ACIL ALLEN CONSULTING

REPORT TO
QUEENSLAND COMPETITION AUTHORITY

7 MAY 2014

ESTIMATED ENERGY COSTS

2014-15 RETAIL TARIFFS

FOR USE BY THE QUEENSLAND COMPETITION AUTHORITY IN ITS FINAL DETERMINATION ON RETAIL ELECTRICITY TARIFFS

ACIL ALLEN CONSULTING PTY LTD
ABN 68 102 652 148

LEVEL FIFTEEN
127 CREEK STREET
BRISBANE QLD 4000
AUSTRALIA
T+61 7 3009 8700
F+61 7 3009 8799

LEVEL TWO
33 AINSLIE PLACE
CANBERRA ACT 2600
AUSTRALIA
T+61 2 6103 8200
F+61 2 6103 8233

LEVEL NINE
60 COLLINS STREET
MELBOURNE VIC 3000
AUSTRALIA
T+61 3 8650 6000
F+61 3 9654 6363

LEVEL ONE
50 PITT STREET
SYDNEY NSW 2000
AUSTRALIA
T+61 2 8272 5100
F+61 2 9247 2455

SUITE C2 CENTA BUILDING
118 RAILWAY STREET
WEST PERTH WA 6005
AUSTRALIA
T+61 8 9449 9600
F+61 8 9322 3955

ACILALLEN.COM.AU

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ACIL ALLEN (2014) ESTIMATED 2014-15 ENERGY COSTS FOR QCA

Contents

List of figures

List of tables

1 Introduction

This report provides estimates of expected energy costs for use by the Queensland Competition Authority (the QCA) in its Final Determination on retail electricity tariffs for 2014-15.

The report considers the submissions made by various parties following the QCA's Draft Determination for 2014-15 electricity tariffs, where those submissions refer to the cost of energy in regulated retail electricity prices.

It also takes into consideration material and stakeholder views on the estimation of energy costs discussed at the workshop held on 17 February 2013 following release of the Draft Determination.

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 QCA and which is attached as Appendix B, the methodology developed by ACIL Allen provides an estimate of energy costs to be incurred by a retailer to supply customers on notified prices for 2014-15; 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 allowances for transmission and distribution losses.

In addition to the scope of work outlined in the TOR, the QCA has asked ACIL Allen to provide energy cost estimates for two cases assuming certainty about carbon pricing as follows:

1. Carbon case - the fixed full carbon price continues throughout 2014-15 in its present form of \$25.40/tonne CO_2-e and that this was always evident to the market
2. No carbon case - assumes that the Clean Energy Act (CEA) is repealed on 1 July 2014 and that this was always evident to the market.

ACIL Allen also developed energy cost estimates based on the market's view of the likelihood of the CEA being repealed (referred to as the risk adjusted carbon price). This reflects the observable historical prices at which futures contracts were transacted and as a consequence the observable hedging costs for prudent retailers hedging in accordance with the methodology. ACIL Allen recommends that the QCA use the estimate based on the risk adjusted carbon price allowance in determining the energy cost allowance.

1.1 Background

ACIL Allen notes that in accordance with the Delegation and TOR, its task is to provide expert advice to the QCA on the energy costs to be incurred by a retailer to supply customers on notified prices for 2014-15 taking into account the uncertainty over the carbon price and any other uncertainties.

For the carbon and no carbon cases requested by the QCA, ACIL Allen is to provide its best estimate of energy costs for a case assuming that the full carbon price applies for the whole of 2014-15 (Carbon case) and that this was always evident to the market and a case which assumes that the carbon price is repealed for the whole of 2014-15 (No carbon case) and that this was always evident to the market. In each of these two cases the status of the carbon price is assumed to be known and the market risks associated with the current carbon price uncertainty are not considered.

1.1.1 ACIL Allen's best estimate of wholesale energy costs

In preparing the advice on the estimate as outlined in the TOR, ACIL Allen is 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 2014-15.

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 (WEC) component.

In the interest of clarity, in undertaking the task, ACIL Allen 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.

These matters will be considered by the QCA when making its Determination.

In considering the question as to what constitutes the actual cost of making, producing or supplying customer retail services to customers supplied on notified prices, ACIL Allen has taken a consistent approach with advice it provided to the QCA 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. The same approach was taken in the Draft Determination of the 2014-15 tariffs.

1.1.2 Estimation of WEC – for Carbon and No carbon cases

In estimating energy costs for the two additional cases (Carbon and No carbon), ACIL Allen has estimated the WEC for two hypothetical situations, using the best available information, given the actual uncertainty around the proposed repeal of the CEA including the timing of any repeal. In these cases it is assumed that the carbon price is \$25.40/tonne CO_2-e in the Carbon case and \$0/tonne CO_2-e in the No carbon case.

ACIL Allen has extracted broker price data for electricity contracts that trade ex-carbon (these contracts incorporate the AFMA addendum which allows the cost of carbon pricing to be added as necessary) for the No carbon case.

For the Carbon case, a full carbon allowance of \$22.10/MWh (the full carbon price of \$25.40 multiplied by the estimated emissions intensity of the NEM) is added to the No carbon case futures price estimates to derive the Carbon case futures price estimates.

ACIL Allen has also used the broker price data in comparison with data on futures prices (which include a market view on the likelihood of the CEA being repealed) to estimate the risk adjusted carbon allowance – i.e. the difference between the No carbon case and the prices at which contracts traded historically.

The other energy costs are assumed to be the same under all carbon pricing cases.

1.2 Methodology

1.2.1 ACIL Allen's best estimate

ACIL Allen’s best estimate methodology is largely the same as the methodology used to provide advice to the QCA for the Draft Determination for 2014-15 (refer to ACIL Allen’s report for the 2014-15 Draft Determination for details of the methodology).

The approach adopted by ACIL Allen 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. Other energy costs are added to the wholesale energy costs and the total is then adjusted for network losses.

The carbon pricing in 2014-15 remains uncertain. For this Final Determination, ACIL Allen has estimated a risk adjusted carbon price of around \$3.00/MWh for ASX Energy futures prices covering 2014-15 by subtracting the ex-carbon broker price contracts with the AFMA addendum from the ASX Energy futures contracts prices. This compares with a risk adjusted price of around \$7/MWh that was estimated for the 2014-15 Draft Determination. The decrease reflects the increasing likelihood of the CEA being repealed.

Given that full effect of carbon pricing would add around \$22.10/MWh to electricity contract costs, the current \$3.00/MWh apparent carbon allowance for 2014-15 suggests that the market is currently factoring in an approximate 1 in 7 chance of the carbon price being retained in 2014-15.

On this basis the cost of energy is taken as the 95th percentile of a distribution containing 3,311 hedged price simulations using contract prices with a risk adjusted carbon price allowance. The distribution was derived by running the hedge model 3,311 times (i.e. 473 annual pool price simulations with the full carbon price in the pool price and 2,838 (6x473) annual pool price simulations with no carbon price in the pool price). This approach meant that a seventh of the simulated hedged prices in the distribution were based on pool prices which included the full carbon price allowance in line with the 1 in 7 chance above[1].

1.2.2 Carbon pricing and No carbon pricing cases

The same methodology is used for the two additional carbon price cases[2] except that the ASX Energy futures contract prices are adjusted:

- in the Carbon price case to incorporate the full carbon price (adjusted for the average emissions intensity of the NEM)
- in the No carbon price case to incorporate a zero carbon price reflecting repeal of the CEA

In each case it is assumed that the carbon price or its repeal was always evident to the market.

ACIL Allen has extracted broker price data for electricity contracts that trade ex-carbon (these contracts incorporate the AFMA addendum which allows the costs associated with a carbon price to be added where it is not repealed). Subtracting these ex-carbon broker contract prices from ASX Energy futures prices that traded around the same time provides an estimate of the risk adjusted carbon allowance in the ASX Energy futures contracts. This risk adjusted carbon estimate has then been subtracted from the actual ASX Energy futures price series to give estimated equivalent futures prices for the No carbon case.

Carbon case futures prices are derived by adding a carbon price allowance of $22.10/MWh (carbon price of $25.40/tCO$_2$-e multiplied by the estimated emissions intensity of the NEM of 0.87tCO$_2$-e/MWh) to the No carbon case futures price estimates.

The Carbon and No carbon case futures prices (base, peak and cap) are used with the normal contracting strategy and pool price modelling that includes or excludes a carbon price to establish the WEC for the Carbon and No carbon cases. In each case the hedge model is run for 473 pool simulations for each settlement class – the Carbon case is based on 473 sets of simulated hourly pool prices with the full carbon price allowance included, and the No carbon case is based on 473 sets of simulated hourly pool prices without a carbon price.

1.2.3 Pool modelling

The pool price modelling involves developing 43 hourly regional demand sets and 11 sets of hourly plant outage profiles to give 473 sets of inputs for the 2014-15 simulations. ACIL Allen's National Electricity Market (NEM) simulator, *PowerMark,* is then run 473 times for each carbon case to give 473 sets of 8,760 hourly prices for 2014-15. These are used in conjunction with the retailer contracting model to estimate the WEC. The pool price modelling is undertaken twice - once with the full carbon price and once without a carbon price, giving two sets of 473 simulations.

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1 As the 3,311 simulations needed to be ordered as a distribution in order to ascertain the 95th percentile, the ratio of carbon to no carbon simulation sets had to be based on integers.

2 These are the two additional cases requested by the QCA, one with full carbon price and the other with no carbon price.

1.2.4 Electricity hedging

The retailer contracting model simplifies the actual contract market in that it is based on observable prices for base, peak and cap contracts only. These building block contracts are used to develop a standardised contract strategy which is then used in conjunction with the two sets of 473 simulations of 2014-15 to estimate the WEC.

The hedged volumes are established for each settlement class on an *ex ante* basis using the 43 sets of simulated hourly demands (the 43 sets of simulated demands for each settlement class are developed in tandem with the development of the 43 sets of regional demands to preserve an appropriate level of correlation).

1.2.5 Other energy costs

Other costs are largely 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)

— NEM management fees as published by AEMO for 2014-15

— Ancillary services as projections from recent history

— Prudential costs based on estimated requirements to post prudentials.

The Queensland Gas Scheme has been discontinued from 1 January 2014 so is not included in the 2014-15 energy cost estimates.

Other energy costs based on market prices have been used in all three carbon pricing cases.

2 Stakeholder submissions

2.1 Introduction

This section responds to a variety of comments and suggestions made in submissions by stakeholders in response to the Draft Determination and raised at the workshop on 17 February 2014.

2.1.1 General themes in submissions

A recurring theme from retailers is that a wider range of hedging instruments should be used in estimating the WEC. It has been argued that other forms of hedging including power purchase agreements (PPAs) and retailer owned generation are bona fide hedging instruments and their actual costs should also be included. The use of LRMC as an alternative to observable contract markets backed by pool simulations also still has widespread support among retailers.

Retailer's again expressed concerns about apparent lack of load variability. In particular, concerns about the use of the 10 per cent probability of exceedence (10% POE) peak demand parameters from the 2013 AEMO National Electricity Forecasting Report (NEFR) to construct the 43 simulated demand sets was cited as a concern. Additionally, retailers have expressed concern that in their view, that the the methodology does not adequately incorporate the effects of successive hot days on peak demand. The main thrust of this is that they consider that extreme demands are underrepresented and hedging risks are not properly represented.

One retailer commented that under the methodology, retailers seemed to be inappropriately profiting from buying caps.

The view has again been expressed that the approach lacks transparency. This, it is argued, makes it difficult for stakeholders to fully comprehend the information and modelling results and provide well based comments and feedback on the process and results.

A number of retailers have suggested that the price of LGCs should be based on the LRMC approach not a pure market approach as the market was a residual source of LGCs and was currently thinly traded.

2.1.2 ACIL Allen's summary response

Following consideration of the various comments and suggestions provided in the submissions, ACIL Allen has not been persuaded to change the overall methodology for estimating hedging costs that was used for the Draft Determination. We continue to be of the view that the market based approach relying on observable electricity market contract data is superior to relying on pricing from long dated contracts or basing the methodology on LRMC. This is, as we have discussed in our work for previous year's determinations, because neither of these alternatives are likely to produce reasonable estimates for energy costs for 2014-15 except for as a matter of coincidence.

However, we have made three refinements since the Draft Determination.

The first relates to the inclusion of extreme demand events in the NSLP load profile as discussed in Section 2.2.

The second refinement is the likelihood of the CEA being repealed is now estimated based on the current inferred carbon allowance in ASX Energy futures not the trade weighted average of the past two years of data. The current carbon price allowance is around $3.00/MWh which suggests that the market is factoring an approximate 1 in 7 chance that carbon pricing will not be repealed. It should be noted that we continue to use the trade weighted average carbon allowance in estimating the contract prices to be used in the hedge model to derive our estimated energy cost.

The third refinement also relates to the estimation of the risk weighted carbon allowance. In the Draft Determination the allowance was calculated on an annual basis. Further analysis of the ASX and OTC data shows the allowance is quite different for the July to September quarter of 2014 compared with the other three quarters of 2014-15, with the data suggesting the market is less convinced the CEA will be repealed within the July to September quarter 2014 – reflecting practical aspects of repealing the legislation through the Senate after the new Senate sits from 1 July 2014.

2.2 Coverage of extreme demand events

As in previous years, some submissions have again expressed concern that the ACIL Allen methodology, for estimating the WEC, results in an under representation of extreme demand events. Given that the ACIL Allen methodology uses the AEMO peak demand forecast as its basis, we continue to be satisfied that extreme demand events are represented for the 42 simulated Queensland demand sets. In our report for the Draft Determination, ACIL Allen provided charts showing the range in modelled price outcomes across a number of metrics (average annual time weighted price, number of and contribution of hourly prices above $300/MWh etc). These charts showed that the modelling produces price outcomes that more than adequately cover the upper end of the distribution of historical outcomes.

Increasing the annual peak demand for Queensland beyond the AEMO 10% POE peak demand for two or three of the 43 demand sets will have a negligible effect if any on the final estimated WEC given we are using the 95th percentile modelled hedged price outcome. This conclusion is based on the general observation that years of higher demand generally have higher annual pool price outcomes but subdued annual hedged price outcomes because the high volume, low risk hedging strategy. This means that generally these higher demand years would tend to be at the lower end of distribution of annual hedged prices and when taken with the flatness of the distribution at the upper end, would have little or no effect on the 95th percentile value.

Furthermore, in our reports for previous determinations we have demonstrated that historically, the peak demand for Queensland does not occur at the same time as the peak demand for the Energex NSLP, so increasing a small number of peak demands for Queensland does not guarantee an increase in the Energex NSLP peak demand nor does it guarantee an increase in the demand weighted price of the Energex NSLP.

Submissions also continued to have similar concerns about the methodology for estimating the 43 Energex NSLP demand sets, in particular the under representation of extreme demand events. Figure 1below shows the daily peak demands for the Energex NSLP for the summers of 2012-13 and 2013-14 against the corresponding maximum daily temperature at Archerfield.

The daily peak demands have been split into three groups based on the daily maximum temperature. It can be seen that:

— there is no change in demand (aside from noise) in response to temperature when the daily maximum temperature is less than or equal to 30 degrees Celsius
— the effect of temperature on demand is strongest between 30 and 35 degrees Celsius
— the effect of temperature on demand weakens as the daily maximum temperature exceeds 35 degrees Celsius.

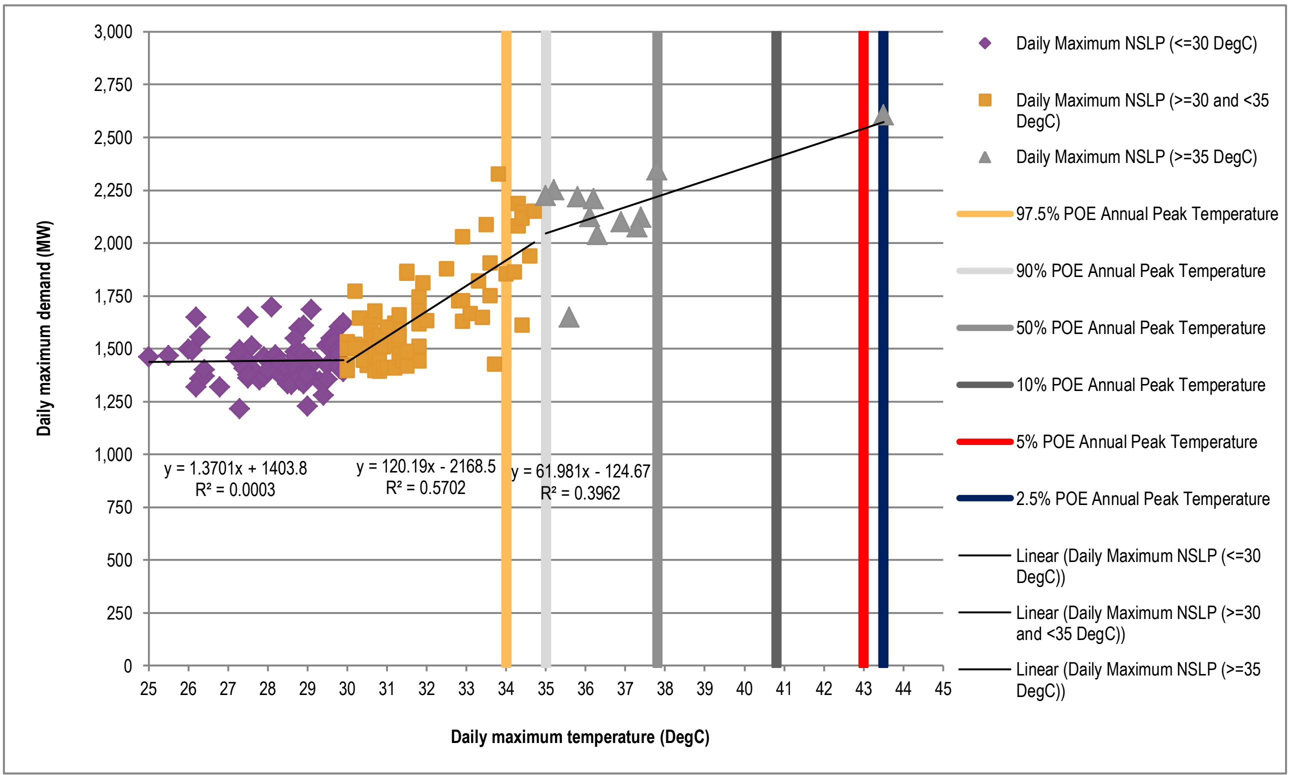
Based on this data, when the maximum daily temperature exceeds 35 degrees Celsius the effect of temperature on the Energex NSLP peak demand is about half of the effect when the temperature is between 30 and 35 degrees Celsius. This is the precise point we were attempting to make in our Draft Determination report – the response of the Energex NSLP demand to temperature diminishes when the temperature exceeds 35 degrees.

Figure 1 includes vertical lines showing the distribution of the annual maximum temperature at Archerfield between 1939[3] and 2014. Consideration of the distribution of annual maximum temperatures against the observed maximum demands helps explain the shape of the distribution of the 43 annual peak demands derived by our methodology. With the exception of the lower 10 percentile, the annual maximum temperatures over the past half a century have occurred in the region of the demand/temperature response curve which is less responsive to temperature. This is why our methodology tends to derive a set of 43 simulated annual peak demands which:

— are not strongly increasing in the upper 50 percent of the 43 demand sets
— exhibit a noticeable drop off in the lower part of the distribution.

[3] There is a gap in temperature data between 1950 and 1984, but the data between 1939 and 1949 was included in the analysis as it includes some extreme temperature recordings.

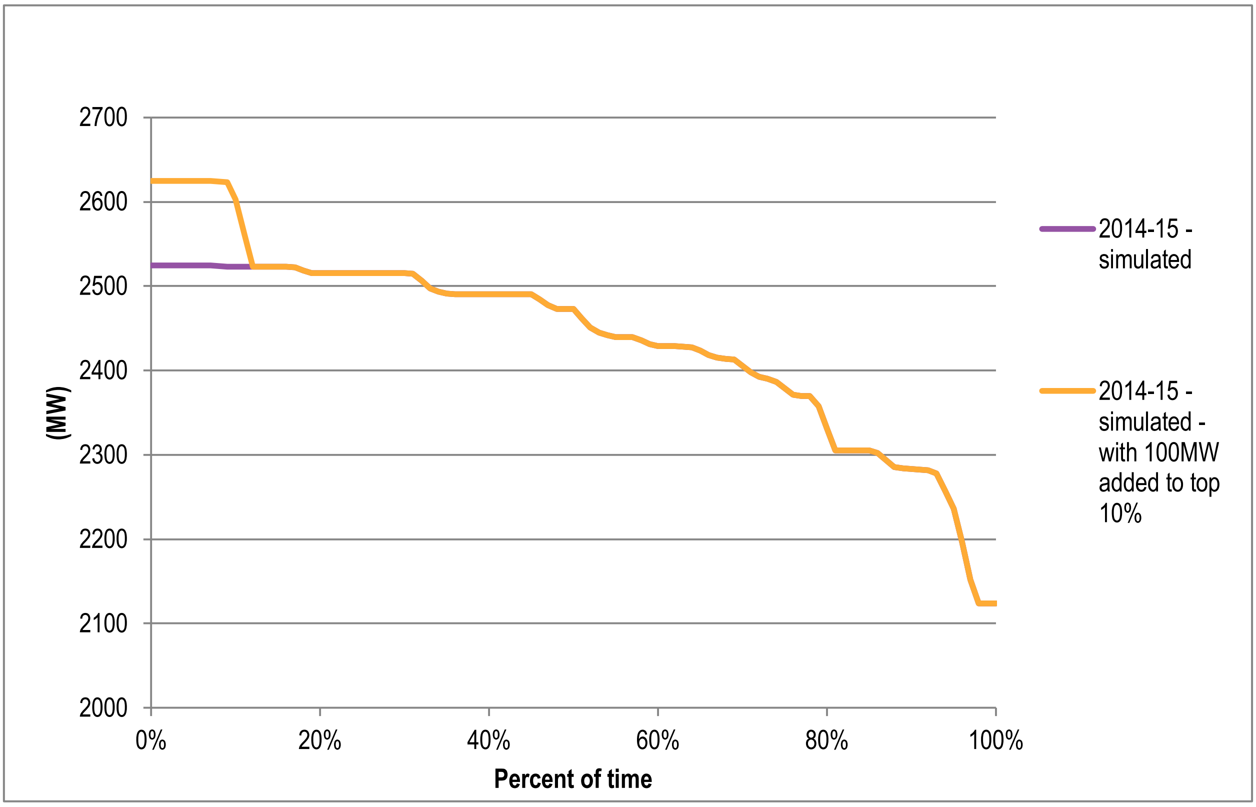
Figure 1 **Daily peak Energex NSLP demand versus daily maximum temperature at Archerfield – for summers 2012-13 and 2013-14**



Source: ACIL Allen analysis and AEMO and BOM data

Figure 2 shows the resulting distribution of annual peak demands for the Energex NSLP for 2014-15 from the 43 simulated demand sets. Although there is a degree of flatness in the upper 10% of the distribution of simulated annual peak demands for the Energex NSLP, the associated annual load factors range between 37.1% and 44.3% compared with a range of 39.6% to 43.3% for the actual Energex NSLP between 2008-09 and 2012-13. Despite being satisfied with the derived demands, ACIL Allen has added 100MW to the top one percent of hourly demands for the demand sets that have a peak demand in the top 10 percent – this is also shown in Figure 2. The added value of 100MW was derived by assessing the difference between the line of best fit (as shown in Figure 1) and the upper edge (or envelope) of the distribution of observed demand outcomes for temperatures above 35 degrees Celsius, reflecting the possible upper bound of the Energex NSLP.

Figure 2 **Energex NSLP simulated annual peak demand – 2014-15**



Note: Demands are presented after the solar PV contribution has been deducted
Source: ACIL Allen analysis and AEMO and BOM data

In terms of estimating the WEC for the Energex NSLP the key aspects of the NSLP demand profile are:

- its relationship with the Queensland demand profile
- its peakiness.

We have used our best endeavours to ensure that both of these aspects are appropriately maintained in the simulated Energex NSLP profiles. The relationship with the Queensland demand profile is based on past observations adjusted for the impact of estimated Solar PV installations. We have observed for example that in summer the Energex NSLP peaks later in the evening than the Queensland demand and this relationship has been preserved in the 2014-15 load profiles. As pool prices are less likely to be highly volatile at the time of the Energex NSLP peak the profile itself offers retailers volume and price risk diversification with respect to other commercial and industrial loads that they might have contracted to serve.

2.2.1 Consecutive hot days

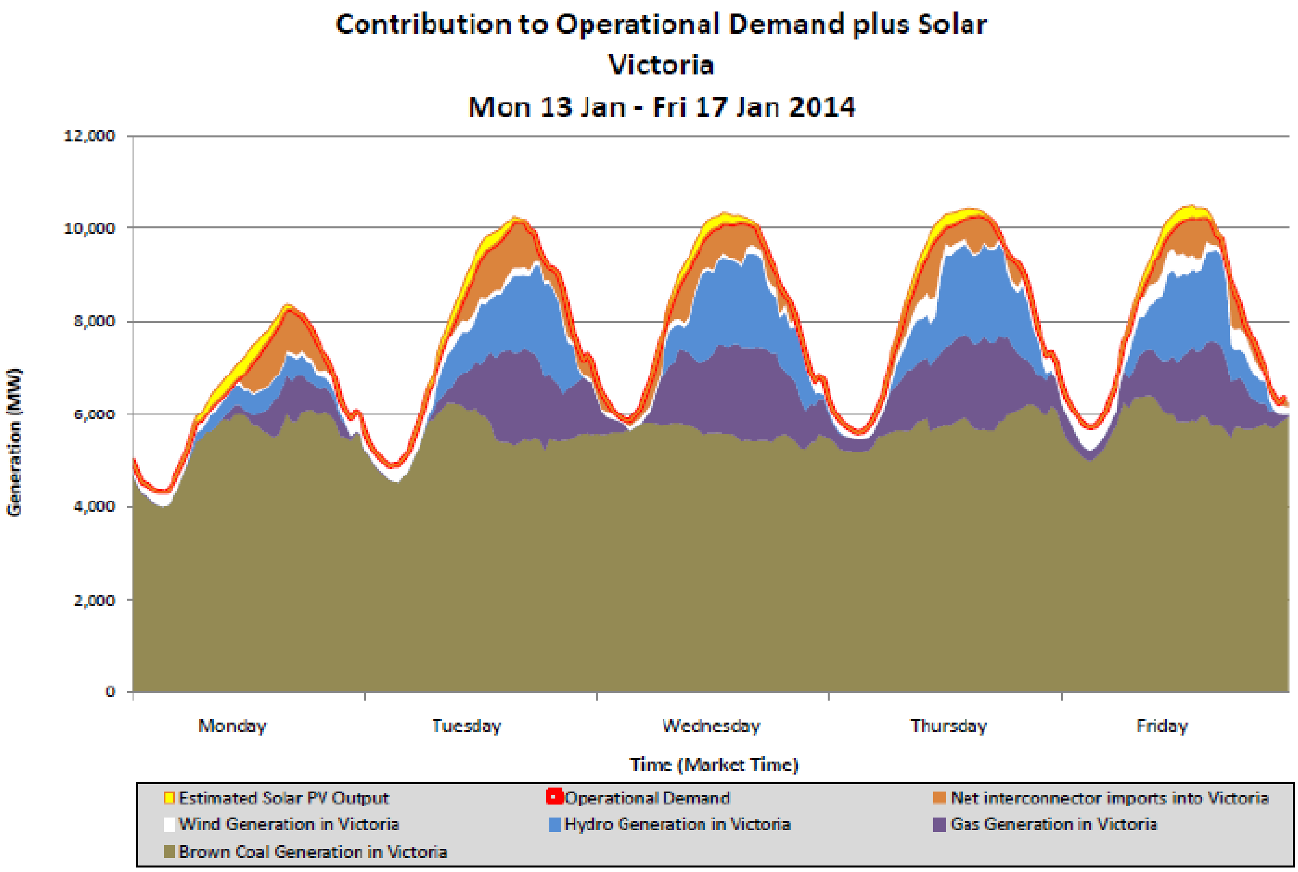
A lack of consecutive hot days over the past four years remains an issue in some submissions with respect to our demand simulation methodology. Although we have addressed this issue in the past, the recent heatwave in Victoria and South Australia in January 2014 provides some support for our scepticism that consecutive hot days have a profound effect[4] on peak demand outcomes. The Introduction on page 3 of the AEMO report titled, *HEATWAVE 13 – 17 JANUARY 2014,* summarises the heatwave as follows:

> Victoria and South Australia experienced record temperatures between Monday 13 January and Friday 17January 2014.
>
> Details for the heatwave in South Australia are:
>
> - First ever five-day period above 42 °C (13-17 Jan 2014).
> - Hottest five-day maximum temperature on record (13-17 Jan 2014).
> - Hottest maximum five-day average temperature: 43.6 °C.
> - Fourth hottest day on record (45.1 °C, 14 Jan 2014).
>
> Details for the heatwave Victoria are:
>
> - First ever four-day period above 41°C (14-17 Jan 2014).
> - Hottest four-day maximum average temperature on record (14-17 Jan 2014).
> - Hottest maximum temperature four-day average: 43.1°C.

The two graphs below are taken from AEMO's report and plot the 5 minute demand for Victoria and South Australia during the heatwave. Despite the consecutive hot days, there appears to be minimal variation in the daily peak demand throughout the course of the week – certainly insufficient growth to add support to the argument that consecutive hot days have a profound effect on regional demand.

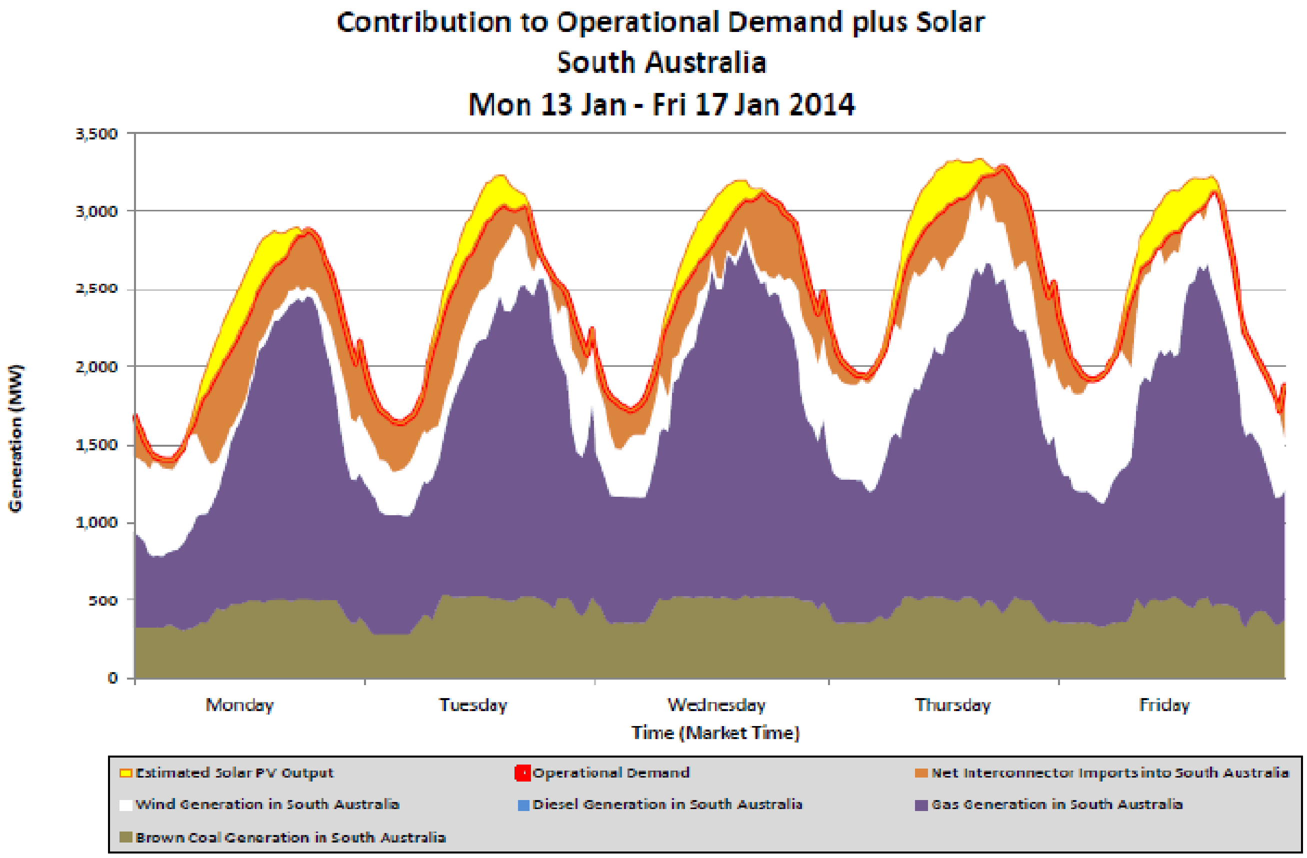
[4] ACIL Allen is not suggesting there is no effect, but rather the effect may well not be as great as suggested in the submissions.

Figure 3 **Victorian demand – 13 January to 17 January 2014**



Source: AEMO report, *HEATWAVE 13 – 17 JANUARY 2014*

Figure 4 **South Australian demand – 13 January to 17 January 2014**



Source: AEMO report, *HEATWAVE 13 – 17 JANUARY 2014*

2.3 Price simulation results

2.3.1 Spot market prices

In the interests of providing greater transparency to stakeholders, in our report for the Draft Determination we provided a number of general observations about the results derived by applying the ACIL Allen methodology. These results demonstrated that there is a wide range of simulated pool price outcomes which we are satisfied covers the expected range of outcomes over the period 2014-15 and are hence not repeated here.

However, Energy Australia included an additional metric in their submission - prices between $70 and $300/MWh - and suggested the volatility in modelled hourly prices between $70/MWh and $300/MWh is understated.

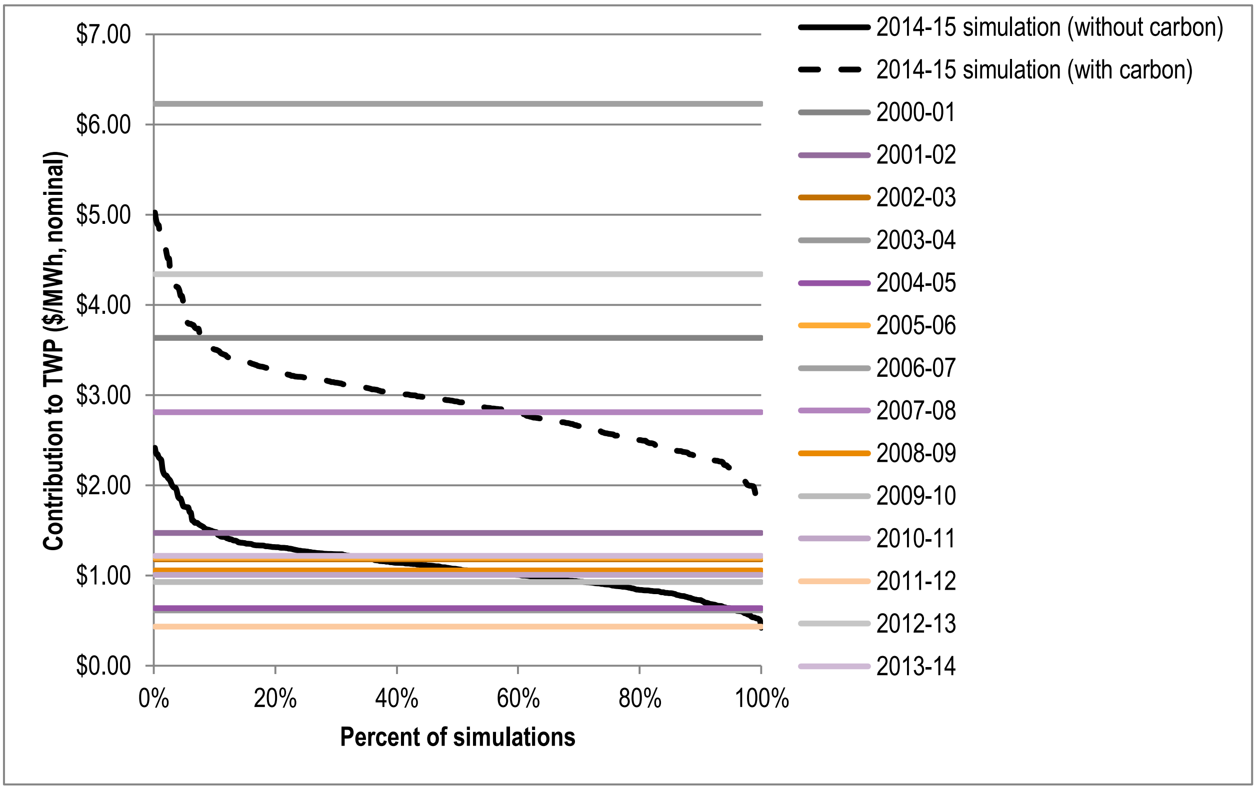
Figure 5 shows the range in annual average contribution to the Queensland time weighted price (TWP), of hourly prices between $70/MWh and $300/MWh, for the 473 simulations is consistent with those recorded in history. Figure 5 also shows the inclusion of a carbon price increases the contribution of prices between $70/MWh and $300/MWh (both for the 2014-15 simulation and the observed outcomes for 2012-13 and 2013-14 to date), which is not surprising given that prices in this range will be influenced by the SRMC of gas fired peaking plant which emit carbon (albeit at lower levels than coal fired generators).

At the peak of the drought in 2006-07 scarcity of water for hydro generation and some water cooled coal fired plant increased the opportunity cost for generation from these technologies and hence increased the number of price outcomes in the $70 to $300 price range, thereby increasing the contribution of these prices to the annual price to about $6.20/MWh. The simulation of 2014-15 does not produce outcomes to the extent that were experienced during the drought – but we are assuming (in our view quite reasonably[5]) that the drought conditions of 2006-07 are not repeated in 2014-15.

A similar conclusion can be reached when considering the contribution of prices between $70/MWh and $300/MWh to the demand weighted price (DWP) of the Energex NSLP as shown in Figure 6. Not only does this demonstrate the reasonableness of the modelling in terms of volatility in the prices between $70 and $300/MWh, it also demonstrates the reasonableness of the modelling in terms of the matching in the timing of price volatility in the $70 to $300/MWh price range with the timing/profile of the NSLP simulated demand sets.

5 Wivenhoe Dam, the main culprit in 2006-07 is currently at 92%.

Figure 5 **Annual average contribution to the Queensland TWP by prices between $70/MWh and $300/MWh in the modelled simulations and recorded in the past**



Source: AEMO historical pool price data and ACIL Allen results from *PowerMark* modelling

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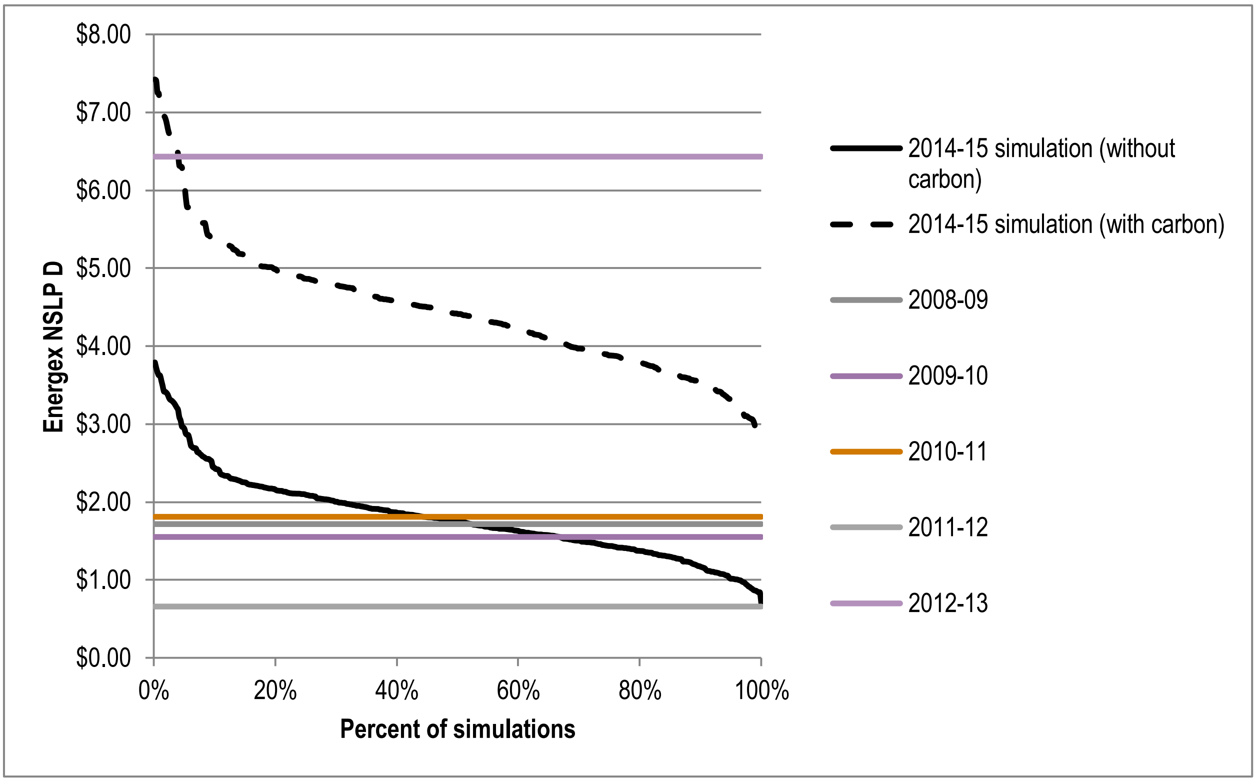
Figure 6 **Annual average contribution to the Energex DWP by prices between $70/MWh and $300/MWh in the modelled simulations and recorded in the past**



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

2.4 The effects of increasing top 10 percent NSLP peak demands by 100MW

As discussed in Section 2.2, ACIL Allen has added 100MW to the top one percent of hourly demands for the Energex NSLP demand sets which had an annual peak demand in the top 10 percent of the 43 simulated demand sets. The effects of this are shown in Table 1 for the No carbon price case. The 95th percentile spot price outcome increases by less than $1/MWh (or an increase of less than 10 percent) – although this is a reasonable increase, and not unexpected, this increase is, as expected, tempered by the hedging strategy.

It is worth noting that the increase in NSLP demand volatility does not change the hedging strategy since the volume of caps is derived from the median of the 43 annual peak demands, and the volume of peak and off-peak swaps are derived as a function of the median of all hourly demands across the 43 demand sets, peak and off-peak respectively. In other words, the increase in demand volatility combined with no change in hedging volumes means there is an increase in the number of simulations in which the simulated demand profiles are not fully covered by hedges. Despite this, the impact on the 95th percentile hedged price outcome is nil – this is because the 95th percentile outcome corresponds to a demand set which does not contain an annual peak demand in the top 10 percent of annual peak demands. Although 10 percent of the 473 simulated outcomes experience an increase in price, as shown in Figure 7, these increases are insufficient to change the value of the 95th percentile.

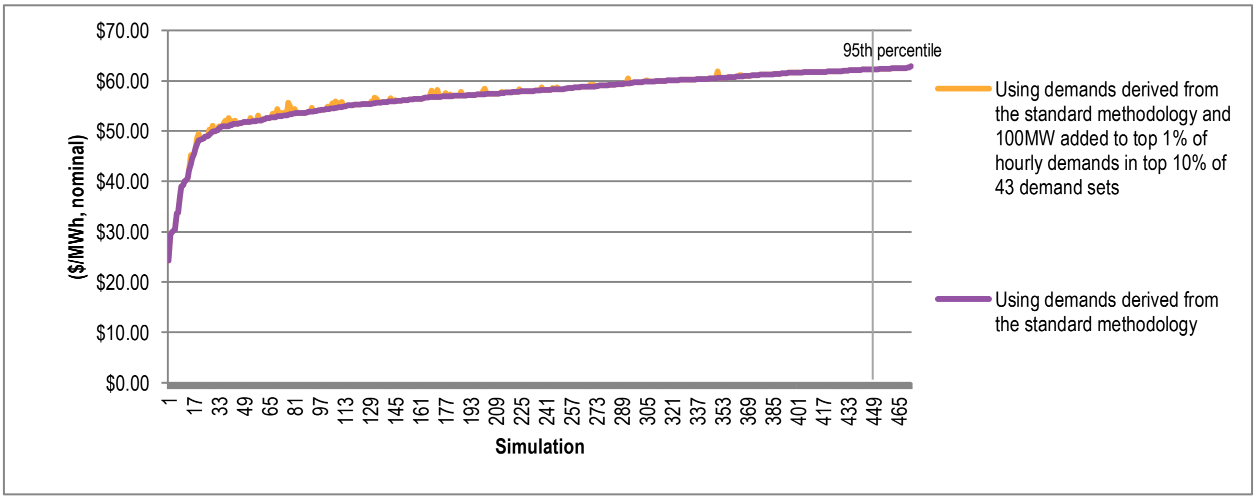
Table 1 **Summary of simulated hedged and spot price outcomes ($/MWh) for Energex NSLP 2014-15 – with adjusted demands – without carbon**

	Hedged outcomes		Spot outcomes	
	Using demands derived from the standard methodology	Using demands derived from the standard methodology and 100MW added to top 1% of hourly demands in top 10% of 43 demand sets	Using demands derived from the standard methodology	Using demands derived from the standard methodology and 100MW added to top 1% of hourly demands in top 10% of 43 demand sets
Average	$57.02	$57.11	$61.26	$61.35
95th percentile	$62.26	$62.26	$93.36	$94.20

Note: Excludes a carbon price from both the pool modelling and contract prices.

Source: ACIL Allen modelling

Figure 7 **Annual hedged price for Energex NSLP 2014-15 for 473 simulations – with adjusted demands – without carbon**



Note: Excludes a carbon price from both the pool modelling and contract prices.

Source: ACIL Allen modelling

2.5 The effects of hedging

The ACIL Allen methodology uses a simplified hedge book approach based on standard quarterly base and peak swaps and caps. The prices for these hedging instruments are taken from the futures market supplied by ASX Energy.

Based on comments in some submissions, there appears to be some confusion as to how the hedge volumes are determined. Quarterly hedge volumes are calculated for each settlement class as follows:

- The base contract volume is set to equal the 80th percentile of the off-peak period hourly demands across all 43 demand sets for the quarter.
- The peak period contract volume is set to equal the 90th percentile of the peak period hourly demands across all 43 demand sets for the quarter.
- The cap contract volume is set at 105 per cent of the median of the annual peak demands across the 43 demand sets minus the base and peak contract volumes.

In other words, the same hourly hedge volumes (in MW terms) apply to each of the 43 demand sets for a given settlement class, and hence to each of the 473 simulations. Some submissions appear to have misinterpreted the hedging strategy and suggest we are altering the hedge volume (in MW terms) on an ex-post basis for each of the 43 demand sets – this is not the case. Therefore, the approach we use results in a hedging strategy that does not rely on perfect foresight but relies on an expectation of the distribution of hourly demands across a range of temperature outcomes.

Submissions suggested that we need to look at not just the demand methodology but the hedging methodology. ACIL Allen tested 125 different hedging strategies against the Energex NSLP demands (which were adjusted by including the additional 100MW for the top one percent of hourly demands in the top 10 percent of the 43 demand sets).

The different strategies are a combination of five variations of each of the base, peak and cap volumes:

- The base contract volume is set to equal the 80th, 70th, 60th, 50th or 40th percentile of the off-peak period hourly demands across all 43 demand sets for the quarter.
- The peak period contract volume is set to equal the 90th, 80th, 70th, 60th or 50th percentile of the peak period hourly demands across all 43 demand sets for the quarter.
- The cap contract volume is set at 105, 95, 85, 75 or 65 per cent of the median of the annual peak demands across the 43 demand sets minus the base and peak contract volumes.

The top graph in Figure 8 shows the results of applying the 125 different hedging strategies to the 473 simulations for the Energex NSLP (for simulations without a carbon price). For each strategy the minimum, average, 95th percentile and maximum of the 473 annual hedged prices is shown. The corresponding percentiles of the 473 annual spot prices are also shown for reference (noting these are unaffected by the hedging strategy). The second graph shows the order of the strategies in terms of cap, peak and off-peak volumes. **Strategy number 1 (i.e. the left most strategy on** Figure 8**) is the <u>standard strategy</u> used to date in all determinations ACIL Allen has been involved in advising**. In general terms, the volume of contracts decreases from left to right in the graph. Figure 9 presents a subset of the data from Figure 8 – focusing on the 95th percentile outcome.

As the overall volume of contract cover decreases (from left to right in the graphs) the hedged price tends to increase and becomes slightly more volatile – this is not surprising since as the proportion of demand covered by contracts approaches zero the hedged price will converge to the more volatile spot price outcomes.

Whilst a decrease in peak swap volume results in a slight increase in hedged price, it is the change in cap volume which has the biggest influence on the hedge price outcomes.

Focusing on the 95th percentile outcomes (Figure 9) it can be seen that decreasing the cap volume from the standard 105 percent of the median annual peak demand to 95 percent of the median annual peak demand decreases the hedged price by about $2/MWh. Continuing to decrease the cap volume below 95 percent reverts to an increasing effect on the hedged price. In other words, using 95 percent of the median annual peak demands to set the cap volume, as part of a hedging strategy, represents the minimum 95th percentile hedged price outcome.

For a given volume of cap cover, a decrease in peak contract volume increases the 95th percentile hedge price; and this increase is amplified when the cap volume declines. Conversely, a decrease in base contract volume tends to results in a decrease in the 95th percentile hedged price outcome and this decrease is curtailed when the cap volume declines.

The lowest 95th percentile hedged price outcome (referred to below as the minimum strategy) is about $3/MWh lower than that of the standard hedging strategy, and occurs with hedging strategy number 30 consisting of:

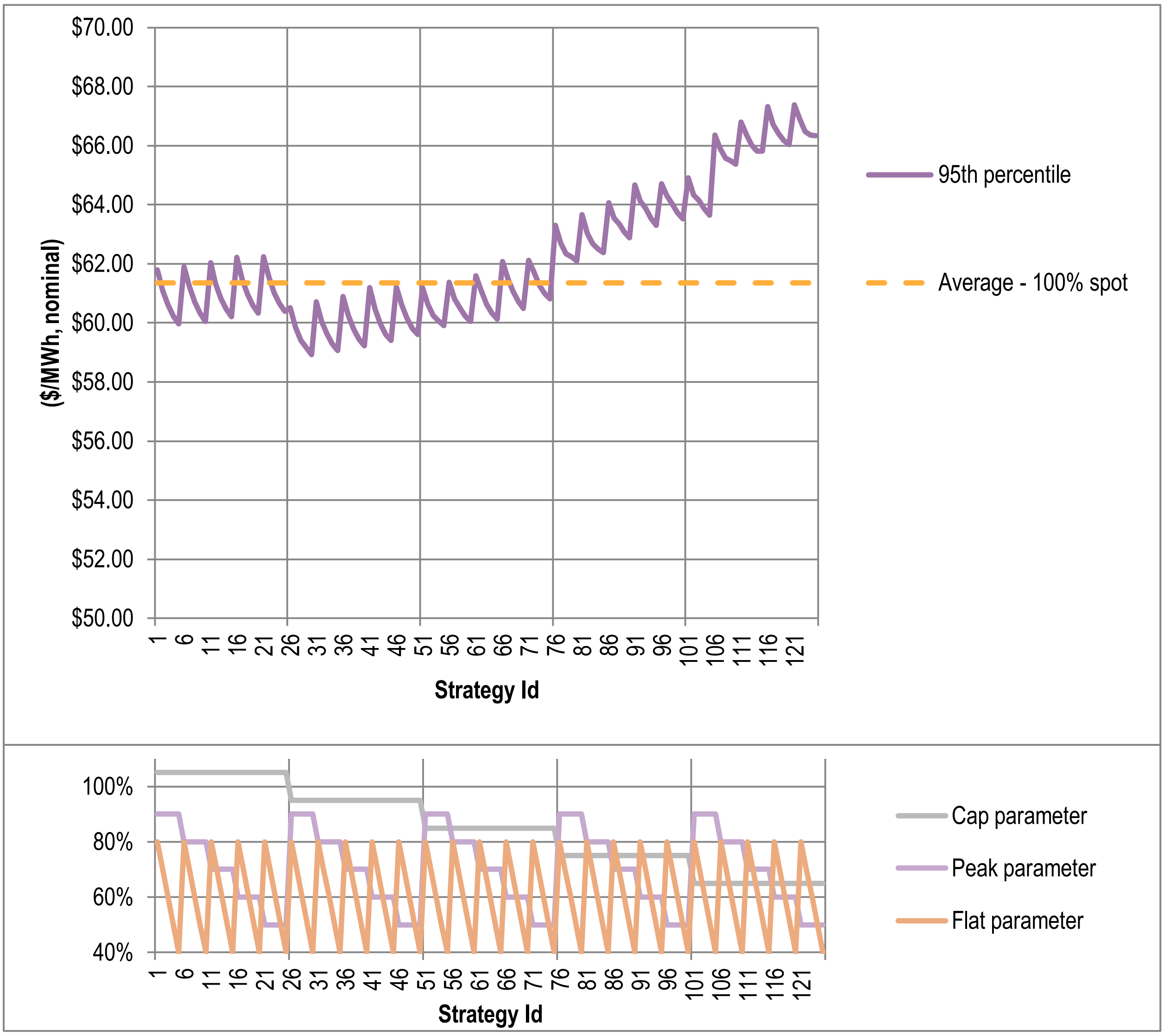
- the base contract volume set to equal the <u>40th</u> percentile of the off-peak period hourly demands across all 43 demand sets for the quarter
- the peak period contract volume is set to equal the <u>90th</u> percentile of the peak period hourly demands across all 43 demand sets for the quarter
- the cap contract volume is set at <u>95</u> per cent of the median of the annual peak demands across the 43 demand sets minus the base and peak contract volumes.

In other words, the standard hedging strategy (number 1) by having a higher level of contract cover could be regarded as being more conservative or risk averse than the minimum strategy (number 30), and in effect is over contracting the demand profile with flat swaps and to a lesser degree, over contracting with caps. However, moving to the minimum strategy with its lower cap and base swap cover, while providing a lower 95th percentile hedged price than the standard strategy, has higher maximum and minimum prices. On this basis ACIL Allen does not propose to depart from the standard contracting strategy given that the strategy is designed to be low risk and produces a 95th percentile price which is close to the minimum strategy.

Figure 8 **Summary of 2014-15 annual hedged price and spot DWP ($/MWh) for the 473 simulations by hedging strategy - Energex NSLP – without carbon**

Note: Excludes a carbon price from both the pool modelling and contract prices.
Source: ACIL Allen modelling

Figure 9 **Summary of 95th percentile hedged price and average spot DWP ($/MWh) for the 473 simulations by hedging strategy - Energex NSLP – without carbon**



Note: Excludes a carbon price from both the pool modelling and contract prices.

Source: ACIL Allen modelling

2.5.1 Profit from caps

Origin in its submission suggests the impact of the hedging strategy is that for "*both years modelled since the QCA adopted this new approach*" the modelled retailer receives a net income from its cap purchases which is highly implausible. We agree that this would be highly implausible, although not impossible in extreme circumstances (i.e. if the pool price volatility was much greater than that allowed for in the cap price).

ACIL Allen is unsure as to how Origin arrived at this conclusion as our report for the 2013-14 Final Domination shows for the 95th percentile case, the cost of purchasing the caps is

$47.43M and the cap payout (to the retailer) is $6.01M – a net cost of $41.42M. Further, our report for the 2014-15 Draft Determination does not include this data so it is not possible to make such a claim.

ACIL Allen can confirm for the 2014-15 Final Determination, for the 95th percentile case, the cost of purchasing the caps is $44.108M and the cap payout (to the retailer) is $3.55M – a net cost of $40.56M (which when averaged across the energy for the year, is a cost of $4.93/MWh).

2.6 LRMC approach to estimating LGC prices

Some retailers have continued to call for use of an LRMC approach to estimate the price of LGCs.

As we indicated in our Draft Determination report, we believe that transparent market prices provide a much better indicator of current prices compared with any modelled outcomes. A modelled price should only be used where market pricing is not available. No material was supplied in the submissions to persuade us to change this view.

As we have already indicated there are a number of problems with using a LRMC approach for LGC prices. LRMC is a long run (a period of time over which all factors of production may be varied) and forward looking concept and in the case of LGC would be expected to largely relate to future wind which is currently (and for the foreseeable future) the lowest cost form of large-scale renewable power generation.

LRMC can be classified under two broad headings, being the brownfields and greenfields approaches. Brownfields is the more traditional approach in that it considers the existing market status and then assesses the long run costs of meeting an incremental increase in demand (in this case demand for LGC). Greenfields generally assumes that the complete market demand is met by new supply – in effect more of an average cost concept of meeting all existing plus future supply over a specified time period.

For the purpose of the following discussion we use a greenfields approach as it is simpler to calculate. In effect we are interested in the long run average costs of new build wind generation. Taking a specific example of a 25 year wind project with the following settings:

- $2,300/kW installed overnight capacity cost; 18 month construction period
- $50,000/MW/year fixed operating and maintenance cost; zero variable cost
- 35% capacity factor
- WACC of 7% (post-tax real).

This yields a calculated LRMC of around $95/MWh.[6] This means that such a project would need to achieve revenues that equate to $95/MWh on average in real terms of the 25 years in order to be commercially viable. However there are two components to this revenue: black energy revenue from sales of electricity and LGC revenue. There are a large number

[6] There would likely be broad agreement that the LRMC of wind is currently somewhere in the vicinity of $85-110/MWh (noting that the assumed capacity factor is a principal determinant in this calculation).

of factors which will impact black energy prices over this 25 year period including the supply demand balance in the market and the carbon pricing assumption.

Assuming no future changes to the renewable energy scheme, to obtain the estimated levelised LGC price required, one needs to have a view on the levelised black energy component of this revenue stream over the 25 year project life (including any future changes with respect to carbon). To illustrate the effect of black prices we consider three scenarios as detailed in Table 2 which result in different levelised costs for the LGC revenue component (assumes no changes to the LRET scheme). This analysis assumes a 2015 wind installation which would receive 16 years of LGC revenue (the LRET ends in 2030) and 25 years of black energy revenue. In each case the present value of the revenue stream is the same at $3,386 million per MW installed.

Table 2 **LRMC of LGC prices based on various black energy scenarios**

Black price scenario	Required levelised LGC price
$55 flat in real terms	49.06
$55 increasing at 2% in real terms	35.66
$55 decreasing at 2% in real terms	59.41

Note: Assumes a 2015 installation (16 years of LGC creation; 25 years of black energy revenue)

Clearly the use of LRMC in estimating LGC prices requires a significant shift in modelling approach across to LRMC and requires at least a 25 year outlook for black energy prices. It is also dependent on an estimate of the LRMC of the marginal renewable energy supplier which for wind alone covers a possible range from $85/MWh to 110/MWh.

While the above discussion shows that using LRMC to determine LGC prices is largely impractical, there are broader issues with respect to the use of LRMC similar to its use in estimating wholesale energy costs. In particular, any calculation of LRMC is unlikely to be reflective of the actual costs faced by a retailer in supplying non-market customers in Queensland with electricity retail services in 2014-15, except as a matter of coincidence.

2.7 STC Price

ACIL Allen notes that apart from QCOSS most making submissions agree with the use of the $40.00 as set by the Clearing House. We are not convinced that the current market price for STCs provides a sound measure of prices in 2014-15. This is because historical prices might not be the best indicator of future prices as the market is designed to clear every year In theory prices could be $40 or at least very close to it. This assumes that the Clean Energy Regulator sets the STP at the level where the market just clears valuing STCs at the Clearing House price of $40.00.

3 Estimation of wholesale energy cost (WEC)

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

3.1 Outline of approach

The approach adopted by ACIL Allen 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 473 simulations of 2014-15, estimated using ACIL Allen'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 Allen 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. Furthermore ACIL Allen is of the view that the traded market derivatives provide a sound basis for evaluating the actual cost of energy to retailers. In addition, 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.

A more detailed description of the ACIL Allen approach is included in the report for the Draft Determination.

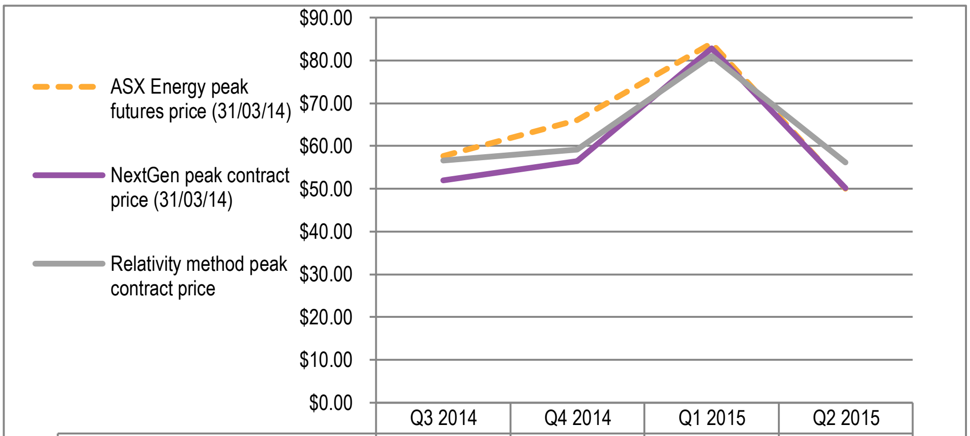
3.1.1 Estimating contract prices (Risk adjusted carbon case)

Contract prices for Queensland in the Risk adjusted carbon case were estimated using the trade-weighted average of ASX Energy daily settlement prices since the contract was listed and up until and including the cut-off date of 31 March 2014.

Due to insufficient trading of ASX Energy peak contracts in Queensland, the peak contract prices in the Risk adjusted carbon case were found by selecting the maximum of peak contract prices from three sources - ASX Energy futures data, NextGen broker data and an adjustment to the ASX Energy data using a relativity factor based on the 2013-14 Final Determination peak, base and cap contract prices.

Quarterly peak prices for Queensland from the three sources are shown in Figure 10 and are very similar. The maximum estimate in each quarter was selected to minimise the risk of underestimating the contract price.

Figure 10 **Estimated quarterly peak contract prices for Queensland in 2014-15**



	Q3 2014	Q4 2014	Q1 2015	Q2 2015
ASX Energy peak futures price (31/03/14)	$57.64	$66.00	$84.00	$50.00
NextGen peak contract price (31/03/14)	$51.95	$56.47	$82.92	$50.21
Relativity method peak contract price	$56.56	$59.21	$81.04	$56.18

Source: ACIL Allen analysis using ASX Energy and NextGen data

Table 3 compares the estimated quarterly swap and cap contract prices for the Final and Draft Determinations for 2014-15.

Table 3 **Quarterly base, peak and cap estimated contract prices for Queensland - Risk adjusted carbon case – Final Determination versus Draft Determination 2014-15 ($/MWh)**

	Final Determination 2014-15			
	Q3 2014	Q4 2014	Q1 2015	Q2 2015
Base	$49.46	$50.52	$60.76	$45.73
Peak [a]	$57.64	$66.00	$84.00	$56.18
Cap	$3.52	$5.91	$12.07	$3.75
	Draft Determination 2014-15			
	Q3 2014	Q4 2014	Q1 2015	Q2 2015
Base	$50.54	$51.96	$63.91	$48.85
Peak	$59.52	$66.00	$90.50	$53.50
Cap	$3.39	$5.68	$13.37	$3.75
	Change (Final minus Draft)			
	Q3 2014	Q4 2014	Q1 2015	Q2 2015
Base	-$1.07	-$1.44	-$3.15	-$3.11
Peak	-$1.89	$0.00	-$6.50	$2.68
Cap	$0.13	$0.23	-$1.30	$0.00

[a] Peak contract prices were estimated using the maximum of the three estimates in Figure 10 and as described in this subsection.

Data source: ACIL Allen analysis using ASX Energy and NextGen data up to, and including 31 March 2014.

Base contracts for Queensland in the Final Determination for 2014-15 are $2.19/MWh lower on average than base contracts used in the Draft Determination for 2014-15. Peak contracts for Queensland in the Final Determination for 2014-15 are $1.41/MWh lower on average and average cap contracts are marginally lower than that used in the Draft Determination for 2014-15. Final Determination contract prices are lower than the Draft Determination contract prices because the Final Determination contract prices incorporate a lower risk adjusted allowance for carbon. In fact, the underlying contract prices when removing the effects of carbon are higher in the Final Determination (as discussed in more detail in Section 3.1.2)

Table 4 compares the estimated quarterly swap and cap contract prices for Queensland for the Final Determination for 2014-15 and the Final Determination for 2013-14.

Table 4 **Quarterly base, peak and cap estimated contract prices - Risk adjusted carbon case – Final Determination 2014-15 and Final Determination 2013-14 ($/MWh)**

	Final Determination 2014-15			
	Q3 2014	Q4 2014	Q1 2015	Q2 2015
Base	$49.46	$50.52	$60.76	$45.73
Peak a	$57.64	$66.00	$84.00	$56.18
Cap	$3.52	$5.91	$12.07	$3.75
	Final Determination 2013-14			
	Q3 2013	Q4 2013	Q1 2014	Q2 2014
Base	$54.20	$55.60	$66.19	$53.62
Peak	$60.79	$65.93	$87.95	$60.83
Cap	$3.27	$7.03	$12.95	$2.59
	Change (2014-15 minus 2013-14)			
	Q3	Q4	Q1	Q2
Base	-$4.74	-$5.08	-$5.43	-$7.89
Peak	-$3.16	$0.07	-$3.95	-$4.66
Cap	$0.25	-$1.12	-$0.88	$1.16

[a] Peak contract prices were estimated using the maximum of the three estimates in Figure 10 and as described in this subsection.

Data source: ACIL Allen analysis using ASX Energy and NextGen data up to, and including 31 March 2014.

The average base contract price for 2014-15 is $5.78/MWh lower than that used in the Final Determination for 2013-14. The average peak contract price is $2.91/MWh lower and the average cap price is marginally lower than that used in the Final Determination for 2013-14. Final Determination contract prices for 2014-15 are lower than Final Determination contract prices for 2013-14 because the market is factoring in a much lower likelihood of there being a price on carbon throughout 2014-15.

3.1.2 Contract prices without carbon pricing (No carbon case)

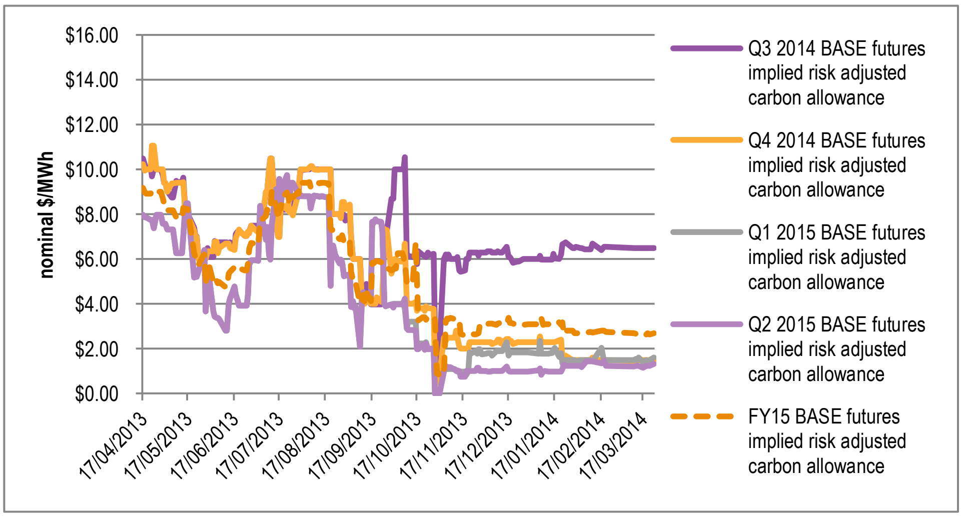
Contract prices *without* carbon pricing were found by subtracting the quarterly risk adjusted carbon allowance from the Final Determination ASX Energy contract prices in Table 3.

The quarterly risk adjusted carbon allowance was found by calculating the trade-weighted average of daily differences between ASX Energy quarterly futures and NextGen over-the counter (OTC) quarterly contracts with the AFMA addendum[7], where daily prices existed. This analysis uses data covering the period from April 2013.

Due to unavailable broker data for Q1 2015 and Q2 2015 AFMA contract prices prior to October 2013, the risk adjusted carbon allowance for Q1 2015 and Q2 2015 prior to October 2013 was inferred using AFMA contract prices for the 2014-15 financial year, along with Q3 2014 and Q4 2014 AFMA contract prices and assumes Q1 2015 and Q2 2015 have equal risk adjusted carbon allowances prior to October 2013.

Figure 11 shows the time series of the risk weighted carbon allowance implied in the ASX Energy base quarterly futures.

Figure 11 **Risk adjusted carbon allowance implied in quarterly ASX Energy base futures for Queensland ($/MWh)**



Source: ACIL Allen analysis based on ASX Energy and NextGen data

Using this method, the risk adjusted carbon allowance for 2014-15 was estimated to be $6.90/MWh for Q3 2014, $4.89/MWh for Q4 2014, $2.89/MWh for Q1 2015 and $3.02/MWh for Q2 2015 and are shown in Table 5.

[7] OTC contracts with the AFMA addendum are contracts where prices are quoted without carbon and the carbon cost is added at prevailing carbon price.

Table 5 **Quarterly risk adjusted carbon allowance for Queensland - Final Determination 2014-15 ($/MWh)**

	Final Determination 2014-15			
	Q3 2014	Q4 2014	Q1 2015	Q2 2015
Risk adjusted carbon allowance implied in quarterly base futures	$6.90	$4.89	$2.89	$3.02

Data source: ACIL Allen analysis using ASX Energy and NextGen data to 31 March 2014.

This method applies to the base and peak contracts only. The carbon price has very little or no influence prices greater than $300, and therefore cap contract prices are the same in all three carbon pricing scenarios.

Table 6 shows the estimated quarterly base, peak and cap contract prices without carbon pricing (used in the No carbon case) for the Final Determination. The No carbon base and peak contract prices in Table 6 are derived by subtracting the risk adjusted carbon allowance in Table 5 from the carbon risk adjusted contract prices in Table 4.

Table 6 **Quarterly base, peak and cap estimated contract prices for Queensland - No carbon case – Final Determination 2014-15 ($/MWh)**

	Final Determination 2014-15			
	Q3 2014	Q4 2014	Q1 2015	Q2 2015
Base	$42.56	$45.63	$57.86	$42.72
Peak	$50.73	$61.11	$81.11	$53.16
Cap	$3.52	$5.91	$12.07	$3.75

Note: These No carbon contract prices are derived by subtracting the risk adjusted carbon allowance in Table 5 from the carbon risk adjusted contract prices in Table 4.

Data source: ACIL Allen analysis using ASX Energy and NextGen data up to, and including 31 March 2014.

Base contracts without carbon for 2014-15 are $11.40/MWh higher on average than that used for the Final Determination for 2013-14 and peak contracts without carbon are $14.27/MWh higher. This reflects an anticipation of some tightening in the supply demand with the coming of the LNG loads and higher fuel prices (mainly gas) compared with 2013-14.

3.1.3 Contract prices with carbon pricing (Carbon case)

Contract prices with the full carbon pricing assumed (used in the Carbon case) were found by adding allowance for the full carbon price to the contract prices without carbon pricing in Table 6.

The carbon allowance was calculated by multiplying the average NEM intensity 0.87 tCO_2-e/MWh by the reference carbon price of $25.4/$tCO_2$-e The estimate of 0.87 tCO_2-e/MWh is based on ACIL Allen estimated power station emission factors and power station dispatch from the pool price modelling. Using this method, the carbon allowance is estimated to be $22.10/MWh.

Again, this full carbon allowance method applies to the base and peak contracts only. Because carbon pricing has very little or no influence on prices greater than $300, cap contract prices remain the same as the no carbon and the risk adjusted carbon cases.

Table 7 shows the estimated quarterly swap and cap contract prices with carbon pricing for the Final Determination. The contract prices in Table 7 are found by adding $22.10 to the No carbon case base and peak contract prices in Table 6. The Cap prices are the same as in Table 6 and Table 4 as these are assumed to be not influenced by carbon pricing.

Table 7 **Quarterly base, peak and cap estimated contract prices for Queensland - Carbon case – Final Determination 2014-15 ($/MWh)**

	Final Determination 2014-15			
	Q3 2014	Q4 2014	Q1 2015	Q2 2015
Base	$64.66	$67.73	$79.96	$64.81
Peak	$72.83	$83.21	$103.20	$75.26
Cap	$3.52	$5.91	$12.07	$3.75

Note: The contract prices in Table 7 are found by adding $22.10 to the No carbon case base and peak contract prices in Table 6. The Cap prices are the same as in Table 6.

Data source: ACIL Allen analysis using ASX Energy and NextGen data up to, and including 31 March 2014.

3.1.4 Summary of contract prices

Table 8 compares estimated quarterly base, peak and cap contract prices for the Risk adjusted carbon case, No carbon case and Carbon case.

Table 8 **Quarterly base, peak and cap estimated contract prices for Queensland for Risk adjusted carbon case, No carbon case and Carbon case 2014-15 –Final Determination ($/MWh)**

	Risk adjusted carbon case			
	Q3 2014	Q4 2014	Q1 2015	Q2 2015
Base	$49.46	$50.52	$60.76	$45.73
Peak	$57.64	$66.00	$84.00	$56.18
Cap	$3.52	$5.91	$12.07	$3.75
	No carbon case			
	Q3 2014	Q4 2014	Q1 2015	Q2 2015
Base	$42.56	$45.63	$57.86	$42.72
Peak	$50.73	$61.11	$81.11	$53.16
Cap	$3.52	$5.91	$12.07	$3.75
	Carbon case			
	Q3 2014	Q4 2014	Q1 2015	Q2 2015
Base	$64.66	$67.73	$79.96	$64.81
Peak	$72.83	$83.21	$103.20	$75.26
Cap	$3.52	$5.91	$12.07	$3.75

Data source: ACIL Allen analysis using ASX Energy and NextGen data up to, and including 31 March 2014.

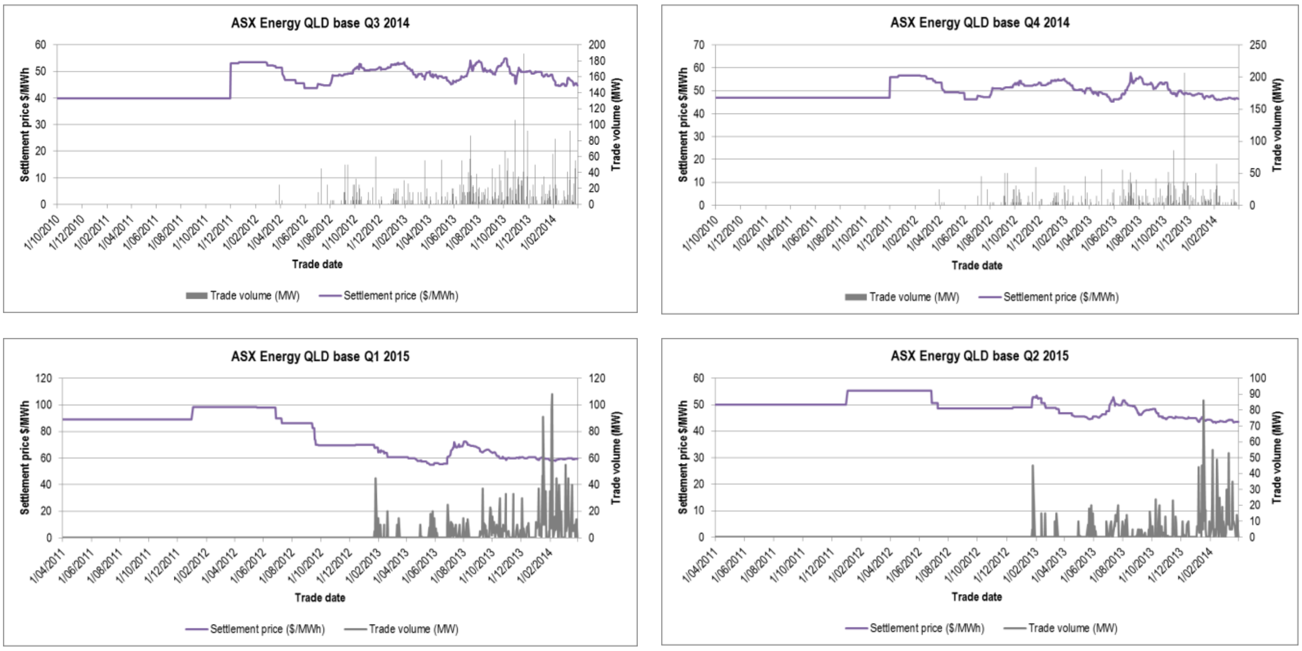
Figure 12 to Figure 14 show daily settlement prices and trade volumes for ASX Energy quarterly base futures, peak futures and cap contracts for Queensland up to and including 31 March 2014.

Base futures traded strongly, with total volumes of 4,326 MW for Q3 2014, 3,321 MW for Q4 2014, 1,887 MW for Q1 2015 and 1,355 MW for Q2 2015.

Cap contracts generally traded well, with total volumes of 289 MW for Q3 2014, 248 MW for Q4 2014, 597 MW for Q1 2015 and 30 MW for Q2 2015.

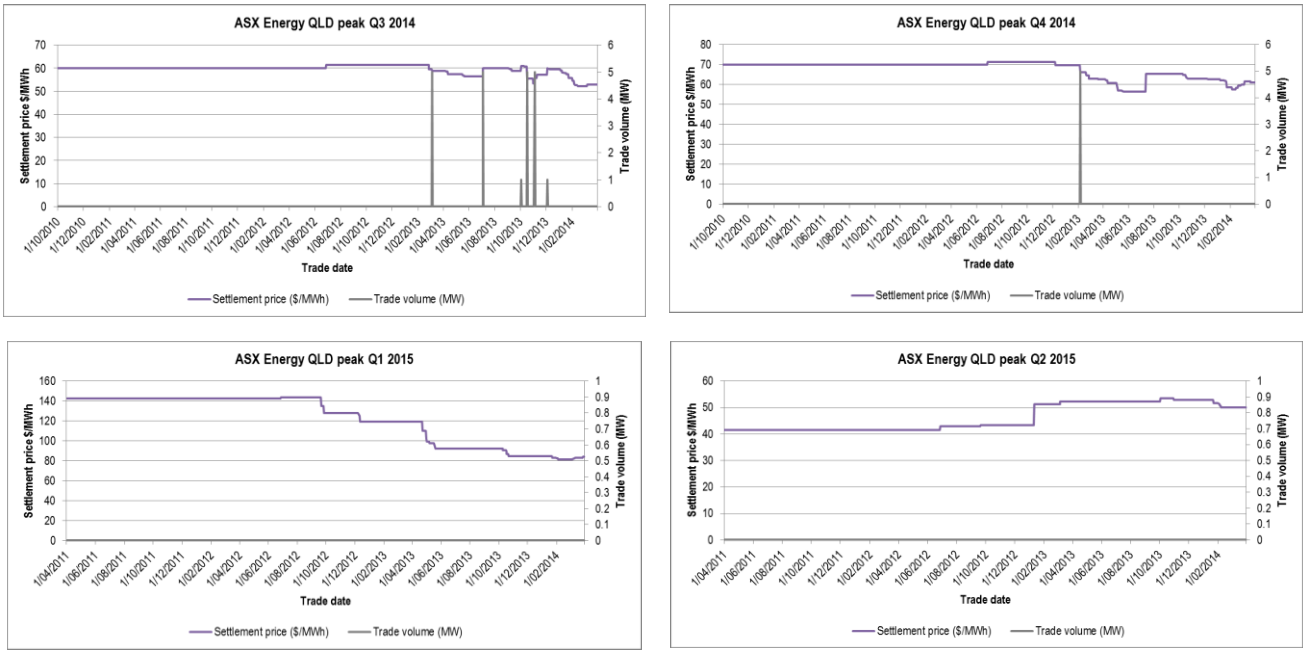
Peak futures were thinly traded with trade volumes of 22 MW for Q3 2014, 5 MW for Q4 2014 and no trades for Q1 2015 and Q2 2015.

Figure 12 **Time series of trade volume and price – ASX Energy QLD BASE futures for Q3 2014, Q4 2014, Q1 2015 and Q2 2015**



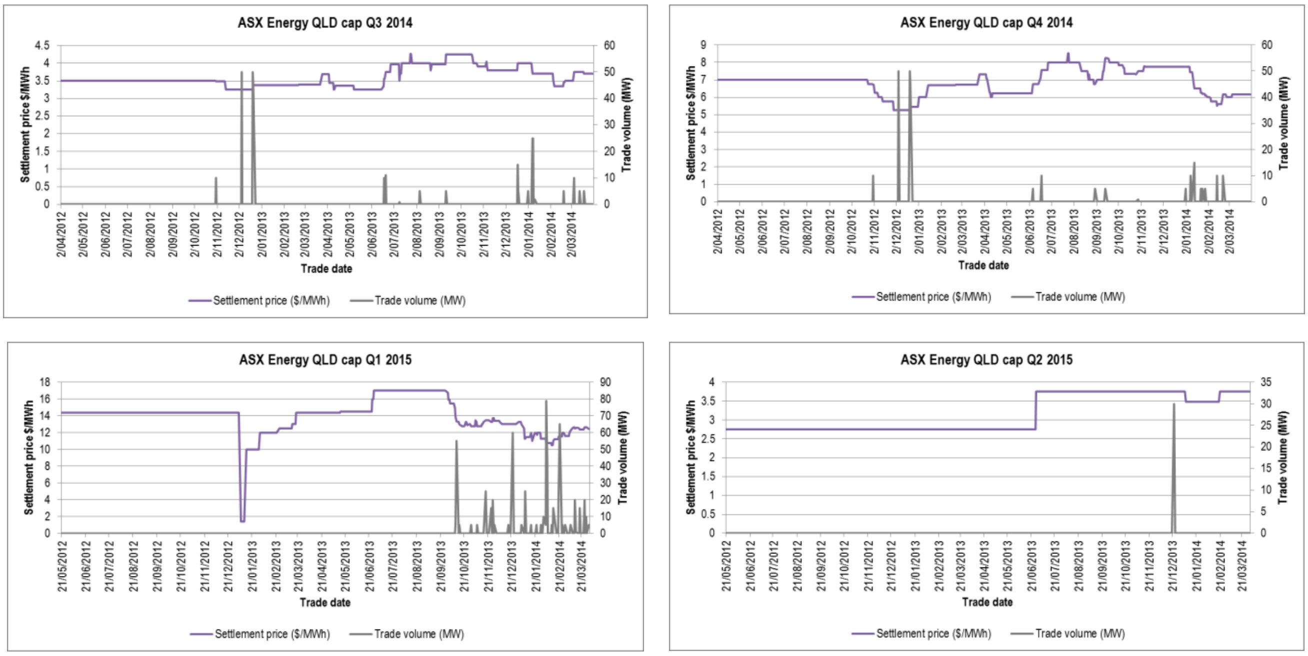
Data Source: ASX Energy data up to, and including 31 March 2014.

Figure 13 **Time series of trade volume and price – ASX Energy QLD PEAK futures for Q3 2014, Q4 2014, Q1 2015 and Q2 2015**



Data Source: ASX Energy data up to, and including 31 March 2014.

Figure 14 **Time series of trade volume and price – ASX Energy QLD $300 CAP contracts for Q3 2014, Q4 2014, Q1 2015 and Q2 2015**



Data Source: ASX Energy data up to, and including 31 March 2014.

3.1.5 Application of transmission and distribution losses

Prices at the Queensland regional reference node need to be adjusted for transmission and distribution 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 2014-15 for the Energex and Ergon Energy east zone Transmission Node Identities (TNI's). This analysis resulted in a transmission loss factor of **1.008** for Energex and **1.053** for the Ergon Energy east zone. These load weighted MLFs are very similar to those calculated for the 2013-14 Final Determination, this small change in MLF was summarised by AEMO in Section 3.3 of its report “List of NEM Regions and Marginal Loss Factors for the 2014-15 financial year” which states:

> The southern Queensland energy demand forecast for 2014-15 increased compared to 2013-14, in particular driven by new LNG load connections around Columboola. Swanbank E power station has been decommitted from October 2014.
>
> Increased demand in Queensland and the decommitment of Swanbank E power station has led to increased power transfers from New South Wales to Queensland.
>
> In spite of the increase in northerly interconnector flows, Queensland connection point MLFs have not significantly changed. This in because much of the increased demand in Queensland is close to the Queensland-New South Wales interconnector and the power flows within Queensland have not changed.

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 2014-15.

The estimated transmission and distribution loss factors for the settlement classes for the 2014-15 Final Determination are shown in Table 9. Loss factors have been updated from the Draft since the release by AEMO MLF and DLF reports for 2014-15.

Table 9 **Estimated transmission and distribution loss factors for Energex and Ergon Energy's east zone – Final Determination 2014-15**

Settlement classes	Distribution loss factor (DLF)	Transmission marginal loss factor (MLF)	Total loss factors (MLFxDLF)
Energex - NSLP - residential and small business and unmetered supply	1.062	1.008	1.071
Energex - Control tariff 9000	1.062	1.008	1.071
Energex - Control tariff 9100	1.062	1.008	1.071
Ergon Energy - NSLP - SAC HV, CAC and ICC	1.034	1.053	1.089
Ergon Energy - NSLP - SAC demand and street lighting	1.094	1.053	1.152

Data source: ACIL Allen analysis on each of the Queensland TNIs, Queensland MLFs and Energex and Ergon Energy east zone DLFs for 2014/15 from AEMO.

The largest change in the loss factors for the Final Determination for 2014-15 was the DLF applying to the Ergon Energy SAC demand and street lighting customers increasing from 1.078 in 2013-14 to 1.094 in 2014-15.

For the Final Determination for 2014-15 ACIL Allen has applied the same methodology as used in the Final Determination for 2013-14 so that it aligns with the application of the MLF and DLF used by AEMO.

As described by AEMO[8], 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:

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

3.1.6 Calculation of wholesale energy costs (WEC) for 2014-15

Using the contract prices and volumes with the projected hourly pool prices for the 473 simulations in the hedge model provides 473 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 473 simulated annual hedged prices is used as the estimate of the WEC for 2014-15.

For the Carbon case and the No carbon case the hedging prices were taken as the 95th percentile of annual hedged prices based on 473 pool price simulations with carbon and 473 pool price simulations without carbon respectively.

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

For the Risk adjusted carbon pricing case based on a risk adjusted carbon price in the current market of around $3.00/MWh, suggests that the market is currently factoring in a 1 in 7 chance of carbon price being retained in 2014-15 assuming a full carbon price would add around $22.10/MWh to energy costs. On this basis the cost of energy was taken as 95th percentile of a distribution containing 3,311 annual hedged price simulations (i.e. 473 simulations with the full carbon price in the pool price modelling and 2,838 (6x473) simulations with no carbon price in the pool price modelling). This approach meant that a seventh of the hedged prices in the distribution were based on pool prices with full carbon in line with the 1 in 7 chance above.

For the control load tariffs ACIL Allen 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.

3.2 Data sources

3.2.1 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 Allen estimates
- Non-sensitive information provided by clients
- AEMO reports

Detailed data is provided in Appendix C.

3.3 Summary of WEC estimates

Table 10 shows the WEC for the settlement classes for the Final Determination using the risk weighted carbon price[9]. It includes the estimate of the cost at the customer terminals after allowance for the transmission and distribution losses.

[9] Estimation of WEC using the risk adjusted carbon price represents ACIL Allen's best estimate of the WEC given the uncertainty around the carbon price.

Table 10 **Estimated WEC ($/MWh, nominal) for 2014-15 – Risk adjusted carbon case**

Settlement class	WEC at the Queensland reference node ($/MWh)	Total transmission and distribution loss factor (MLFxDLF)	WEC at the customer terminal ($/MWh)
Energex - NSLP - residential and small business	$68.41	1.071	$73.24
Energex - Control tariff 9000 (31)	$42.76	1.071	$45.78
Energex - Control tariff 9100 (33)	$56.54	1.071	$60.53
Energex - NSLP - unmetered supply	$68.41	1.071	$73.24
Ergon Energy - NSLP - SAC HV, CAC and ICC	$61.08	1.089	$66.53
Ergon Energy - NSLP - SAC demand and street lighting	$61.08	1.152	$70.39

Note: Based on pool modelling and contract prices assuming carbon price of $25.40
Source: ACIL Allen analysis

The prices at the customer terminal for the Final Determination for 2014-15 in the risk adjusted carbon case are lower than in the Draft Determination by between $1.51 and 3.42/MWh. This has occurred because a reduction in the average risk adjusted allowance for carbon pricing has more than offset any price increase in the underlying energy costs associated with further mothballing of plant since the Draft Determination.

3.3.1 Carbon and No carbon cases

The tables below summarise the WEC for the two additional scenarios requested by the QCA, the with the full carbon price (Carbon case) and with no carbon price (No carbon case)

Table 11 **Estimated WEC ($/MWh, nominal) for 2014-15 – Carbon case**

Settlement class	WEC at the Queensland reference node ($/MWh)	Total transmission and distribution loss factor (MLFxDLF)	WEC at the customer terminal ($/MWh)
Energex - NSLP - residential and small business	$84.38	1.071	$90.34
Energex - Control tariff 9000 (31)	$58.67	1.071	$62.82
Energex - Control tariff 9100 (33)	$72.03	1.071	$77.12
Energex - NSLP - unmetered supply	$84.38	1.071	$90.34
Ergon Energy - NSLP - SAC HV, CAC and ICC	$77.75	1.089	$84.69
Ergon Energy - NSLP - SAC demand and street lighting	$77.75	1.152	$89.61

Note: Based on pool modelling and contract prices assuming carbon price of $25.40
Source: ACIL Allen analysis

The WEC for the Carbon case is generally higher than in the Draft Determination mainly because of the mothballing of Swanbank E and Wallerawang. This more than offsets a generally slightly lower load forecast used in the Final Determination. The current AEMO low forecast has been used following analysis of the outcome for the 2013-14 summer period.

Table 12 **Estimated WEC ($/MWh, nominal) for 2014-15 – No carbon case**

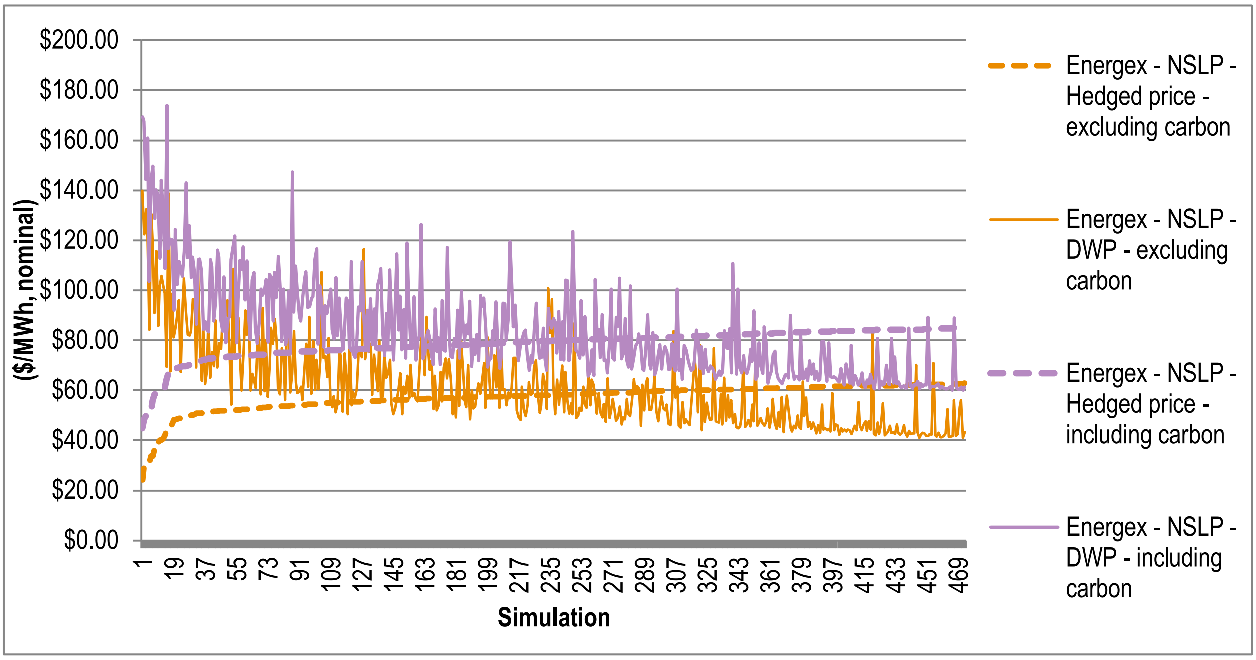
Settlement class	WEC at the Queensland reference node ($/MWh)	Total transmission and distribution loss factor (MLFxDLF)	WEC at the customer terminal ($/MWh)
Energex - NSLP - residential and small business	$62.26	1.071	$66.65
Energex - Control tariff 9000 (31)	$36.60	1.071	$39.18
Energex - Control tariff 9100 (33)	$50.71	1.071	$54.28
Energex - NSLP - unmetered supply	$62.26	1.071	$66.65
Ergon Energy - NSLP - SAC HV, CAC and ICC	$55.75	1.089	$60.72
Ergon Energy - NSLP - SAC demand and street lighting	$55.75	1.152	$64.25

Note: Based on pool modelling and contract prices assuming no carbon price
Source: ACIL Allen analysis

The WEC for the No carbon case is generally slightly higher than in the Draft Determination due to the further mothballing of plant.

Figure 15 shows the relationship between the WEC hedged price and the dispatch weighted pool price (DWP) for the Energex NSLP across the 473 simulation years for the Carbon and No carbon cases. 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. It also shows that the hedged prices used for WEC tend to be negatively correlated with the DWP and this is because a low risk, high cover hedging strategy is used.

Figure 15 **Annual hedged price and DWP for Energex NSLP 2014-15 for the 473 simulations ($/MWh)**



Source: ACIL Allen modelling

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
- 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[10]) 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 Allen has used the following:

- Large-scale Generation Certificate (LGC) market prices from AFMA[11]
- LRET targets for 2014 and 2015 of 16,950 GWh and 18,850 GWh respectively, as published by the Clean Energy Regulator (CER)
- Renewable Power Percentage (RPP) for 2014 of 9.87 per cent[12], as published by CER on 14 March 2014, and an estimated RPP[13] for 2015 of 10.98 per cent
- CER's binding estimate for Small-scale Technology Percentage (STP) of 10.48 per cent for 2014[14] and CER's non-binding estimate for STP of 10.10 per cent for 2015[15]
- CER clearing house price for 2014 and 2015 for Small-scale Technology Certificates (STCs) of $40/MWh.

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[10] 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.

[11] AFMA data includes weekly prices up to 31 March 2014, which is the cut-off date for all relevant market-based data used in the Final Determination for 2014-15 tariffs.

[12] Published on 14 March 2014

[13] Estimated using the default RPP formula under Section 39 (2) (b) of the Renewable Energy (Electricity) Act 2000

[14] Published on 14 March 2014

[15] The 2015 non-binding STP estimate is based on the modelling prepared for the recently published 2014 STP.

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.

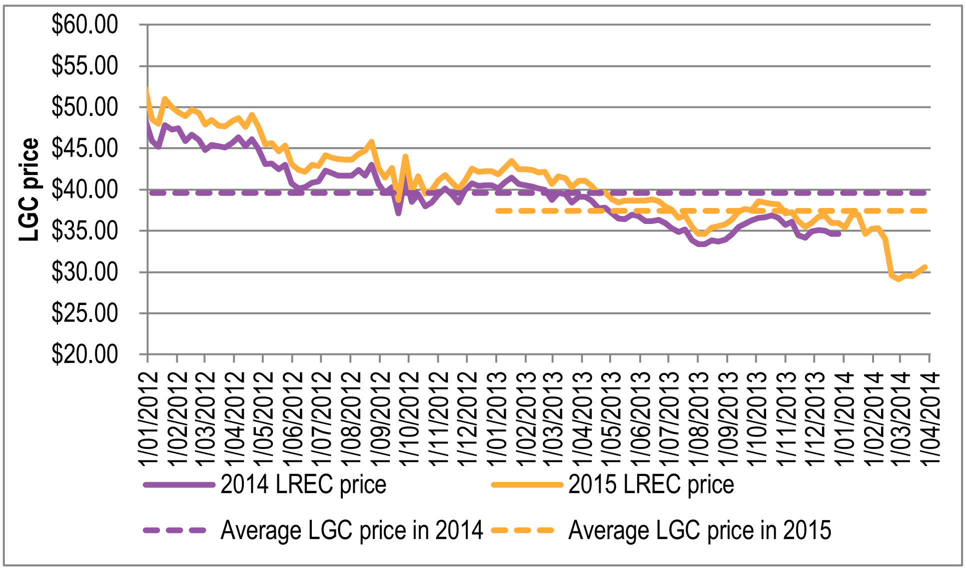
ACIL Allen has estimated the average LGC price using forward looking weekly market prices for LGCs published by the Australian Financial Markets Association (AFMA) [16].

The LGC price used in assessing the cost of the scheme for 2014-15 is found by averaging the forward prices for 2014 and 2015 during the two years prior to the commencement of 2014 and 2015. This assumes that LGC coverage is built up over a two year period (see Figure 16). The average LGC prices calculated from the AFMA data are $39.59/MWh for 2014 and $37.41/MWh for 2015**:**

- 2014 is based on prices starting on 5 January 2012 capturing 104 weeks
- 2015 is based on prices starting on 3 January 2013 capturing 65 weeks.

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

Figure 16 **LGC forward prices for 2014 and 2015 (nominal $/LGC)**



Data source: AFMA and ACIL Allen analysis

ACIL Allen calculates the cost of complying with the LRET in 2014 and 2015 by multiplying the RPPs in 2014 and 2015 by the average LGC prices in 2014 and 2015, respectively. The cost of complying with the LRET in 2014-15 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be **$4.01/MWh** in 2014-15 as shown in Table 13.

Table 13 **Estimated cost of LRET – Final Determination 2014-15**

	2014	2015	Cost of **LRET 2014-15 Final Determination**	Cost of LRET 2014-15 Draft Determination
RPP %	9.87%	10.98%		
Average LGC price ($/LGC, nominal)	$39.59	$37.41		
Cost of LRET ($/MWh, nominal)	$3.91	$4.11	**$4.01**	$3.95

Data source: CER, AFMA, ACIL Allen analysis

4.1.2 SRES

The cost of SRES for calendar years 2014 and 2015 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 2014-15.

The STPs published by CER are as follows:

— 10.48 per cent for 2014 (equivalent to 18.65 million STCs as a proportion of total estimated liable electricity for the 2014 year)

— 10.10 per cent for 2015 (equivalent to 17.73 million STCs as a proportion of total estimated liable electricity for the 2015 year).

ACIL Allen estimates the cost of complying with SRES to be $4.12/MWh in 2014-15 as set out in Table 14.

Table 14 **Estimated cost of SRES – Final Determination 2014-15**

	2014	2015	Cost of SRES **2014-15 Final Determination**	Cost of SRES 2014-15 Draft Determination
STP %	10.48%	10.10% [a]		
STP clearing house price ($/STP, nominal)	$40.00	$40.00		
Cost of SRES ($/MWh, nominal)	$4.19	$4.04	**$4.12**	$3.49

[a] Non-binding estimate published by CER
Data source: CER, ACIL Allen analysis

Combining the LRET and SRES costs for both schemes yields a total cost of $8.13/MWh for 2014-15.

4.2 NEM management fees

NEM management fees are payable by retailers to AEMO to cover operational expenditure, costs associated with full retail contestability (FRC) and costs associated with the National Transmission Planner.

Based on AEMO's *Electricity Draft Budget & Fees 2014-15*, the total fee for 2014-15 is **$0.47/MWh**.

The breakdown of NEM management fees is shown in Table 15.

Table 15 **NEM management fees – Final Determination 2014-15**

Cost category	Draft Determination $/MWh	**Final Determination $/MWh**
NEM operational fees		$0.39
FRC - electricity		$0.06
National Transmission Planner		$0.02
Total NEM fees	$0.39	**$0.47**

Source: AEMO

4.3 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 2014-15, the cost of ancillary services is estimated to be **$0.48/MWh.**

4.4 Prudential costs

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

4.4.1 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 43 days

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

- a future risk-weighted mean pool price of $55.60
- a volatility factor of 1.5, based on published AEMO volatility factors for 2014[17]
- Loss factor of 1.05

results in an MCL of $4,142.06.

However as this applies for a rolling 43 days it actually covers 43 MWh of retailer purchases. Hence the portion of the MCL applicable to each MWh is $4,142/43 = $96.33.

The cost of funding a bank guarantee for the MCL associated with the single MWh is assumed to be a 2.5% annual charge[18] for 43 days or 2.5%*(43/365) = 0.288%. Applying this funding cost to the single MWh charge of $96.33 gives an estimate of **$0.284/MWh.**

4.4.2 Hedge prudential costs

ACIL Allen 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:

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

[18] This is the handling charge for a guarantee facility which is not drawn down.

- the price scanning range (PSR) expressed as a percentage of the contract face value and currently set at around 9% on average for a base contract
- the intra commodity spread charge currently set at $3,300 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 $51.59[19] and applying the above factors gives an average initial margin for each quarter of around $13,800 for a 1 MW quarterly contract. In order to allow for some ongoing future uncertainty we have rounded this to $14,000 per 1 MW quarterly contract. Dividing this by the average hours in a quarter then gives an initial margin of $6.39 per MWh. Assuming a funding cost of 9.7% (consistent with the range of estimates of retailers' WACC that is used to set the retail margin) but adjusted for an assumed 3% return on cash lodged with the clearing house gives a net funding cost of 6.7%. Applying 6.7% to the initial margin per MWh gives a prudential cost for hedging of **$0.430/MWh.**

ACIL Allen 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 Allen considers that the base contract assessment is a reasonable reflection of the prudential obligations faced by retailers.

4.4.3 Total prudential costs

Adding the AEMO and hedge prudential costs gives a total prudential requirement as set out in Table 16:

Table 16 **Total prudential costs - Final Determination ($/MWh)**

Cost category	Draft Determination $/MWh	**Final Determination $/MWh**
AEMO pool	$0.36	$0.28
Hedge	$0.46	$0.43
Total	$0.82	**$0.71**

4.5 Summary of other energy cost estimates

In summary, the ‘other energy costs’ components for 2014-15 Final Determination are estimated to be **$9.79/MWh** compared with $9.04 in the Draft Determination. These costs are summarised in

Table 17.

[19] Average annual price for base futures costs used in estimating WEC.

Table 17 **Summary of OEC – Final Determination at the regional reference node ($/MWh)**

Cost Category	Draft Determination $/MWh	**Final Determination $/MWh**
LRET	$3.95	$4.01
SRES	$3.49	$4.12
NEM fees	$0.39	$0.47
Ancillary services	$0.39	$0.48
Prudential costs	$0.82	$0.71
Total other energy costs	$9.04	**$9.79**

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

Data source: ACIL Allen analysis

The main change since the Draft Determination is the increase in the SRES costs with the latest estimates if the STP in 2014 and 2015 some 1.5 percentage points higher.

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 18 to Table 20 for the Risk adjusted carbon case, Carbon case and No carbon case respectively. The estimated costs in the table include both the WEC and the OEC.

Table 18 **Estimated TEC for 2014-15 Final Determination - Risk adjusted carbon case**

Settlement class	WEC at the Queensland reference node ($/MWh)	Renewable energy and market fees at the Queensland reference node ($/MWh)	Total transmission and distribution loss factor (MLFxDLF)	TEC at the customer terminal ($/MWh)	Change from Draft Determination ($/MWh)
Energex - NSLP - residential and small business	$68.41	$9.79	1.071	$83.72	-$2.31
Energex - Control tariff 9000 (31)	$42.76	$9.79	1.071	$56.26	-$2.64
Energex - Control tariff 9100 (33)	$56.54	$9.79	1.071	$71.01	-$1.58
Energex - NSLP - unmetered supply	$68.41	$9.79	1.071	$83.72	-$2.31
Ergon Energy - NSLP - SAC HV, CAC and ICC	$61.08	$9.79	1.089	$77.19	-$1.57
Ergon Energy - NSLP - SAC demand and street lighting	$61.08	$9.79	1.152	$81.67	-$0.49

Source: ACIL Allen analysis

The change from the Draft Determination is mainly because the risk adjusted carbon allowance in the ASX Energy futures has continued to decline. This means that the risk adjusted carbon case in the Final Determination is closer to the No carbon case than it was in the Draft Determination.

Table 19 **Estimated TEC for 2014-15 Final Determination - Carbon case**

Settlement class	WEC at the Queensland reference node ($/MWh)	Renewable energy and market fees at the Queensland reference node ($/MWh)	Total transmission and distribution loss factor (MLFxDLF)	TEC at the customer terminal ($/MWh)	Change from Draft Determination ($/MWh)
Energex - NSLP - residential and small business	$84.38	$9.79	1.071	$100.82	$2.07
Energex - Control tariff 9000 (31)	$58.67	$9.79	1.071	$73.30	-$0.02
Energex - Control tariff 9100 (33)	$72.03	$9.79	1.071	$87.60	$1.47
Energex - NSLP - unmetered supply	$84.38	$9.79	1.071	$100.82	$2.07
Ergon Energy - NSLP - SAC HV, CAC and ICC	$77.75	$9.79	1.089	$95.35	$2.17
Ergon Energy - NSLP - SAC demand and street lighting	$77.75	$9.79	1.152	$100.89	$3.67

Source: ACIL Allen analysis

Table 20 **Estimated TEC for 2014-15 Final Determination - No carbon case**

Settlement class	WEC at the Queensland reference node ($/MWh)	Renewable energy and market fees at the Queensland reference node ($/MWh)	Total transmission and distribution loss factor (MLFxDLF)	TEC at the customer terminal ($/MWh)	Change from Draft Determination ($/MWh)
Energex - NSLP - residential and small business	$62.26	$9.79	1.071	$77.14	$1.49
Energex - Control tariff 9000 (31)	$36.60	$9.79	1.071	$49.66	$0.71
Energex - Control tariff 9100 (33)	$50.71	$9.79	1.071	$64.77	$1.52
Energex - NSLP - unmetered supply	$62.26	$9.79	1.071	$77.14	$1.49
Ergon Energy - NSLP - SAC HV, CAC and ICC	$55.75	$9.79	1.089	$71.39	$1.81
Ergon Energy - NSLP - SAC demand and street lighting	$55.75	$9.79	1.152	$75.53	$2.95

Source: ACIL Allen analysis

It can be seen that the TEC for Final Determination for the Carbon and No carbon cases are generally higher than those for the Draft Determination. This is mainly because of a slight increase in the trade weighted contract prices since the Draft Determination and an increase in estimated SRES costs.

Appendix A Ministerial Delegation

DELEGATION TO QCA

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

Page 1 of 4

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 on 22 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.

18. This Delegation revokes my previous Delegation issued on 5 September 2012.

DATED this 12th day of February 2013.

[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 2014-15

Assessment of Energy Costs

16 July 2013

1. Project Background

On 12 February 2013, 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. 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 Authority requires the assistance of a consultant to estimate the cost of energy for these annual reviews.

ACIL Allen (then ACIL Tasman) undertook this work for the Authority for its 2013-14 review. At that time, the Authority offered an 'in principle' agreement for ACIL Allen to be engaged to provide similar advice for its 2014-15 and 2015-16 reviews subject to it not undertaking work that might be seen as a conflict of interest and to the proposed costs being reasonable.

The Authority is about to initiate its 2014-15 review and invites ACIL Allen to provide it with a proposal to meet the requirements of this terms of reference.

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 2014-15. 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 2014-15 estimates for:

(a) wholesale energy costs;

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

(c) NEM fees, ancillary services charges and prudential costs; and

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

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

- 1 -

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	Late September
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	18 October 2013
Stakeholder Workshop	• Conduct a workshop with interested parties on changes to the consultant's proposed approach, following feedback on the Draft Determination	To be negotiated.
Final Report	• Address submissions on the Draft Report • Outline the consultant's final approach • Provide final cost estimates	4 April 2014

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 late July 2013 and is expected to be completed by 31 May 2014.

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 requirements 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 26 July 2013.

For further information concerning this consultancy, please contact Rimu Nelson on (07) 3222 0577.

Proposals should be submitted to:

Rimu Nelson

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	2014	2015
Barcaldine	$7.25	$15.32
Braemar 1	$2.94	$3.01
Braemar 2	$5.40	$7.70
Callide B	$1.47	$1.51
Callide C	$1.47	$1.51
Condamine	$9.85	$9.74
Darling Downs	$6.81	$9.45
Gladstone	$1.75	$1.79
Kogan Creek	$0.84	$0.86
Mackay GT	$33.89	$34.74
Millmerran	$0.95	$0.97
Mt Stuart	$33.89	$34.74
Oakey	$4.63	$12.17
Roma	$9.85	$9.74
Stanwell	$1.56	$1.60
Swanbank E	$4.59	$4.66
Tarong	$1.12	$1.15
Tarong North	$1.12	$1.15
Townsville	$4.43	$4.53
Yarwun	$3.88	$3.95
New Entrant CCGT	$9.85	$9.74
New Entrant CCGT-CCS	$9.85	$9.74
New Entrant SC COAL	$1.63	$1.64
New Entrant IGCC-CCS	$1.63	$1.64
New Entrant OCGT	$12.32	$12.17
New Entrant SC COAL-CCS	$1.63	$1.64

Source: ACIL Allen assumptions

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 Allen assumptions

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

Table C3 **Details of Queensland generators used in pool price modelling for 2014-15**

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, 2013 $)
AGL	Oakey	OAKEY1	Gas turbine	Natural gas	141	0	1.5%	32.6%	0.0513	0.0054	$9.98
AGL	Oakey	OAKEY2	Gas turbine	Natural gas	141	0	1.5%	32.6%	0.0513	0.0054	$9.98
AGL	Townsville	YABULU	Gas turbine combined cycle	Natural gas	160	133	3.0%	46.0%	0.0513	0.0054	$1.09
AGL	Townsville	YABULU2	Gas turbine combined cycle	Natural gas	80	67	3.0%	46.0%	0.0513	0.0054	$1.09
Alinta	Braemar 1	BRAEMAR1	Gas turbine	Natural gas	168	90	1.5%	30.0%	0.0513	0.0054	$8.23
Alinta	Braemar 1	BRAEMAR2	Gas turbine	Natural gas	168	90	1.5%	30.0%	0.0513	0.0054	$8.23
Alinta	Braemar 1	BRAEMAR3	Gas turbine	Natural gas	168	90	1.5%	30.0%	0.0513	0.0054	$8.23
CS Energy	Callide B	CALL_B_1	Steam turbine	Black coal	350	200	7.0%	36.1%	0.095	0.002	$1.25
CS Energy	Callide B	CALL_B_2	Steam turbine	Black coal	350	200	7.0%	36.1%	0.095	0.002	$1.25
CS Energy	Callide C	CPP_3	Steam turbine	Black coal	405	200	4.8%	36.5%	0.095	0.002	$2.84
CS Energy	Gladstone	GSTONE1	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.24
CS Energy	Gladstone	GSTONE2	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.24
CS Energy	Gladstone	GSTONE3	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.24
CS Energy	Gladstone	GSTONE4	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.24
CS Energy	Gladstone	GSTONE5	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.24
CS Energy	Gladstone	GSTONE6	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.24
CS Energy	Kogan Creek	KPP_1	Steam turbine	Black coal	750	350	8.0%	37.5%	0.094	0.002	$1.31
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	$2.49
ERM	Braemar 2	BRAEMAR5	Gas turbine	Natural gas	153	150	1.5%	30.0%	0.0513	0.0054	$8.23
ERM	Braemar 2	BRAEMAR6	Gas turbine	Natural gas	153	0	1.5%	30.0%	0.0513	0.0054	$8.23
ERM	Braemar 2	BRAEMAR7	Gas turbine	Natural gas	153	0	1.5%	30.0%	0.0513	0.0054	$8.23
InterGen	Callide C	CPP_4	Steam turbine	Black coal	405	200	4.8%	36.5%	0.095	0.002	$1.25
InterGen	Millmerran	MPP_1	Steam turbine	Black coal	425.5	130	4.7%	36.9%	0.092	0.002	$2.95
InterGen	Millmerran	MPP_2	Steam turbine	Black coal	425.5	130	4.7%	36.9%	0.092	0.002	$2.95

C-3

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, 2013 $)
Origin	Darling Downs	DDPS1	Gas turbine combined cycle	Natural gas	630	270	6.0%	46.0%	0.0513	0.002	$1.09
Origin	Mt Stuart	MSTUART1	Gas turbine	Liquid Fuel	146	0	3.0%	30.0%	0.0697	0.0053	$9.39
Origin	Mt Stuart	MSTUART2	Gas turbine	Liquid Fuel	146	0	3.0%	30.0%	0.0697	0.0053	$9.39
Origin	Mt Stuart	MSTUART3	Gas turbine	Liquid Fuel	126	0	3.0%	30.0%	0.0697	0.0053	$9.39
Origin	Roma	ROMA_7	Gas turbine	Natural gas	40	0	3.0%	30.0%	0.0513	0.0054	$9.98
Origin	Roma	ROMA_8	Gas turbine	Natural gas	40	0	3.0%	30.0%	0.0513	0.0054	$9.98
QGC	Condamine	CPSA	Gas turbine combined cycle	Natural gas	140	0	3.0%	48.0%	0.0513	0.002	$1.09
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	$11.85
Stanwell - Tarong	Barron Gorge	BARRON-2	Hydro	Hydro	30	15	1.0%	100.0%	0	0	$11.85
Stanwell - Tarong	Kareeya	KAREEYA1	Hydro	Hydro	21	8	1.0%	100.0%	0	0	$6.46
Stanwell - Tarong	Kareeya	KAREEYA2	Hydro	Hydro	21	8	1.0%	100.0%	0	0	$6.46
Stanwell - Tarong	Kareeya	KAREEYA3	Hydro	Hydro	18	8	1.0%	100.0%	0	0	$6.46
Stanwell - Tarong	Kareeya	KAREEYA4	Hydro	Hydro	21	8	1.0%	100.0%	0	0	$6.46
Stanwell - Tarong	Mackay GT	MACKAYGT	Gas turbine	Fuel oil	34	0	3.0%	28.0%	0.0697	0.0053	$9.39
Stanwell - Tarong	Stanwell	STAN-1	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	0.002	$3.34
Stanwell - Tarong	Stanwell	STAN-2	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	0.002	$3.34
Stanwell - Tarong	Stanwell	STAN-3	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	0.002	$3.34
Stanwell - Tarong	Stanwell	STAN-4	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	0.002	$3.34
Stanwell - Tarong	Swanbank E	SWAN_E	Gas turbine combined cycle	Coal seam methane	385	150	3.0%	47.0%	0.0513	0.0054	$1.09

C-4

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, 2013 $)
Stanwell - Tarong	Tarong	TARONG#1	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	0.002	$7.80
Stanwell - Tarong	Tarong	TARONG#2	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	0.002	$7.80
Stanwell - Tarong	Tarong	TARONG#3	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	0.002	$7.80
Stanwell - Tarong	Tarong	TARONG#4	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	0.002	$7.80
Stanwell - Tarong	Tarong North	TNPS1	Steam turbine	Black coal	443	175	5.0%	39.2%	0.0921	0.002	$1.49

Data source: ACIL Allen PowerMark database

C-5

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