ACIL ALLEN CONSULTING

REPORT TO
QUEENSLAND COMPETITION AUTHORITY

2 JUNE 2015

ESTIMATED ENERGY COSTS

2015-16 RETAIL TARIFFS

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

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ACIL ALLEN (2014) ESTIMATED 2015-16 ENERGY COSTS FOR QCA DRAFT DETERMINATION

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1 Introduction

ACIL Allen has been engaged by the Queensland Competition Authority (the QCA) to provide advice on the energy related costs likely to be incurred by a retailer to supply customers on notified retail prices for 2015-16.

Retail prices generally consist of three components:

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

ACIL Allen's engagement relates to the energy costs component only. In accordance with the Ministerial Delegation (the Delegation), which is published on the QCA's website[1], and the Consultancy Terms of Reference (TOR) provided by the QCA and which is also published on the QCA's website[2], 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 2015-16; i.e. non-market customers. Although the QCA's determination was originally to apply only to the Ergon Energy distribution area, the QCA received a new delegation on 28 April 2015, following the government's announcement of delaying the deregulation of retail prices for residential and small business customers in south east Queensland by 12 months. In any case, the TOR specifically requests that ACIL Allen's analysis cover the same tariff classes as covered in the analyses for the 2013-14 and 2014-15 determinations, and therefore includes residential and small business customers in south east Queensland.

This report provides estimates of the energy costs for use by the QCA in its Final Determination. These estimates have been revised since the Draft Determination in December 2014 and take into account feedback from submissions in response to the Draft Determination, the QCA's Further Consultation Paper, as well as updated data applicable to the analysis.

This report also provides responses to submissions made by various parties following the QCA's Draft Determination, *Regulated Retail Electricity Prices 2015-16* (December 2014), and the QCA's *Further Consultation Paper: Regulated Retail Electricity prices for 2015-16* (May 2015), where those submissions refer to the cost of energy in regulated retail electricity prices.

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[1] http://www.qca.org.au/getattachment/e0aa30e0-e806-45f1-a51f-44b1edd8d128/Ministerial-Delegation.aspx

[2] http://www.qca.org.au/getattachment/0fa9b74d-502a-422e-b23b-90890011ca1e/ACIL-Allen-Terms-of-Reference.aspx

2 Overview of approach

2.1 Introduction

In preparing advice on the estimated energy costs, 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 the tariff year 1 July 2015 to 30 June 2016.

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.

ACIL Allen understands that these matters will be considered by the QCA when making its Determination.

2.2 Components of the energy cost estimates

Energy costs comprise:

- wholesale energy costs for various demand profiles
- costs of complying with state and federal government policies, including the Renewable Energy Target (RET)
- National Electricity Market (NEM) fees, ancillary services charges and costs of meeting prudential requirements
- energy losses incurred during the transmission and distribution of electricity to customers.

2.3 Methodology

ACIL Allen's methodology is a continuation of the methodology used to provide advice to the QCA for the 2015-16 Draft Determination, and the 2013-14 and 2014-15 Determinations (please refer to ACIL Allen's report for the 2014-15 Draft Determination[3] and the 2014-15 Final Determination[4] 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.

Unlike previous years, as the Clean Energy Act and associated legislation was repealed in July 2014, there is no carbon price in the analysis.

2.3.1 Wholesale energy costs

As with the 2013-14 and 2014-15 review, ACIL Allen continues to use the market hedging approach for estimating the WEC for 2015-16.

We have utilised the:

- stochastic demand model to develop 44 weather influenced simulations of hourly demand traces for each of the tariff profiles – using temperature data from 1970-71 to 2013-14 and demand data for 2010-11 to 2013-14
- stochastic outage model to develop 11 power station availability simulations
- energy market models to run 484 simulations of hourly pool prices of the NEM using the stochastic demand traces and power station availabilities as inputs
- analysis of contract data to estimate contract prices
- hedge model taking the above analyses as inputs to estimate a distribution of hedged prices for each tariff class.

We have then analysed the distribution of outcomes produced by the above approach to provide a risk adjusted estimate of the WEC for each tariff class.

We have continued to rely on the Australian Energy Market Operator (AEMO) as a source for the various demand data required for the analysis. The QCA provided ACIL Allen with access to ASX Energy data for the purpose of estimating contract prices.

The peak demand and energy forecasts for the demand profiles are referenced to the current AEMO demand forecasts for Queensland and take into account past trends and relationships between the NSLPs and the Queensland region demand.

Changes since the 2015-16 Draft Determination

In the Draft Determination, it was our assessment that the AEMO medium series demand projection for 2015-16 provided in AEMO's 2014 National Electricity Forecasting Report

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[3] http://www.qca.org.au/getattachment/4cb8b436-7b50-4328-8e27-13f51a4d021c/ACIL-Allen-Estimated-Energy-Costs-2015-15-Retail-T.aspx

[4] http://www.qca.org.au/getattachment/9be567a8-92e2-4d53-85f0-3781e4f8662f/ACIL-Allen-Final-Report-Estimated-Energy-Costs-for.aspx

(NEFR) was the most reasonable demand forecast for the purposes of this analysis. However, since the Draft Determination, the summer of 2014-15 has concluded and it is evident that the 2014 NEFR forecasts for Queensland for summer 2014-15 are conservative relative to the actual outcomes.

AEMO, in its February 2015 publication, *Energy Update*[5], noted that despite record temperatures in Queensland in November 2014, there was a rise in demand in the October to December 2014 quarter from the residential and commercial sector as a result of a lower than expected rate of installation of rooftop solar PV panels.

ACIL Allen has analysed the change in electricity consumption between 2013-14 and 2014-15, and in particular the change between the summer of 2013-14 and the summer of 2014-15. This analysis took into account different temperature conditions during the two summer periods. ACIL Allen concludes that the residential load (as measured by the NSLPs) has grown between 2013-14 and 2014-15 on a weather corrected basis by about 167MW across the peak periods of the day and into the evening, and by about 40MW overnight on average. As noted by AEMO, the increase across the daytime is likely to be a result of lower than expected rooftop solar PV installs. During the overnight period, the increase in average demand could be the result of a slowdown in the expected impact of energy efficiency measures (such as energy efficient lighting) which has resulted in population based demand growth outpacing reductions due to efficiency measures.

ACIL Allen also established that there was an increase in the average non-NSLP demand of about 280MW between summer 2013-14 and summer 2014-15. Further, this increase occurs from about November 2014 onwards and is reasonably flat across the day. This increase is likely to be associated with the commissioning of the LNG export facilities in Gladstone.

The 2014 NEFR includes demand growth associated with the LNG loads and therefore this observed step change in actual demand, although perhaps earlier than assumed in the 2014 NEFR, is included nonetheless, and certainly by 2015-16 is assumed to be on-line. However, the NEFR assumes little or no growth in residential and commercial load and therefore ACIL Allen has adjusted the demand forecast for 2015-16 to account for the growth observed in the NSLP between 2013-14 and 2014-15.

On the supply side, the energy market modelling for the Draft Determination assumed a return to service of Tarong unit 2 prior to 2015-16. However, Stanwell Corporation announced in February 2015 that the unit is now scheduled to return in March 2016 and this has been adopted in the modelling.

There was a change in the Queensland State Government in February 2015. The new government has suggested in its energy policy a plan to merge CS Energy and Stanwell Corporation in order to reduce operating costs. If the two portfolios are merged, and their respective trading teams are also merged, then there would be an increase in market concentration. In the past, ACIL Allen's modelling of the aggregation of the previous three

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[5] http://www.aemo.com.au/About-the-Industry/Resources/Industry-Newsletter-Energy-Update

portfolios (CS Energy, Stanwell and Tarong) into two (which occurred in July 2011) indicated a wholesale price increase due to an increase in market concentration. The Australian Competition and Consumer Commission (ACCC), in March 2015, expressed concern at the plan to merge CS Energy and Stanwell, also suggesting an increase in wholesale electricity prices would be a likely outcome. In response, the government stated it would not implement changes that would result in an increase in prices and that it would work with the ACCC to find an appropriate approach.

Given the indication of the government to consult with the ACCC, the market modelling has continued to treat the state government generator assets as two separate portfolios. That being said, we have updated the estimates of the contract prices used in the hedge model (see section 4.2.1) for the Final Determination, and they by their very nature will reflect the market's sentiment of a potential for a merge.

2.3.2 Renewable energy policy costs

Energy costs associated with the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES) have been estimated using the latest price information from AFMA and renewable energy percentages published by the Clean Energy Regulator (CER). Retailer compliance with these schemes operates on a calendar year basis and hence estimates are required for both 2015 and 2016 calendar years, with the costs averaged to estimate the 2015-16 financial year costs.

To estimate the costs to retailers of complying with both the LRET and SRES, ACIL Allen uses the following elements:

- historical Large-scale Generation Certificate (LGC) market prices sourced from AFMA
- currently legislated LRET GWh targets for 2015 and 2016
- official Renewable Power Percentage (RPP) for 2015 published by CER
- an estimate of the RPP for 2016
- binding Small-scale Technology Percentage (STP) for 2015 and non-binding STP for 2016 as published by CER
- The fixed clearing house price for Small-scale Technology Certificates (STCs).

2.3.3 Other energy costs

Market fees and ancillary service costs are estimated based on data and policy documents published by AEMO.

Prudential costs, both AEMO and to support hedging, are more complex and need to take into account:

- the AEMO assessed maximum credit limit (MCL)
- the future risk-weighted pool price
- participant specific risk adjustment factors
- AEMO published volatility factors
- futures market prudential obligation factors, including:

– the price scanning range (PSR)
– the intra commodity spread charge
– the spot isolation rate.

2.3.4 Energy losses

The estimated wholesale energy costs resulting from the analysis is referenced to the Queensland Regional Reference Node. These estimates need to be adjusted for transmission and distribution losses associated with transmitting energy from the Regional Reference Node to end-users. Distribution Loss Factors (DLF) for Energex and for the 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 to the wholesale energy cost estimates to incorporate losses.

Since the Draft determination, the MLFs and DLFs used in the calculations have been updated based on the final 2015-16 MLFs and DLFs published by AEMO on 1 April 2015.

2.4 Renewable energy policy uncertainty

Renewable energy policy continues to face uncertainty in the near term.

The Federal Government established an independent panel to review the RET led by Mr Dick Warburton in the first half of 2014. The Panel submitted its final report to the Government in August 2014. The Panel made two recommendations with respect to the LRET:

— Close the LRET scheme to new entrants and grandfather existing participants to 2030
— Set the target annually based on 50 per cent share of electricity demand growth.

In relation to the SRES, the panel recommended closing the scheme or rapidly phasing it out by 2020.

At the time of the Draft Determination the government was pressing for either a “real 20 per cent” target or a floating annual targets set based on 50 percent of future demand growth. In early 2015, the government attempted to negotiate a revised target of about 30,000GWh in 2020, and the opposition appeared to have a lower bound of 35,000GWh. The Clean Energy Council released a statement in late March 2015 urging the government and opposition to remove the regulatory and subsequent investment uncertainty created by the impasse and adopt a target of 33,500GWh. In mid May 2015 the government and opposition reached an in principal agreement with a target of 33,000GWh.

We have continued with the current approach which relies on analysing the forward curves for LGCs over time and assumes that retailers supplying non-market customers will acquire LGCs gradually on a portfolio basis over time. Similar to the estimates of electricity hedges, the LGC price estimate has been updated for the Final Determination accounting for the most recent trades, which reflect the market’s sentiment about the resolution of the LRET policy (see Section 4.3).

2.5 Extension of the data collection completion date

In previous years, ACIL Allen in undertaking its analysis for the QCA completed the collection of electricity and LGC contract data at the end of March. This closure date allowed ACIL Allen time to compile its analysis and deliver its final report to the QCA for its final determination as per a date agreed with the QCA.

Given the change in delegation issued to the QCA in April 2015 coupled with the release of a further consultation paper by the QCA in mid May 2015, ACIL Allen has extended the data collection closure date to 15 May 2015 for electricity and LGC contract data for the 2015-16 Final Determination.

3 Responses to submissions to Draft Determination and Further Consultation Paper

3.1 Introduction

The QCA forwarded to ACIL Allen a total of 16 submissions in response to its Draft Determination, and 16 submissions in response to its Further Consultation Paper. ACIL Allen reviewed the submissions to identify issues that required our consideration. A summary of the review is shown below in Table 1 and Table 2. The following sections in this chapter address each of the relevant issues raised in the submissions.

Table 1 **Review of issues raised in submissions in response to Draft Determination**

Id	Stakeholder	Wholesale energy costs	Contract prices /hedge model	Renewable energy policy costs	NEM fees	Prudential costs	Energy losses
1	Australians in Retirement (Cairns District Branch)	No	No	No	No	No	No
2	Confidential sunmission	No	No	No	No	No	No
3	Canegrowers ISIS Ltd	No	No	No	No	No	No
4	ERAA	Yes	No	No	No	No	No
5	Origin	Yes	Yes	No	No	No	No
6	Pioneer Cangegrowers	No	No	No	No	No	No
7	Queensland Consumers' Association	No	No	No	No	No	No
8	Queensland Farmers' Federation	No	No	No	No	No	No
9	Toowoomba Regional Council	No	No	No	No	No	No
10	Chamber of Commerce and Industry Queensland	No	No	No	No	No	No
11	Cummings Economics (For Far North Queensland Electricity Users Network)	Yes	No	No	No	No	No
12	Energy Supply Association of Australia	No	No	No	No	No	No
13	Ergon Energy Corporation Limited	No	No	No	No	No	No
14	Ergon Energy Queensland Pty Ltd	No	No	Yes	No	No	No
15	Local Government Association Queensland	No	No	No	No	No	No
16	Queensland Council of Social Service (QCOSS)	Yes	No	Yes	No	Yes	Yes

Note: Yes = an issue was raised that required ACIL Allen's consideration
Source: ACIL Allen analysis of QCA supplied documents

Table 2 **Review of issues raised in submissions in response to Further Consultation Paper**

Id	Stakeholder	Wholesale energy costs	Contract prices /hedge model	Renewable energy policy costs	NEM fees	Prudential costs	Energy losses
1	AGL	Yes	No	No	No	No	No
2	Australians in Retirement	No	No	No	No	No	No
3	Canegrowers ISIS	No	No	No	No	No	No
4	Energy Australia	Yes	No	No	No	No	No
5	Energy Supply Association of Australia	No	No	Yes	No	No	No
6	ERAA	Yes	No	No	No	No	No
7	Ergon Energy Corporation Limited	No	No	No	No	No	No
8	Ergon Energy Queensland	Yes	No	No	No	Yes	No
9	Far North Queensland Electricity Users Network	Yes	No	No	No	No	No
10	Lumo Energy	No	No	No	No	No	No
11	Origin Energy	Yes	Nil	Yes	No	No	No
12	QCOSS	No	No	No	No	No	No
13	Queensland Consumers' Association	No	No	No	No	No	No
14	Queensland Farmers' Federation	No	No	No	No	No	No
15	Red Energy	No	No	No	No	No	No
16	Australian Sugar Milling Council	No	No	No	No	No	No

Note: Yes = an issue was raised that required ACIL Allen's consideration
Source: ACIL Allen analysis of QCA supplied documents

3.2 Wholesale energy costs

3.2.1 Overall approach

A number of the submissions supported the continuation of ACIL Allen's approach for the purposes of consistency.

ERAA, Energy Australia and Origin, both continue to express their opinion that the estimates should be based on the long run marginal cost (LRMC) rather than the market based approach.

ACIL Allen has in previous years discussed and rejected the use of LRMC as a basis for determining the cost of making, producing or supplying customer retail services to customers supplied on notified prices.

ACIL Allen's proposed approach is consistent with the approach used in the advice it provided to the QCA for the 2012-13 Determination and subsequent determinations. This approach was tested in the Supreme Court of Queensland and found to meet the requirements of the Act and Delegation.

3.2.2 Update of data

AGL in its submission in response to the Further Consultation Paper suggested that all market data used in the analysis be updated to be as recent as possible. ACIL Allen agrees with this suggestion. Our standard approach in setting the closure date for the collection of data used in our analysis has been to work back from the date set by the QCA for delivery of our final estimates. Since the date for delivery of our final estimates has been extended in this instance to 20 May 2015, it is consistent to extend the closure date for the collection of data to 15 May 2015.

3.2.3 Proposed merger of Stanwell and CS Energy

ERAA on page two of its submission to the Draft Determination notes:

> The ERAA is aware of previously expressed policy contained in the Labor Party's Our Assets Our Future Policy Paper and A Solar Future Policy Paper with respect to both the commitment to cease privatisation of electricity assets and the consolidation of generation businesses in Queensland. If implemented, the ERAA considers these policies may have a materially adverse impact on the Queensland electricity market and consumers. Of particular concern is the proposed merger of the Queensland Government's electricity generation businesses and potentially their retail businesses into a single entity. If this was to occur it would create a more onerous market that was significantly less attractive for retailer participation relative to other jurisdictions. The ERAA is therefore seeking further information from the QCA as to what actions it may take should these Government policies come into effect during this notified price period.

As noted in Section 2.3.1, ACIL Allen has considered the possible merger of CS Energy and Stanwell and its implications, but based on comments from the ACCC and the response from the State Government of its intention not to implement a policy which increases electricity prices we have continued to model the wholesale market in its current generation portfolio structure. If the two generation portfolios were to be merged in a way that increased market concentration then wholesale prices would likely increase (all other things equal). However, the increase may be offset to some extent by other supply side changes in response to the merger, such as the earlier return to service of unit 2 at Tarong. The wholesale market modelling produces multiple simulations in terms of varying degrees of power station availability and hence varying degrees of market concentration, so to some extent future changes in market concentration due to a change in portfolio structure are simulated in an indirect manner – but it is fair to say that the base assumption is that the merger does not occur.

3.2.4 WEC levels

Two submissions commented on the increase in the control load tariffs (31 and 33). The Far North Queensland Electricity Users Network noted on pages 8 and 9 of their submission to the Draft Determination, that:

> The introduction of Time Of Use charges and smart meters is aimed at assisting all customers to understand that their demand behaviour does impact on the cost of the distribution network

> (poles and wires). Time of Use tariffs are specifically designed to alter the load profile and reduce peak demand.
>
> It is therefore interesting to note that Tariff 31 (overnight controlled loads) is an off peak tariff that is forecast to rise by 4.3 percent due to higher fuel costs prevailing overnight.
>
> This substantial increase in a major off peak tariff is counter-productive to encouraging customers to use off peak tariffs. This forecast rise also brings in the question of why distribution and generation are not discussed at the same time. Distribution and generation are intrinsically linked and the reason for the increase needs to be fully investigated.

QCOSS on page 22 of its Draft Determination submission notes

> QCOSS notes with concern the increase in wholesale energy costs for Tariff 31. Tariff 31 is a controlled load tariff that is used predominantly for hot water heating overnight. The QCA has referred to advice from ACIL Allen and has attributed this increase to the increased unit costs of fuel at night due to gas and coal being used for base load.
>
> While QCOSS does not dispute the ACIL Allen commentary, or the underlying data which they are explaining, we have concerns about the fact that controlled load tariffs in recent times have been increasing in cost at a faster rate than Tariff 11, thus undermining the customer incentive to access these tariffs.

For the Final Determination, ACIL Allen has updated the load profile data for Tariff 31 from AEMO as it became apparent there were some inconsistencies in the underlying load data for 2013-14 – with unexplainable step changes occurring in the underlying half-hourly data for particular parts of the data used in the Draft Determination (in some cases it appears as though a block load was temporarily included in the data set). For the Final Determination, ACIL Allen has not used the 2013-14 Tariff 31 data and instead used the same load data as used for the 2014-15 determination (i.e. the 2012-13 load data).

The revision of the load data in conjunction with the revised modelled prices (as a result of the revised demand forecast) and updated contract prices, used within the hedging model, has resulted in the wholesale energy costs of Tariff 31 declining marginally.

3.2.5 PV installations

The Far North Queensland Electricity Users Network noted on page 10 of their Draft Determination submission that:

> The energy costs for the Draft 2015/16 Determination need to be revisited in light of the consistent pattern of falling solar PV installations and uncertain State and Federal Government policies.

As discussed in Section 2.3.1, ACIL Allen has revised the demand forecast to account for the recent slower than forecast uptake of rooftop solar PV.

The Far North Queensland Electricity Users Network also noted on page 4 of their Further Consultation Paper submission that:

> The new Queensland Government has a policy of 1 million solar PVs by 2020. ... One million solar PVs will also adversely affect the wholesale cost of energy.

At this stage there are no details on the Solar Future program policy of one million Queensland rooftops fitted with solar panels by 2020 other than the intent of the policy itself. However, it appears that the policy is not in addition to the current 400,000 or so household installations in Queensland. The rooftop solar PV installation forecast published by AEMO in its 2014 NEFR certainly has the output from installations more than doubling between 2014-15 and 2019-20 in Queensland which suggests at a high level that the number of households with solar PV would be at least 800,000 by 2019-20 in any case. Further, given the lead time required to develop any mechanism to achieve the policy (assuming a mechanism is developed), it is unlikely to impact the uptake rate of solar PV in 2015-16.

3.2.6 Variability in demand

Origin, as in previous years, raised the issue of ACIL Allen's demand simulation on page 2 of their submission:

> In our submission to the QCA's Discussion paper we also raised a number of concerns with the approach taken to generate load profiles. ACIL's presentation of modelled Energex demand simulations (Figure 4) shows that the current approach continues to under-represent load variability. The top 100 hourly demands in ACIL's upper and lower demand simulations sit within the boundary created by the actual demand traces for each of the last four years. We would expect that upper and lower demand simulations would sit outside recent historic demands as they are intended to represent extreme conditions. A tight range of demand distributions naturally leads to a more efficient 'model hedge position' in turn understating modelled energy costs.

ACIL Allen is of the opinion that it has adequately covered the range in outcomes, and indeed the revision to the load forecast results in a wider range of peak demand outcomes (see Section 4.2.2). The range in outcomes may not be a wide as what has occurred historically, but this is because we are modelling 2015-16 only and not multiple years into the future. A contributing factor to the range of demand outcomes over the past five or so years is cumulative change in manufacturing related demand, industrial demand and solar PV installations. But the demands used in the analysis do include 'extreme conditions' in terms of weather driven demand variability.

3.3 Contract prices

Origin Energy states on page two of their submission to the Draft Determination that:

> In our view, the QCA's hedging based method does not appropriately reflect the dynamic of the wholesale market with respect to the relationship between contract and pool prices. Under the QCA's approach, the portfolio cost is at its lowest under a scenario when pool prices are at their highest and the supply demand balance is at its tightest; conversely, portfolio costs are at their highest under a situation when pool prices and demand are at their lowest.
>
> Our experience is that when the supply demand balance is tight, generators have more ability to price contracts at higher values to reflect the value of scarce capacity. Furthermore, we consider that historic practise demonstrates that when pool prices are high so too are contact prices.
>
> As a result (and as detailed more fully in previous submissions), we maintain our view that it is unrealistic to assume retailers will consistently be able to profit from buying an insurance product and that the higher the pool price scenario, the lower the wholesale energy cost.

ACIL Allen supports the view that futures prices tend to follow or be influenced by current spot prices and the expectation of where spot prices will be at the time the product is traded. For example, since the Draft Determination, Q4 2015 and Q1 2016 futures prices have increased by as much as $18/MWh, influenced by the higher pool prices over the 2014-15 summer period resulting from demand growth.

In the Final Determination, ACIL Allen has estimated contract prices by using the trade-weighted average of ASX Energy daily settlement prices since the contract was listed up until 15 May 2015. This ensures movements in contract prices are adequately reflected in the overall contract price used in calculating the cost of energy.

Although we agree that for a given quarter, futures prices will converge to the spot price at the completion of that quarter, this does not mean that all trades in futures contracts are priced at the final spot price for the quarter. Trades completed prior to the completion of the quarter will have occurred at the prevailing futures price at the time of the trade.

Origin Energy states on page three of their submission to the Draft Determination that:

> We understand that as with previous years the QCA will update its analysis before making a final determination and consider this an important process given the historic improvement in contract liquidity in this period and recent movements in contract market prices.

ACIL Allen has observed that ASX Energy futures trade volumes across all contracts (base, peak and cap) in the 2015-16 year have almost doubled since the Draft Determination. In the Final Determination, ACIL Allen has based its estimate of contract prices on ASX Energy data up to 15 May 2015, which includes the significant increase in trade volumes since the Draft Determination.

3.4 Renewable energy policy costs

The Energy Supply Association of Australia (ESAA) states on page two of their submission to the Further Consultation Paper:

> In determining wholesale energy costs, the Association considers it important to be mindful of the uncertainties associated with such estimates. The cost of Large-scale Generation Certificates (LGC) is a perfect example in this regard. It has only been in recent months that industry and the market has gained confidence in policy makers agreeing to a forward target. This confidence has translated into higher trading volumes and a corresponding increase in the average LGC price above that observed over the past 12-months.
>
> To this end, the ESAA maintains a more appropriate methodology for determining wholesale energy costs is one that takes account of the different approaches to procuring wholesale electricity and recognises the longer term costs of generating electricity.

While ACIL Allen recognises that the RET review created uncertainty around the future of the scheme, ACIL Allen continues to hold the view that the prices within the spot and futures market represent the most reliable indicator of the current market consensus view of the price of LGCs. ACIL Allen's preference is to maintain the two year book-build methodology as this gives appropriate weight to market trading opportunities and allows new information to be included when it becomes available to the market. In this Final Determination, ACIL Allen has updated its analysis to include AFMA LGC price data up to 15 May 2015.

ACIL Allen recognises that in practice retailers build a portfolio of LGCs from a number of sources including:

- Direct investment in renewable generation projects
- PPAs written with renewable generators

— Spot and forward purchases transacted through brokers and direct trades with counterparties.

Of these, the only one which is traded regularly with observable pricing are the spot and forward contracts transacted through brokers. ACIL Allen on page 27 in its report for the 2014-15 Final Determination[6] addressed the issue of using longer term costs of generating electricity in detail.

Origin Energy (Origin) states on page two of their submission to the Further Consultation Paper:

> As QCA noted in its Draft Determination, Origin has previously advocated that the policy uncertainty around the Renewable Energy Target has led to a lack of liquidity in the LGC market over the past year, with retailers and large customers holding off purchasing forward volumes of LGCs until they have a more certain understanding of the future target. It has only been in the past few months that industry and the market has gained confidence in policy makers agreeing to a forward target. This confidence has translated into higher trading volumes and a corresponding increase in the average LGC price. With greater certainty around the likely 33,000 GWh target, the market is now actively trading to meet future compliance requirements, including those for 2015-16.
>
> If the QCA is committed to using a market-based methodology for determining the costs of the RET, we strongly recommend placing a greater weighting on market prices since February-March 2015, where there was clearly a step change in market confidence around policy agreement to a revised target. This adjustment in approach would result in RET costs that more closely reflect that actual costs retailers are incurring to meet their liability for 2015-16.

We acknowledge the uncertainty due to the RET review, but there are a large number of other uncertainties which influence the LGC price – such as the level of future black energy price outcomes over the life of the LRET (not just in 2015-16), trends in capital costs of new build plant, the potential for inclusion of a carbon price in the future. Each of these uncertainties have been, in effect, factored into the futures prices.

The AFMA LGC price data being relied upon is survey based, including, amongst others, eight retailer respondents. The data includes bids, asks and mid-points excluding outliers. The mid-points excluding outliers reflect the market consensus view of the price of LGCs at the time of surveying. Although the AFMA data does not provide a measure of trades, our analysis of the AFMA data suggests that, during the time of lower LGC prices in 2014, the average number of respondents had not decreased.

3.5 Prudential costs

QCOSS on pages 23 and 24 of their submission to the Draft Determination argue that prudential costs are already included in the QCA's estimate of the general retail costs:

> Page 23/24: QCOSS has previously argued that prudential capital costs should not be included as a separate itemised component of retailer costs. Other regulators have not separately itemised these costs, for example the Independent Pricing and Regulatory Tribunal (IPART) in New South Wales (NSW) as stated:

[6] http://www.qca.org.au/getattachment/9be567a8-92e2-4d53-85f0-3781e4f8662f/ACIL-Allen-Final-Report-Estimated-Energy-Costs-for.aspx

> - "We consider that these costs (for example the cost of meeting AEMO prudential requirements) are part of the normal costs for running a retail electricity business. These, along with other retail costs, are captured within our cost allowances."
>
> Given that the QCA has used IPART's general retail costs in its benchmarking, by separately itemising the costs of meeting Australian Energy Market Operator (AEMO) prudential costs, QCA is double counting the same costs. If and only if QCA were to remove these costs from the general retail costs, it could then legitimately separately itemise them.
>
> As ACIL Allen advises the QCA, retailers can reallocate prudential obligations or may meet requirements through vertical integration, so there is considerable uncertainty as to the applicability of the calculation that has been used by QCA. QCOSS questions the appropriateness of the assumptions and methodology that have been used to calculate the costs, particularly as there is no benchmark of calculation by other retailers against which to compare. QCOSS would particularly question the use of the Weighted Average Cost of Capital (WACC) of Energex. The cost of capital of Energex for regulated network pricing determinations was not intended to be used for this purpose, and is certainly not applicable to a retailer of energy.

ACIL Allen notes the issue raised by QCOSS that IPART considers the costs of meeting prudential requirements as part of the cost of running a retail business and therefore since the QCA adopts the general retail costs produced by IPART then prudential costs are being double counted. However, it is unclear from the IPART report whether prudential costs have been explicitly calculated or are assumed to be wrapped into their estimates general retail costs. ACIL Allen understands that the QCA has confirmation from IPART that prudential costs are included in the estimates of retail operating costs (ROC) to some degree. ACIL Allen is of the opinion that since prudential costs are a function of the underlying volatility in the market and are necessary for a standalone retailer to participate in the NEM and contract markets, that they should be treated as a component of the energy cost. However, ACIL Allen acknowledges that since there is no detail of the way IPART has estimated the prudential costs, it is difficult for the QCA to disentangle this element from the ROC.

Ergon Energy Queensland (EEQ) note on page five of their submission to the Further Consultation Paper:

> EEQ acknowledges the QCA's consideration of the appropriate treatment of the prudential capital cost allowance given IPART's (as the benchmark) approach to include this allowance in its ROC. In calculating the allowance EEQ suggests that the QCA consider the differences in the underlying drivers of prudential capital costs between the Queensland and NSW markets. In particular ensuring that, the relative volatility of the Queensland wholesale market price in comparison to NSW (an input to the AEMO's prudential requirements) and the prudential credit support requirements of Distribution Network Service Providers are appropriately accounted for.

Although ACIL Allen agrees that the approach suggested by EEQ has merit, it is difficult to assess to what extent the level of price volatility is included in the IPART estimate. Further, the time frame to finalise the cost estimates for the 2015-16 determination does not allow for a detailed investigation into the IPART process.

ACIL Allen is of the view that although the prudential obligations could be satisfied to some extent through vertical integration, the energy costs provided in this report are estimated for a stand-alone retailer and as such the prudential obligations should be taken into account to ensure the estimates of the components of energy costs are internally consistent.

3.6 Outcomes of hedging model

Origin Energy on page one of its submission to the Further Consultation Paper state:

> In our earlier submissions, Origin has raised some questions around the accuracy of QCA's current hedging-based approach. In our view, the QCA's hedging based method does not appropriately reflect the dynamic of the wholesale market with respect to the relationship between contract and pool prices. As previously stated, this approach results in a portfolio cost at its lowest under a scenario when pool prices are at their highest and the supply demand balance is at its tightest; conversely, portfolio costs are at their highest under a situation when pool prices and demand are at their lowest.

ACIL Allen addressed this matter in detail in its report for the 2014-15 Final Determination, and remains satisfied with the hedging approach adopted.

3.7 Providing data used in the analysis

Origin Energy on page one of its submission to the Further Consultation Paper state:

> We also have some queries regarding ACIL Allen's pool price distribution and simulation outcomes. While ACIL describe their methodology at a high level, they do not provide sufficient detailed data for stakeholders to analyse accurately the sensibility and historical appropriateness of their modelling outcomes. To undertake these verifications, stakeholders would require details of the actual price curves generated (either hourly or half hourly data), not just an average annual summary.
>
> In lieu of data, a further breakdown of results would be beneficial. Presently, it is difficult to make a thorough assessment of ACIL's results without an understanding of how much volatility is in the price curves. In particular, it would be good to see a breakdown of the price curve, including details around the "under-cap" area (typically between $100/MWh and $299.99/MWh) in both a graph or table form to help verify the validity of ACIL's chosen 95th percentile curve.

The request for "under-cap" price impacts made by Origin is similar to that made by Energy Australia in 2014-15, and ACIL Allen has included in section 4.2.2 a summary of these impacts.

In previous determinations, ACIL Allen provided more detailed hourly data but we are of the opinion that this did not contribute to stakeholders improving their understanding and therefore, assessment of the methodology. ACIL Allen is satisfied with the level of data and summaries it provides.

4 Estimation of energy costs

4.1 Introduction

In this section we apply the methodology and summarise the estimates of each component of the total energy costs for each of the tariff classes for 2015-16.

4.2 Estimation of WEC

4.2.1 Estimating contract prices

Contract prices for Queensland were estimated using the trade-weighted average of ASX Energy daily settlement prices since the contract was listed up until 15 May 2015.

Table 3 shows the estimated quarterly swap and cap contract prices for the Final Determination 2015-16, Draft Determination 2015-16 and the Final Determination 2014-15.

Table 3 **Quarterly base, peak and cap estimated contract prices ($/MWh) – 2015-16**

	Final determination 2015-16			
	Q3 2015	Q4 2015	Q1 2016	Q2 2016
Base	$38.92	$45.72	$60.05	$41.15
Peak	$46.25	$62.75	$95.86	$48.49
Cap	$3.57	$7.89	$14.89	$3.95
	Draft determination 2015-16			
	Q3 2015	Q4 2015	Q1 2016	Q2 2016
Base	$41.11	$45.77	$56.85	$41.95
Peak	$47.00	$59.60	$81.00	$48.00
Cap	$3.81	$6.99	$13.67	$3.83
	Final determination (no carbon case) 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

Source: ACIL Allen analysis using ASX Energy data up to 15 May 2015

Trade weighted base contract prices for 2015-16 are generally lower than for 2014-15, whereas peak contract prices and Cap prices tend to be higher. It is possible that the base prices are lower due to the market registering a degree of pessimism in terms of the timing of demand associated with the LNG projects, given previous delays. Certainly, the increase in peak and cap prices can be traced to the increase in price volatility observed in the NEM during the summer of 2014-15 due to very hot weather.

The following charts show daily settlement prices and trade volumes for ASX Energy quarterly base futures, peak futures and cap contracts up to 15 May 2015.

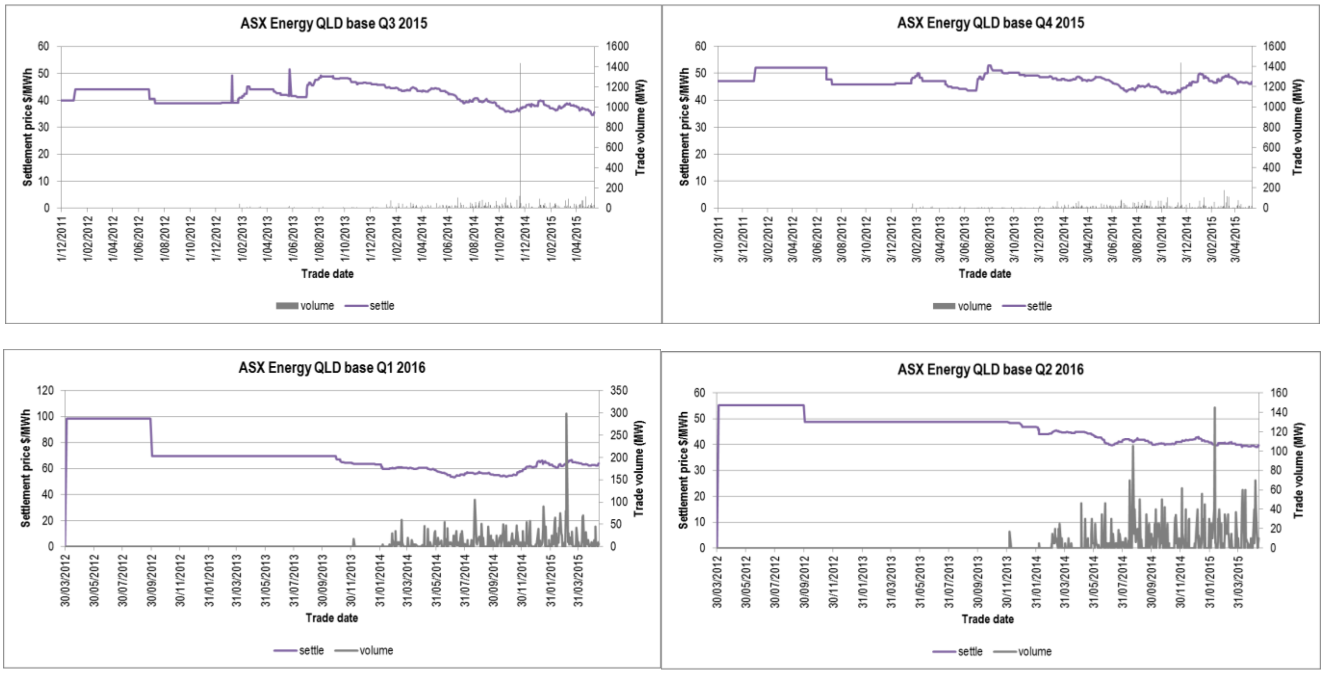
Since the Draft Determination, trade volumes have more than doubled. Base futures have traded strongly, with total volumes of 7,128 MW (Q3 2015), 6,583 MW (Q4 2015), 3,932 MW (Q1 2016), and 3,148MW (Q2 2016).

Cap futures trade volumes also traded strongly with volumes of 454 MW (Q3 2015), 388 MW (Q4 2015), 1,792 MW (Q1 2016) and 399 MW (Q2 2016).

2015 peak futures trade volumes were low with 10 MW (Q3 2015) and no trade volume in Q4 2015, however, 2016 peak futures traded strongly with 100 MW (Q1 2016) and 85 MW (Q2 2016).

While 2015 peak futures contracts are thinly traded, we are comfortable with using the ASX Energy prices, because they are consistent with OTC peak contract prices.[7]

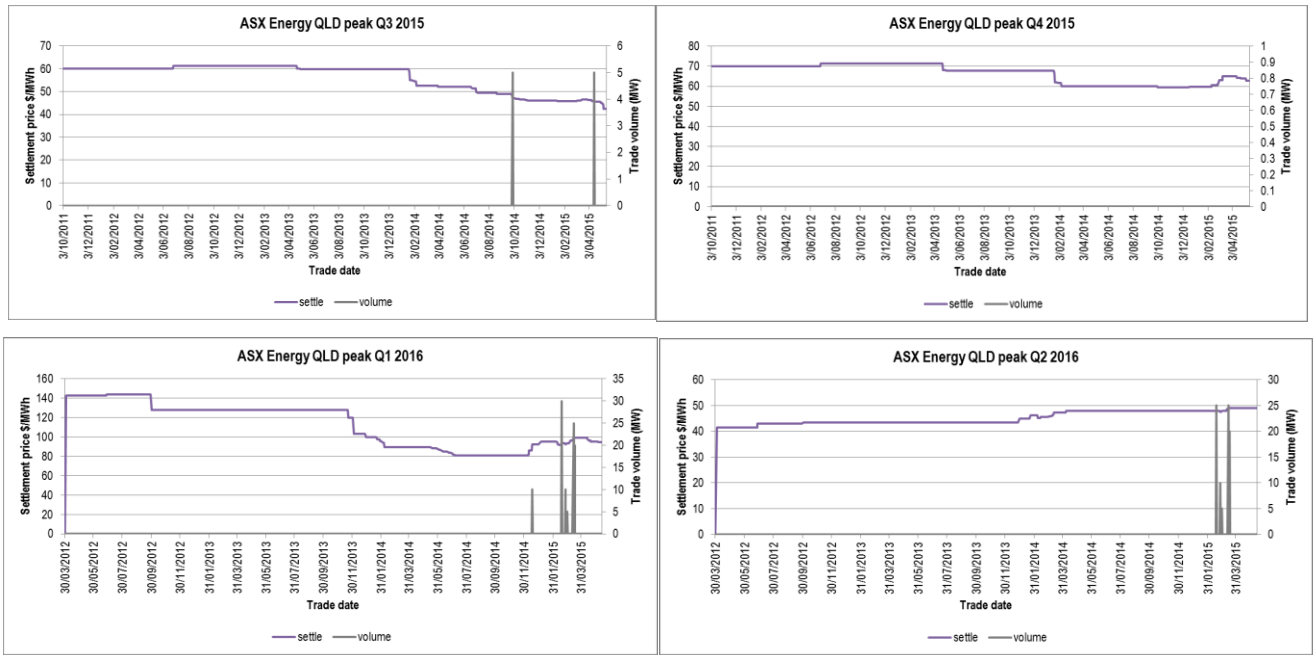
Figure 1 **Time series of trade volume and price – ASX Energy QLD BASE futures for Q3 2015, Q4 2015, Q1 2016 and Q2 2016**



Data Source: ASX Energy data up to 15 May 2015.

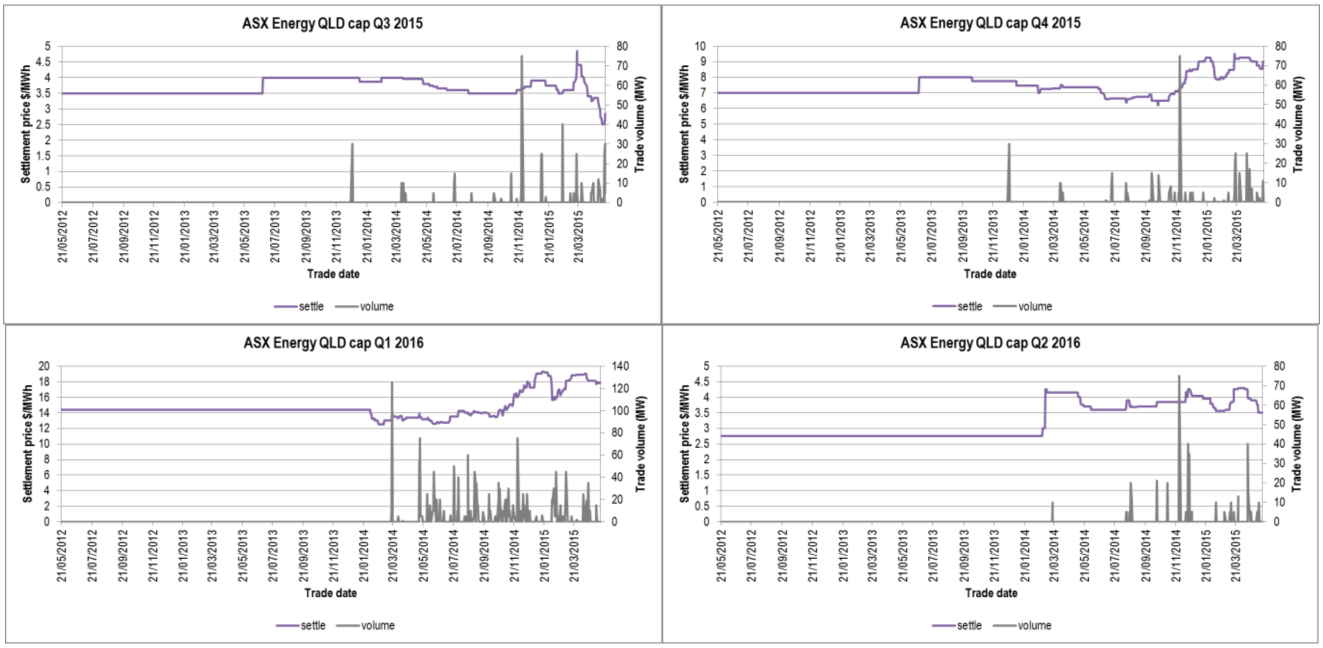
[7] OTC contract data from NextGen

Figure 2 **Time series of trade volume and price – ASX Energy QLD PEAK futures for Q3 2015, Q4 2015, Q1 2016 and Q2 2016**



Data Source: ASX Energy data up to 15 May 2015.

Figure 3 **Time series of trade volume and price – ASX Energy QLD $300 CAP contracts for Q3 2015, Q4 2015, Q1 2016 and Q2 2016**



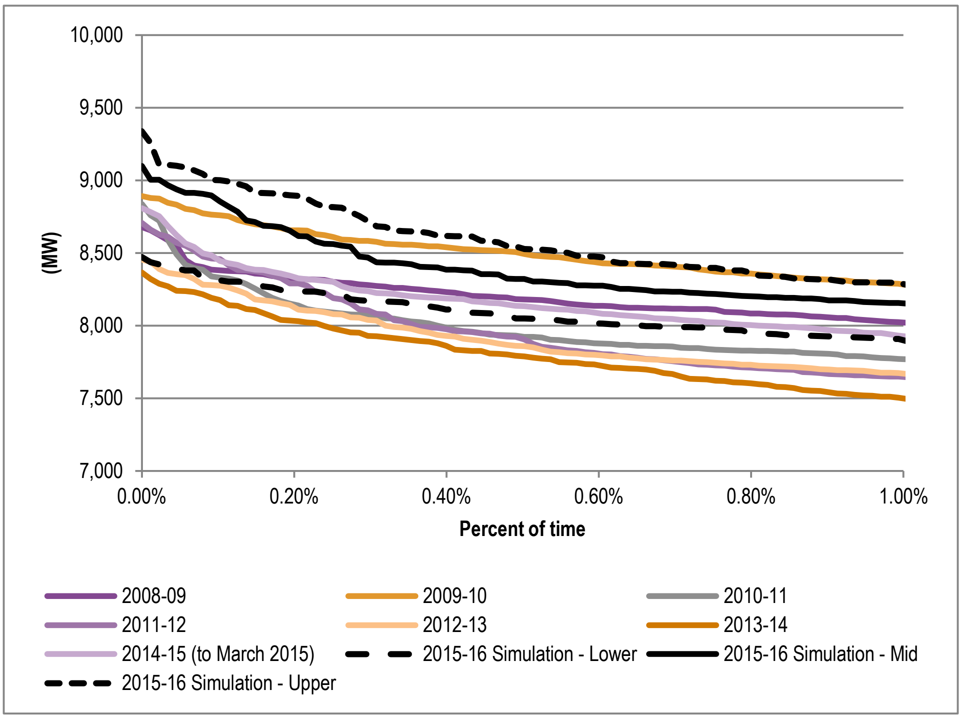
Data Source: ASX Energy data up to 15 May 2015.

4.2.2 Estimating wholesale spot prices

PowerMark was run to estimate the hourly pool prices for 2015-16 for 484 simulations by (44 demand and 11 outage sets).

Figure 4 shows the upper one percent segment of the demand duration curves for three of the 44 simulated Queensland demand sets resulting from the methodology along with the historical demands since 2008-09. The three simulated demand sets represent the upper, lower and middle of the range of demand duration curves across all 44 simulated sets. It can be seen that the demand duration curves of the simulated demand sets for 2015-16 not only envelope the recent historic demand duration curves, but demonstrate that the difference between the maximum and minimum of the envelope averages around 500MW across the top one percent of demands - that is, the variation between the simulated demand sets does not just occur at the single peak annual demand but across a reasonable portion of the demands within the given simulation. This variation in demand contributes to the variation in modelled pool price outcomes as discussed further in this section.

Figure 4 **Top one percent hourly demands – Queensland**



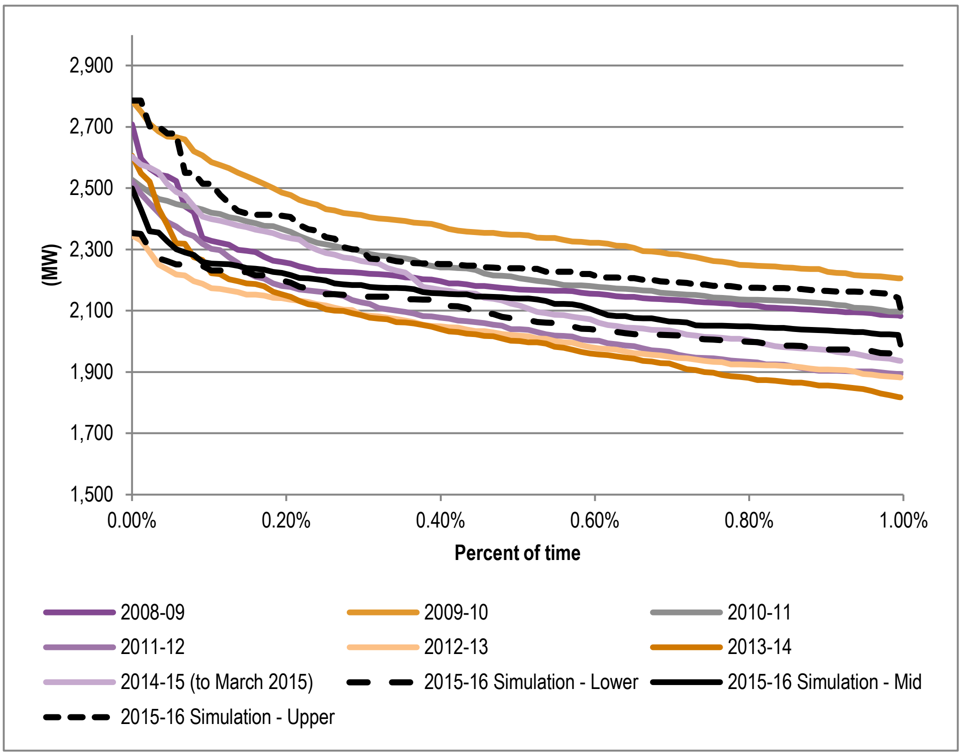
Source: ACIL Allen analysis and AEMO data

Figure 5 shows the variation in the simulated Energex NSLP demand sets envelopes recent outcomes and covers an average range of about 250MW across the top one percent of hours. This variation results in the annual load factor[8] ranging between 30% and 37% compared with a range of 40% to 33% for the actual NSLP between 2008-09 and 2013-14. There has been a lowering in the load factor in the NSLPs in recent years due to an increase in penetration of rooftop solar PV panels – the increased penetration no longer reduces the peak demand (since the peak demand now occurs between 6:30pm and 8:30pm) but continues to reduce the average metered demand.

All other things equal, the increased peakiness of the load, which still requires to be hedged, is likely to result in a larger degree of over hedging across the general day-time peak periods of the day, resulting in a larger degree of over hedging overall on an annual basis, which means hedging costs increase.

[8] The load factor is a measure of the peakiness in the half hourly load profile across a given period of time. The annual load factor is the average of the half hourly loads for the given year divided by the maximum of the half hourly loads for that same given year.

Figure 5 **Top one percent hourly demands – Energex NSLP**

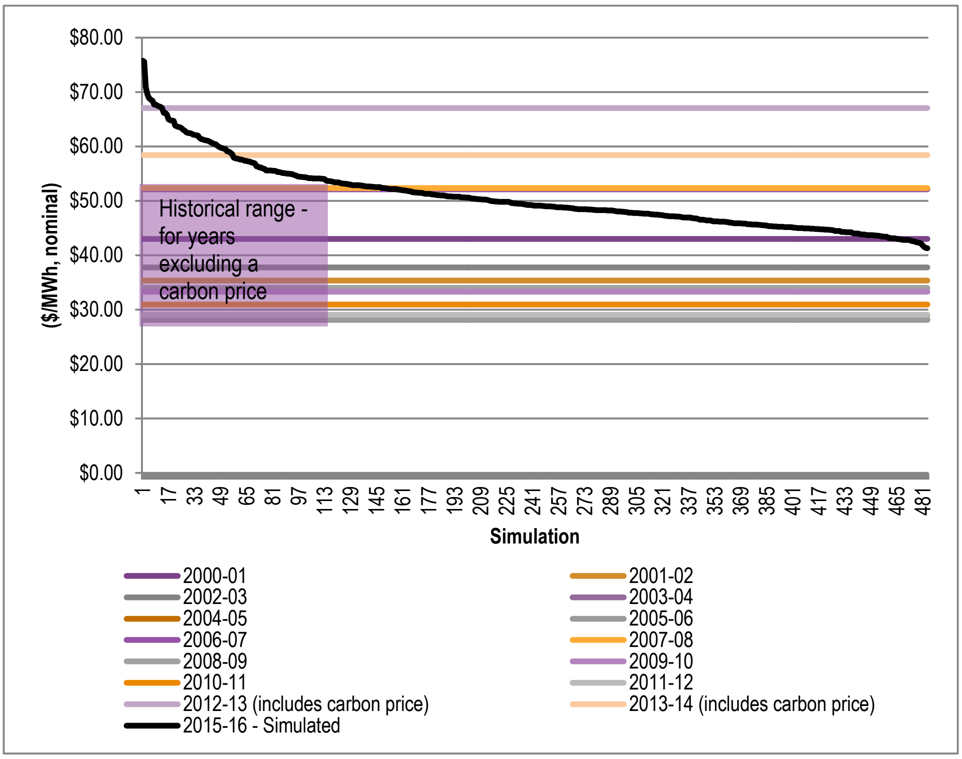


Source: ACIL Allen analysis and AEMO data

The annual time weighted pool prices (TWP) for Queensland from the 484 simulations range from a low of $41.32/MWh to a high of $75.73/MWh. This compares with the lowest recorded Queensland TWP in the last 14 years of $30.06/MWh in 2011-12 to the highest during the drought year of 2007-08 of $58.07/MWh; in 2012-13 the inclusion of the carbon price increased outcomes to $70.34/MWh (but this would be less than the price during the drought if there was no carbon price in 2012-13).

Figure 6 compares the Queensland TWP for the 484 simulations for 2015-16 with the Queensland TWPs from the past 14 years. Although there have been changes to both the supply and demand side of the market, the graph clearly shows that the simulations cover a wide range in potential prices for 2015-16 when compared with the past 14 years of history. The lower part of the distribution of simulated outcomes sits above some of the actual outcomes (particularly of the earlier years of the market), but by 2015-16 gas prices are projected to be around $9/GJ, compared with $3 - $4/GJ in recent years, and the operating costs of coal plant have increased since the market's inception, and these, coupled with demand growth due to the LNG terminals, have the effect of influencing an increase in the lower bound on annual price outcomes. ACIL Allen is satisfied that in an aggregate sense the distribution of the 484 simulations for 2015-16 cover an adequately wide range of possible annual pool price outcomes.

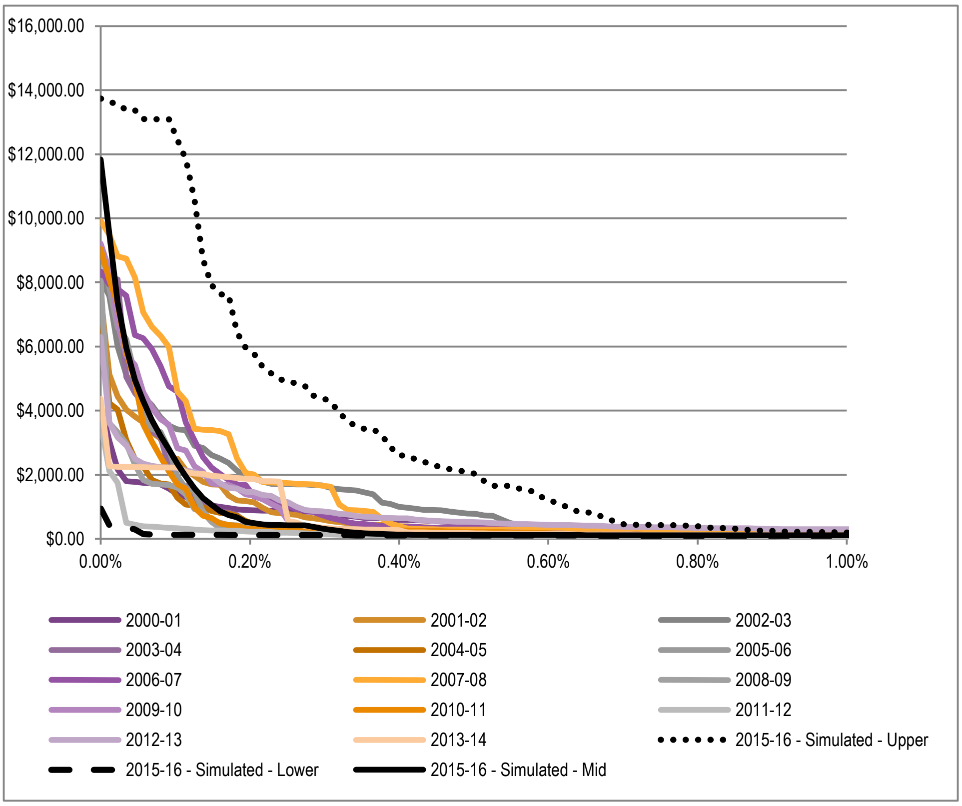
Figure 6 **Annual TWP for Queensland for 484 simulations for 2015-16 compared with actual annual outcomes in past years**



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

Comparing the upper one percent of hourly prices in the simulations with historical spot prices shows the spread of the hourly prices from the simulations also more than adequately covers the historical spread of spot prices. The comparison is illustrated in Figure 7 which clearly demonstrates that range of upper one percent of prices from the 484 simulations for 2015-16 easily encompasses the range of historical prices. It is also notable, that as would be expected, the distribution of simulated price outcomes demonstrates a strong positive skewness.

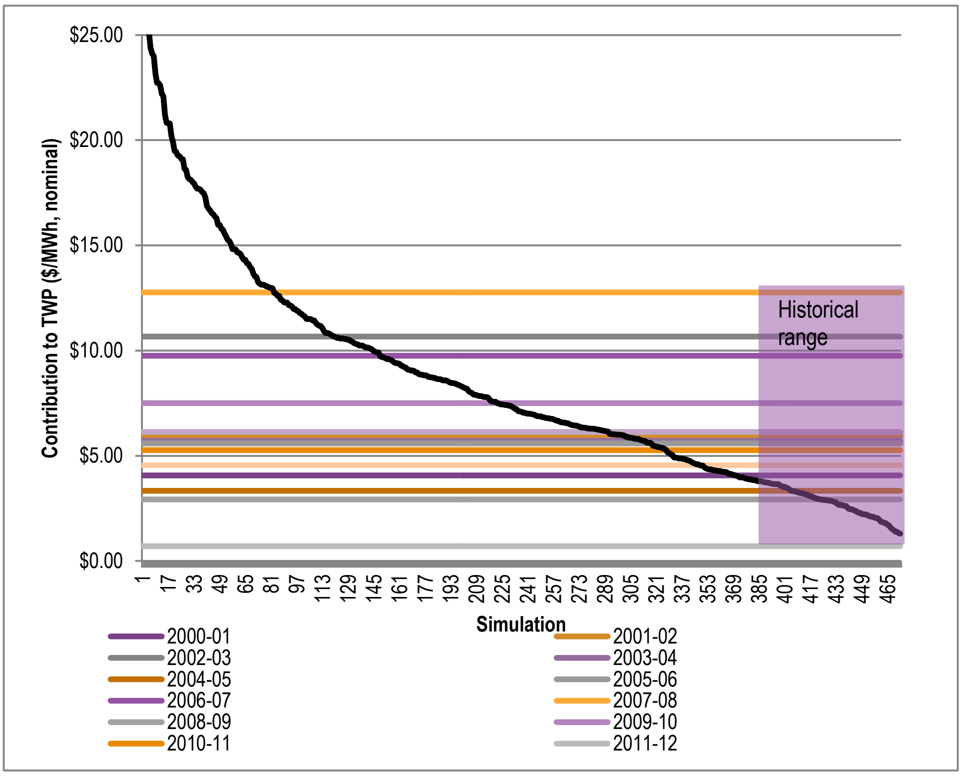
Figure 7 **Comparison of upper tail of hourly price duration curve for Queensland for 484 simulations for 2015-16 compared with actual outcomes in past years**



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

ACIL Allen is also satisfied that *PowerMark* has performed adequately in capturing the extent and level of the high price events based on the demand and outage inputs for the 484 simulations. The range in annual average contribution to the TWP, of hourly prices above $300/MWh, for the 484 simulations is consistent with those recorded in history as shown in Figure 8.

Figure 8 **Annual average contribution to the TWP by prices above $300/MWh in the modelled simulations and recorded in the past**



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

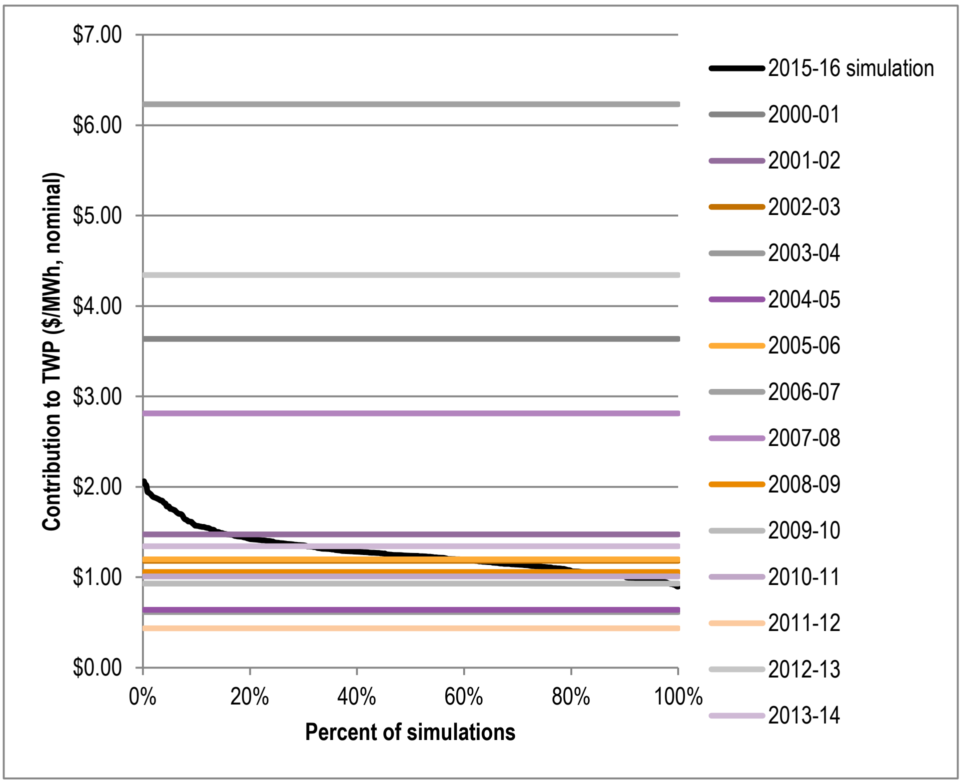
Figure 9 shows the range in annual average contribution to the Queensland time weighted price (TWP), of hourly prices between $70/MWh and $300/MWh, for the 484 simulations is consistent with those recorded in history.

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 2015-16 does not produce outcomes to the extent that were experienced during the drought – but we are assuming (in our view quite reasonably) that the drought conditions of 2006-07 are not repeated in 2015-16.

Figure 9 also shows the inclusion of a carbon price increases the contribution of prices between $70/MWh and $300/MWh (eg. 2012-13 and 2013-14), 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).

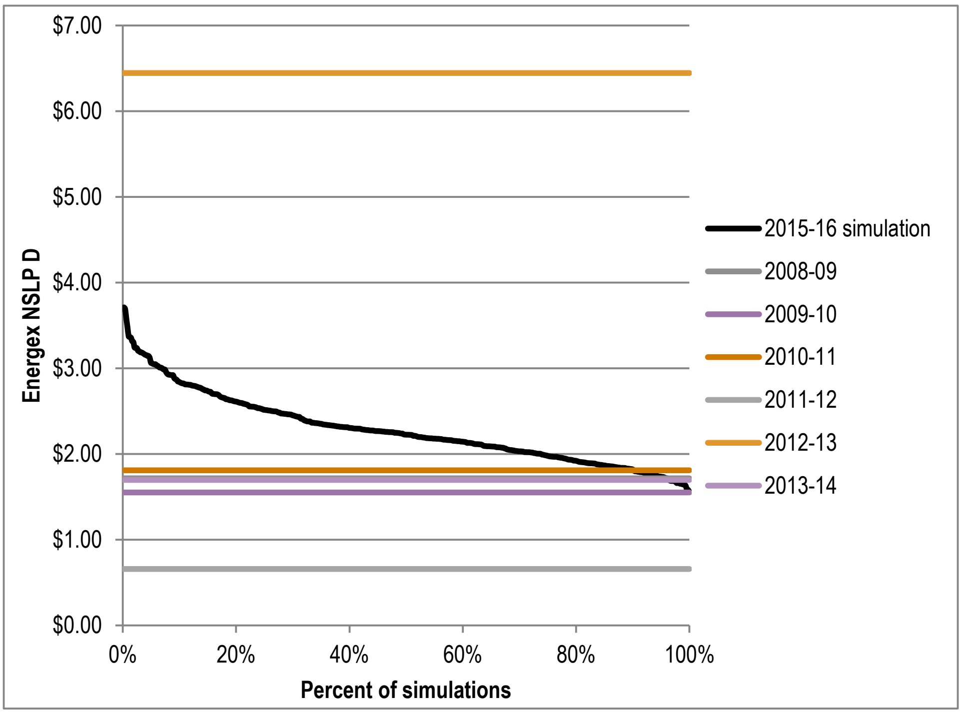
A similar conclusion can be reached when considering the contribution of prices between $70/MWh and $300/MWh to the demand weighted price (DWP) of the Energex NSLP as shown in Figure 10. Not only does this demonstrate the reasonableness of the modelling in terms of volatility in the prices between $70 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.

Figure 9 **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 historic pool price data and ACIL Allen results from PowerMark modelling

Figure 10 **Annual average contribution to the Energex DWP by prices between $70/MWh and $300/MWh in the modelled simulations and recorded in the past**



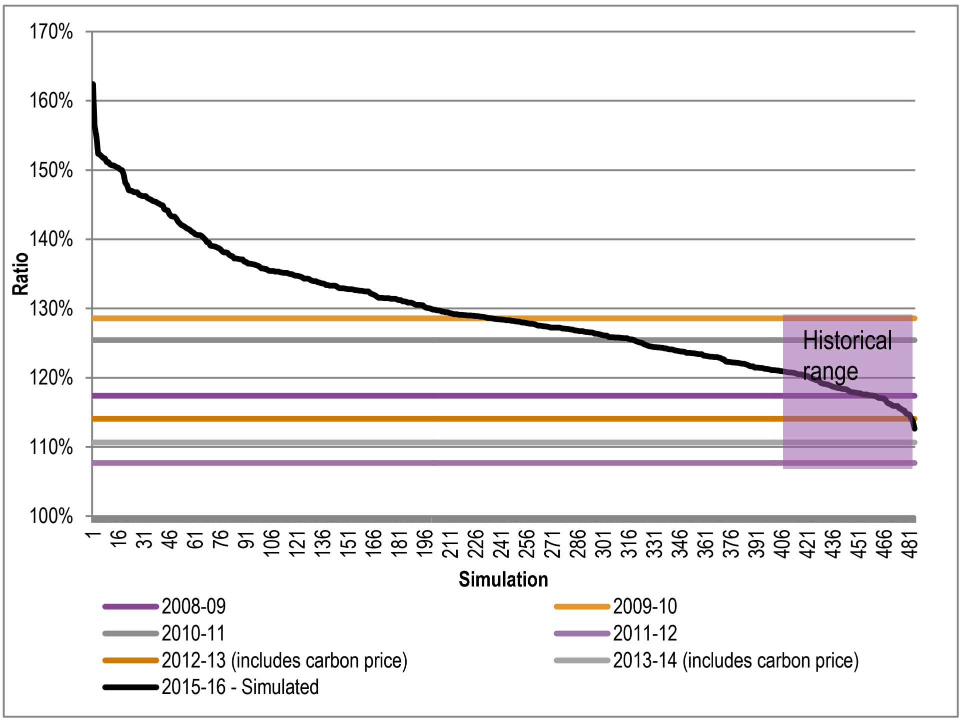
Source: AEMO historic pool price data and ACIL Allen results from PowerMark modelling

Submissions to previous determinations suggested that the simulated NSLP peak demand was too low which in turn was presumed to lead to a lower cost to supply the NSLP. However, the maximum demand of the NSLP is not in isolation a critical feature in determining the cost of supply. The shape of the NSLP demand trace and its relationship to the shape of the Queensland demand/price traces is a critical factor in the cost of supplying the NSLP demand. The summer maximum demand for the NSLP occurs in the evening (typically around 7:30pm) while the Queensland summer demand peaks occur earlier in the afternoon (usually between 2pm and 4pm). This means that the peak of the NSLP is less likely to be coincident with extreme price events associated with the afternoon Queensland peak. Furthermore, using past data as a guide, the annual peak of the NSLP may occur in winter which has a different set of characteristics and relationship to price.

A test of the appropriateness of the NSLP demand shape and its relationship with the Queensland demand shape can be undertaken by comparing the annual demand weighted price (DWP) for the Energex NSLP with the Queensland TWP. Figure 11 shows that, for the past six financial years, the DWP for the Energex NSLP as a percentage of the Queensland TWP has varied from a low of 108% in 2011-12 to a high of 129% in 2009-10. In the 484 simulations for 2015-16, this percentage varies from 113% to 162%. These results more than adequately cover the historical range.

The comparison with actual outcomes over the past five years in Figure 11 demonstrates that the relationship between the Energex NSLP demand and Queensland pool prices in the 484 simulations is sound. Further, the cost of supplying the Energex NSLP in the simulations relates well to the Queensland pool price and covers the full range of possible outcomes for 2015-16. It also provides a sound cross check on the shape of the NSLP demand and its relationship with the Queensland demand.

Figure 11 **Annual DWP for Energex NSLP as percentage of annual TWP for Queensland for 484 simulations for 2015-16 compared with actual outcomes in past years**



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

ACIL Allen is satisfied the Queensland pool prices from the 484 simulations cover the range of expected price outcomes for 2015-16 both on average and in the upper tail. These comparisons clearly show that the 44 simulated demand traces combined with the 11 plant outage scenarios provide a sound basis for modelling the expected future outcomes for 2015-16.

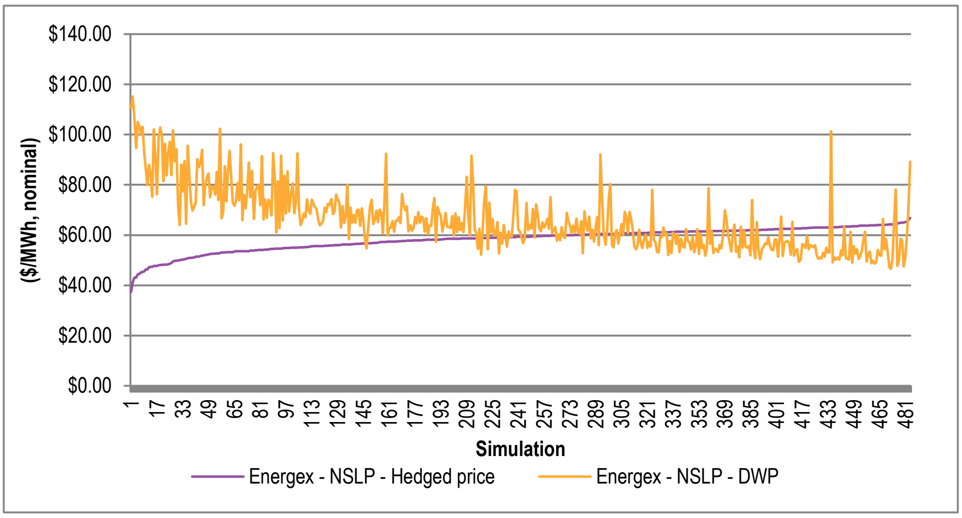
4.2.3 Applying the hedge model

The ACIL Allen methodology uses a simple hedge book approach based on standard quarterly base and peak swaps and caps. The prices for these hedging instruments are taken from the estimates provided in Section 4.2.1.

As hedge benefits are inversely related to pool prices, simulations with higher demand weighted pool prices usually produce lower hedged prices. Figure 12 shows that, under the ACIL Allen methodology, the higher estimates of supply costs including hedge effects are not associated with high demand and high pool price years. This is because, the benefits from the hedge strategy used in the methodology dominate the pool prices such that the higher hedged prices after hedging is taken into account are generally related to the lower pool price simulations and vice versa.

In other words the current conservative hedging strategy adopted in the ACIL Allen methodology has an inherent bias which rewards the retailer during price events in the pool that are higher than the contract price. This conservative hedging strategy has a significant cost in that hedges in excess of most expected demand outcomes must be acquired to put it into effect.

Figure 12 **Annual hedged price and DWP for Energex NSLP for the 484 simulations ($/MWh)**



Source: ACIL Allen modelling

Contract volumes continues to be calculated for each settlement class for each quarter as follows:

— The base contract volume is set to equal the 80th percentile of the off-peak period hourly demands across all 44 demand sets for the quarter.

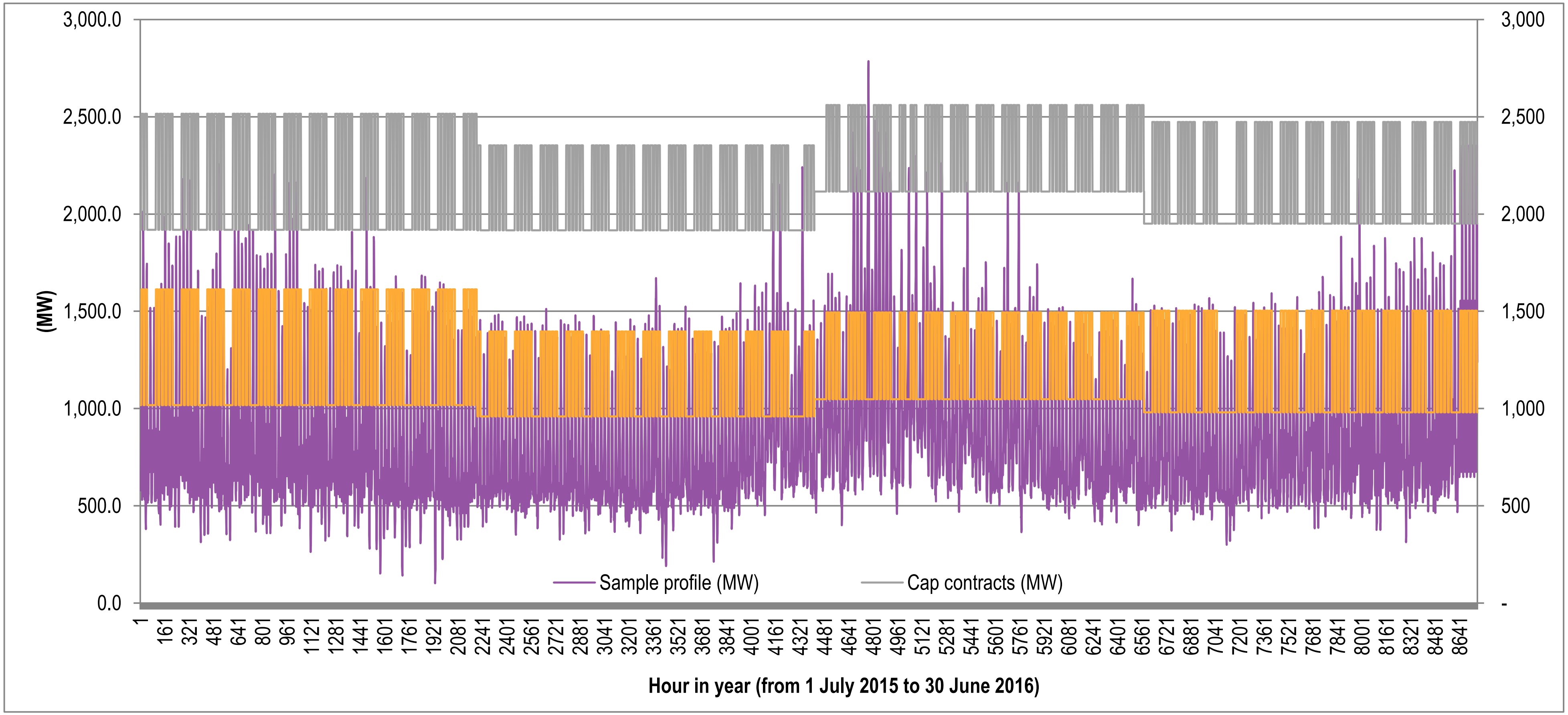
— The peak period contract volume is set to equal the 90th percentile of the peak period hourly demands across all 44 demand sets for the quarter.

— The cap contract volume is set at 105 per cent of the median of the annual peak demands across the 44 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 44 demand sets for a given settlement class, and hence to each of the 484 simulations. To be clear, we are not altering the hedge volume (in MW terms) on an ex-post basis for each of the 44 demand sets. 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.

Once established, these contract volumes are then fixed across all 484 simulations when calculating the wholesale energy cost. The contract volumes used are shown in Figure 13.

Figure 13 **Contract volumes used in hedge modelling of 484 simulations for 2015-16 for Energex NSLP**



Source: ACIL Allen

4.2.4 Summary of estimated WEC

After applying the hedge model, the WEC was taken as the 95th percentile of the distribution containing 484 annual hedged prices. ACIL Allen's estimate of the WEC for each tariff class for the 2015-16 Final Determination are shown in Table 4.

Overall, the changes in WEC from 2014-15 to 2015-16 are small compared with changes in determinations from previous years.

Broadly, the WEC for the controlled load tariffs and the less peaky Ergon Energy NSLP have decreased slightly compared with the 2014-15 determination and this is due to the decrease in base contract prices; whereas the WEC for the more peaky Energex NSLP has increased slightly due to its load profile being weighted more in the peak periods and contract prices in the peak periods have increased.

Energy costs for the Energex and Ergon Energy NSLPs have increased and decreased slightly, respectively, compared with the Final Determination of 2014-15. Compared with the 2014-15 determination, base contract prices for 2015-16 have decreased by 1.5% and peak contract prices have increased by 2.9% (on a carbon exclusive basis). In the case of the Energex NSLP, the increase in wholesale energy costs for 2015-16 is the result of higher peak demand outcomes and rooftop solar generation increasing the peakiness of the demand profile. As a result the Energex NSLP energy costs are forecast to increase by 2.4%. The Ergon Energy NSLP energy costs decrease slightly by 0.1%. The Ergon NSLP has a much less peaky load profile compared with the Energex NSLP and hence benefits more from the decreases in base contract prices. As 70% of solar installations are located in the Energex distribution network, day-time demand for the Energex NSLP is comparatively lower, and correspondingly benefits less from the reduction in day-time electricity prices than the Ergon Energy NSLP.

Energy costs for controlled loads, Tariff 31 and Tariff 33, are 1.4% and 0.6% lower than 2014-15 levels, respectively, due to lower base contract prices. Tariff 31, which was forecast to increase slightly in the draft determination, is forecast to decrease slightly as a result of using revised demand data. As mentioned earlier, ACIL Allen has updated the load profile data for Tariff 31 from AEMO as it became apparent there were some inconsistencies in the 2013-14 load data.

Table 4 **Estimated WEC ($/MWh, nominal) for 2015-16 at the Queensland reference node**

Settlement class	2015-16 – Final Determination	2015-16 – Draft Determination	2014-15 – Final Determination
Energex - NSLP - residential and small business	$63.73	$63.42	$62.26
Energex - Control tariff 9000 (31)	$36.10	$38.56	$36.60
Energex - Control tariff 9100 (33)	$50.39	$49.72	$50.71
Energex - NSLP - unmetered supply	$63.73	$63.42	$62.26
Ergon Energy - NSLP - SAC HV, CAC and ICC	$55.70	$55.60	$55.75
Ergon Energy - NSLP - SAC demand and street lighting	$55.70	$55.60	$55.75

Source: ACIL Allen analysis

4.3 Estimation of renewable energy policy costs

The RET scheme consists of two elements – the LRET and the SRES. Liable parties (i.e. all electricity retailers[9]) 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[10]
- Mandated LRET targets for 2015 and 2016 of 18,850 GWh and 21,431 GWh, respectively
- Published Renewable Power Percentage (RPP) for 2015 of 11.11 per cent
- Estimated RPP for 2016 of 12.34 per cent[11]
- Binding Small-scale Technology Percentage (STP) for 2015 of 11.71
- Non-binding STP for 2016 of 9.98[12]
- CER clearing house price for 2015 and 2016 for Small-scale Technology Certificates (STCs) of $40/MWh.

4.3.1 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) [13].

The LGC price used in assessing the cost of the scheme for 2015-16 is found by averaging the forward prices for 2015 and 2016 during the two years prior to the commencement of 2015 and 2016. This assumes that LGC coverage is built up over a two year period (see Figure 14). The average LGC prices calculated from the AFMA data are $36.50/MWh for 2015 and $38.18/MWh for 2016**.** These prices are higher than the Draft Determination, due

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9 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.

10 AFMA data includes weekly prices up to and including 15 May 2015.

11 2016 RPP value was estimated using liable electricity acquisitions implied in the non-binding STP for 2016 as published by CER.

12 The binding 2015 STP and non-binding 2016 STP estimates are based on the modelling prepared for CER for the 2015 STP.

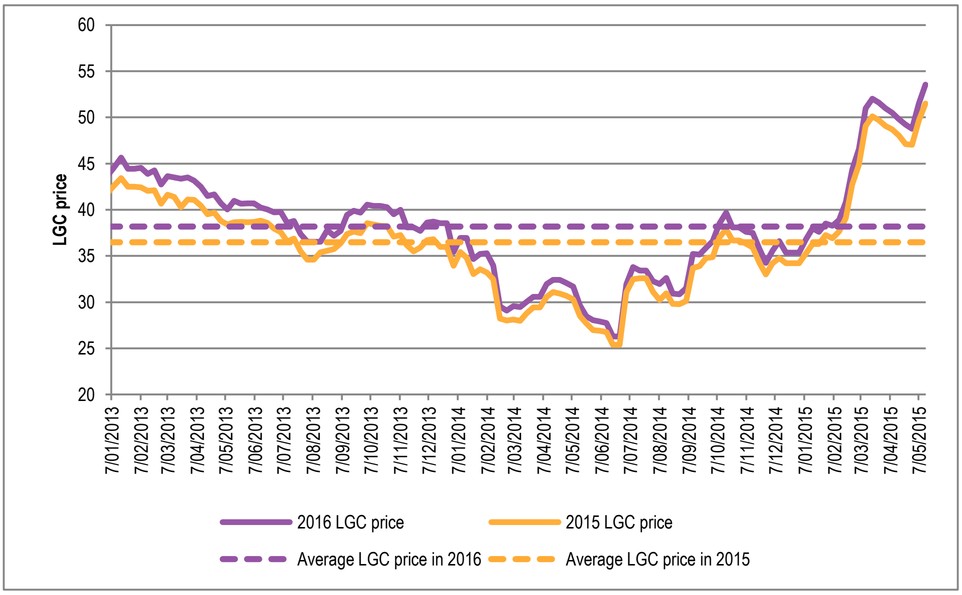
13 The Australian Financial Markets Association (AFMA) publishes reference information on Australia's wholesale over-the-counter (OTC) financial market products. This includes a survey of bids and offers for LGCs, STCs and other environmental products which is published weekly. Survey contributors include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

to a recent surge in the forward price on the back of the agreement to revise the target to 33,000GWh by 2020.

Over the past 12 months or so, LRET policy has been one the largest uncertainties for the market. Since the announcement of the Warburton review in February 2014, LGC spot prices have been volatile, ranging from $21 in mid-2014 to $50 in 2015.

The estimate of the LGC price has been influenced by the RET Review and by the recent agreement between the Government and Opposition to revise the target, as shown in the graph below. However, it was possible to purchase LGCs during the period of the review at the discounted prices. Although attempting to remove the effects of the review is an option, such a change to methodology would then require consideration of other risks; their identification and quantification.

Figure 14 **LGC futures prices for 2015 and 2016 (nominal $/LGC)**



Source: AFMA and ACIL Allen analysis

The 2016 RPP of 12.34 per cent was estimated using the mandated target for 2016 and the reduced relevant acquisitions implied in the non-binding STP for 2016.

The 2015 RRP of 11.11 per cent has been set by CER and does not need to be estimated.

Key elements of the 2016 RPP estimation are shown in Table 5.

Table 5 **Estimating the 2016 RPP**

	2016
Non-binding 2016 STP (CER)	9.98%
Projected STCs in 2016 (CER)	17,334,000
Implied reduced relevant acquisitions [a]	173,687,375
Mandated LRET target in 2016	21,431,000
Estimated 2016 RPP using implied reduced relevant acquisitions	12.34%

[a] Implied reduced relevant acquisitions was found by dividing projected STCs by the non-binding STP.
Source: CER and ACIL Allen analysis

ACIL Allen calculates the cost of complying with the LRET in 2015 and 2016 by multiplying the RPPs in 2015 and 2016 by the average LGC prices in 2015 and 2016, respectively. The cost of complying with the LRET in 2015-16 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be $4.38/MWh in 2015-16 as shown in Table 6.

Table 6 **Estimated cost of LRET – 2015-16**

	2015	2016	Cost of LRET 2015-16
RPP %	11.11%	12.34%	
Average LGC price ($/LGC, nominal)	$36.50	$38.18	
Cost of LRET ($/MWh, nominal)	$4.06	$4.71	$4.38

Source: CER, AFMA, ACIL Allen analysis

4.3.2 SRES

The cost of SRES for calendar years 2015 and 2016 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 2015-16.

The STPs published by CER are as follows:

— Binding 2015 STP of 11.71 per cent (equivalent to 20.56 million STCs as a proportion of total estimated liable electricity for the 2015 year)

— Non-binding 2016 STP of 9.98 per cent (equivalent to 17.33 million STCs as a proportion of total estimated liable electricity for the 2016 year).

ACIL Allen estimates the cost of complying with SRES to be $4.34/MWh in 2015-16 as set out in Table 7.

Table 7 **Estimated cost of SRES – 2015-16**

	2015	2016	Cost of SRES 2015-16
STP %	11.71%	9.98%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of SRES ($/MWh, nominal)	$4.68	$3.99	$4.34

Source: CER, ACIL Allen analysis

4.3.3 Summary of estimated LRET and SRES costs

Adding these component costs gives a total other cost requirement as set out in Table 12. This is compared to the costs from the Draft Determination and the Final Determination from last year (2014-15).

Since the Draft Determination, total renewable energy costs have increased, due to a higher published RPP and STP for 2015 and higher LGC prices.

Table 8 **Total renewable energy policy costs ($/MWh) – Final Determination 2015-16, Draft Determination 2015-16 and Final Determination 2014-15**

Cost category	Final Determination 2015-16	Draft Determination 2015-16	Final Determination 2014-15
LRET	$4.38	$4.18	$4.01
SRES	$4.34	$4.08	$4.12
Total	$8.72	$8.26	$8.13

Source: ACIL Allen analysis

4.4 Estimation of other energy costs

The other energy costs estimates for the Draft Determination provided in this section consist of:

- Market fees and charges including:
  - NEM management fees
  - Ancillary services costs
- Pool and hedging prudential costs.

4.4.1 NEM management fees

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

ECA is a new cost category, approved by the Council of Australian Governments (COAG) Energy Council in May 2014 to promote the long term interests of energy consumers, in particular for residential customers and small business customers. The commencement date of the ECA was 30 January 2015.

AEMO is required to recover the funding for the ECA from market participants from 2015-16.

ECA requirements are measured in terms of connection points for small customers. It is not clear in AEMO's *Draft Budget & Fees 2015-16* of the assumed number of connection points for small customers used in the cost estimate, therefore, ACIL Allen has used DNSP customer numbers, to estimate the cost of ECA requirements in $/MWh terms.

Based on projected fees in AEMO's *Electricity Draft Budget & Fees 2015-16*, the total fee for 2015-16 is $0.47/MWh. This estimate is lower than the Draft Determination due to a budgeted increase in consumption, a reduction in NEM expenditure and a forecast surplus in the current year.

The breakdown of total fees is shown in Table 9.

Table 9 **NEM management fees ($/MWh) – 2015-16**

Cost category	Fees ($/MWh)
NEM fees (admin, registration, etc.)	$0.38
FRC - electricity	$0.045
NTP - electricity	$0.024
ECA - electricity	$0.026
NEM management fees	$0.47

Source: ACIL Allen analysis of AEMO, AER State of the Energy Market 2014

4.4.2 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 2015-16, the cost of ancillary services is estimated to be $0.36/MWh.

4.4.3 Prudential costs

Prudential costs have been calculated for the Energex NSLP. These costs are then used as a proxy for prudential costs for all tariffs.

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 = OSL + PML

> Where for the Summer (December to March), Winter (May to August) and Shoulder (other months):
>
> OSL = (Average daily load x Average future expected spot price x Participant Risk Adjustment Factor * OS Volatility factor x Loss factor x (GST + 1) x 7 days
>
> PML = (Average daily load x Average future expected spot price x Participant Risk Adjustment Factor * PM Volatility factor x Loss factor x (GST + 1) x 35 days

Taking a 1 MWh average daily load and assuming the following inputs for each season for Energex NSLP:

Table 10 **AEMO prudential costs**

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price	$77.24	$58.06	$61.33
Participant Risk Adjustment Factor	1.2147	1.1720	1.1611
OS Volatility factor	1.75	1.28	1.49
PM Volatility factor	3	1.72	1.91
Loss Factor	1.069	1.069	1.069
OSL	$8,208	$4,201	$5,070
PML	$1,642	$840	$1,014
MCL	$9,849	$5,041	$6,085
Average MCL		**$6,989**	

Source: ACIL Allen analysis

However as this applies for a rolling 42 days it actually covers 42 MWh of retailer purchases. Hence the portion of the MCL applicable to each MWh is $6,989/42 = $166/MWh.

The cost of funding a bank guarantee for the MCL associated with the single MWh is assumed to be a 2.5% annual charge[14] for 42 days or 2.5%*(42/366) = 0.287%. Applying this funding cost to the single MWh charge of $166 gives $0.477/MWh.

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 2.25%. Additional margin calls may apply where contracts move unfavourably for the purchaser or seller. However, as these may be favourable or unfavourable we have assumed that they average out over time.

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

- the price scanning range (PSR) expressed as a percentage of the contract face value and currently set at around 9.0% on average for a base contract
- the intra commodity spread charge currently set at $6,500 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 $46.51[15] and applying the above factors gives an average initial margin for each quarter of $16,091 for a 1 MW quarterly contract. Dividing this by the average hours in a quarter then gives an initial margin of $7.35 per MWh. Assuming a funding cost of 9.7% but adjusted for an assumed 2.25% return on cash lodged with the clearing house gives a net funding cost of 7.47%. Applying 7.47% to the initial margin per MWh gives a prudential cost for hedging of $0.55/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.

4.4.4 Total prudential costs

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

Table 11 **Total prudential costs ($/MWh) - 2015-16**

Cost category	Cost
AEMO pool	$0.48
Hedge	$0.55
Total	$1.03

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

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

4.4.5 Summary of estimated total other costs

Adding these component costs gives a total other cost requirement as set out in Table 12. This is compared to the costs from the Draft Determination and the Final Determination from last year (2014-15).

Table 12 **Total other costs ($/MWh) – Final Determination 2015-16, Draft Determination 2015-16 and Final Determination 2014-15**

Cost category	Final Determination 2015-16	Draft Determination 2015-16	Final Determination 2014-15
NEM management fees	$0.47	$0.50	$0.47
Ancillary services	$0.36	$0.36	$0.48
Hedge and pool prudential costs	$1.03	$0.79	$0.71
Total	$1.86	$1.65	$1.66

Source: ACIL Allen analysis

4.5 Estimation of energy losses

The methodology up to this point produces price estimates at the Queensland regional reference node (RRN). Prices at the Queensland RRN must be adjusted for losses to the end-users. Distribution loss factors (DLF) for Energex and Ergon Energy east zone and average Marginal Loss Factors (MLF) for transmission losses from the reference node to major supply points in the distribution networks are applied.

The transmission loss factors from the Queensland reference node to the distribution network for Energex and Ergon Energy's east zone area are based on the average energy-weighted marginal loss factors (MLFs) for the Energex and Ergon Energy east zone Transmission Node Identities (TNIs). This analysis resulted in a transmission loss factor of 1.006 for Energex and 1.037 for the Ergon Energy east zone. These estimates are based on the final MLFs for 2015-16 as published by AEMO on 1 April 2015, weighted by the 2013-14 energy for the TNIs.

The distribution loss factor by settlement class for the Energex area and the Ergon energy east zone are taken from the Final Distribution Loss Factors for 2015-16 published by AEMO on 1 April 2015 (Version 2). The DLFs for 2015-16 used in the calculation of energy costs for the Final Determination are noticeably lower than those used for the Final determination for 2014-15. The reasons for the reduction in DLF are not discussed in the AEMO release but a lowering in the load forecast for 2015-16 is likely to be a major factor.

The weighted MLFs to be used in estimating energy costs for the 2015-16 Final Determination are based on final estimates for 2015-16 published by AEMO on 1 April 2015. The MLFs for 2015-16 are lower than used in the Final Determination last year due mainly to a reduction in forecast load for 2015-16. Changed geographic dispersion of generation and increased interconnector flows have also influenced the MLF in Queensland. As observed by AEMO in its report, the reduction is most noticeable in northern Queensland.

Table 13 **Estimated transmission and distribution loss factors for Energex and Ergon Energy's east zone**

Settlement classes	Distribution loss factor (DLF)	Transmission marginal loss factor (MLF)	Total loss factors (MLFxDLF)
Energex - NSLP - residential and small business and unmetered supply	1.059	1.006	1.065
Energex - Control tariff 9000	1.059	1.006	1.065
Energex - Control tariff 9100	1.059	1.006	1.065
Ergon Energy - NSLP - SAC HV, CAC and ICC	1.028	1.037	1.066
Ergon Energy - NSLP - SAC demand and street lighting	1.083	1.037	1.123

Data source: ACIL Allen analysis based on Queensland TNI energy for 2013-14, MLFs for 2015-16 and Energex and Ergon Energy east zone DLFs for 2015-16 from the AEMO.

For the Final Determination for 2015-16 ACIL Allen has applied the same methodology as used in previous years so that it aligns with the application of the MLFs and DLFs used by AEMO.

As described by AEMO[16], 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)

4.6 Summary of estimated energy costs

Drawing together the analyses from the previous sections of this report, ACIL Allen's estimates of the 2015-16 total energy costs (TEC) for the Draft Determination for each of the settlement classes are presented in Table 14.

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

Table 14 **Estimated TEC for 2015-16 Final Determination**

Settlement class	WEC at Qld reference node ($/MWh)	Renewable energy costs at Qld reference node ($/MWh)	Market fees at the Qld reference node ($/MWh)	Total transmission and distribution loss factor (MLF x DLF)	Network losses ($/MWh)	TEC at the customer terminal ($/MWh)	Change from 2014-15 Final Determination ($/MWh)
Energex - NSLP - residential and small business	$63.73	$8.72	$1.87	1.065	$4.83	$79.14	2.60%
Energex - Control tariff 9000 (31)	$36.10	$8.72	$1.87	1.065	$3.03	$49.71	0.09%
Energex - Control tariff 9100 (33)	$50.39	$8.72	$1.87	1.065	$3.96	$64.93	0.25%
Energex - NSLP - unmetered supply	$63.73	$8.72	$1.87	1.065	$4.83	$79.14	2.60%
Ergon Energy - NSLP - SAC HV, CAC and ICC	$55.70	$8.72	$1.87	1.066	$4.37	$70.65	-1.03%
Ergon Energy - NSLP - SAC demand and street lighting	$55.70	$8.72	$1.87	1.123	$8.15	$74.43	-1.46%

Source: ACIL Allen analysis