ACIL Tasman analysis and AEMO data

2.5.3 Peak demands for the 2013-14 Energex NSLP are lower than actual of 2009-10

Concern was also raised that the resulting peak demands for the Energex NSLP are less than the 2009-10 levels.

As noted in the ACIL Tasman report for the Draft Determination, there has been a fundamental change in the NSLP profile since 2009-10 - with a general decline in the overall profile. The top end of this decline is evident in Figure 9 above. However, the decline occurs across all parts of the demand profile and it can be concluded that the decline is a result of factors other than different weather patterns. This is likely to include slower economic activity, increased penetration of rooftop solar PV installations, and demand associated with larger customers 'exiting' the NSLP and moving to interval metering arrangements.

Further, since the publication of the Draft Determination, demand data for the summer of 2012-13 is now available. The Energex NSLP peaked at 2,346MW at 6:30pm on Tuesday 4 December 2012. Temperature in Brisbane peaked at 37.9 degrees on 4 December 2012.The median annual maximum temperature in Brisbane over the past 42 years is 35 degrees. Taking into account possible regional differences in temperature within the Energex distribution area, it would not be unreasonable to assume that 4 December 2012 represents something close to a 50% POE temperature outcome. The median peak demand for the Energex NSLP for 2013-14 based on our methodology is 2,487MW. The latest available demand data does not support the assertion that the methodology is underestimating the peak demand for the Energex NSLP.

2.5.4 Consecutive hot days

The methodology for developing the demand traces incorporates the last 42 years of temperature data to establish the 42 annual demand traces. These 42 annual demand traces are combined with 11 outage scenarios to create the 462 annual simulations used in estimating the WEC. The occurrence of hot days in the various demand traces reflects the historical distribution of such days over the last 42 years. As a consequence consecutive hot days are reasonably reflected in the demand traces used in the modelling.

2.5.5 Using the past three years of demands to generate the 42 simulated demand sets

Submissions suggested that given the weather and demand in the three base years (2009-10 to 2011-12) used to construct the 42 simulated demand sets are subdued, the resulting simulated profiles do not incorporate sufficient variation and under represent high demands.

The Figure 8 and Figure 9 in Section 2.5.4 show quite clearly that there is reasonable variation in demand outcomes for Queensland and the Energex NSLP. Further, the graphs in Section 2.2 show the adoption of the simulated demand sets in the pool modelling results in a reasonable spread in pool price outcomes.

Submissions also questioned why ACIL Tasman recommended using 10 years of past data for developing the demand forecast for the Energex Network Management Plan in 2012 but uses three years of data in its work for the QCA.

The requirements of the Energex work is substantially different to those of the work being undertaken for the QCA - to the point where it is difficult to draw any meaningful comparison. The methodology developed for Energex was based on the requirement to estimate the annual peak demand, and its distribution (which occurs in summer) over a 10-year projection period. The Energex process estimates a single annual peak demand and does not include estimating hourly demand traces. When projecting longer term forecasts it is usual to consider longer term trends in the drivers on demand - hence the recommendation to use the past 10 years of data for the Energex forecast.

ACIL Tasman is not producing a long term forecast of the Queensland peak demand for the QCA work; instead it is relying on and using the forecast of peak demand as provided by AEMO (which no doubt also is based on a longer term analysis).

2.5.6 Overall peak simulated for 2013-14 should exceed the AEMO 10%POE peak demand

Some submissions suggested the overall peak demand for Queensland across the 42 simulated demand sets should exceed the AEMO 10% POE demand forecast which is a 1 in 10 year peak demand not a 1 in 42 year peak.

ACIL Tasman acknowledges that this is a limitation in the methodology. But the key question is whether changing this aspect of the methodology would make a difference to the projected pool price outcomes?

The overall peak demand is a single instance or representation of the state of the market . Increasing it, but maintaining the overall level of energy (AEMO assume the same level of energy for each of the 90%POE, 50%POE and 10%POE peak demand scenarios) would require a reduction in demand at some other point of the demand distribution - and this reduction is likely to occur in the upper part of the distribution. So simply increasing the overall peak demand does not necessarily guarantee higher priced outcomes across all 42 simulated demand sets and certainly does not guarantee a higher price for the 95th percentile of the hedged prices simulation.

In any case, the increase in demand beyond the 10%POE level would need to be estimated and is likely to be just as contentious. ACIL Tasman has analysed the relationship between temperature outcomes and demand in previous engagements for other clients and found a softening of the demand response to an increase in temperature when temperature exceeds 35 degrees. Put simply, at 35 degrees the majority of air conditioning demand is likely to be activated and beyond 35 degrees variations in demand levels are a function of the timing of the cycling of air conditioning demand and regional variations in temperature within the state.

Further, given that the various TNSPs and AEMO as part of transmission network planning exercises do not project or report peak demand above the 10%POE suggests that there is an expectation that the increase in demand beyond the 10%POE is not substantial. Otherwise TNSPs would be concerned of under representing extreme outcomes and their associated consequences on the network.

2.5.7 Peak demand for the NSLP is not affected by the installation of PVs or economic growth

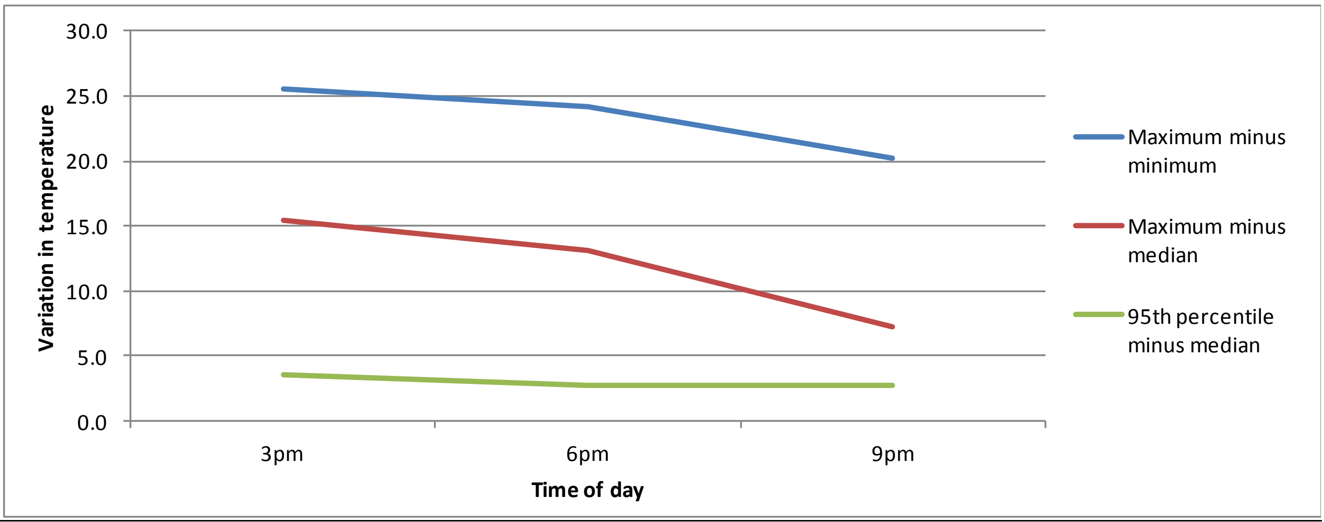
Submissions suggested that the ACIL Tasman report for the Draft Determination concluded that the installation of solar PV has impacted the annual peak demand for the Energex NSLP.

The increased solar PV penetration has changed the shape of the NSLP so that the peak demand now occurs typically around 7pm in summer, compared with about 3pm-4pm had there been no take up of rooftop solar PV. ACIL Tasman readily agrees given the annual peak now occurs at 7pm that further installation of solar PV will not reduce the annual peak demand.

However, solar PV is reducing NSLP demand across the Queensland peak periods - particularly during times of the day when prices tend to spike. Although prices can, and do, spike at 7pm, when the NSLP is peaking, there is a higher propensity for price spikes between 12 noon and 5pm - the time at which the Queensland demand tends to peak. So the continued penetration of solar PV is reducing NSLP demand at the time that price volatility tends to be greatest.

Further, the increased penetration of solar and corresponding move of the NSLP peak from around 4pm to 7pm means that the NSLP is peaking during the time of day when there is less variation in temperature outcomes. The graph below shows that when analysing temperature data for the summers of 1970-71 to 2011-12 the variation in temperature outcomes diminishes when moving from 3pm to 6pm to 9pm. Hence it is not surprising that the move of the NSLP peak to 7pm reduces the variation in the annual NSLP peak demand across the 42 simulated demand sets.

Figure 10 **Variation in Brisbane temperature at 3pm, 6pm and 9pm - across the summers of 1970-71 to 2011-12**



Data source: ACIL Tasman analysis of BOM data

2.5.8 Greater weighting should be given to Brisbane and Sydney temperatures in selection of days.

Energy Australia suggest that greater weight be given to the Sydney and Brisbane temperature profiles when undertaking the matching process to develop the weather influenced demand sets. The basis of the suggestion seems centred on the concern that the temperatures of the southern states may be closely correlated, but loosely correlated with Brisbane, thereby possibly resulting in unreasonably high or low demands in Queensland (and hence prices).

ACIL Tasman is modelling the entire NEM not just the Queensland and NSW regions of the NEM in isolation, therefore it is important to retain our standard approach in order to avoid introducing bias. In any case, the issue is largely negated by the underlying demand forecast to which the demands are scaled.

2.6 Queries on pool price modelling

2.6.1 Transmission constraints and hourly settlement

Origin Energy expressed concern that the pool price modelling does not allow for intra-regional transmission constraints which were the main cause of the high Queensland prices in January 2013.

As we responded to this query in our report for the Draft Determination, any model is, by definition, a simplification of the real word - whether it be heuristic, deterministic or statistical. ACIL Tasman considered the potential impact of inter-regional transmission constraints on market outcomes when developing *PowerMark*. However, there is a balance to be struck between over specifying the model and model accuracy. ACIL Tasman regularly tests the accuracy of *PowerMark* by undertaking back casting exercises and continues to be satisfied that the model is fit for purpose.

We repeat that the transmission constraints referred to by Origin will be alleviated when Powerlink completes construction of the Calvale to Stanwell 275kV line augmentation in 2013 (according to information in the December 2012 newsletter from Powerlink[4]).

Origin also suggested that by modelling on an hourly basis and the results needed to be checked against historic levels. ACIL Tasman is satisfied that its pool price modelling is producing a range of price outcomes which are consistent with historical volatility and adequate for the purpose of estimating wholesale energy costs in 2013-14.

2.6.2 Release of detailed modelling results

Stanwell Corporation and EnergyAustralia have requested that more information on the modelling assumptions and results be released such as individual plant capacity factors, interconnector flows, monthly peak and off-peak prices, etc. as this in their view would allow proper scrutiny of the results.

ACIL Tasman modelling of the NEM is routinely informed by analysing the actual bidding behaviour of market participants and by back casting exercises which are undertaken on a regular basis to test the validity of *PowerMark's* mechanisms as well as the underlying assumptions and continues to be satisfied that the model is fit for purpose. Furthermore, the range of pool prices from the modelling of the 462 simulations for 2013-14 described in Section 2.2 indicated that a very wide range of possible outcomes have been considered in the assessment of WEC for 2013-14.

ACIL Tasman has assessed the information already released on the 462 simulations and believes that it is adequate for participants to assess the results.

2.7 Cost of shaped hedges

Qenergy has stated:

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4 http://www.powerlink.com.au/Projects/Central/Documents/Calvale_Stanwell/Community_Update_-_December_2012.aspx

> On the other hand, if a retailer had been at least partially hedged using reallocated load-following hedges, the impact would have been significantly mitigated (particularly if the retailer were over reallocated). For this reason, a retailer will logically pursue this hedging strategy, despite it causing them to incur higher costs. This element is not costed into the d-Cypha hedge approach, and is one of a number of examples demonstrating that ACIL's simplified approach to hedging does not include all costs.

ACIL Tasman has previously noted that as a load following contract by definition has less residual pool risk than standard contracts, it may be expected to have a higher price than the expected price of a strategy with residual pool risk. Otherwise the seller of the load following contract is taking on additional risk for no expected benefit. ACIL Tasman also notes that buyers may pay large premiums for load following contracts, because while they are attractive to retailers, they are potentially very costly to sellers in terms of capacity to sell other hedge products.

We have calculated the ACIL Tasman hedging strategy cost using standard d-cypha Trade hedges (i.e. base, peak and cap) to cover the Energex NSLP for a sample of simulations including the 95th percentile case. The cost of hedging across the sample ranges from 1.44 to 1.47 times the d-cypha Trade base contract price.

ACIL Tasman also notes that the cost of reallocation avoids the cost to a retailer of providing prudential obligations to AEMO. ACIL Tasman, in Other Costs, have separately made an allowance for some prudential costs to AEMO.

2.8 Including a forward volatility premium

Ergon Energy have argued for a forward volatility premium to be added to the WEC to reflect hedge price uncertainty between the time that modelling is completed and the time when retailers might finalise their hedge arrangements for each quarter of 2013-14. The futures contracts used in the methodology would be expected to include the option value associated with the length of time to expiry. Therefore in our view the methodology already reflects any volatility premium.

2.9 Queensland Gas Scheme

The QCOSS Energy Consumer Advocacy Project could see no basis for extending the period for calculating the GEC price.

As stated in our report for the Draft Determination, we continue to use a period of four years because there is no volume data available for GEC trades. ACIL Tasman understands from anecdotal evidence that trade volumes for GECs have fallen significantly in the past two years or so and therefore extending the period of time to estimate the costs of GECs is in our view appropriate.

This scheme is to be discontinued on 1 January 2014 and this has been accounted for in the estimates cost for 2013-14.

2.10 STC Prices

QCOSS again suggests that the market price should be used for the STC price rather than the $40.00 penalty price.

ACIL Tasman acknowledges that although there is an active market for STCs it is not compelled to use market prices. This is mainly because historic prices might not be the best indicator of future prices as the market is designed to clear every year - so in theory prices could be $40 or at least very close to it. This assumes that the Clean Energy Regulator provides an accurate forecast of created certificates underpinning the STP for the next year.

3 Estimation of Wholesale energy cost

This section of the report sets out our estimates for the WEC.

3.1 Outline of approach

The approach adopted by ACIL Tasman is designed to simulate the wholesale energy market from a retailing perspective, where retailers hedge the pool price risk by entering into electricity contracts with prices represented by the observable futures market data. It involves passing hourly pool prices and demand profiles for 462 simulations of 2013-14, estimated using ACIL Tasman's electricity market simulator, *PowerMark,* through a retailer contracting model to estimate wholesale energy costs.

The approach is a simplification of the actual contract market in that it is based on specified hedging strategy using observable prices for base, peak and cap contracts only. It does not include other instruments available to retailers, as ACIL Tasman does not have sufficient independently verified information on the costs of the hedging benefits of any such instruments to incorporate them into the energy cost estimates. However, as retailers could avail themselves of the simplified hedging strategy, it is reasonable to assume more sophisticated strategies would result in costs being no higher with an expectation that they should be lower.

3.2 Detailed approach

Following assessment of the submissions to the Draft Determination ACIL Tasman can see no reason to alter its approach to estimating WEC.

3.2.1 Developing 42 simulations of demand traces each representing 2013/14

The data used in the analysis is in the public domain and is as follows:

- 42 years of three hourly capital city temperature data from 1970-71 to 2011-12
- NEM regional demand traces for three years from 2009-10 to 2011-12[5]

[5] There are a number of reasons for limiting the analysis to the 2009-10 to 2011-12 time series. First, the process used to develop the 42 simulated demand sets, described below, also develops, simultaneously, 42 corresponding wind farm output traces for a number of wind zones in the NEM. There are insufficient wind farm data to populate the wind traces for all wind zones by using data prior to 2009-10. Second, NSLP data prior to 2009-10 only partly complete.

- Energex and Ergon NSLP demand traces for three years from 2009-10 to 2011-12
- 10%, 50% and 90% POE demand and annual energy forecast parameters from the AEMO 2012 NEFR
- forecast of installed solar PV capacity for each NEM region for 2013-14 from the AEMO 2012 NEFR
- estimates of installed solar PV capacity for each NEM region for the years 2009-10 to 2011-12 from AEMO 2012 NEFR.

The first step in the process is to extract the actual demand traces for three years 2009-10 to 2011-12 from the AEMO published data and include the NEM regional totals, the NSLP and controlled demands in the Energex area and the NSLP in the Ergon area.

The Energex NSLP is used to estimate the wholesale energy costs for <100MWh customers for Queensland and unmetered demand in the Energex area. The Ergon Energy NLSP is used to estimate the wholesale energy costs applying to unmetered demand and >100MWh customers in the Ergon Energy area.

The extracted NEM regional demands are then adjusted by adding back to the half hourly demand values an estimate of the rooftop solar PV output. The estimated rooftop output is based on data provided by AEMO in the 2012 NEFR as well as an estimate of the typical hourly output profile of the aggregated installations. This step is important since the rapid uptake of rooftop solar PV has changed the demand profile. This step is not applied to the settlement class traces (i.e. the Energex NSLP and controlled tariffs and the Ergon Energy NSLP) since there is insufficient information on the extent of rooftop solar PV penetrating by class (however, this is dealt with further below).

The NEM and settlement class demands for 2009-10 and 2010-11 are scaled so that in broad terms they are at a comparable level to the 2011-12 demands. This is done by assessing the change in underlying energy between 2009-10 and 2011-12 for periods unaffected by weather variations.

At the completion of this step there are three years worth of demand data at 2011-12 levels for each NEM region and settlement class. These demands are then used to populate 42 simulated demand sets each representing 2011-12 based on different weather (temperature) outcomes.

39 simulated demand traces (using weather data for 1970-71 to 2008-09) are developed for each NEM region and settlement class. For each day of the 39 weather data sets a set of daily demands (from 2009-10 to 2011-12) is adopted by finding the best matching daily temperature profile (given the month and

day type) across the NEM. 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 three years 2009-10 to 2011-12 across all NEM regions simultaneously. Once the day with the same day type and season in the three years from 2009-10 to 2011-12 that best matches the temperature profile of the day in question is identified, then all the associated NEM regional and settlement class demand 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 demands traces and settlement class demand traces.

The 39 simulated demand sets together with the actual demand sets for 2009-10 to 2011-12 give a total of 42 demand traces representing 2011-12.

The 42 sets of NEM regional demand traces are then scaled to match the 2013-14 demand and energy forecasts from the NEFR (which have been adjusted by adding back on the contribution of rooftop solar PV). The scaling process is applied simultaneously across the 42 simulated demand traces so that the total energy of the aggregate 42 simulated demand traces is equal to 42 times the forecast annual energy in each NEM region. The maximum of the annual peak demands from the 42 simulated demand traces is scaled to match the 10% POE summer demand forecasts in each region. Similarly, the median of the annual peak demands from the 42 simulated demand traces is scaled to the 50% POE summer demand forecasts in each region. And, the minimum of the annual peak demands from the 42 simulated demand traces is scaled to the 90% POE summer demand forecasts in each region.

The hot weather experienced early in December 2012 resulted in a Queensland demand of 8,453MW which is well below the AEMO 50% POE medium growth forecast of 9,007MW which suggests that the medium growth forecast has a lower probability of being actually achieved. For this reason, ACIL Tasman has adopted the energy and peak demand parameters from the low economic growth scenario in the NEFR which tend to be about 100MW less than the medium growth scenario.

The 42 demand sets for the regional NEM demands are then adjusted by subtracting an assumed solar PV output profile which is derived by adopting the assumed growth in rooftop solar PV installations provided in the NEFR.

All demand analysis is done on a half hourly basis whereas pool price modelling and hedging analysis is undertaken on an hourly basis. Hourly demands used in the price modelling are taken to be the demand recorded in the first half hour of the hourly period.

3.2.2 Adjustment of the 42 NSLP demand traces

There are a number of additional steps used to establish the 42 simulated demand sets for the NSLPs which, because of the need to consider the effects of solar photovoltaic (PV) on demand, have been introduced for the 2013-14 analysis. Unlike the NEM regions, the Energex and Ergon NSLPs do not have an official demand or solar PV forecast.

The following steps describe the process developed by ACIL Tasman to establish the 42 simulations of these NSLPs representing 2013-14:

Step 1. Classify each half hour by month by working or non working day and by peak or off peak. This means that each half hour is classified as one of 48 period types (12 x 2 x 2).

Step 2. Calculate the average half hour demand for each of the 42 simulated years for 2011-12 for both Queensland NEM demand (with the contribution of solar PV deducted) and the NSLPs for each of the 48 period types.

Step 3. For each half hour in the 42 simulations for 2011-12 calculate the differences between the simulated value and the corresponding average value (from Step 2) for Queensland and the NSLPs .

Step 4. For each of the 42 simulations for the year 2011-12, in each half hourly interval calculate the difference that each of the NSLPs difference is (from Step 3) as a percentage of the Queensland difference (from Step 3).

Step 5. For each half hourly interval and for each of the 42 simulations, calculate the difference between the Queensland demand for 2011-12 and Queensland for 2013-14 (with the assumed 2013-14 solar PV contribution deducted for the Queensland demands).

Step 6. For each half hourly interval and for each of the 42 simulations, for each of the NSLPs apply the percentage (from Step 4) to the difference (from Step 5). This is an estimate of the NSLP contribution to variations in the Queensland demand.

Step 7. For each half hourly interval and for each of the 42 simulations, add the results (from Step 6) to each of the NSLPs for 2011-12 to give the 42 simulated demand traces representing NSLPs in 2013-14.

This process is designed to allow estimation of the 42 simulated years representing 2013-14 for the Energex and Ergon NSLPs based on the NSLPs contribution to variations in the Queensland demand. It avoids the need to produce individual forecasts of demand or solar PV for the two NSLPs.

3.2.3 Developing 11 plant outage sets for the NEM

PowerMark requires as an input the availability of each generator unit for each half-hour of the year.

Using binomial probability theory ACIL Tasman has simulated 11 sets of forced outages which are defined by an outage rate assumption as well as an outage duration assumption.

This process allows 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.

3.2.4 Running *PowerMark* using the 42 demand sets and 11 outage sets

PowerMark is then run to estimate the hourly pool prices for 2013-14 for 462 simulations by using the 42 demand sets and 11 outage sets developed using the steps described above.

The model is then run a second time but with the carbon tax removed so as to provide cost estimates excluding a price on carbon.

Fuel price and other plant cost and other assumptions used in the *PowerMark* modelling are those developed by ACIL Tasman over the past 15 years and are consistent with ACIL Tasman's latest internal Base Case. These assumptions come from a wide variety of sources and are constantly being monitored and updated.

3.2.5 Determine hedging strategy and volumes

For each settlement class, an appropriate hedging strategy which a prudent retailer would be expected to use for each settlement class is estimated by setting the parameters to calculate the base, peak and cap contract volumes based on the median demand/price year. ACIL Tasman has used the same strategy as employed for 2012-13. It was shown to remove almost all the price volatility and produced hedged prices which were very stable regardless of the weather and outage conditions.

Contract volumes are calculated by applying the hedging strategy to a simulated demand trace which has a peak demand and annual energy very close to the 50% POE peak demand and energy forecast and has an annual demand weighted price for Queensland very close to the median demand weighted price across all 462 simulations. Once established, these contract volumes are then fixed across all 462 simulations when calculating the wholesale energy costs.

Contract volumes are calculated for each settlement class by assuming the following for each quarter:

- Base contract volume is set to equal the 80th percentile of the off-peak hourly demands for the quarter.
- Peak period contract volume is set to equal the 90th percentile of quarterly peak period demands minus the base contract volume.
- Cap contract volume set at 105 per cent of the quarterly peak demand minus the base and peak contract volumes.

ACIL Tasman has tested a range of hedging strategies around the selected strategy and is satisfied that the selected strategy represents a conservative and low risk strategy for a retailer.

3.2.6 Estimating contract prices

Contract prices for the 2013-14 year were estimated using d-cypha Trade daily settlement prices and trade volumes since the contract was listed and up until and including the cut-off date of 29 April 2013.

The method used to estimate contract prices is the trade-weighted average of daily settlement prices.

Ergon Energy suggested using a straight average of daily settlement prices over three years. We have already established that trade-weighting best reflects the market price of energy purchased. The straight average skews the average price towards prices where no trades occurred and therefore does not accurately reflect the market price of energy purchased.

Table 2 shows the estimated quarterly swap and cap contract prices for the Final Determination and compares them with the Draft Determination.

Between the Draft and Final Determinations base and peak contract prices have increased by around $0.75/MWh on average over the 2013-14 year, while cap contract prices have decreased by around $0.05/MWh on average over the 2013-14 year.

Table 2 **Quarterly base, peak and cap estimated contract prices with carbon pricing , 2013-14 – Final Determination vs Draft Determination ($/MWh)**

	Final Determination			
	Q3 2013	Q4 2013	Q1 2014	Q2 2014
Base	$54.28	$55.80	$66.33	$53.67
Peak	$61.54	$66.19	$88.09	$61.38
Cap	$3.18	$6.83	$12.93	$2.59
	Draft Determination			
	Q3 2013	Q4 2013	Q1 2014	Q2 2014
Base	$53.53	$54.97	$65.77	$53.28
Peak	$60.12	$64.90	$87.88	$60.75
Cap	$3.32	$7.03	$12.87	$2.59
	Change (Final minus Draft)			
	Q3 2013	Q4 2013	Q1 2014	Q2 2014
Base	$0.75	$0.83	$0.56	$0.39
Peak	$1.43	$1.29	$0.20	$0.63
Cap	-$0.14	-$0.20	$0.06	$0.00

Data source: ACIL Tasman analysis using d-cypha Trade data up to, and including 29 April 2013.

Contract prices without carbon pricing

Contract prices *without* carbon pricing are estimated by subtracting the carbon price[6], adjusted for the estimated NEM intensity, from the trade-weighted contract prices in Table 2.

This method applies to the base and peak contracts only. The carbon tax does not heavily influence prices greater than $300, and therefore cap contract prices are unchanged.

The NEM intensity is estimated using modelling output from the median case of the 462 simulations (the same case used to define the hedging strategy). The NEM intensity is equal to NEM total emissions divided by NEM sent-out dispatch, which is consistent with the emissions intensity published by AEMO.

Estimated quarterly NEM emissions intensities are shown in Table 3.

[6] The carbon price in 2013-14 is the legislated carbon tax of $24.15/tCO2-e

Table 3 **Estimation of the NEM emissions intensity used to calculate contract prices without carbon pricing**

	NEM total emissions (million tonnes CO2-e)	NEM generation (GWh, sent-out)	NEM emissions intensity (tonnes CO2-e/ MWh, sent-out)
Q3 2013	42.31	47,651	0.89
Q4 2013	41.64	46,411	0.90
Q1 2014	41.99	46,366	0.91
Q2 2014	40.28	45,252	0.89

Note: Total emissions = combustion emissions + fugitive emissions

Data source: ACIL Tasman analysis based on the median case of the 462 simulations.

Table 4 shows the estimated quarterly swap and cap contract prices without carbon pricing for the Final Determination and compares them with estimates for the Draft Determination.

Table 4 **Quarterly base, peak and cap estimated contract prices <u>without carbon pricing</u>, 2013-14 – Final Determination vs Draft Determination ($/MWh)**

	Final Determination			
	Q3 2013	Q4 2013	Q1 2014	Q2 2014
Base	$32.84	$34.13	$44.46	$32.18
Peak	$40.10	$44.53	$66.22	$39.88
Cap	$3.18	$6.83	$12.93	$2.59
	Draft Determination			
	Q3 2013	Q4 2013	Q1 2014	Q2 2014
Base	$32.09	$33.30	$43.89	$31.78
Peak	$38.68	$43.23	$66.01	$39.25
Cap	$3.32	$7.03	$12.87	$2.59
	Change (Final minus Draft)			
	Q3 2013	Q4 2013	Q1 2014	Q2 2014
Base	$0.75	$0.83	$0.56	$0.39
Peak	$1.43	$1.29	$0.20	$0.63
Cap	-$0.14	-$0.20	$0.06	$0.00

Data source: ACIL Tasman analysis using d-cypha Trade data up to, and including 29 April 2013.

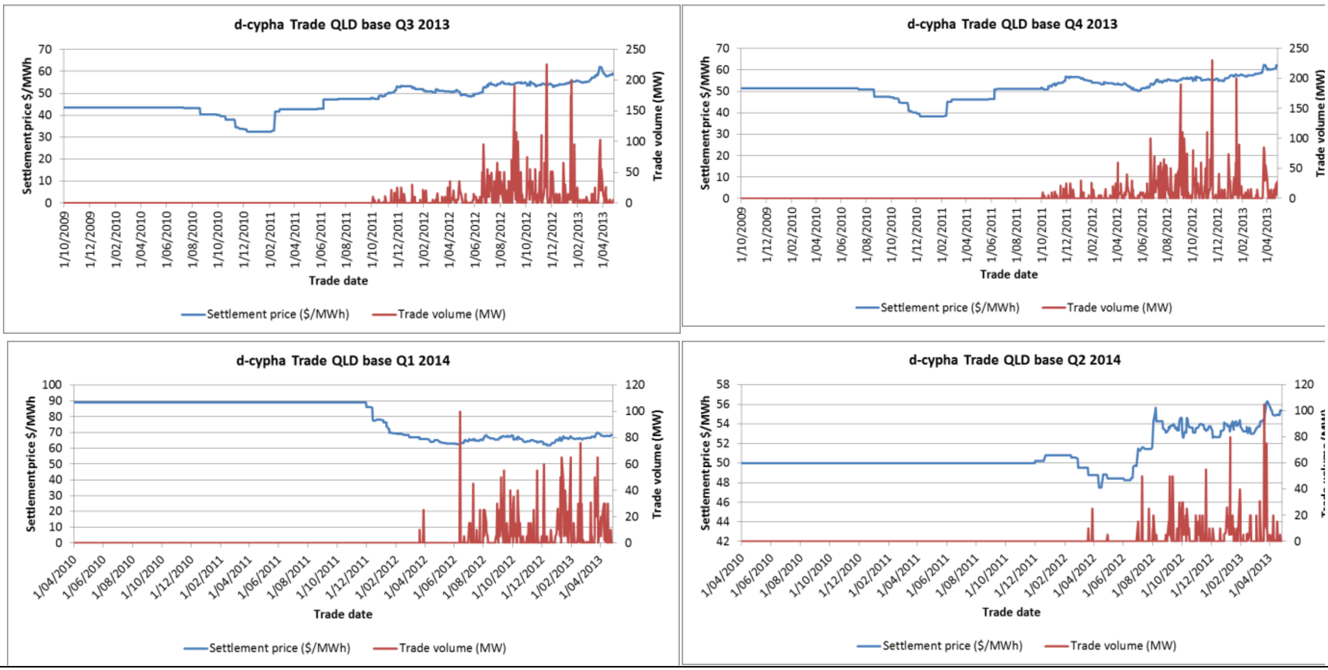
The following charts show daily settlement prices and trade volumes for d-cypha Trade quarterly base futures, peak futures and cap contracts.

Base contracts have traded strongly, with total volumes between 1,528MW (Q2 2014) and 4,834MW (Q3 2013).

Peak futures have trade volumes of between 20MW (Q2 2014) and 120MW (Q4 2013), which are consistent with peak contract trade volumes in previous years.

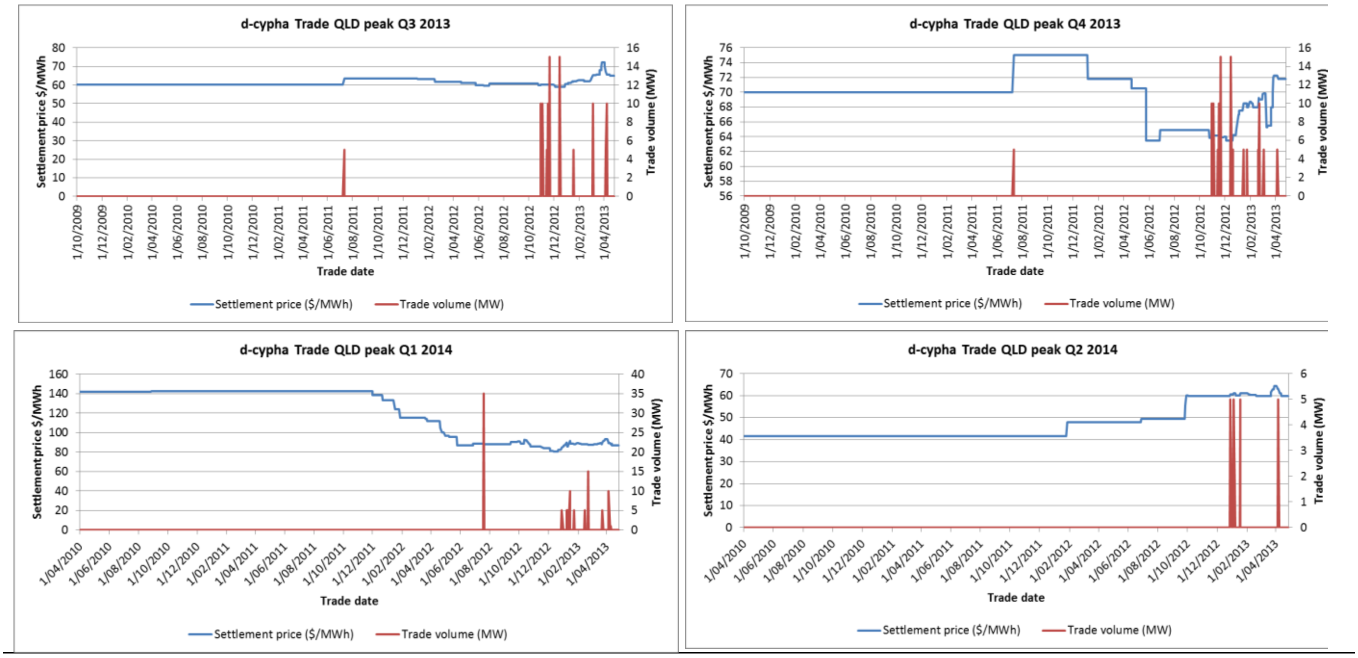
Cap contracts have traded reasonably strongly compared to previous years, with trade volumes of between 155MW (Q4 2013) and 329MW (Q3 2013).

Figure 11 **Time series of trade volume and price – d-cypha Trade QLD BASE futures for Q3 2013, Q4 2013, Q1 2014 and Q2 2014**



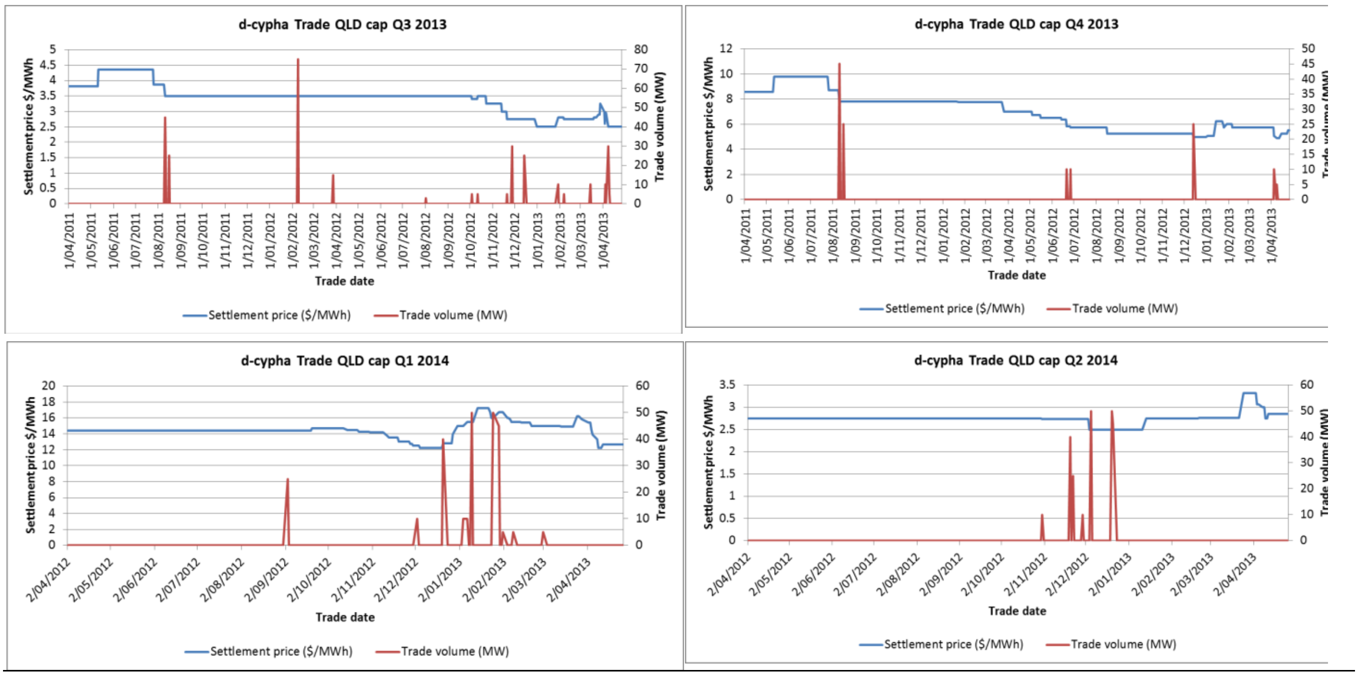
Data Source: d-cypha Trade data up to, and including 29 April 2013.

Figure 12 **Time series of trade volume and price – d-cypha Trade QLD PEAK futures for Q3 2013, Q4 2013, Q1 2014 and Q2 2014**



Data Source: d-cypha Trade data up to, and including 29 April 2013.

Figure 13 **Time series of trade volume and price – d-cypha Trade QLD $300 CAP contracts for Q3 2013, Q4 2013, Q1 2014 and Q2 2014**



Data Source: d-cypha Trade data up to, and including 29 April 2013.

3.2.7 Application of transmission and distribution losses

Prices at 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 average Marginal Loss Factors (MLF) for transmission losses from the node to major supply points in the distribution networks are applied.

The transmission loss factors from the Queensland reference node to the distribution network for Energex and Ergon Energy's east zone area are based on the average energy-weighted marginal loss factors (MLFs) for the Energex and Ergon Energy east zone TNI's. This analysis resulted in a transmission loss factor of 1.008 for Energex and 1.053 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 2013-14.

The estimated transmission and distribution loss factors for the settlement classes are shown in Table 5. The main change between the Draft and Final Determinations is in the estimated transmission loss factors which are smaller in Energex area and larger in Ergon Energy east zone.

Table 5 **Estimated transmission and distribution loss factors for Energex and Ergon Energy's east zone - Final and Draft Determinations**

Settlement classes	Distribution loss factor (DLF)	Transmission marginal loss factor (MLF)	Total loss factors (MLFxDLF)
Final Determination			
Energex - NSLP - residential and small business and unmetered supply	1.064	1.008	1.073
Energex - Control tariff 9000	1.064	1.008	1.073
Energex - Control tariff 9100	1.064	1.008	1.073
Ergon Energy - NSLP - SAC HV, CAC and ICC	1.033	1.053	1.088
Ergon Energy - NSLP - SAC demand and street lighting	1.078	1.053	1.135
Draft Determination			
Energex - NSLP - residential and small business and unmetered supply	1.062	1.010	1.072
Energex - Control tariff 9000	1.063	1.010	1.073
Energex - Control tariff 9100	1.063	1.010	1.073
Ergon Energy - NSLP - SAC HV, CAC and ICC	1.038	1.046	1.086
Ergon Energy - NSLP - SAC demand and street lighting	1.078	1.046	1.128

Note: For the Draft Determination the losses were quoted as a percentage but to be consistent with the Final Determination the losses are represented in the AEMO MLF and DLF format.

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.

For the Final Determination ACIL Tasman has adjusted the methodology used in applying the losses to prices at the Queensland reference node so that it aligns with the application of the transmission marginal loss factors (MLF) and distribution loss factors (DLF) used by AEMO.

As described by AEMO7, to arrive at prices at the customer terminal (price at load connection point) the MLF and DLF are applied to the prices at the regional reference node (RRN) as follows:

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[7] See Page 23 of the AEMO publication *Treatment of loss factors in the national electricity market- July 2012*

Price at load connection point = RRN Spot Price * (MLF * DLF)

3.2.8 Calculation of wholesale energy costs for 2013-14

Using the contract prices and volumes with the projected hourly pool prices for the 462 simulations in the hedge model provides 462 estimates of the wholesale energy cost for each settlement class.

In recognition that there is some residual volume and price risk retained in the hedging strategy, the 95th percentile of the 462 simulated annual hedged prices is used as the estimate of the WEC for 2013-14.

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 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.

3.3 Data sources

3.3.1 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:

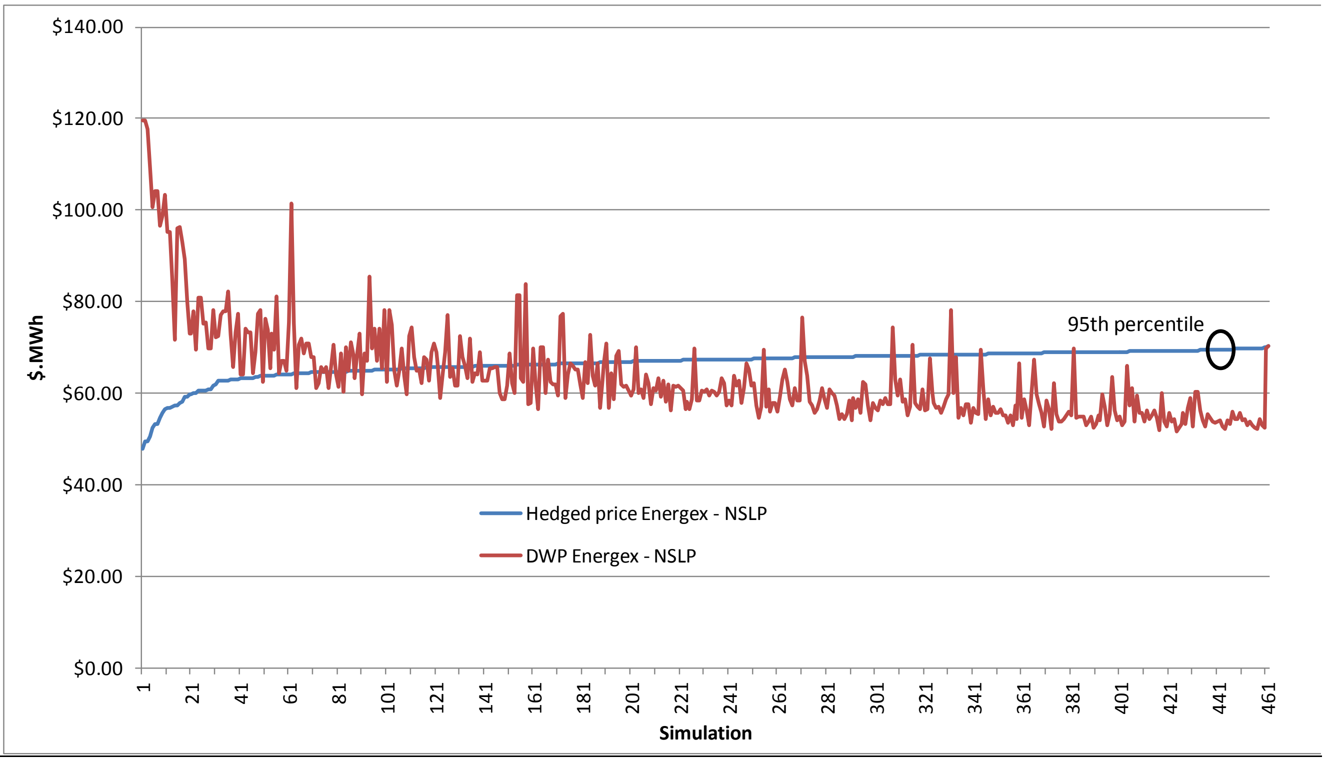
- annual reports
- gas price modelling using *GasMark*
- announced contractual arrangements for fuel
- ACIL Tasman estimates
- Non-sensitive information provided by clients
- AEMO reports

Detailed data is provided in Appendix C.

3.4 Summary of WEC estimates

Figure 14 demonstrates that there is limited variation in the WEC across the 462 simulation years after applying the hedging strategy to the Energex NSLP, when compared with the non-hedged price variation. This indicates that the hedging strategy while relatively unsophisticated is a reasonable approach to hedging the retailer demand. Although the unhedged approach yields lower prices in general, the volatility in outcomes represents significant risk to a retailer. A similar conclusion holds for the other settlement classes.

Figure 14 **Price outcomes ($/MWh, nominal) of 462 simulations for the Energex NSLP - 2013-14**



Note: Projected prices based on 462 simulations of the low energy growth scenario
Data source: ACIL Tasman analysis

Table 6 shows the results for the WEC modelling for the Final Determination with carbon pricing. It includes an allowance for the transmission and distribution losses and the estimate of the cost at the customer terminals. The methodology used to apply losses to calculate WEC at the customer terminal has been altered to align with the AEMO methodology as discussed in Section 3.2.7.

The Draft Determination, adjusted for the revised approach for calculating the allowance for losses, is included to allow comparison. The Final Determination is generally slightly higher than the Draft Determination mainly because of higher base and peak contract prices and increased loss factors.

Table 7 summarises the WEC without carbon pricing. Again prices are higher in the Final Determination due to a upward revision to the contract prices and an increase in the estimated loss factors.

Table 6 **Estimated WEC ($/MWh, nominal) for 2013-14 - including a price on carbon - Final and Draft Determinations**

Settlement class	WEC at the Queensland reference node [(1)] ($/MWh)	Total transmission and distribution loss factor (MLFxDLF)	WEC at the customer terminal ($/MWh)
Final Determination			
Energex - NSLP - residential and small business	$69.43	1.073	$74.50
Energex - Control tariff 9000	$47.06	1.073	$50.50
Energex - Control tariff 9100	$57.89	1.073	$62.12
Energex - NSLP - unmetered supply	$69.43	1.073	$74.50
Ergon Energy - NSLP - SAC HV, CAC and ICC	$64.08	1.088	$69.72
Ergon Energy - NSLP - SAC demand and street lighting	$64.08	1.135	$72.73
Draft Determination [(2)]			
Energex - NSLP - residential and small business	$68.59	1.072	$73.53
Energex - Control tariff 9000	$46.84	1.073	$50.26
Energex - Control tariff 9100	$57.15	1.073	$61.32
Energex - NSLP - unmetered supply	$68.59	1.072	$73.53
Ergon Energy - NSLP - SAC HV, CAC and ICC	$63.33	1.086	$68.78
Ergon Energy - NSLP - SAC demand and street lighting	$63.33	1.128	$71.44
Change			
Energex - NSLP - residential and small business	$0.84	0.001	$0.97
Energex - Control tariff 9000	$0.22	0.000	$0.24
Energex - Control tariff 9100	$0.74	0.000	$0.80
Energex - NSLP - unmetered supply	$0.84	0.001	$0.97
Ergon Energy - NSLP - SAC HV, CAC and ICC	$0.75	0.002	$0.94
Ergon Energy - NSLP - SAC demand and street lighting	$0.75	0.007	$1.29

Note 1:. Projected prices based on the 95th percentile of the 462 simulations of the low energy growth scenario

Note 2: The estimates of WEC at the customer terminal for Draft Determination have been adjusted for the changed methodology used to calculate the allowance for transmission and distribution losses (see Section 3.2.7)

Data source: ACIL Tasman analysis

Table 7 **Estimated WEC ($/MWh, nominal) for 2013-14 - excluding a price on carbon - Final and Draft Determination**

Settlement class	WEC at the Queensland reference node (1) ($/MWh)	Total transmission and distribution loss factor (MLFxDLF)	WEC at the customer terminal ($/MWh)
Final Determination			
Energex - NSLP - residential and small business	$47.74	1.073	$51.22
Energex - Control tariff 9000	$25.25	1.073	$27.10
Energex - Control tariff 9100	$36.49	1.073	$39.16
Energex - NSLP - unmetered supply	$47.74	1.073	$51.22
Ergon Energy - NSLP - SAC HV, CAC and ICC	$42.32	1.088	$46.04
Ergon Energy - NSLP - SAC demand and street lighting	$42.32	1.135	$48.03
Draft Determination (2)			
Energex - NSLP - residential and small business	$46.88	1.072	$50.26
Energex - Control tariff 9000	$25.07	1.073	$26.90
Energex - Control tariff 9100	$35.74	1.073	$38.35
Energex - NSLP - unmetered supply	$46.88	1.072	$50.26
Ergon Energy - NSLP - SAC HV, CAC and ICC	$41.56	1.086	$45.13
Ergon Energy - NSLP - SAC demand and street lighting	$41.56	1.128	$46.88
Change			
Energex - NSLP - residential and small business	$0.86	0.001	$0.97
Energex - Control tariff 9000	$0.18	0.000	$0.20
Energex - Control tariff 9100	$0.75	0.000	$0.81
Energex - NSLP - unmetered supply	$0.86	0.001	$0.97
Ergon Energy - NSLP - SAC HV, CAC and ICC	$0.76	0.002	$0.91
Ergon Energy - NSLP - SAC demand and street lighting	$0.76	0.007	$1.15

Note 1:. Projected prices based on the 95th percentile of the 462 simulations of the low energy growth scenario

Note 2: The estimates of WEC at the customer terminal for Draft Determination have been adjusted for the changed methodology used to calculate the allowance for transmission and distribution losses (see Section 3.2.7)

Data source: ACIL Tasman analysis

4 Estimation of other energy costs

The other energy costs (OEC) estimates provided in this section consist of:

- Costs associated with compliance with the Renewable Energy Target (RET) encompassing:
  - LRET
  - SRES
- Costs of compliance with the Queensland Gas Scheme
- Market fees and charges including:
  - NEM management fees
  - Ancillary services costs
- Pool and hedging prudential costs.

4.1 Renewable Energy Target scheme

The RET scheme consists of two elements – the LRET and the SRES. Liable parties (i.e. all electricity retailers[8]) are 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 the following:

- Large-scale Generation Certificate (LGC) market prices from AFMA[9]
- Adjusted LRET targets for 2013 and 2014 of 19,088 GWh and 16,950 GWh respectively, as published by the Clean Energy Regulator (CER)
- The Renewable Power Percentage (RPP) for 2013 as published by CER and an ACIL Tasman estimate for the RPP for 2014 based on the inferred liable energy from the CER's non-binding estimate for the STP for 2014. These RPP are set out in Table 8[10]
- CER's binding and non-binding estimate for Small-scale Technology Percentage (STP) of 19.7 and 8.98 per cent for 2013 and 2014, respectively[11]

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8 Emissions Intensive Trade Exposed (EITE) industries such as aluminium are wholly or partially exempted and receive Partial Exemption Certificates (PEC) to be surrendered to the named liable entity.

9 AFMA data includes weekly settlement prices to end of April 2013, which is the cut-off date for all relevant market-based data used in the Final Determination for 2013-14 tariffs.

10 Note that these estimates differ slightly from the Default RPP values for future years calculated in accordance with Section 39 (2)(b) of the Act

11 Published on 15 March 2013

- CER clearing house price for 2013 and 2014 for Small-scale Technology Certificates (STCs) of $40/MWh.

4.1.1 LRET

To translate the aggregate LRET target for any given year into a mechanism such that liable entities under the scheme may determine how many LGCs they must purchase and acquit, the LRET legislation requires the CER to publish the RPP by the 31 March within the compliance year.

The RPP is determined ex-ante by the CER and represents the relevant year's LRET target (in fixed GWh terms) as a percentage of the estimated volume of liable electricity consumption throughout Australia in that year.

The estimated cost of compliance with the LRET scheme is derived by applying the RPP to the determined LGC price to establish the cost per MWh of liable energy supplied to customers. Since the cost is expressed as a cost per MWh, it is applicable across all retail tariffs.

Spot and futures markets exist for LCGs. ACIL Tasman recognises that the volume of LGC trades through the spot market comprises a relatively small proportion of overall liabilities and might not be a reliable indicator of costs. However, the relatively low volume of trading does not necessarily mean that traded prices are an unreliable source on which to base the estimation of scheme costs.

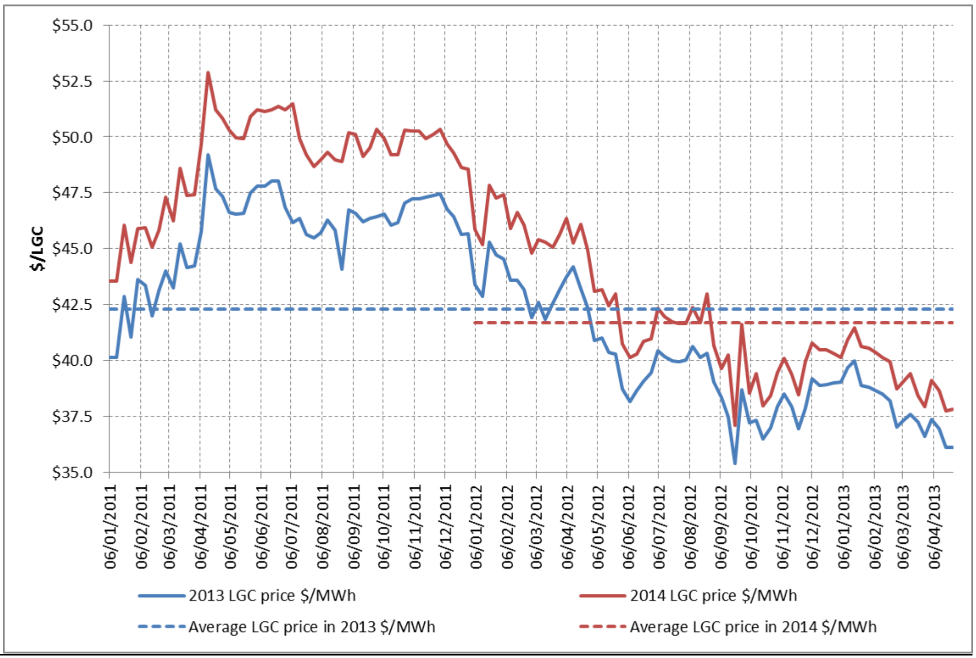
As discussed in our advice for the Draft Determination, ACIL Tasman is satisfied that using the forward looking weekly market prices for LGCs published by the Australian Financial Markets Association (AFMA) [12] provides a sound estimate for the cost of a retailer meeting the LRET in 2013-14.

The LGC price used in assessing the cost of the scheme for 2013-14 is found by averaging the futures prices for 2013 and 2014 during the two years prior to the commencement of 2013 and 2014. This assumes that LGC coverage is built up over a two year period (see Figure 15). The average LGC prices calculated from the AFMA data are $42.31/MWh for 2013 and $41.68/MWh for 2014:

- 2013 is based on prices starting on 6 January 2011 capturing 121 weeks
- 2014 is based on prices starting on 5 January 2012 capturing 69 weeks.

[12] The Australian Financial Markets Association (AFMA) publishes reference information on Australia's wholesale over-the-counter (OTC) financial market products. This includes a broker survey of bids and offers for LGCs, STCs and other environmental products which is published weekly.

Figure 15 **LGC futures prices for 2013 and 2014 (nominal $/LGC)**



Data source: AFMA

For 2013, the RPP of 10.65 per cent, as published by the CER, has been used. For 2014, the RPP component of the calculation is estimated using data published by CER. The non-binding STP estimate published on 15 March 2013 under section 40B of the Act provides the percentage as a proportion of total estimated liable electricity for 2014, as well as the equivalent number of STCs. Using this data, the CER's current view of the total estimated liable energy is derived. Combining the total estimated liable energy with the legislated target, ACIL Tasman then calculated the implied RPP for 2014 (see Table 8). The decline in the RPP from 2013 to 2014 is due to the lower legislated target of 16,950 GWh in 2014 (2,138 GWh lower than 2013).

Table 8 **CER's 2013 RPP and calculated 2014 RPP**

	Binding	Non-binding
	2013	2014
Small-scale Technology Percentage (%)	19.7%	8.98%
Equivalent to ('000) STCs	35,700	16,700
Estimated total liable energy (GWh)		185,968.82
LRET target (GWh)	19,088	16,950
Implied RPP (%)	10.65%	9.11%

Note: The targets for 2013 and 2014 have been adjusted for the inclusion of eligible waste coal mine gas in accordance with Section 40 (2)-(5) of the Act

Data source: CER, ACIL Tasman analysis

Therefore, ACIL Tasman estimates the cost of complying with the LRET scheme to be $4.15/MWh in 2013-14 as shown in Table 9.

Table 9 **Estimated cost of LRET – Final Determination 2013-14**

	2013	2014	Cost of LRET Final Determination 2013-14
RPP %	10.65%	9.11%	
Average LGC price ($/LGC, nominal)	$42.31	$41.68	
Cost of LRET ($/MWh, nominal)	$4.51	$3.80	$4.15

Data source: CER, AFMA, ACIL Tasman analysis

4.1.2 SRES

The cost of SRES for calendar years 2013 and 2014 is calculated by applying the CER published STP to the STC price. The average of these calendar year costs is then used to obtain the estimated cost for 2013-14.

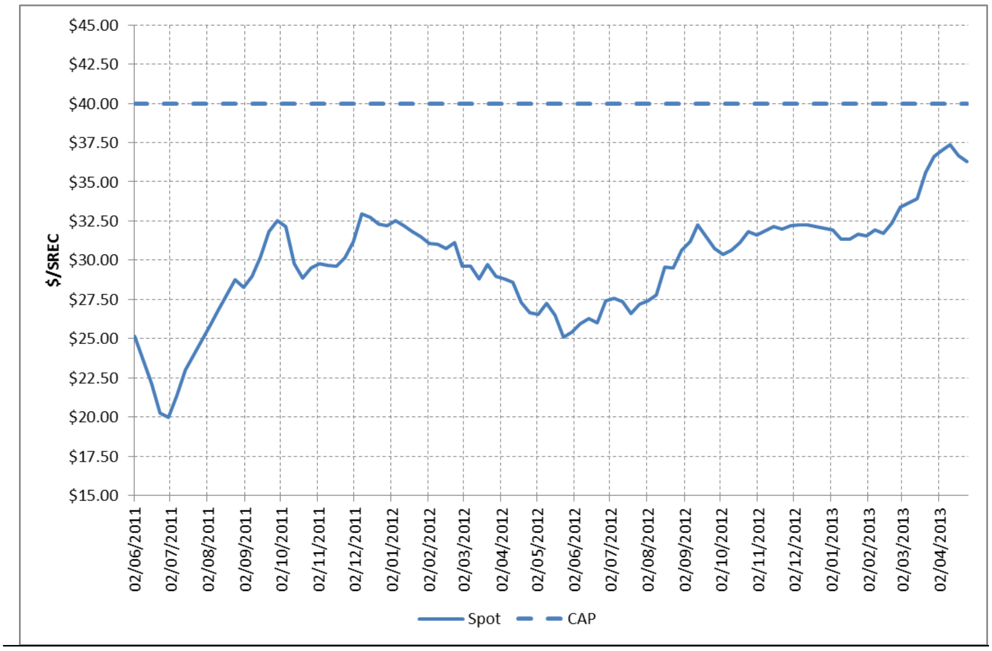
The binding and non-binding STP published on 15 March 2013 under section 40B of the Act by CER was as follows:

- 19.70 per cent for 2013 (equivalent to 35.7[13] million STCs as a proportion of total estimated liable electricity for the 2013 year)
- 8.98 per cent for 2014 (equivalent to 16.7 million STCs as a proportion of total estimated liable electricity for the 2014 year).

The 'STC clearing house' is a mechanism designed to facilitate the exchange of STCs between buyers and sellers at a fixed price of $40, with the purpose to cap the scheme at a predetermined price as well as deliver a set subsidy to entities creating STCs. The clearing house is a voluntary mechanism and liable entities can source STCs through secondary markets. In practice, the annual oversupply of STCs since the inception of the SRES has resulted in a secondary market STC price of $25 to $36 over the last 12 months. In regards to the STC spot prices, it is noteworthy that prices have been steady at around $32 since September 2012 but have risen sharply to just under $37 since the binding 2013 estimate has been announced on the 15 March 2013 (see Figure 16).

[13] Includes an estimate of 15 million excess STCs created in 2012 over the 22.306 million estimate used in setting the 2012 STP (which totalled 44.786 with the 2011 surplus added). It also includes an updated estimated total of 20.7 million STCs to be created in 2013.

Figure 16 **Small-scale Technology Certificate spot price**



Data source: AFMA

In the estimation of STC prices there are two distinct options:

- Use the nominal clearing house price of $40/STC
- Estimate an average price for STCs on the secondary market over 2013-14.

The first option is relatively straight forward as this price is set within the legislation and is held fixed in nominal terms. It provides a price cap for the scheme.

The second option of a 'market price' approach would be relevant where supply was expected to continue to significantly exceed forecast demand. The removal of the solar credits multiplier and reform of feed-in-tariffs suggest that this is less likely. Recent AFMA data[14] seem to validate this assumption with spot prices moving close to $37. By applying a holding cost of 9.72% (the approved WACC for Energex) it can be concluded that the market expects prices to move closer to the nominal clearing house price of $40/STC rather than the $32 which prevailed over most of 2012.

In addition while not necessarily linearly related, lower costs would imply higher demand than assumed in the non-binding CER estimates which would be expected to largely offset lower prices.

[14] AFMA data is based on a survey of bids and offers. No actual trade volumes is attached to this data.

For these reasons ACIL Tasman continues to use the best published CER estimates and the clearing house price of $40 for STCs in determining the contribution to energy costs. We estimate the cost of complying with SRES to be $5.74/MWh in 2013-14 as set out in Table 10.

Table 10 **Estimated cost of SRES – Final Determination 2013-14**

	2013	2014	Cost of SRES Final Determination 2013-14
STP %	19.70%	8.98%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of LRET ($/MWh, nominal)	$7.88	$3.59	$5.74

Data source: CER, ACIL Tasman analysis

Combining the LRET and SRES costs for both schemes yields a total cost of $9.89/MWh for 2013-14.

4.2 Queensland Gas Scheme

On 8 March 2013, the Queensland Government announced that the Queensland Gas Scheme would close on the 31 December 2013 making 2013 the last liable year.

In order to estimate the cost of the scheme, ACIL Tasman adjusted the methodology used in the 2012-13 Final Determination to reflect the closure of the scheme.

The methodology relies on a 4-year average of the weekly GEC prices as published by AFMA for 2013 and assumes prices to be zero for 2014. The 4-year average has been chosen since there is no available information on the volumes of GECs being traded or if any of the legacy contracts still apply. The selection of the time interval attempts to capture the whole range of hedging strategies.

The AFMA weekly GEC prices have been averaged over an extended period of 208 weeks or 4 years starting on January 2009 for 2013. The cut-off date for the AFMA data used in this Report is April 2013. The average GEC prices calculated from the AFMA data are $3.29/MWh for 2013.

The average of the 2013 and 2014 prices ($0 in 2014) results in a GEC price of $1.64/MWh, which when multiplied by the 15% liability, results in a GEC allowance of **$0.25/MWh** for 2013-14.

4.3 NEM management 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.

Based on AEMO's *Draft budget fees for 2013-14*, the total NEM fee for 2013-14 is **$0.37/MWh**[15], down from $0.40/MWh in 2012-13. According to AEMO, the NEM is forecast to return a significant surplus in 2012-13 and the 2013-14 fee is reduced to return this surplus to participants.

4.4 Ancillary services

AEMO provides weekly aggregated settlements data for ancillary service payments in each interconnected region. Using the average costs over the preceding 52 weeks of currently available NEM ancillary services data as a basis for 2013-14, the cost of ancillary services is estimated to be **$0.30/MWh.**

4.5 Prudential costs

This section covers cost estimates for AEMO and hedge prudential costs.

4.5.1 AEMO prudential costs

AEMO calculates a maximum credit limit for each counterparty in order to determine the requirement for any or a combination of:

- bank guarantees
- reallocation certificates
- prepayment of cash.

There is no fundamental requirement to reallocate prudential obligations – it is a retailer's choice to do so. Assuming no reallocation and no vertical integration (either owned generation or PPAs), a retailer is required to provide suitable guarantees to the AEMO assessed maximum credit limit (MCL) which is calculated as follows:

MCL = (Average daily load x Average future price x Volatility factor x Loss factor x (GST + 1) x 42 days

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[15] The total NEM fees include the following components: Market customer allocated, General admin, Advocacy panel, National Transmission Planner, National Smart Metering and FRC fees.

Taking a 1 MWh average daily load and assuming the following inputs:

- a future mean pool price of $55.75[16]
- a volatility factor of 1.5, based on published AEMO volatility factors for 2012-13[17]
- Loss factor of 1.05

results in an MCL of $4,056.75.

However as this applies for a rolling 42 days it actually covers 42 MWh of retailer purchases. Hence the portion of the MCL applicable to each MWh is $4,056/42 = $96.60. [18]

The cost of funding a bank guarantee for the MCL associated with the single MWh is assumed to be a 2.5% annual charge[19] for 42 days or 2.5%*(42/365) = 0.288%. Applying this funding cost to the single MWh charge of $96.60 gives **$0.278/MWh.**

4.5.2 Hedge prudential costs

ACIL Tasman has relied on the futures market to determine hedging costs. The futures market includes prudential obligations by requiring entities to lodge initial margins (we assume cash) when contracts are purchased or sold. We understand that the cash that is lodged as an initial margin receives a money market related return which offsets some of the funding costs. The current money market rate is around 3%. Additional margin calls may apply where contracts move unfavourably for the purchaser or seller. However, as these may be favourable or unfavourable we have assumed that they average out over time.

We understand that the initial margin is set based on three parameters being:

- the price scanning range (PSR) expressed as a percentage of the contract face value and currently set at around 5.5% on average for a base contract

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16 ACIL Tasman has revised this assumption to be the mean pool price, since the volatility factor of 1.5. According to AEMO, the volatility factor "is a scaling factor used to derive a reasonable worst case value". The mean pool price multiplied by the volatility factor encompasses the 95th percentile pool simulation.

17 http://www.aemo.com.au/Electricity/Settlements/Prudentials/NEM-Regional-Volatility-Factor

18 QEnergy suggest that the division by 42 is incorrect, since prudential costs apply to every MWh consumed. ACIL Tasman has considered this issue and is confident that the treatment is correct based on AEMO's calculation of the MCL which is based on the average daily load for a period and not the whole load across the period.

19 This is the handling charge for a guarantee facility which is not drawn down.

- the intra commodity spread charge currently set at $2,200 for a base contract of 1 MW for a quarter
- the spot isolation rate currently set at $400

Using an annual average futures price of $57.48[20] and applying the above factors gives an average initial margin for each quarter of around $9,500 for a 1 MW quarterly contract. In order to allow for some ongoing future uncertainty we have rounded this to $10,000 per 1 MW quarterly contract. Dividing this by the average hours in a quarter then gives an initial margin of $4.57 per MWh. Assuming a funding cost of 9.72% (the approved WACC for Energex as proposed by QEnergy) but adjusted for an assumed 3% return on cash lodged with the clearing house gives a net funding cost of 6.72%. Applying 6.72% to the initial margin per MWh gives a prudential cost for hedging of **$0.307/MWh.**

ACIL Tasman notes that the prudential requirements are higher for peak and cap contracts but where contracts are bought across the various types a discount is applied to the overall margin which largely offsets the higher individual contract initial margins (reflecting the diversification of risk). Hence ACIL Tasman considers that the base contract assessment is a reasonable reflection of the prudential obligations faced by retailers.

4.5.3 Total prudential costs

Adding the AEMO and hedge prudential costs gives a total prudential requirement as set out in Table 11:

Table 11 **Total prudential costs - Final Determination ($/MWh)**

Cost category	Final Determination 2013-14
AEMO pool	$0.278
Hedge	$0.307
Total	$0.585

4.6 Summary of other energy cost estimates

In summary, the ‘other energy costs’ components for 2013-14 are estimated to be **$11.38/MWh**. These costs are summarised in Table 12.

20 Average annual price for base futures costs used in estimating WEC.

Table 12 **Summary of OEC – Final Determination at the regional reference node ($/MWh)**

Cost category	Fees ($/MWh)
LRET	$4.15
SRES	$5.74
Queensland Gas Scheme	$0.25
NEM fees	$0.37
Ancillary services	$0.30
Prudential costs	$0.58
Total other energy costs	$11.38

Note: All costs are presented at the Queensland regional reference node. Numbers may not add due to rounding.
Data source: ACIL Tasman analysis

5 Summary of energy costs

Estimated total energy costs (TEC) for the Final Determination for the settlement classes in the Energex area and Ergon Energy are presented in Table 13 and Table 14 - with and without carbon respectively. The estimated costs in the table include both the WEC and the OEC.

Table 13 **Estimated TEC with carbon pricing - Final and Draft Determinations for 2013-14**

Settlement class	WEC at the Queensland reference node [1] ($/MWh)	Renewable energy and market fees at the Queensland reference node ($/MWh)	Total transmission and distribution loss factor (MLFxDLF)	TEC at the customer terminal ($/MWh)
Final Determination				
Energex - NSLP - residential and small business	$69.43	$11.38	1.073	$86.71
Energex - Control tariff 9000	$47.06	$11.38	1.073	$62.71
Energex - Control tariff 9100	$57.89	$11.38	1.073	$74.33
Energex - NSLP - unmetered supply	$69.43	$11.38	1.073	$86.71
Ergon Energy - NSLP - SAC HV, CAC and ICC	$64.08	$11.38	1.088	$82.10
Ergon Energy - NSLP - SAC demand and street lighting	$64.08	$11.38	1.135	$85.65
Draft Determination[2]				
Energex - NSLP - residential and small business	$68.59	$11.36	1.072	$85.71
Energex - Control tariff 9000	$46.84	$11.36	1.073	$62.45
Energex - Control tariff 9100	$57.15	$11.36	1.073	$73.51
Energex - NSLP - unmetered supply	$68.59	$11.36	1.072	$85.71
Ergon Energy - NSLP - SAC HV, CAC and ICC	$63.33	$11.36	1.086	$81.11
Ergon Energy - NSLP - SAC demand and street lighting	$63.33	$11.36	1.128	$84.25
Change				
Energex - NSLP - residential and small business	$0.84	$0.02	0.001	$1.00
Energex - Control tariff 9000	$0.22	$0.02	0.000	$0.26
Energex - Control tariff 9100	$0.74	$0.02	0.000	$0.82
Energex - NSLP - unmetered supply	$0.84	$0.02	0.001	$1.00
Ergon Energy - NSLP - SAC HV, CAC and ICC	$0.75	$0.02	0.002	$0.99
Ergon Energy - NSLP - SAC demand and street lighting	$0.75	$0.02	0.007	$1.40

Note 1:. Projected prices based on the 95th percentile of the 462 simulations of the low energy growth scenario

Note 2: The estimates of TEC at the customer terminal for Draft Determination have been adjusted for the changed methodology used to calculate the allowance for transmission and distribution losses (see Section 3.2.7)

Data source: ACIL Tasman analysis

Table 14 **Estimated TEC without carbon pricing - Final and Draft Determinations for 2013-14**

Settlement class	WEC at the Queensland reference node (1) ($/MWh)	Renewable energy and market fees at the Queensland reference node ($/MWh)	Total transmission and distribution loss factor (MLFxDLF)	TEC at the customer terminal ($/MWh)
Final Determination				
Energex - NSLP - residential and small business	$47.74	$11.38	1.073	$63.44
Energex - Control tariff 9000	$25.25	$11.38	1.073	$39.31
Energex - Control tariff 9100	$36.49	$11.38	1.073	$51.37
Energex - NSLP - unmetered supply	$47.74	$11.38	1.073	$63.44
Ergon Energy - NSLP - SAC HV, CAC and ICC	$42.32	$11.38	1.088	$58.42
Ergon Energy - NSLP - SAC demand and street lighting	$42.32	$11.38	1.135	$60.95
Draft Determination(2)				
Energex - NSLP - residential and small business	$46.88	$11.36	1.072	$62.43
Energex - Control tariff 9000	$25.07	$11.36	1.073	$39.09
Energex - Control tariff 9100	$35.74	$11.36	1.073	$50.54
Energex - NSLP - unmetered supply	$46.88	$11.36	1.072	$62.43
Ergon Energy - NSLP - SAC HV, CAC and ICC	$41.56	$11.36	1.086	$57.47
Ergon Energy - NSLP - SAC demand and street lighting	$41.56	$11.36	1.128	$59.69
Change				
Energex - NSLP - residential and small business	$0.86	$0.02	0.001	$1.00
Energex - Control tariff 9000	$0.18	$0.02	0.000	$0.22
Energex - Control tariff 9100	$0.75	$0.02	0.000	$0.83
Energex - NSLP - unmetered supply	$0.86	$0.02	0.001	$1.00
Ergon Energy - NSLP - SAC HV, CAC and ICC	$0.76	$0.02	0.002	$0.95
Ergon Energy - NSLP - SAC demand and street lighting	$0.76	$0.02	0.007	$1.25

Note 1:. Projected prices based on the 95th percentile of the 462 simulations of the low energy growth scenario

Note 2: The estimates of TEC at the customer terminal for Draft Determination have been adjusted for the changed methodology used to calculate the allowance for transmission and distribution losses (see Section 3.2.7)

Data source: ACIL Tasman analysis

Appendix A Ministerial Delegation

ELECTRICITY ACT 1994
Section 90AA(1)

DELEGATION

I, Mark McArdle, the Minister for Energy and Water Supply, in accordance with the power of delegation in section 90AA(1) of the *Electricity Act 1994* (the Act), delegate to the Queensland Competition Authority (QCA) the function under section 90(1) of the Act of deciding the prices that a retail entity may charge its non-market customers for customer retail services for the tariff years from 1 July 2013 to 30 June 2016.

The following are the Terms of Reference of the price determination:

Terms of Reference

1. These Terms of Reference apply for each of the tariff years in the delegation period.

2. In each tariff year of the delegation period, QCA is to calculate the notified prices and publish an annual price determination, in the form of a tariff schedule, in accordance with these Terms of Reference.

3. In accordance with section 90(5)(a) of the Act, in making a price determination for each tariff year QCA must have regard to all of the following:

   (a) the actual costs of making, producing or supplying the goods or services;

   (b) the effect of the price determination on competition in the Queensland retail electricity market; and

   (c) the matters set out in paragraph 5 of these Terms of Reference.

4. In accordance with section 90(5)(b) of the Act, QCA may have regard to any other matter that QCA considers relevant.

5. The matters that QCA is required by this delegation to consider are:

   (a) Uniform Tariff Policy - QCA must consider the Government's Uniform Tariff Policy, which provides that, wherever possible, non-market customers of the same class should have access to uniform retail tariffs and pay the same notified price for their electricity supply, regardless of their geographic location;

   (b) Time of Use Pricing – QCA must consider whether its approach to calculating time-of-use tariffs can strengthen or enhance the underlying network price signals and encourage customers to switch to time-of-use tariffs and reduce their energy consumption during peak times;

(c) Framework - QCA must use the Network (N) plus Retail (R) cost build-up methodology when working out the notified prices and making the price determination, where N (network cost) is treated as a pass-through and R (energy and retail cost) is determined by QCA;

(d) When determining the N components for each regulated retail tariff for each tariff year, QCA must consider the following:

(i) for residential and small business customers, that is, those who consume less than 100 megawatt hours (MWh) per annum - basing the network cost component on the network charges to be levied by Energex;

(ii) for large business customers in the Ergon Energy distribution region who consume 100MWh or more per annum - basing the network cost component on the network charges to be levied by Ergon Energy given that, from 1 July 2012, large business customers in the Energex distribution region no longer have access to notified prices;

(e) Transitional Arrangements - QCA must consider:

(i) for the standard regulated residential tariff (Tariff 11), implementing a three-year transitional arrangement to rebalance the fixed and variable components of Tariff 11, so that each component (fixed and variable) of Tariff 11 is cost-reflective by 1 July 2015;

(ii) for the existing obsolete tariffs (i.e. farming, irrigation, declining block, non-domestic heating and large business customer tariffs), implementing an appropriate transitional arrangement should QCA consider there would be significant price impacts for customers on these tariffs if required to move to the alternative cost-reflective tariffs; and

(iii) for the large business customer tariffs introduced in 2012-13 (i.e. Tariffs 44, 45, 46, 47 and 48), whether customers on these tariffs should be able to access the transitional arrangements for the obsolete large business customer tariffs should QCA consider that a transitional arrangement for the obsolete tariffs is necessary.

Interim Consultation Paper

6. As part of each annual price determination, QCA must publish an interim consultation paper identifying key issues to be considered when calculating the N

and R components of each regulated retail electricity tariff and transitioning relevant retail tariffs over the three-year delegation period.

7. QCA must publish a written notice inviting submissions about the interim consultation paper. The notice must state a period during which anyone can make written submissions to QCA about issues relevant to the price determination.

8. QCA must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

Consultation Timetable

9. As part of each annual price determination, QCA must publish an annual consultation timetable within two weeks after submissions on the interim consultation paper are due, which can be revised at the discretion of QCA, detailing any proposed additional public papers and workshops that QCA considers would assist the consultation process.

Workshops and additional consultation

10. As part of the Interim Consultation Paper and in consideration of submissions in response to the Interim Consultation Paper the QCA must consider the merits of additional public consultation (workshops and papers) on identified key issues.

11. Specifically, given the three-year period of the delegation the QCA must conduct a public workshop on the energy and retail cost components used to determine regulated retail tariffs prior to the release of the 2013-14 Draft Determination.

Draft Price Determination

10. As part of each annual price determination, QCA must investigate and publish an annual report of its draft price determination on regulated retail electricity tariffs, with each tariff to be presented as a bundled price, for the relevant tariff year. The draft price determination must also specify the carbon cost allowances for the relevant tariff year.

11. QCA must publish a written notice inviting submissions about the draft price determination. The notice must state a period during which anyone can make written submissions to QCA about issues relevant to the draft price determination.

12. QCA must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

Final Price Determination

13. As part of each annual price determination, QCA must investigate and publish an annual report of its final price determination on regulated retail electricity tariffs, with each tariff to be presented as a bundled price, for the relevant tariff year, and gazette the bundled retail tariffs. The final price determination must also specify the carbon cost allowances for the relevant tariff year.

Timing

14. QCA must make its reports available to the public and, at a minimum, publicly release for each tariff year the papers and price determinations listed in paragraphs 6 to 13.

15. QCA must publish the interim consultation paper for the 2013-14 tariff year no later than one month after the date of this Delegation and no later than 30 August before the commencement of the subsequent tariff years.

16. QCA must publish the draft price determination on regulated retail electricity tariffs no later than 15 February 2013 for the 2013-14 tariff year and no later than 13 December before the commencement of the subsequent tariff years.

17. QCA must publish the final price determination on regulated retail electricity tariffs for each relevant tariff year, and have the bundled retail tariffs gazetted, no later than 31 May each year.

DATED this 5th day of September 2012.

[redacted]

SIGNED by the Honourable
Mark McArdle,
Minister for Energy and Water Supply) *(signature)*

Appendix B Consultancy Terms of Reference

Terms of Reference

Review of Regulated Retail Electricity Tariffs and Prices for 2013-14

Assessment of Energy Costs and Tariff Structure

31 October 2012

1. Project Background

On 5 September 2012, the Minister for Energy and Water Supply provided the Authority a Delegation requiring it to determine regulated retail electricity prices (notified prices) for a three-year period from 1 July 2013 to 30 June 2016 (**Attachment 1**).

While the task is delegated for three years (rather than a one-year period as previously), the Authority is still required to determine prices annually. The first determination is to apply from 1 July 2013 to 30 June 2014.

The Authority will require the assistance of a consultant to estimate the cost of energy for notified prices.

2. Outline of Consultancy

The consultant will be required to provide expert advice to the Authority on the energy costs to be incurred by a retailer to supply customers on notified prices for 2013-14. In preparing its advice, the consultant must have regard to the actual costs of making, producing or supplying the goods or service.

The Authority will require 2013-14 estimates for:

(a) wholesale energy costs;

(b) the costs of complying with state and federal government policies such as the Queensland Gas Scheme, the Enhanced Renewable Energy Target Scheme and the carbon tax;

(c) NEM fees and ancillary services charges; and

(d) losses in the transmission and distribution of electricity to customers.

The Authority is also offering an 'in principle' agreement for the consultant to be engaged to provide similar advice for its 2014-15 and 2015-16 reviews. This offer is subject to the consultant not undertaking work over the three-year period that might be seen as a conflict of interest or could otherwise preclude their appointment as the Authority's advisor. Appointment in each year would of course be subject to the proposed cost being reasonable given the nature of the task for the year and the cost in previous years.

3. Deliverables

The consultant will be required to provide a series of deliverables and take part in workshops, consultations and meetings. While Table 1 outlines the mandatory deliverables for the

- 1 -

consultancy, there may be additional requests made of the consultants from time to time as needed by the Authority.

Table 1: Timetable for the Consultancy

Deliverable	*Task*	*Due date*
Stakeholder Workshop	• Conduct a workshop with interested parties on the consultant's proposed approach to calculating energy costs	Early December 2012
Draft Report	• Address submissions on the Authority's Interim Consultation Paper and issues raised in the Stakeholder Workshop • Outline the consultant's approach • Provide draft cost estimates	7 December 2012
Final Report	• Address submissions on the Draft Report • Outline the consultant's final approach • Provide final cost estimates	5 April 2013

4. Resources/Data Provided

The consultant will be required to source modelling data and information independently.

Additional information relevant to this consultancy may be found in the Authority's publications which can be obtained from the Authority's website.

5. Project Time Frame

The consultancy will commence in mid October 2012 and is expected to be completed by 31 May 2013.

6. Proposal Specifications and Fees

The proposal should:

- include the name, address and legal status of the tenderer;
- provide the proposed methods and approach to be applied;
- provide a fixed price quote for the provision of the services detailed herein; and
- nominate the key personnel who will be engaged on the assignment together with the following information:
  - name;
  - professional qualifications;

- general experience and experience which is directly relevant to this assignment;
- expected time each consultant will work on the project; and
- standard fee rates for any contract variations.

The fee quoted is to be inclusive of all expenses and disbursements. A full breakdown of consultancy costs is required with staff costs reconciled to the consultancy work plan.

Total payment will be made within 28 days of receiving an invoice at the conclusion of the consultancy.

7. Contractual Arrangements

This consultancy will be offered in accordance with the Authority's standard contractual agreement.

This agreement can be viewed at http://www.qca.org.au/about/consultancyagreement.php

8. Reporting

The consultant will be required to provide the Authority with progress reports on an "as needs" basis or at least weekly and drafts of final reports will be required prior to project completion. If necessary, the consultant should advise at the earliest opportunity any critical issues that may impede progress of the consultancy, particularly issues that impact on the successful delivery of the Consultancy Objectives outlined in Section 2 above.

9. Confidentiality

Under no circumstance is the selected consultant to divulge any information obtained from any distributor, retailer or the Authority for the purposes of this consultancy to any party, other than with the express permission of the distributor or retailer concerned, and the Authority.

10. Conflicts of Interest

For the purpose of this consultancy, the consultant is required to affirm that there is no, and will not be any, conflict of interest as a result of this consultancy.

11. Authority Assessment of Proposal

The proposal will be assessed against the following criteria:

- understanding of the project;
- skills and experience of the firm and team;
- the proposed methods and approach;
- capacity to fulfil the project's timing requirements; and
- value for money.

In making its assessment against the criteria, the Authority will place most weight on relevant experience of the team members involved and the proposed method for the completion of the task.

12. Insurance

The consultant must hold all necessary workcover and professional indemnity insurance.

13. Quality Assurance

The consultant is required to include details of quality assurance procedures to be applied to all information and outputs provided to the Authority.

14. Lodgement of Proposals

Proposals are to be lodged with the Authority by 19 October 2012.

For further information concerning this consultancy, please contact Charles Millsteed, Energy Team Leader on (07) 3222 0543.

Proposals should be submitted to:

The Chief Executive Officer

Queensland Competition Authority
GPO Box 2257
Brisbane Qld 4001

Phone: (07) 3222 0555
Fax: (07) 3222 0599
Email: electricity@qca.org.au

Appendix C Detailed modelling assumptions

This appendix provides detailed inputs to the PowerMark model used in the estimates of energy costs.

C.1 Fuel Prices

Fuel prices assumed for the Queensland generators is shown in Table C1.

Table C1 **Fuel prices assumed for Queensland power stations ($/GJ, nominal - by calendar year**

Generator	Fuel	2013	2014
Barcaldine	Natural gas	$7.11	$7.26
Braemar 1	Natural gas	$2.87	$2.95
Braemar 2	Natural gas	$3.11	$4.59
Callide B	Black coal	$1.44	$1.47
Callide C	Black coal	$1.44	$1.47
Collinsville	Black coal	$2.30	$2.35
Condamine	Natural gas	$2.26	$8.15
Darling Downs	Natural gas	$4.31	$5.05
Gladstone	Black coal	$1.71	$1.75
Kogan Creek	Black coal	$0.82	$0.84
Mackay GT	Liquid Fuel	$33.07	$33.90
Millmerran	Black coal	$0.93	$0.95
Mt Stuart	Liquid Fuel	$33.07	$33.90
Oakey	Natural gas	$4.53	$4.64
Roma	Natural gas	$5.85	$6.44
Stanwell	Black coal	$1.53	$1.56
Swanbank B	Black coal	$3.90	$3.74
Swanbank E	Natural gas	$3.87	$4.05
Tarong	Black coal	$1.10	$1.12
Tarong North	Black coal	$1.10	$1.12
Townsville	Natural gas	$4.33	$4.43
Yarwun	Natural gas	$3.80	$3.88

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

C.2 Plant outages

Planned and forced outages assumed for the Queensland plant are shown in Table C2.

Table C2 **Planned and forced outages for Queensland power stations**

Generator	Forced outage rate	Planned outage schedule
Barcaldine	2.5%	1 month every two years
Barron Gorge	1.5%	1 month every two years
Braemar 1	1.5%	1 month every four years
Braemar 2	1.5%	1 month every four years
Callide B	4.0%	1 month every four years
Callide C	6.0%	1 month every two years
Condamine	1.5%	1 month every two years
Darling Downs	3.0%	1 month every two years
Gladstone	4.0%	1 month every two years
Kareeya	1.5%	1 month every four years
Kogan Creek	4.0%	1 month every two years
Mackay GT	1.5%	1 month every four years
Millmerran	5.0%	1 month every two years
Mt Stuart	2.5%	1 month every four years
Oakey	2.0%	1 month every four years
Roma	3.0%	1 month every four years
Stanwell	2.5%	1 month every two years
Swanbank E	3.0%	1 month every four years
Tarong	3.0%	1 month every four years
Tarong North	3.0%	1 month every two years
Townsville	2.3%	1 month every four years
Yarwun	3.0%	1 month every four years

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

Summary data for Queensland power stations is provided in Table C3.

Table C3 Details of Queensland generators used in pool price modelling for 2013-14

Portfolio	Generator	DUID	Gen Type	Fuel	Capacity (MW)	Min Gen (MW)	Auxiliaries (%)	Thermal efficiency HHV (%) sent-out	Combustion emission factor (kg CO2-e/GJ of fuel)	Fugitive emission factor (kg CO2-e/GJ of fuel)	VOM ($/MWh sent-out, 2012 $)
AGL	Oakey	OAKEY1	Gas turbine	Natural gas	141	0	1.5%	32.6%	0.0513	0.0054	$9.74
AGL	Oakey	OAKEY2	Gas turbine	Natural gas	141	0	1.5%	32.6%	0.0513	0.0054	$9.74
AGL	Townsville	YABULU	Gas turbine combined cycle	Coal seam methane	160	133	3.0%	46.0%	0.0513	0.0054	$1.07
AGL	Townsville	YABULU2	Gas turbine combined cycle	Coal seam methane	80	67	3.0%	46.0%	0.0513	0.0054	$1.07
Alinta	Braemar 1	BRAEMAR1	Gas turbine	Natural gas	168	90	1.5%	30.0%	0.0513	0.0054	$8.03
Alinta	Braemar 1	BRAEMAR2	Gas turbine	Natural gas	168	90	1.5%	30.0%	0.0513	0.0054	$8.03
Alinta	Braemar 1	BRAEMAR3	Gas turbine	Natural gas	168	90	1.5%	30.0%	0.0513	0.0054	$8.03
CS Energy	Callide B	CALL_B_1	Steam turbine	Black coal	350	200	7.0%	36.1%	0.095	0.002	$1.22
CS Energy	Callide B	CALL_B_2	Steam turbine	Black coal	350	200	7.0%	36.1%	0.095	0.002	$1.22
CS Energy	Callide C	CPP_3	Steam turbine	Black coal	405	200	4.8%	36.5%	0.095	0.002	$2.77
CS Energy	Gladstone	GSTONE1	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.21
CS Energy	Gladstone	GSTONE2	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.21
CS Energy	Gladstone	GSTONE3	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.21
CS Energy	Gladstone	GSTONE4	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.21
CS Energy	Gladstone	GSTONE5	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.21
CS Energy	Gladstone	GSTONE6	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.21
CS Energy	Kogan Creek	KPP_1	Steam turbine	Black coal	750	350	8.0%	37.5%	0.094	0.002	$1.28
CS Energy	Wivenhoe	W/HOE#1	Hydro	Hydro	250	0	1.0%	100.0%	0	0	$0.00
CS Energy	Wivenhoe	W/HOE#2	Hydro	Hydro	250	0	1.0%	100.0%	0	0	$0.00
Ergon	Barcaldine	BARCALDN	Gas turbine	Natural gas	55	27	3.0%	40.0%	0.0513	0.0054	$2.43
ERM	Braemar 2	BRAEMAR5	Gas turbine	Natural gas	153	150	1.5%	30.0%	0.0513	0.0054	$8.03
ERM	Braemar 2	BRAEMAR6	Gas turbine	Natural gas	153	0	1.5%	30.0%	0.0513	0.0054	$8.03
ERM	Braemar 2	BRAEMAR7	Gas turbine	Natural gas	153	0	1.5%	30.0%	0.0513	0.0054	$8.03
InterGen	Callide C	CPP_4	Steam turbine	Black coal	405	200	4.8%	36.5%	0.095	0.002	$1.22
InterGen	Millmerran	MPP_1	Steam turbine	Black coal	425.5	130	4.7%	36.9%	0.092	0.002	$2.88
InterGen	Millmerran	MPP_2	Steam turbine	Black coal	425.5	130	4.7%	36.9%	0.092	0.002	$2.88
Origin	Darling Downs	DDPS1	Gas turbine combined cycle	Natural gas	630	270	6.0%	46.0%	0.0513	0.002	$1.07
Origin	Mt Stuart	MSTUART1	Gas turbine	Liquid Fuel	146	0	3.0%	30.0%	0.0697	0.0053	$9.16
Origin	Mt Stuart	MSTUART2	Gas turbine	Liquid Fuel	146	0	3.0%	30.0%	0.0697	0.0053	$9.16
Origin	Mt Stuart	MSTUART3	Gas turbine	Liquid Fuel	126	0	3.0%	30.0%	0.0697	0.0053	$9.16
Origin	Roma	ROMA_7	Gas turbine	Natural gas	40	0	3.0%	30.0%	0.0513	0.0054	$9.74
Origin	Roma	ROMA_8	Gas turbine	Natural gas	40	0	3.0%	30.0%	0.0513	0.0054	$9.74
QGC	Condamine	CPSA	Gas turbine combined cycle	Natural gas	140	0	3.0%	48.0%	0.0513	0.002	$1.07

Portfolio	Generator	DUID	Gen Type	Fuel	Capacity (MW)	Min Gen (MW)	Auxiliaries (%)	Thermal efficiency HHV (%) sent-out	Combustion emission factor (kg CO2-e/GJ of fuel)	Fugitive emission factor (kg CO2-e/GJ of fuel)	VOM ($/MWh sent-out, 2012 $)
Rio Tinto	Yarwun	YARWUN_1	Gas turbine	Natural gas	168	143	2.0%	34.0%	0.0513	0.0054	$0.00
Stanwell - Tarong	Barron Gorge	BARRON-1	Hydro	Hydro	30	15	1.0%	100.0%	0	0	$11.56
Stanwell - Tarong	Barron Gorge	BARRON-2	Hydro	Hydro	30	15	1.0%	100.0%	0	0	$11.56
Stanwell - Tarong	Kareeya	KAREEYA1	Hydro	Hydro	21	8	1.0%	100.0%	0	0	$6.30
Stanwell - Tarong	Kareeya	KAREEYA2	Hydro	Hydro	21	8	1.0%	100.0%	0	0	$6.30
Stanwell - Tarong	Kareeya	KAREEYA3	Hydro	Hydro	18	8	1.0%	100.0%	0	0	$6.30
Stanwell - Tarong	Kareeya	KAREEYA4	Hydro	Hydro	21	8	1.0%	100.0%	0	0	$6.30
Stanwell - Tarong	Mackay GT	MACKAYGT	Gas turbine	Fuel oil	34	0	3.0%	28.0%	0.0697	0.0053	$9.16
Stanwell - Tarong	Stanwell	STAN-1	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	0.002	$3.26
Stanwell - Tarong	Stanwell	STAN-2	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	0.002	$3.26
Stanwell - Tarong	Stanwell	STAN-3	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	0.002	$3.26
Stanwell - Tarong	Stanwell	STAN-4	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	0.002	$3.26
Stanwell - Tarong	Swanbank E	SWAN_E	Gas turbine combined cycle	Coal seam methane	385	150	3.0%	47.0%	0.0513	0.0054	$1.07
Stanwell - Tarong	Tarong	TARONG#1	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	0.002	$7.61
Stanwell - Tarong	Tarong	TARONG#2	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	0.002	$7.61
Stanwell - Tarong	Tarong	TARONG#3	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	0.002	$7.61
Stanwell - Tarong	Tarong	TARONG#4	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	0.002	$7.61
Stanwell - Tarong	Tarong North	TNPS1	Steam turbine	Black coal	443	175	5.0%	39.2%	0.0921	0.002	$1.46

Data source: ACIL Tasman *PowerMark* database

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