ACIL ALLEN CONSULTING

REPORT TO
QUEENSLAND COMPETITION AUTHORITY

19 FEBRUARY 2019

ESTIMATED ENERGY COSTS

2019-20 RETAIL TARIFFS

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

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ESTIMATED ENERGY COSTS FOR 2019-20 RETAIL TARIFFS: DRAFT DETERMINATION, ACIL ALLEN, FEBRUARY 2019

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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 2019-20 regulatory period.

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), and the Consultancy Terms of Reference (TOR) provided by the QCA, 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 2019-20. Although the QCA's determination is to apply only to the area outside of the Energex distribution area, the TOR specifically requests that ACIL Allen's analysis cover the same tariff classes as covered in the analyses for the 2013-14 to 2018-19 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 Draft Determination, and is presented as follows:

— Chapter 2 summarises our methodology.
— Chapter 3 provides responses to submissions made by various parties following the release of the QCA's interim consultation paper, *Interim Consultation Paper – Regulated retail electricity prices for 2019-20* (December 2018), where those submissions refer to the methodology used to estimate the cost of energy in regulated retail electricity prices.
— Chapter 4 summarises our derivation of the energy cost estimates.
— Finally, Appendix A summarises our high-level comparison with the AEMC's *2018 Residential Electricity Price Trends Review* released in December 2018.

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 customers on notified prices for the tariff year 1 July 2019 to 30 June 2020.

In undertaking the task, ACIL Allen has not been asked to provide 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 (WEC) 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 follows the methodology used to provide advice to the QCA for the 2013-14 to 2018-19 determinations (refer to ACIL Allen's report for the 2014-15 Draft Determination[1] and the 2014-15 Final Determination[2] for more details of the methodology).

The ACIL Allen methodology estimates costs from a retailing perspective. This includes wholesale energy market simulations to estimate expected pool costs and volatility and the hedging of the pool

[1] http://www.qca.org.au/getattachment/4cb8b436-7b50-4328-8e27-13f51a4d021c/ACIL-Allen-Estimated-Energy-Costs-2015-15-Retail-T.aspx
[2] http://www.qca.org.au/getattachment/9be567a8-92e2-4d53-85f0-3781e4f8662f/ACIL-Allen-Final-Report-Estimated-Energy-Costs-for.aspx

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.

2.3.1 Wholesale energy costs

As with the 2013-14 to 2018-19 reviews, ACIL Allen continues to use the market hedging approach for estimating the WEC for 2019-20.

We have utilised our:

- stochastic demand model to develop 48 weather influenced simulations of hourly demand traces for each of the tariff profiles – using temperature data from 1970-71 to 2017-18 and demand data for 2015-16 to 2017-18
- stochastic outage model to develop 11 hourly power station availability simulations
- energy market models to run 528 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, and OTC data from TFS Australia 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. It is our assessment that the AEMO medium series demand projection for 2019-20 provided in AEMO's 2018 Electricity Statement of Opportunities (ESOO) is the most reasonable demand forecast for the purposes of this analysis.

Supply side settings

ACIL Allen incorporates changes to existing supply where companies have formally announced the changes – including, mothballing, closure and change in operating approach. Near term new entrants are included where the plants are deemed by ACIL Allen to be committed projects.

Table 2.1 provides a summary of the near term new entrants that ACIL Allen considers committed projects which have been included in the market simulations.

TABLE 2.1 NEAR-TERM ADDITION TO SUPPLY

Project Name	Generation Technology	Capacity (MW)	Region	Expected entry
Ballarat	Battery storage	30	VIC	Q4-2018
Barket Inlet	Natural gas reciprocating engine	210	SA	Q3 2019
Bayswater upgrade	Black coal steam turbine	100	NSW	Q2-2020
Berrybank	Wind	165	VIC	Q3-2020
Beryl	Solar	87	NSW	Q3-2019
Bulgana Power Hub	Wind, Battery Storage	214	VIC	Q3-2019
Carwarp	Solar	99	VIC	Q4-2019
Childers	Solar	56	QLD	Q1-2019
Chinchilla	Solar	112	QLD	Q3-2019
Clermont	Solar	75	QLD	Q4-2018
Coopers Gap	Wind	453	QLD	Q3-2019

Project Name	Generation Technology	Capacity (MW)	Region	Expected entry
Crowlands	Wind	80	VIC	Q1-2019
Crudine Ridge	Wind	135	NSW	Q4-2019
Dundonell	Wind	302	VIC	Q3-2020
Finley	Solar	133	NSW	Q4-2019
Gannawarra	Battery storage	25	VIC	Q4-2018
Granville Harbour	Wind	112	TAS	Q3-2019
Haughton	Solar	100	QLD	Q1-2019
Karadoc	Solar	90	VIC	Q1-2019
Kennedy Energy Park	Solar, Wind, Battery Storage	60	QLD	Q4-2018
Lal Lal	Wind	216	VIC	Q4-2019
Lilyvale	Solar	100	QLD	Q2-2019
Lincoln Gap	Wind	126	SA	Q4-2018
Loy Yang B upgrade	Brown coal steam turbine	80	VIC	Q1-2019
Mortlake South	Wind	150	VIC	Q3-2020
Murra Warra	Wind	226	VIC	Q4-2018
Nevertire	Solar	105	NSW	Q3-2019
Numurkah	Solar	100	VIC	Q1-2019
Oakey	Solar	80	QLD	Q4-2018
Stockyard Hill	Wind	530	VIC	Q1-2019
Susan River	Solar	98	QLD	Q4-2018
Tailem Bend	Solar	108	SA	Q3-2019
TeeBar	Solar	53	QLD	Q3-2019
Warwick	Solar	64	QLD	Q4-2019
Wemen	Solar	88	VIC	Q4-2018
Wild Cattle Hill	Wind	144	TAS	Q4-2019
Winton	Solar	85	VIC	Q1-2020
Yarranlea	Solar	103	QLD	Q3-2019
Yatpool	Solar	81	VIC	Q4-2018

Note: Renewable plant larger than 100 MW are assumed to come online progressively in stages, as are coal plant upgrades. The date of expected entry of a plant's capacity represents the entry of its first stage.

SOURCE: ACIL ALLEN ANALYSIS

The market modelling includes the restructure of the Queensland Government's assets and the formation of CleanCo from 1 July 2019. The CleanCo portfolio includes Wivenhoe pumped storage facility, Swanbank E, Barron Gorge, Kareeya and Koombooloomba power stations. The key impact of CleanCo is the change in operation of Wivenhoe. Under the spot price modelling for the 2019-20 Draft Determination, Wivenhoe operates more aggressively, reflecting its position in the new, smaller portfolio.

The modelling does not include the new renewable projects associated with the 50 per cent renewable energy policy beyond the already committed Renewables 400 reverse auction.

Similarly, the modelling does not include new renewable projects associated with the Victorian Renewable Energy Target beyond the winning projects of the first round of successful projects (totalling around 800 MW), which were announced in late 2018.

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 TFS, the latest information published by the Clean Energy Regulator (CER) and modelling by ACIL Allen[3]. Retailer compliance with these schemes operates on a calendar year basis and hence estimates are required for both 2019 and 2020 calendar years, with the costs averaged to estimate the 2019-20 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 from TFS[4]
- mandated LRET targets for 2019 and 2020 of 31,244 GWh and 33,850 GWh, respectively
- estimated RPP values for 2019 and 2020 of 18.33 per cent and 19.75 per cent, respectively[5]
- estimated STP values for 2019 and 2020 of 19.75 per cent and 12.72 per cent, respectively[6]
- CER clearing house price for 2019 and 2020 for Small-scale Technology Certificates (STCs) of $40/MWh.

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 representing capital used to meet prudential requirements to support hedging 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 month 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 (RRN). 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.

The MLFs used in this analysis are based on the 2018-19 MLFs published by AEMO. It is expected that AEMO will have published the 2019-20 MLF estimates in time for them to be used in our revised analysis for input to the Final Determination in mid-April 2019.

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3 The STP estimates are based on ACIL Allen modelling of small-scale technology certificates, which is a departure from our usual methodology of using the non-binding STP estimates published by CER. The reason for using ACIL Allen modelling is to capture the latest market information and is discussed further in Section 4.3.

4 TFS data includes prices up to and including 10 January 2019.

5 The 2019 and 2020 RPP values were estimated using liable electricity acquisitions implied in the STP values for 2019 and 2020, as estimated by ACIL Allen.

6 The STP estimates are based on ACIL Allen modelling.

RESPONSES TO SUBMISSIONS TO INTERIM CONSULTATION PAPER

3

3.1 Introduction

The QCA forwarded to ACIL Allen a total of 13 submissions in response to its Interim Consultation Paper. ACIL Allen reviewed the submissions to identify issues that related to our methodology and required our consideration for the 2019-20 Draft Determination. A summary of the review is shown below in **Table 3.1**. The following sections in this chapter address each of the relevant issues raised in the submissions.

TABLE 3.1 REVIEW OF ISSUES RAISED IN SUBMISSIONS IN RESPONSE TO INTERIM CONSULTATION PAPER

ID	Stakeholder	Wholesale energy costs	Contract prices /hedge model	Renewable energy policy costs	NEM fees	Prudential costs	Energy losses
1	Bundaberg Regional Irrigators Group	Nil	Nil	Nil	Nil	Nil	Nil
2	(CONFIDENTIAL)	Nil	Nil	Nil	Nil	Nil	Nil
3	Canegrowers Isis Ltd	Nil	Yes	Nil	Nil	Nil	Nil
4	Canegrowers	Nil	Nil	Nil	Nil	Nil	Nil
5	Cotton Australia	Nil	Nil	Nil	Nil	Nil	Nil
6	Origin	Yes	Yes	Yes	Nil	Nil	Nil
7	Pioneer Valley Water	Nil	Nil	Nil	Nil	Nil	Nil
8	Queensland Farmers' Federation	Nil	Nil	Nil	Nil	Nil	Nil
9	Energy Queensland	Yes	Nil	Yes	Nil	Nil	Nil
10	Queensland Council of Social Service	Nil	Nil	Nil	Nil	Nil	Nil
11	Queensland Consumers Association	Nil	Nil	Nil	Nil	Nil	Nil
12	Kinchant Dam Water Users Association	Nil	Nil	Nil	Nil	Nil	Nil

ID	Stakeholder	Wholesale energy costs	Contract prices /hedge model	Renewable energy policy costs	NEM fees	Prudential costs	Energy losses
13	Kalamia Cane Growers	Nil	Nil	Nil	Nil	Nil	Nil

Note: Yes = an issue was raised that required ACIL Allen's consideration

SOURCE: ACIL ALLEN ANALYSIS OF QCA SUPPLIED DOCUMENTS

3.2 Modelled load profiles, wholesale spot prices, and hedging strategy

Origin on page 3 of their submission stated:

As Origin's previous submissions noted we encourage the QCA to ensure that modelled load profiles and pool price simulations reflect the variability of outcomes experienced in the NEM over an extended period.

The QCA will need to carefully consider the appropriate hedging strategy to be modelled in light of a tighter supply/demand balance and continued reduction in 'middle of day' demand due to solar penetration.

Energy Queensland on page 8 of their submission note:

Energy Queensland considers that the QCA should take into account the significant new renewable energy generation connected, or about to be connected, to the National Electricity Market (NEM), and the impact on the wholesale electricity market.

...

When combined with additional renewable generation due to come on line in 2019, Energy Queensland expects that wholesale prices in the middle of the day will be further suppressed, resulting in higher evening prices as other forms of generation make up for lost daytime revenue in the evening peak period.

This change will also impact the NSLPs of both Ergon Energy Network and Energex. This changing load shape and changing pool price pattern will have an impact on wholesale energy costs and electricity retailers will need to hedge to manage morning and evening peaks, but will be over-hedged during the middle of the day when pool prices are suppressed. This will result in significant contract-for-difference payments.

Energy Queensland considers that the methodology developed by consultants ACIL Allen to determine wholesale energy costs should capture these effects. However, as the evolving wholesale market is only just starting to see the market effects of utility-scale solar, this development will require particular attention from the QCA in this determination process.

ACIL Allen has used the latest available data and market information when modelling the wholesale electricity spot price and for estimating the hedged price.

With regard to the load profile used in the analysis supporting the Draft Determination for 2019-20, ACIL Allen notes that there has been an observable fall in the load factor in the actual NSLP 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 throughout the middle of the day.

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

Regarding the wholesale spot price modelling used in the analysis supporting the Draft Determination for 2019-20, ACIL Allen is satisfied that the distribution of the NEM simulations for 2019-20 cover an adequately wide range of possible annual pool price outcomes, when accounting for the increase in renewable capacity. Further, we do not share Energy Queensland's view that because the increase in solar generation will reduce prices in daylight hours then it necessarily holds that prices during the evening peak must be higher to make up for lost daytime revenue. We maintain that prices during the evening peak will continue to reflect the demand-supply balance at that time.

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.

3.3 Inclusion of updated data in the analysis for the Draft Determination

A number of the submissions supported extending the energy cost data cut-off date. For example, Canegrowers Isis noted on page 3 of their submission:

In our view yes, extending the energy cost data cut-off date to the end of January should be used to account for the majority of the summer period and any corresponding changes in wholesale energy costs as it makes it easier to achieve an accurate estimate of relevant energy costs.

Additionally, Origin noted on page 3 of their submission:

With respect to updating the data for its wholesale energy modelling, on the basis that the QCA's draft is likely to be considered by other regulators we believe the draft should include the most relevant data available; i.e. the end of January 2019. This would provide more accurate guidance to other regulators observing the QCA decision as well as minimising fluctuations in outcomes between the QCA's draft and final decisions.

Additionally, Energy Queensland noted on page 3 of their submission:

Energy Queensland supports the extension of the energy cost data cut-off date to the end of January as this will result in a more accurate estimate of wholesale energy costs by including summer's seasonal influences on pricing.

ACIL Allen agrees that accuracy is improved if the latest possible data is included in our analysis. The key input used in our analysis that is a function of the data cut-off date are the contract prices and trade volumes, which we obtain from ASX Energy. Given we were required to deliver the energy purchase cost estimates by mid-February 2019, we have extended the data cut-off date to 15 February 2019 for contract price and volume data. Compared with a cut-off date of mid-November 2016 for the 2017-18 Draft Determination and mid-January 2018 for the 2018-19 Draft Determination, we now include an additional two to three months of contract price and volume data in our analysis for the 2019-20 Draft Determination.

Further, in an attempt to reduce the potential for change in estimates between the Draft Determination and Final Determination we have extrapolated the ASX Energy data from 16 February 2019 to early April 2019 by assuming the ASX prices do not change from 15 February 2019 onwards[7], and using the trade volumes observed between 16 February 2018 and early April 2018 from the 2018-19 Final Determination. Although this is a refinement in the methodology for the Draft Determination, it is not required for the Final Determination since all required data will be available at that point in time.

3.4 Large-scale Generation Certificate prices

Origin on page 2 and 3 of their submission noted:

The forward price curve for LGC's is in decline reflecting the anticipated delivery of enough large-scale renewable generation to meet the peak Renewable Energy Target in 2020 and no planned extension of the scheme. The QCA should carefully consider whether its current approach of using the market price will adequately compensate retailers for their prudent LGC costs over the remaining years of the scheme. Retailers have progressively invested in renewables or entered into PPA's over the duration of the scheme with prices for earlier renewable projects generally made at a significantly higher price point, which may now be in excess of the current LGC/energy market price. There appears to be a risk of a perverse regulatory outcome over the remaining years of the scheme if the current LGC market price is

[7] ACIL Allen has not attempted to predict how the ASX prices will evolve between 16 February 2019 and early April 2019.

applied without adjustment. Retailers will effectively be penalised for acting commercially and prudently by supporting sufficient renewable investment to meet scheme obligations.

Origin acknowledges that the QCA has previously not adjusted its methodology when energy market prices are either higher or lower than long run costs. However, the decline in LGC prices is a consequence of policy/regulatory mechanisms rather than market conditions. The RET will peak in 2020 with no replacement carbon scheme in place to provide value for renewables. The marginal value of an LGC has fallen because retailers collectively supported enough renewable build to meet their legislated RET obligations. Had this not been the case then renewable supply would be reduced and the LGC market price (and QCA cost allowance) would naturally be higher.

Energy Queensland also note on page 8 of their submission that:

…Ergon Energy Retail, like many other retailers, has entered into long-term power purchase agreements with new renewable energy projects. This enables these projects to be developed while also enabling Ergon Energy Retail to meet its obligations under the Renewable Energy Target. For Ergon Energy Retail these will take full effect in the 2019-20 financial year. This constitutes a regulatory-driven change in how retailers purchase energy.

Origin notes that LGC forward market prices are in decline because it is highly likely that the LRET scheme will be satisfied by 2020. However, somewhat at odds with this notion, Origin then suggests that the decline in LGC prices is a consequence of policy/regulatory mechanisms and *not market conditions*. We agree that LGC costs will decline due to the LRET not just being fully supplied but oversupplied. The decline in price is a function of market conditions – including investments in renewable generation not underwritten by retailers but due to the appetite of corporates to enter directly into wind and solar farm PPAs, and some renewable investors willing to take on merchant risk – both of which will contribute further to an oversupply of LGCs.

In addition, Origin also states, and Energy Queensland infers, that if retailers had not supported enough renewable build to meet their legislated RET obligations, by entering into PPAs, then the LGC market price would naturally be higher. Notwithstanding the point made above regarding the appetite for corporate PPAs and merchant investment, this could potentially be true, but ignoring the observable downward trend in LGC prices is analogous to suggesting that the consumer should not benefit from an oversupplied LGC market. ACIL Allen notes that this matter was not raised by retailers for the recent previous determinations when LGC prices (or wholesale electricity prices alone) were above new renewable energy investment costs when there was a shortfall of LGCs. This sentiment is at odds with a market-based approach.

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 is the spot and forward contracts transacted through brokers.

ACIL Allen continues to hold the view that the LGC prices within the spot and futures market represent the most reliable indicator of the current market consensus view of the price of LGCs. Therefore, with the importance of year-on-year consistency in mind for the Draft Determination in comparison with previous determinations, we maintain the view that transparent market prices provide a much better indicator compared with any other approach.

3.5 Small-scale Technology Percentage

Origin on page 2 of its submission stated that:

We note that the most recent update from the CER in December 2018 indicates a significant surplus of STCs created in Cal 2018 estimated at around 6-8 million STCs, this represents a variance of over 20 per cent above the published STP. This surplus will need to be added to the STP for 2019, which will be relevant to this determination. As the final binding STP for 2019 will not be published until March 2019, *we suggest the QCA consults with the CER to obtain an up to date estimate for inclusion in the QCA's draft determination.*

Further, as the Cal 2020 STP is also relevant to this determination, we suggest that the QCA also consider revising upward the estimation provided by the CER's current non-binding STP. We would be happy to discuss our view of the Cal 2020 STP based on our expectations of the rate of installation. We note that various State incentives have increased installation rates, and that further policy announcements may further accelerate activity.

ACIL Allen recognises that there has been significant policy developments (e.g. the Solar Homes Program) in the small-scale market over the past 12 months and that the non-binding STPs for 2019 and 2020, currently on the CER's website, are out of date because they are based on information up to 31 December 2017. Therefore, ACIL Allen (with approval from the QCA) has departed from its usual methodology of adopting the non-binding CER estimates for this Draft Determination for 2019-20 and instead we have used estimates of the 2019 and 2020 STP values based on our own modelling using data up to 30 November 2018.

4 ESTIMATION OF ENERGY COSTS

4.1 Introduction

In this section we apply the methodology described in Section **2** and summarise the estimates of each component of the Total Energy Cost (TEC) for each of the tariff classes for 2019-20.

4.1.1 Historic energy cost levels

Figure 4.1 shows the average time of day pool (spot) price for the Queensland region of the NEM, and the average time of day load profiles for Queensland, the Energex NSLP, the Energex controlled load profiles (tariffs 31 and 33), and the Ergon NSLP for the past seven years. The graphs are useful in understanding the dynamics of the absolute and relative wholesale electricity price changes in the tariffs.

It is worth noting the uplift in spot prices in 2015-16, and again in 2016-17, across most periods of the day, compared with 2014-15. This is a result of an increase in the underlying demand in Queensland due to the ramping up of production associated with the LNG export facilities in Gladstone, as well as an increase in gas prices into gas fired generators (as shown by the ramp up in gas prices on AEMO's short term trading market (STTM) in Figure 4.2), and export coal prices (see **Figure 4.3**).

Further, it can be seen that in 2016-17 prices are noticeably higher and more volatile during the evening periods – this is largely due to the strong price outcomes in the protracted summer period driven by strong gas prices over the same period, as well as reduced output from some of the NSW coal fired power stations due to coal supply constraints. Base generation from some of the NSW coal fired power stations continues to be offered into the NEM at prices between $55/MWh and $100/MWh – this has acted like a price floor in some respects – increasing overnight prices. Spot price outcomes in 2016-17 were on an average time weighted basis about $95/MWh – compared with about $60/MWh in 2015-16 (representing an increase of just under 60 per cent).

Prices in 2017-18 declined by about $20/MWh compared with 2016-17 to about $73/MWh (representing a decrease of just over 20 per cent). This decline is driven by a slight decrease in gas prices, the commissioning of just under 700 MW of solar and wind farms, the decline in coal costs in New South Wales coal fired power stations, and the return to service of Swanbank E.

Prices to date in 2018-19 have increased by about $7/MWh compared with 2017-18 to about $80/MWh. This is largely driven by an increase in morning and evening peak prices due to an increase in gas prices, and an increase in prices at other times due to an increase in the export coal price (which affects NSW and some Queensland coal fired power stations), rather than an increase in price volatility.

In relation to each profile, we note the following:

— The annual time of day price profile has been volatile over the past five years – with the overall level and shape of the price profile changing from one year to the next. For example, in 2011-12 the time of day profile was very flat compared with 2014-15. In 2012-13 and 2013-14, prices increased largely because of the carbon tax. Prices have generally peaked in the afternoon and evening, whereas in some years there is also a morning peak. In short, the profile of prices varies from one year to the next – noting that these are the annual profiles (seasonal profiles are even more variable over time).

— The load profile of tariff 31 has been relatively consistent from one year to the next since 2011-12 – ramping up from about 9:30 pm, peaking at about midnight and then ramping down to about 3:00 am. This is inversely correlated with the price profile – with load higher at times of lower spot prices. This has resulted, on average, in a relatively low wholesale energy cost for tariff 31, compared with the other tariffs.

— The load profile of tariff 33 has been relatively consistent from one year to the next for most parts of the day. However, there was some volatility between 5:30 pm and 10:30 pm over the past few years. The load exhibits a morning peak at around 8:00 am – and prices also experience uplift around that time. The load also exhibits an evening peak at around 9:30 pm – but this varied from year to year (note that in 2014-15 and 2015-16 it tends to peak around 8:30 pm). Compared with tariff 31, the load profile of tariff 33 is weighted slightly more towards the daylight hours and the evening peak, and hence it is not surprising that its wholesale energy costs are higher than those of tariff 31.

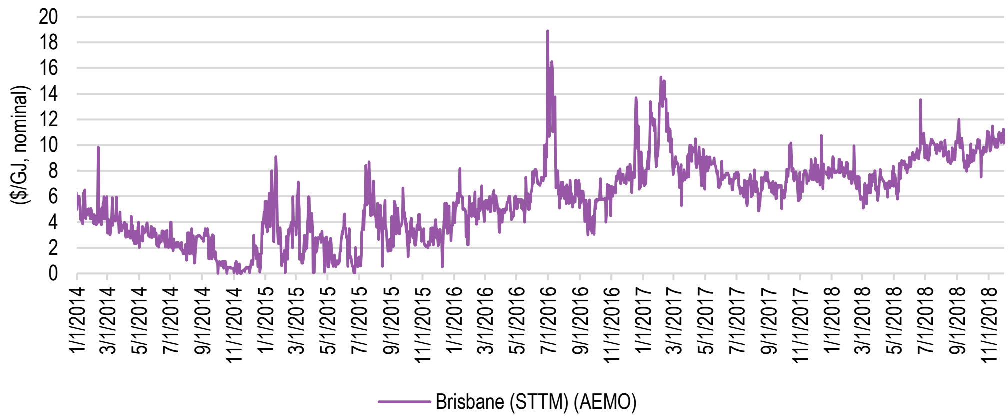
— Over the past few years, the Energex NSLP load profile, and to a similar degree, the Ergon NSLP, have experienced a carving out of load during daylight hours with the increased penetration of rooftop solar PV. This results in the load profile becoming peakier over time. The Energex NSLP load profile has a higher weighting towards the peak periods – particularly the evening peak and hence it is not surprising that the NSLP has the highest wholesale energy cost out of the profiles.

FIGURE 4.1 ACTUAL AVERAGE TIME OF DAY QLD WHOLESALE SPOT PRICE ($/MWH, NOMINAL) AND LOAD PROFILE (MW, RELATIVE) – 2011-12 TO 2017-18

Note: The term relative MW means the loads for each tariff and year have been scaled so they sum to one. This removes differences in absolute scale between the different tariffs and changes in absolute size over time. This is an appropriate representation of the loads since it is the relative shape of the load profile, not its absolute size, which determines its wholesale energy cost. Insufficient data available for 2018-19 for tariff classes due to lag in release of data by AEMO.

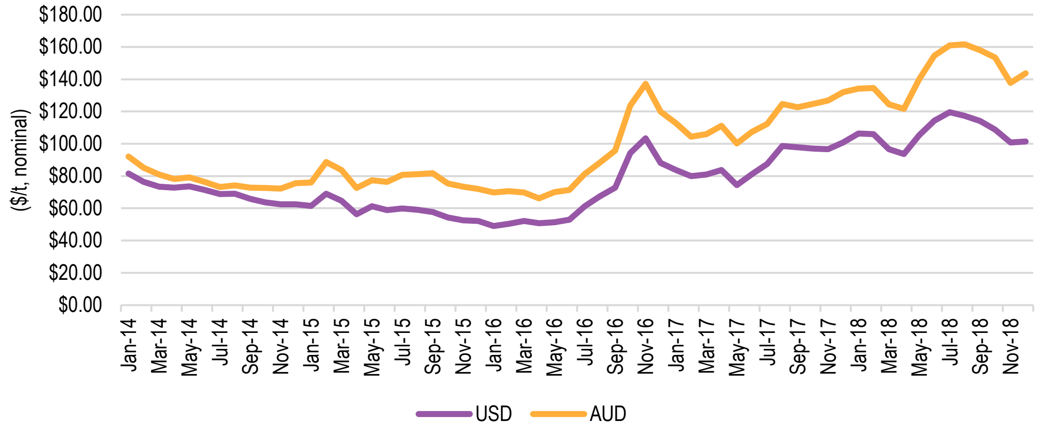
SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

FIGURE 4.2 DAILY STTM GAS PRICE ($/GJ, NOMINAL) - BRISBANE



SOURCE: AEMO DATA

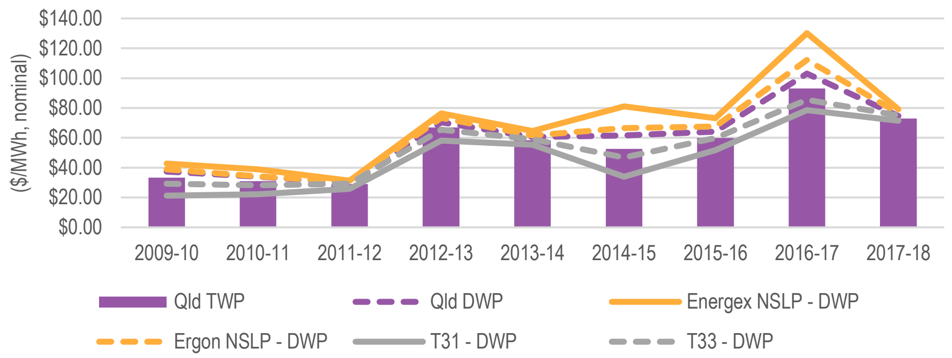
FIGURE 4.3 MONTHLY AUSTRALIA THERMAL EXPORT COAL PRICE ($/T, NOMINAL)



SOURCE: ACIL ALLEN ANALYSIS OF VARIOUS SOURCES

Figure 4.4 shows the actual annual demand weighted spot price (DWP) for each of the tariff loads compared with the time weighted average spot price in Queensland (TWP) over the past nine years. As expected, the DWPs for tariffs 31 and 33 are below the DWP for the NSLPs in each year, with tariff 31 having the lowest price. Although the rank order in prices by tariff has been consistent in each year, the dollar value differences between the prices has varied from one year to the next. For example, in 2011-12 and 2017-18, the flat half-hourly price profile resulted in the three tariffs having relatively similar wholesale spot prices. However, from 2014-15 and 2016-17, the increased price volatility across the afternoon period has resulted in the NSLP spot price diverging away from tariff 31 and 33. Conversely, the increase in off-peak spot prices in 2015-16 lifted the DWP of tariff 31 and 33 up towards that of the NSLP.

FIGURE 4.4 ACTUAL ANNUAL AVERAGE DEMAND WEIGHTED PRICE ($/MWH, NOMINAL) BY TARIFF AND QUEENSLAND TIME WEIGHTED AVERAGE PRICE ($/MWH, NOMINAL) – 2009-10 TO 2017-18



Note: Values reported are spot (or uncontacted) prices. Insufficient data available for 2018-19 for tariff classes due to lag in release of data by AEMO.
SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

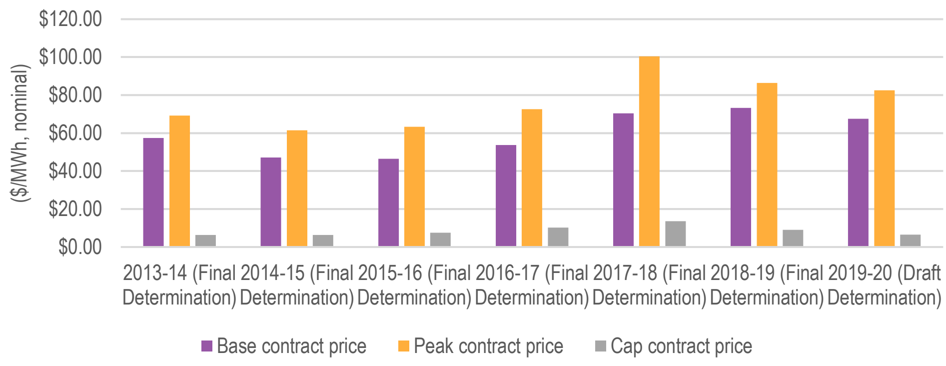
The volatility of spot prices (timing and incidence) in the Queensland region of the NEM provides the incentive to a retailer to hedge their load, since hedging of the loads reduces a retailer's exposure to the volatility. The suite of contracts (as defined by base/peak, swap/cap and quarter) available to retailers does not really change from one year to the next. However, the movements in contract price is the key contributor to movements in the estimated wholesale energy costs of the different tariffs year on year, as is shown in Figure 4.5.

The market modelling undertaken by ACIL Allen, and reported in this chapter, broadly aligns with the market's expectations of price outcomes in 2019-20. Compared with the 2018-19 Final Determination, futures contract prices for 2019-20, on an annualised and trade weighted basis to date, have:

- decreased by about $5.70/MWh for base contracts
- decreased by about $4.00/MWh for peak contracts
- decreased by about $2.60/MWh for cap contracts.

The market is clearly expecting some softening in price outcomes due to the strong increase in renewable investment coming on-line in 2019-20 (as shown in Table 2.1). About 5,200 MW of renewable investment will enter the NEM over the next 18 months – about 1,350 MW of which will be in Queensland. However, there is a competing tension in the futures market – base contract prices have not fallen to the same extent as peak and cap contracts. Strong gas prices as well as stronger coal prices (particularly when taking into account the recent export prices and weaker Australian dollar) for some of the NSW coal fired plant has influenced the market's view and hence has acted as a bound on the decrease in base contract prices for 2019-20.

FIGURE 4.5 QUARTERLY BASE, PEAK AND CAP CONTRACT PRICES ($/MWH) – DRAFT DETERMINATION 2019-20 AND PREVIOUS FINAL DETERMINATIONS



SOURCE: ACIL ALLEN ANALYSIS OF ASX ENERGY DATA

4.2 Estimation of the Wholesale Energy Cost

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 February 2019 inclusive. In an attempt to reduce the potential for change in contract price estimates between the Draft Determination and Final Determination we have extrapolated the ASX Energy data from 16 February 2019 to early April 2019 by assuming the ASX prices do not change from 15 February 2019 onwards[8], and using the trade volumes observed between 16 February 2018 and early April 2018 from the 2018-19 Final Determination. Although this is a refinement in the methodology for the Draft Determination, it is not required for the Final Determination since all required data will be available at that point in time.

Table 4.1 shows the estimated quarterly swap and cap contract prices for the 2019-20 Draft Determination and compares them with the estimates under the 2018-19 Final Determination.

[8] ACIL Allen has not attempted to predict how the ASX prices will evolve between 16 February 2019 and early April 2019.

TABLE 4.1 ESTIMATED CONTRACT PRICES (MWH)

	Q3	Q4	Q1	Q2
Draft Determination 2019-20				
Base	$67.96	$63.52	$79.80	$58.91
Peak	$77.17	$72.90	$107.71	$72.73
Cap	$2.94	$4.97	$14.91	$3.15
Final Determination 2018-19				
Base	$70.18	$70.12	$88.16	$64.51
Peak	$83.14	$82.48	$108.89	$71.49
Cap	$4.85	$9.61	$16.77	$4.93
% change from Final Determination 2018-19				
Base	-3.2%	-9.4%	-9.5%	-8.7%
Peak	-7.2%	-11.6%	-1.1%	1.7%
Cap	-39.5%	-48.3%	-11.1%	-36.1%

SOURCE: ACIL ALLEN ANALYSIS USING ASX ENERGY DATA UP TO 15 FEBRUARY 2019

Trade weighted base, peak and cap contract prices for 2019-20 are on average 8 per cent, 5 per cent and 28 per cent lower than 2018-19, respectively.

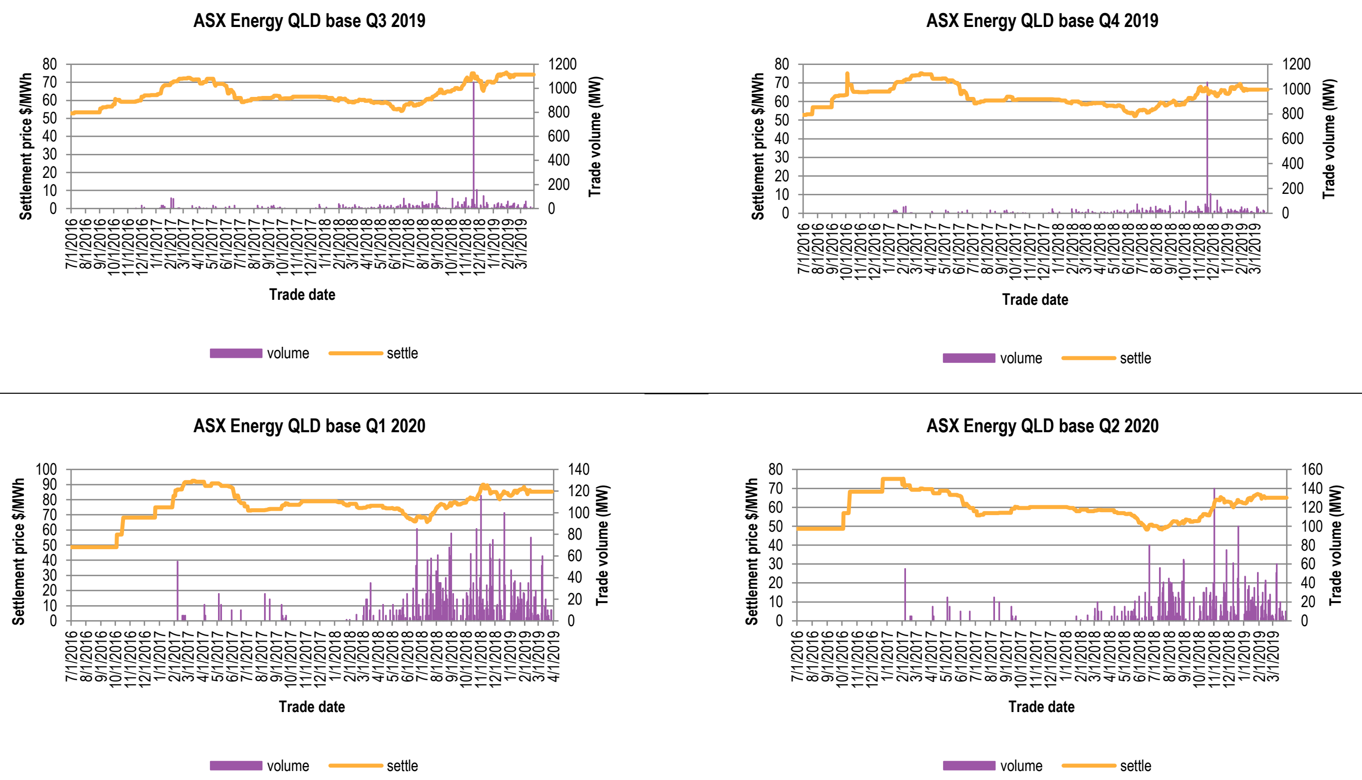
The lower base, peak and cap contract prices reflect the market's expectation that both the underlying price and price volatility will reduce in 2019-20 due to:

— the large amount of new renewable capacity that is expected to enter the market in 2019-20
— the restructure of Queensland government owned generators via the formation of CleanCo.

The following charts show daily settlement prices and trade volumes for ASX Energy quarterly base futures, peak futures and cap contracts up to 15 February 2019, and then extrapolated to early April 2019. Trade volumes up to 15 February 2019 inclusive are:

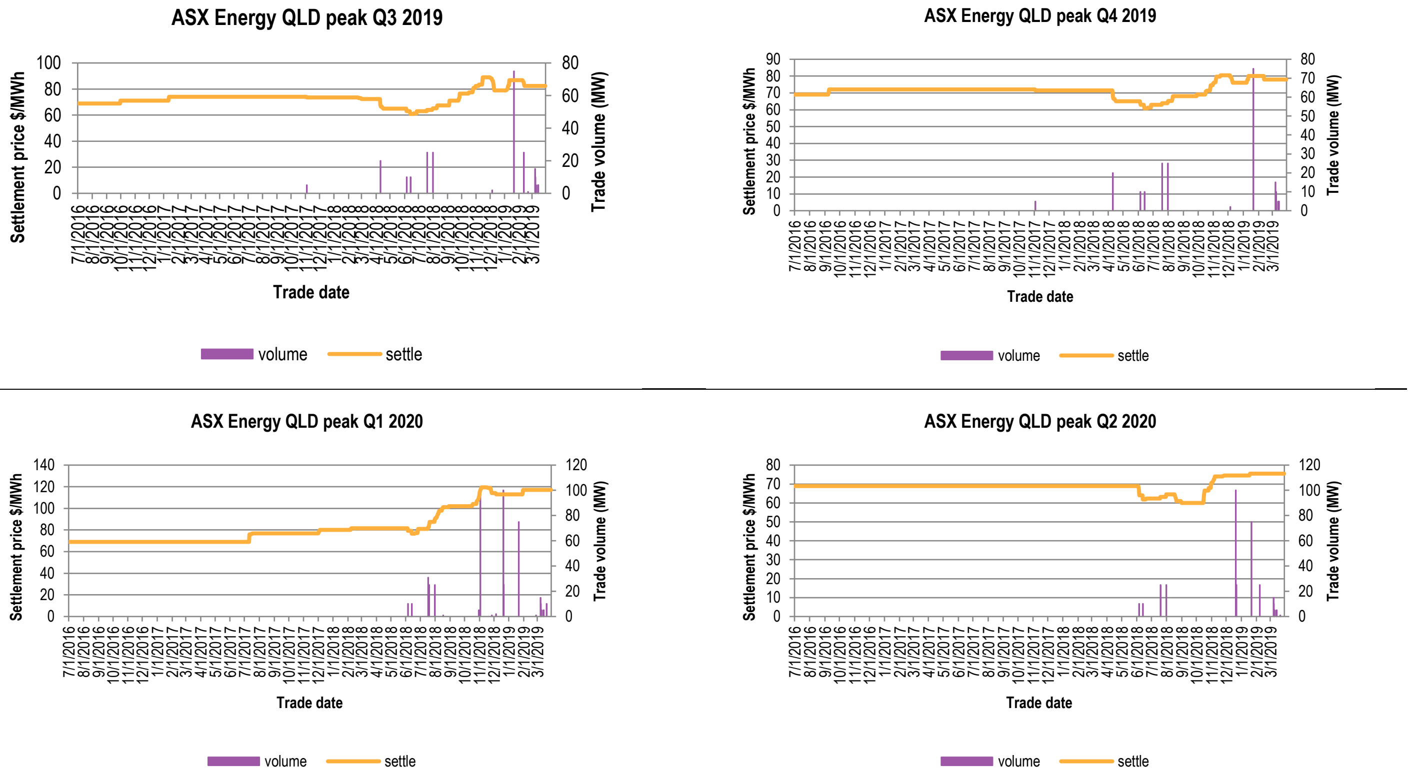
— Base futures have traded strongly, with total volumes of 5,102 MW (Q3 2019), 4,486 MW (Q4 2019), 3,760 MW (Q1 2020), and 3,130 MW (Q2 2020).
— Peak futures have also traded strongly with 197 MW (Q3 2019), 172 MW (Q4 2019), 337 MW (Q1 2020) and 295 MW (Q2 2020).
— Cap contract trade volumes have also traded strongly with 1,082 MW (Q3 2019), 1,097 MW (Q4 2019), 1,916 MW (Q1 2020) and 894 MW (Q2 2020).

FIGURE 4.6 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY QUEENSLAND BASE FUTURES



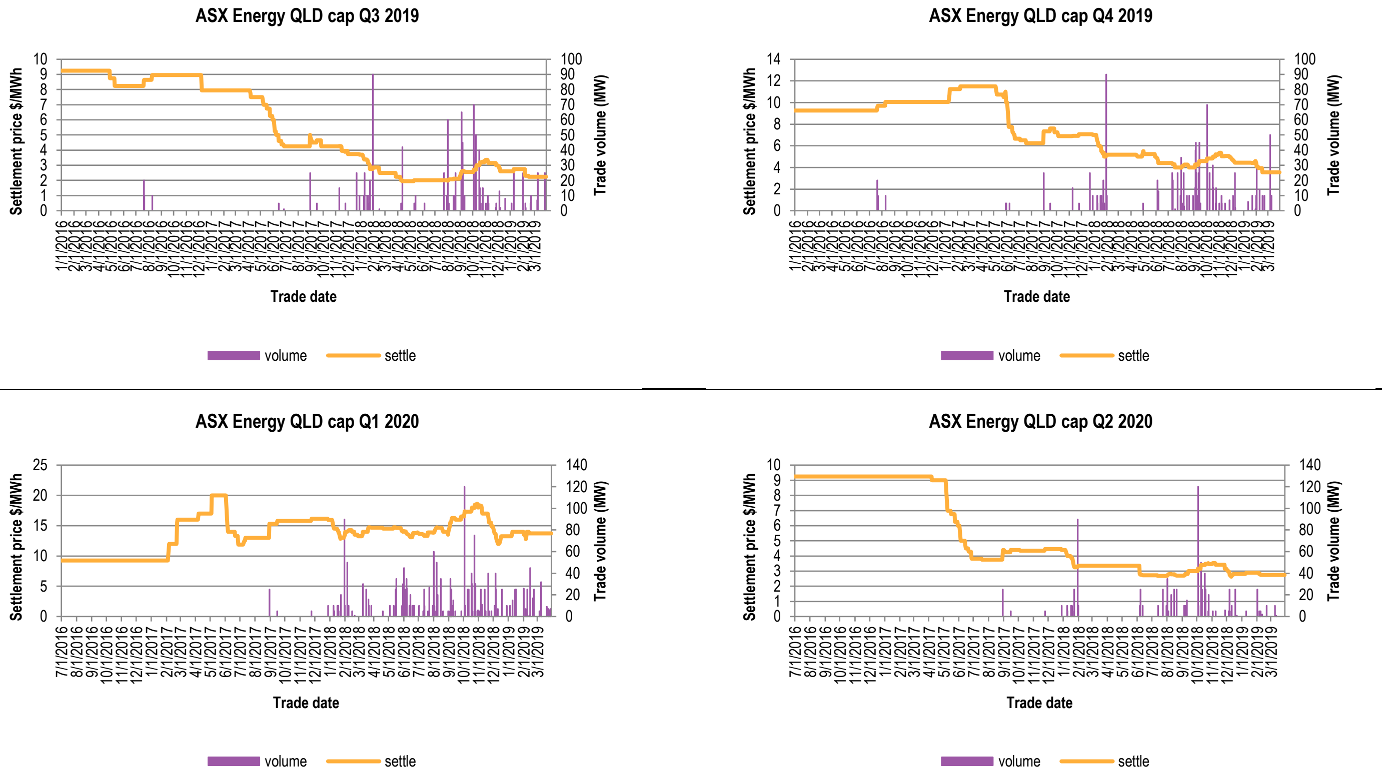
SOURCE: ASX ENERGY DATA UP TO 15 FEBRUARY 2019, AND EXTRAPOLATED TO EARLY APRIL 2019

FIGURE 4.7 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY QUEENSLAND PEAK FUTURES



SOURCE: ASX ENERGY DATA UP TO 15 FEBRUARY 2019, AND EXTRAPOLATED TO EARLY APRIL 2019

FIGURE 4.8 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY QUEENSLAND $300 CAP CONTRACTS



SOURCE: ASX ENERGY DATA UP TO 15 FEBRUARY 2019, AND EXTRAPOLATED TO EARLY APRIL 2019

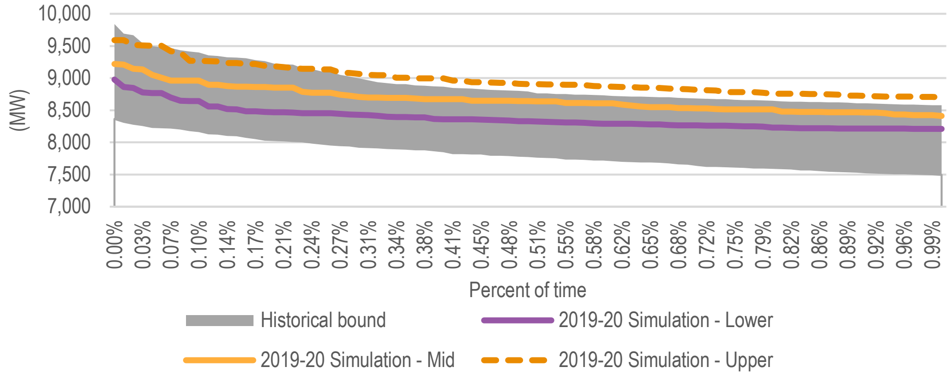
4.2.2 Estimating wholesale spot prices

ACIL Allen's proprietary electricity model, *PowerMark* was run to estimate the hourly pool prices for 2019-20 for the 528 simulations (48 demand and 11 outage sets).

Figure 4.9 shows the range of the upper one percent segment of the demand duration curves for the 48 simulated Queensland demand sets resulting from the methodology, along with the historical demands since 2011-12. The simulated demand sets represent the upper, lower and middle of the range of demand duration curves across all 48 simulated sets. It can be seen that the demand duration curves of the simulated demand sets for 2019-20 have a variation similar to that observed over the past five years - 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[9]. This variation in demand contributes to the variation in modelled pool price outcomes as discussed further in this section.

[9] The simulated demand sets for 2019-20 are generally higher than the pre-2016-17 observed demand outcomes due to the step increase in demand due to the in-field compression associated with the LNG export projects in Gladstone.

FIGURE 4.9 TOP ONE PERCENT HOURLY DEMANDS – QUEENSLAND

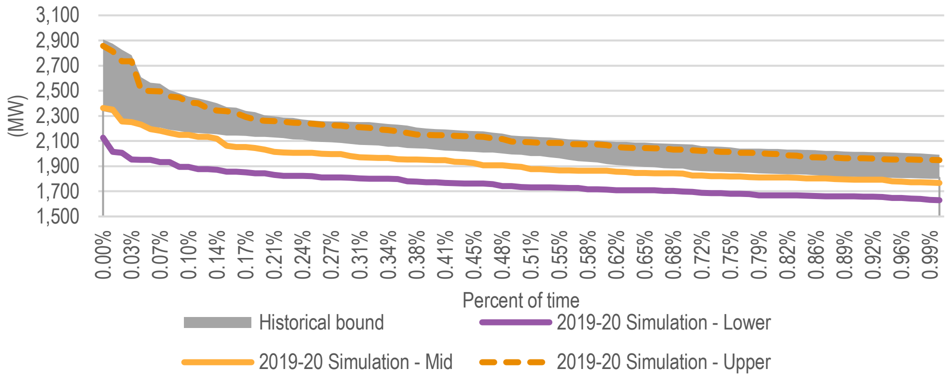


SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

Figure 4.10 shows the range of the simulated Energex NSLP demand envelopes recent outcomes and covers an average range of about 700 MW across the top one percent of hours. This variation results in the annual load factor[10] of the 2019-20 simulated demand sets ranging between 26 percent and 36 percent compared with a range of 43 percent to 29 percent for the actual NSLP between 2008-09 and 2016-17 (as shown in **Figure 4.11**). There has been an observable fall in the load factor in the actual NSLP 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 throughout the middle of the day.

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

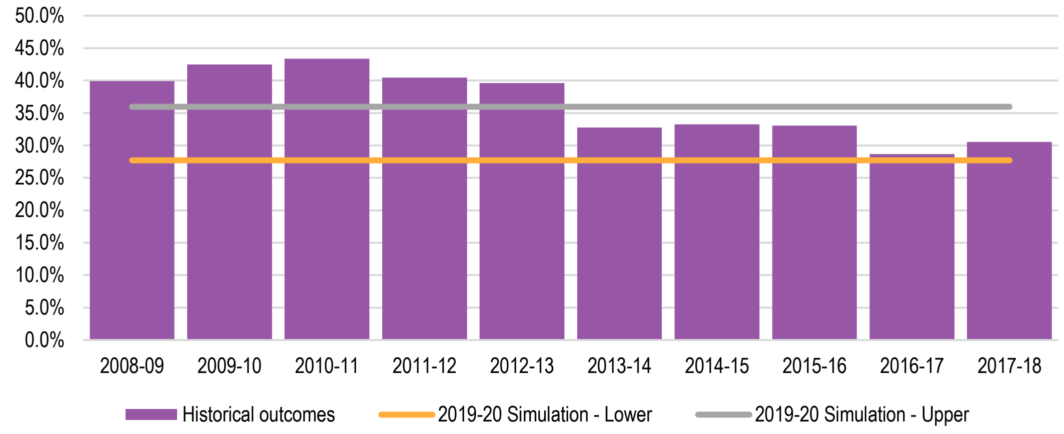
FIGURE 4.10 TOP ONE PERCENT HOURLY DEMANDS – ENERGEX NSLP



SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

[10] 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 4.11 COMPARISON OF LOAD FACTOR OF SIMULATED HOURLY DEMAND DURATION CURVES FOR ENERGEX NSLP AND HISTORICAL OUTCOMES



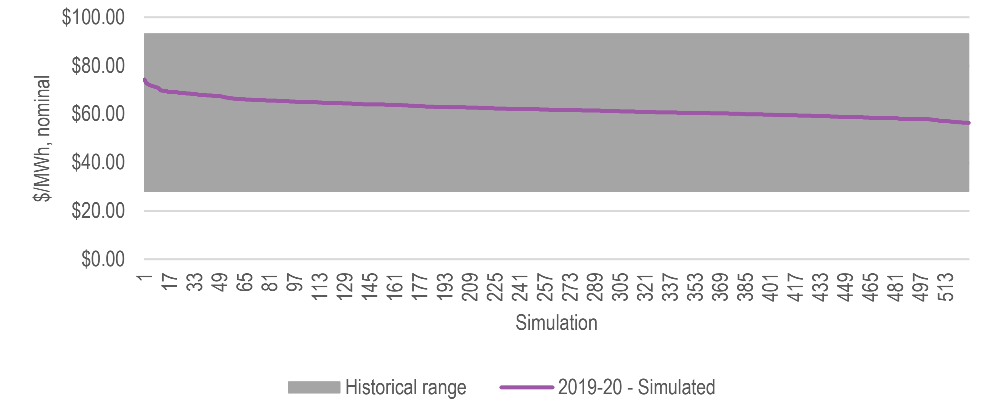
SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

The modelled annual time weighted pool prices (TWP) for Queensland in 2019-20 from the 528 simulations range from a low of \$56.43/MWh to a high of \$74.33/MWh. This compares with the lowest recorded Queensland TWP in the last 17 years of \$28.12/MWh in 2005-06 to the highest of \$93.13/MWh in 2016-17. The average TWP simulated for 2019-20 is \$62.27/MWh – about 15 per cent less than the actual 2017-18 outcomes.

Figure 4.12 compares the modelled annual Queensland TWP for the 528 simulations for 2019-20 with the Queensland TWPs from the past 17 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 2019-20 when compared with the past 17 years of history. The lower part of the distribution of annual simulated outcomes sits above a number of the actual annual outcomes (particularly for the earlier years of the market), due to the increase in gas prices in recent years, and the operating costs of coal plant have increased since the market's inception, and these, coupled with the assumed substantial demand growth due to the LNG terminals, have the effect of influencing an increase in the lower bound of annual price outcomes. The upper bound of the simulations for 2019-20 sits below the historic upper bound of actual outcomes. This is not surprising – price volatility in the market in 2019-20 is projected to be lower due to the large amount of capacity entering the market. Although it is generally stated that renewable capacity is intermittent and therefore may contribute to an increase in price volatility, the sheer increase in capacity entering the market in 2019-20 outweighs this feature. Further, the modelling assumes the commencement of CleanCo from July 2019 in which we assume Wivenhoe to operate more frequently since it is no longer part of a large portfolio.

ACIL Allen is satisfied that in an aggregate sense the distribution of the 528 simulations for 2019-20 cover an adequately wide range of possible annual pool price outcomes.

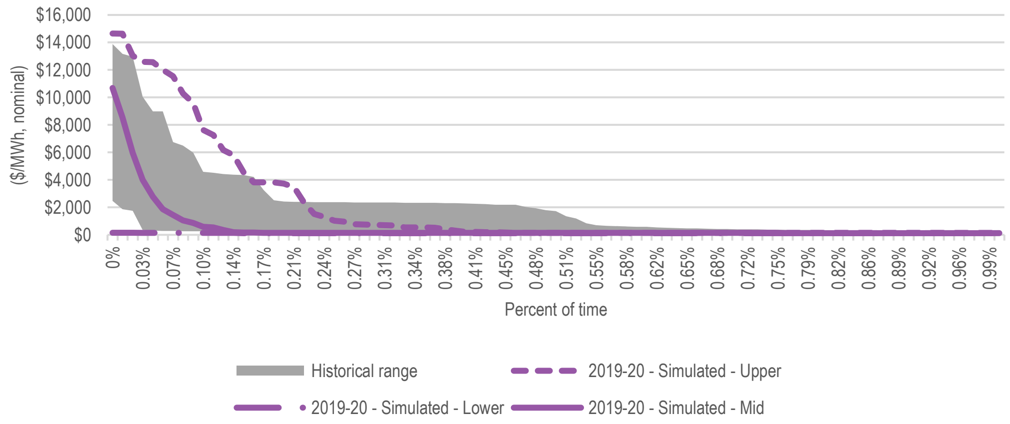
FIGURE 4.12 ANNUAL TWP FOR QUEENSLAND FOR 528 SIMULATIONS FOR 2019-20 COMPARED WITH ACTUAL ANNUAL OUTCOMES IN PAST YEARS



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, as shown in Figure 4.13. It is also notable, that as would be expected, the distribution of simulated price outcomes demonstrates a strong positive skewness.

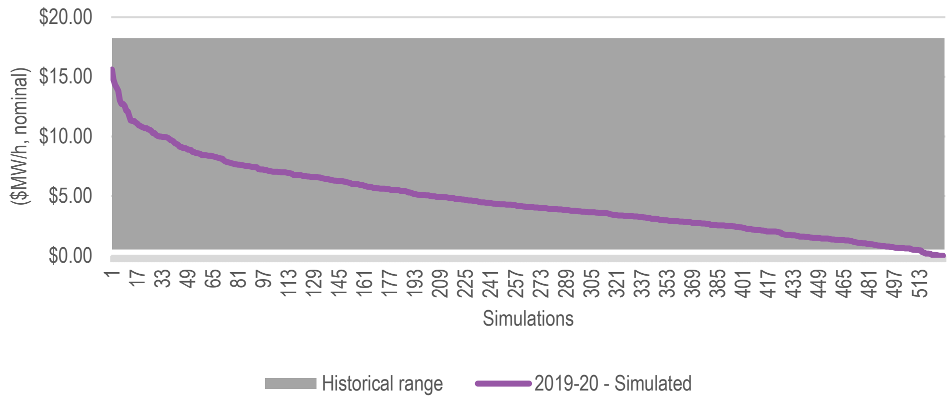
FIGURE 4.13 COMPARISON OF UPPER 1 PERCENT TAIL OF SIMULATED HOURLY PRICE DURATION CURVES FOR QUEENSLAND AND HISTORICAL OUTCOMES



SOURCE: AEMO HISTORIC POOL PRICE DATA AND ACIL ALLEN RESULTS FROM POWERMARK MODELLING

ACIL Allen is satisfied that *PowerMark* has performed adequately in capturing the extent and level of high price events based on the demand and outage inputs for the 528 simulations. The range in annual average contribution to the TWP, of hourly prices above $300/MWh, for the 528 simulations is consistent with those recorded in history as shown in Figure 4.14.

FIGURE 4.14 ANNUAL AVERAGE CONTRIBUTION TO THE QUEENSLAND TWP BY PRICES ABOVE $300/MWH FOR QUEENSLAND IN 2019-20 FOR 528 SIMULATIONS COMPARED WITH ACTUAL OUTCOMES IN PAST YEARS



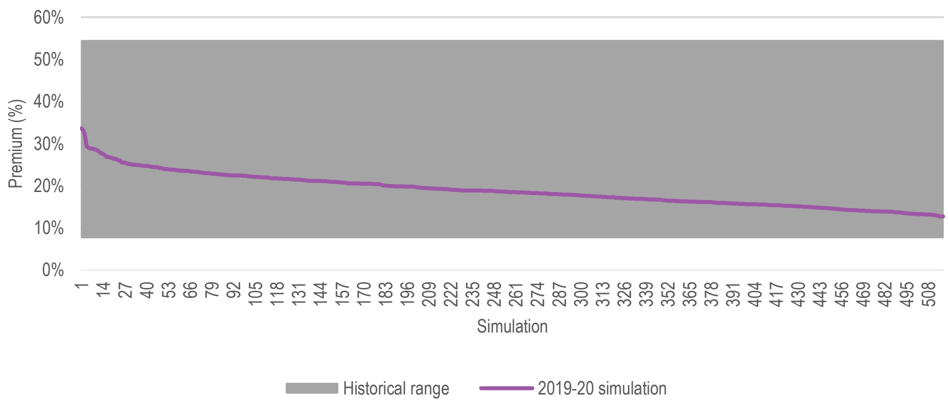
SOURCE: AEMO HISTORIC POOL PRICE DATA AND ACIL ALLEN RESULTS FROM POWERMARK MODELLING

Submissions to earlier 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.

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 4.15 shows that, for the past 10 financial years, the DWP for the Energex NSLP as a percentage premium over the Queensland TWP has varied from a low of 8 percent in 2011-12 and 2017-18 to a high of 54 percent in 2014-15. In the 528 simulations for 2019-20, this percentage varies from 12 percent to 34 percent. This is lower when compared with recent previous determinations but not surprising given the lower price volatility and reduced time of day price differentiation projected for 2019-20 (which was also exhibited in the actual outcomes 2017-18.

The comparison with actual outcomes over the past 10 years in Figure 4.15 demonstrates that the relationship between the Energex NSLP demand and Queensland pool prices in the 528 simulations is sound. Further, the cost of supplying the Energex NSLP from the spot market in the simulations relates well to the Queensland pool price and covers an adequate range of possible outcomes for 2019-20. It also provides a sound cross check on the shape of the NSLP demand and its relationship with the Queensland demand.

FIGURE 4.15 ANNUAL DWP FOR ENERGEX NSLP AS PERCENTAGE PREMIUM OF ANNUAL TWP FOR QUEENSLAND FOR 528 SIMULATIONS FOR 2019-20 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 modelled Queensland pool prices from the 528 simulations cover the range of expected price outcomes for 2019-20 in terms of annual averages and distributions. These comparisons clearly show that the 48 simulated demand traces combined with the 11 plant outage scenarios provide a sound basis for modelling the expected future spot market outcomes for 2019-20.

4.2.3 Applying the hedge model

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

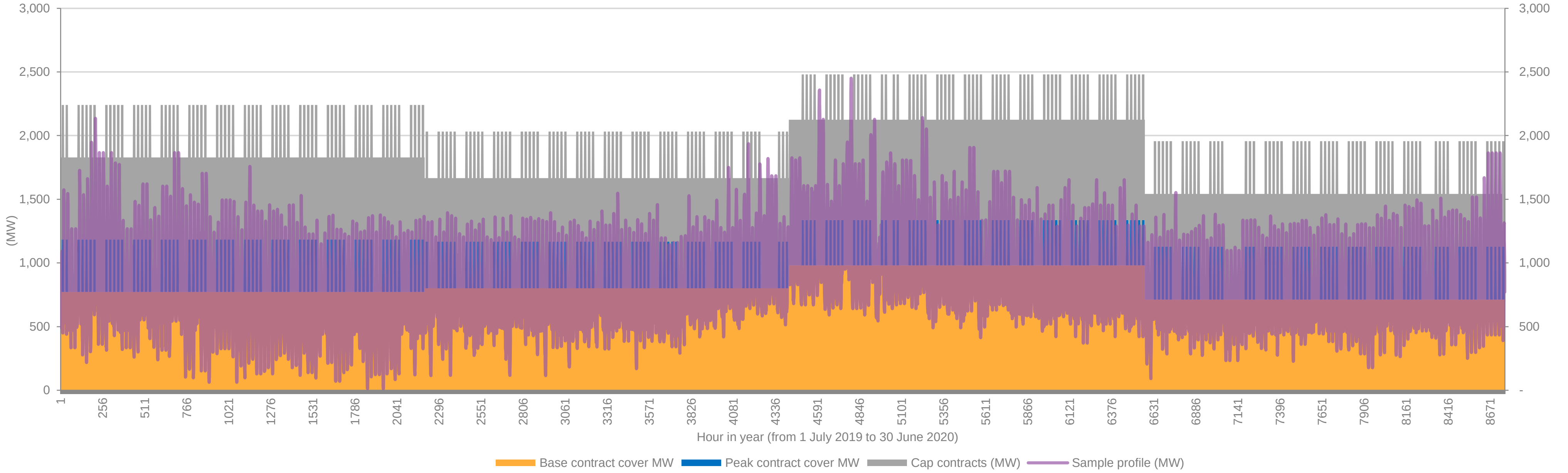
Contract volumes are calculated for each settlement class for each quarter as follows:

— The base contract volume is set to equal the 70th percentile of the off-peak period hourly demands across all 48 demand sets for the quarter.
— The peak period contract volume is set to equal the 80th percentile of the peak period hourly demands across all 48 demand sets minus the base contract volumes for the quarter.
— The cap contract volume is set at 105 per cent of the median of the annual peak demands across the 48 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 48 demand sets for a given settlement class, and hence to each of the 528 simulations. To be clear, we are not altering the hedge volume (in MW terms) on an ex-post basis for each of the 48 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 528 simulations when calculating the wholesale energy cost. The contract volumes used are shown in Figure 4.16.

FIGURE 4.16 CONTRACT VOLUMES USED IN HEDGE MODELLING OF 528 SIMULATIONS FOR 2019-20 FOR ENERGEX NSLP

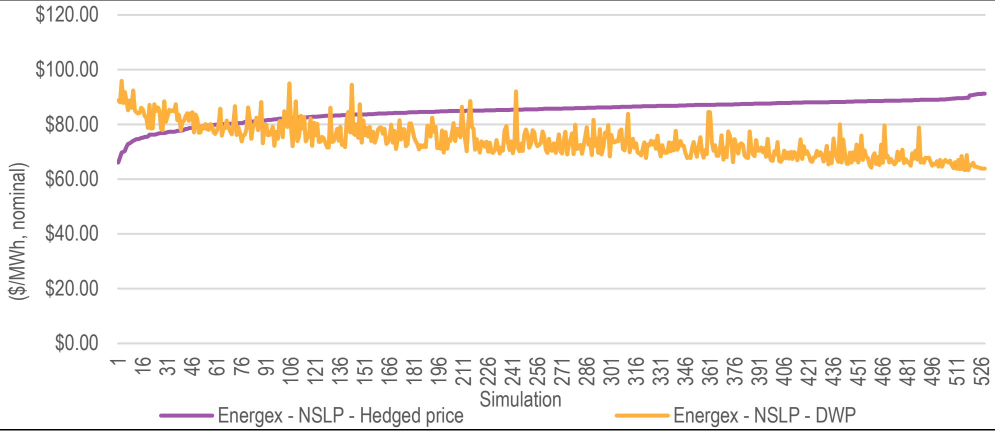


SOURCE: ACIL ALLEN

As hedge benefits are inversely related to pool prices, simulations with higher demand-weighted pool prices usually produce lower hedged prices. Figure 4.17 shows that, under the current methodology, the higher estimates of supply costs including hedge effects are not associated with high demand and high pool price years.

In other words the current risk averse hedging strategy adopted in 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 4.17 ANNUAL HEDGED PRICE AND DWP ($/MWH, NOMINAL) FOR ENERGEX NSLP FOR THE 528 SIMULATIONS – 2019-20



SOURCE: ACIL ALLEN MODELLING

4.2.4 Summary of estimated Wholesale Energy Cost

After applying the hedge model, the WEC is taken as the 95th percentile of the distribution containing 528 annual hedged prices. ACIL Allen's estimate of the WEC for each tariff class for the 2019-20 Draft Determination are shown in Table 4.2.

TABLE 4.2 ESTIMATED WEC ($/MWH, NOMINAL) FOR 2019-20 AT THE QUEENSLAND REFERENCE NODE

Settlement classes	2019-20 – Draft Determination	2018-19 – Final Determination	Change from 2018-19 to 2019-20 (%)
Energex - NSLP - residential and small business	$89.08	$99.10	-10.11%
Energex - Controlled load tariff 9000 (31)	$64.89	$61.26	5.93%
Energex - Controlled load tariff 9100 (33)	$72.49	$78.66	-7.84%
Energex - NSLP - unmetered supply	$89.08	$99.10	-10.11%
Ergon Energy - NSLP - CAC and ICC	$75.39	$88.18	-14.50%
Ergon Energy - NSLP - SAC demand and street lighting	$75.39	$88.18	-14.50%

SOURCE: ACIL ALLEN ANALYSIS

Compared with the 2018-19 Final Determination, the estimated WEC for 2019-20 for the NSLPs has decreased by about $10-13/MWh, decreased by about $6/MWh for control load tariff 33, and increased by about $3.60/MWh for control load tariff 31.

The decrease in estimated WEC for the NSLPs reflects the projected decrease in price volatility in Queensland and other regions of the NEM due to the expected entry of around 5,200 MW of renewable investment over the next 18 months – about 1,350 MW of which will be in Queensland, and the assumed increase in output from Wivenhoe as part of the CleanCo operations.

As discussed earlier, the WEC for each tariff class is unlikely to increase (or decrease for that matter) by the same amount between one determination and the next – whether in dollar or percentage terms – due to their different load shapes and differences in how the load shapes are changing over time.

Control load tariff 31 has about 65 per cent of its load requirements occurring between 10pm and 2am at night, and our modelling is suggesting that prices during these periods are not declining (given the extent of rooftop and utility scale investment and the operation of Wivenhoe do not impact prices during these periods).

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[11]) 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:

— historical Large-scale Generation Certificate (LGC) market prices from TFS[12]
— mandated LRET targets for 2019 and 2020 of 31,244 GWh and 33,850 GWh, respectively
— estimated RPP values for 2019 and 2020 of 18.33 per cent and 19.75 per cent, respectively[13]
— estimated STP values for 2019 and 2020 of 19.75 per cent and 12.72 per cent, respectively[14]
— CER clearing house price for 2019 and 2020 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 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 LGC forward prices provided by broker TFS.

The LGC price used in assessing the cost of the scheme for 2019-20 is found by averaging the forward prices for the 2019 and 2020 calendar years, during the two years prior to the commencement of 2019 and 2020. This assumes that LGC coverage is built up over a two year period (see Figure 4.18). The average LGC prices calculated from the TFS data are $72.54/MWh for 2019 and $32.22/MWh for 2020**.** Since the 2018-19 Final Determination, LGC forward prices have fallen due to:

— A number of renewable projects reaching financial close in recent months with most of the projects expected to be commissioned during 2019
— The mix of near-term renewable projects skewed more towards solar than wind, with solar having a shorter lead time to commissioning
— The significantly lower average price for 2020 reflects the high likelihood that the LRET scheme will be fully subscribed by 2020.

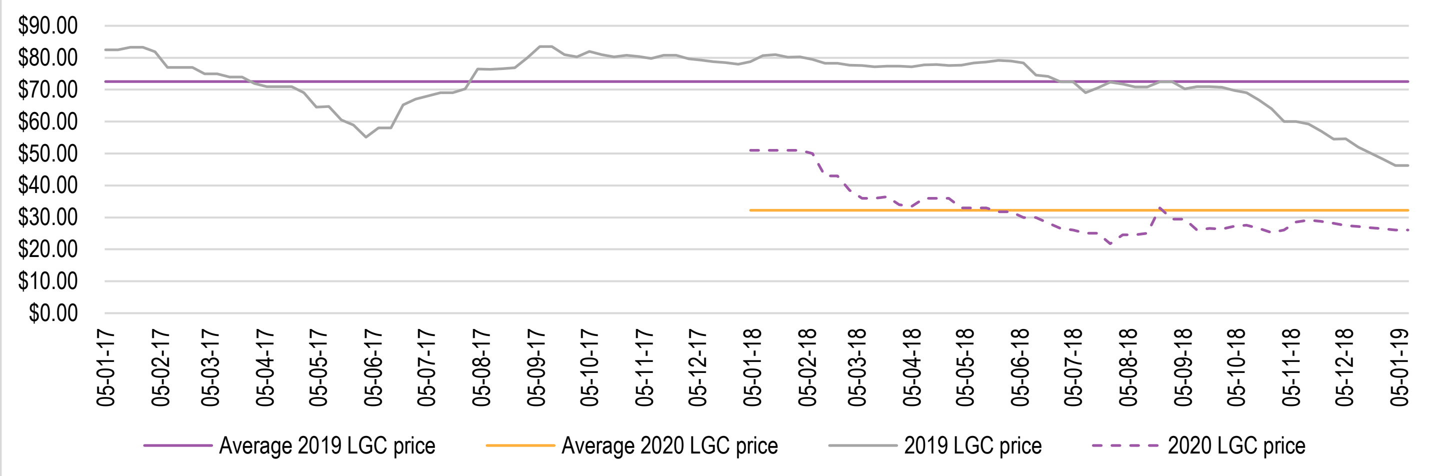
11 Emissions Intensive Trade Exposed (EITE) industries such as aluminium are wholly or partially exempted and receive Partial Exemption Certificates (PEC) to be surrendered to the named liable entity.

12 TFS data includes prices up to and including 10 January 2019.

13 The 2019 and 2020 RPP values were estimated using liable electricity acquisitions implied in the STP values for 2019 and 2020, as estimated by ACIL Allen.

14 The 2019 and 2020 STP estimates are based on ACIL Allen modelling of small-scale technology certificates, which is a departure from our usual methodology of using the non-binding STP estimates published by CER. The reason for using ACIL Allen modelling is to capture the latest market information.

FIGURE 4.18 LGC PRICES FOR 2019 AND 2020 ($/LGC, NOMINAL)



SOURCE: TFS AND ACIL ALLEN ANALYSIS

The 2019 and 2020 RPP values of 18.33 per cent and 19.75 per cent, respectively, were estimated using the mandated targets for 2019 and 2020 and the total estimated electricity consumption implied in the estimated STP values for 2019 and 2020. Key elements of the 2019 and 2020 RPP estimation are shown in Table 4.3.

TABLE 4.3 ESTIMATING THE 2019 AND 2020 RPP VALUES

	2019	2020
Estimated STP (ACIL Allen)	19.75%	12.72%
Projected STCs (ACIL Allen)	33,661,220	21,799,493
Implied total estimated electricity consumption	170,432,318	171,387,814
LRET target	31,244,000	33,850,000
Estimated RPP using implied total estimated electricity consumption	18.33%	19.75%

[a] Implied total estimated electricity consumption is found by dividing projected STCs by the estimated STP.

SOURCE: CER AND ACIL ALLEN ANALYSIS

ACIL Allen calculates the cost of complying with the LRET in 2019 and 2020 by multiplying the RPP values for 2019 and 2020 by the average LGC prices for 2019 and 2020, respectively. The cost of complying with the LRET in 2019-20 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be $9.83/MWh in 2019-20 as shown in Table 4.4.

TABLE 4.4 ESTIMATED COST OF LRET – 2019-20

	2019	2020	Cost of LRET 2019-20
RPP %	18.33%	19.75%	
Average LGC price ($/LGC, nominal)	$72.54	$32.22	
Cost of LRET ($/MWh, nominal)	$13.30	$6.36	$9.83

SOURCE: CER, TFS, ACIL ALLEN ANALYSIS

4.3.2 SRES

The cost of the SRES for calendar years 2019 and 2020 is calculated by applying the estimated STP value to the STC price. The average of these calendar year costs is then used to obtain the estimated cost for 2019-20.

The STP values have been estimated by ACIL Allen. In previous Draft Determinations, we have used the non-binding STPs published by CER. However, the non-binding STPs are based on data to 31 December 2017 and are somewhat out of date, given higher than expected uptake in distributed solar PV in 2018. ACIL Allen's modelling of the small-scale generating units incorporates information up to the end of November 2018[15].

The STPs estimated by ACIL Allen are as follows:

— 2019 STP of 19.75 per cent (equivalent to 33.7 million STCs as a proportion of total estimated electricity consumption for the 2019 year).This estimate includes an uplift due to the carry over of overflow STCs from 2018.
— 2020 STP of 12.72 per cent (equivalent to 21.8 million STCs as a proportion of total estimated electricity consumption for the 2020 year). This is lower than the 2019 estimate due to the modelling not resulting in any overflow STPs from 2019 to be carried over to 2020.

ACIL Allen estimates the cost of complying with SRES to be $6.49/MWh in 2019-20 as set out in Table 4.5. This is an increase compared with the 2018-19 Final Determination and reflects a higher projected uptake in 2019 and 2020.

TABLE 4.5 ESTIMATED COST OF SRES – 2019-20

	2019	2020	Cost of SRES 2019-20
STP %	19.75%	12.72%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of SRES ($/MWh, nominal)	$7.90	$5.09	$6.49

SOURCE: ACIL ALLEN ANALYSIS

4.3.3 Summary of estimated LRET and SRES costs

Adding these component costs gives a total cost requirement as set out in Table 4.6. This is compared to the costs from the Final Determination from 2018-19.

Since the 2018-19 Final Determination, the cost of LRET has decreased by 28 per cent, driven by lower LGC prices and the cost of SRES has increased by 11 per cent, driven by higher estimated STCs. Overall, the renewable energy costs have decreased by about 17 per cent because the lower LGC prices offsets the increase in estimated STCs.

TABLE 4.6 TOTAL RENEWABLE ENERGY POLICY COSTS ($/MWH)

	Draft Determination 2019-20	Final Determination 2018-19
LRET	$9.83	$13.72
SRES	$6.49	$5.84
Total	$16.33	$19.56

4.4 Estimation of other energy costs

The estimates of other energy costs 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.

[15] ACIL Allen will include the impacts of the Victorian Solar Home Program, which is estimated to bring forward the installation of rooftop solar PV on 650,000 homes over the next 10 years, for the Final Determination.

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)[16].

Based on projected fees in AEMO's *Electricity Final Budget & Fees 2018-19*, the total fee for 2019-20 is $0.63/MWh. The breakdown of total fees is shown in Table 4.7. AEMO is yet to publish their draft budget for 2019-20, but it is expected to be available for the Final Determination.

TABLE 4.7 NEM MANAGEMENT FEE ($/MWH) – 2019-20

Cost category	Fees ($/MWh)
NEM fees (admin, registration, etc.)	$0.50
FRC - electricity	$0.080
NTP - electricity	$0.025
ECA - electricity	$0.029
Total NEM management fees	**$0.63**

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA, AER STATE OF THE ENERGY MARKET 2018

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 2019-20, the cost of ancillary services is estimated to be $0.37/MWh.

4.4.3 Prudential costs

Prudential costs have been calculated for the Energex and Ergon NSLP. The prudential costs for the Energex NSLP are then used as a proxy for prudential costs for the Energex controlled load profiles.

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 (GST + 1) x 35 days

PML = (Average daily load x Average future expected spot price x Participant Risk Adjustment Factor * PM Volatility factor x (GST + 1) x 7 days

Taking a 1 MWh average daily load and assuming the inputs in Table 4.8 for each season for Energex NSLP gives an estimated MCL of $5,940.

[16] ECA requirements are measured in terms of connection points for small customers. It is not clear in AEMO's *Electricity Final Budget and Fees 2018-19* of the assumed number of connection points for small customers used in the estimate, therefore ACIL Allen has used DNSP customer numbers to estimate the cost of ECA requirements in $/MWh terms.

TABLE 4.8 AEMO PRUDENTIAL COSTS FOR ENERGEX NSLP – 2019-20

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price	$84.57	$57.39	$56.59
Participant Risk Adjustment Factor	1.1993	1.2194	1.1669
OS Volatility factor	1.70	1.28	1.38
PM Volatility factor	3.51	1.75	2.23
OSL	$7,270	$3,808	$3,790
PML	$1,454	$762	$758
MCL	$8,724	$4,570	$4,548
Average MCL		$5,940	

SOURCE: ACIL ALLEN ANALYSIS, AEMO

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 $5,940/42 = $141.42/MWh.

The cost of funding a bank guarantee for the MCL associated with the single MWh is assumed to be a 2.5 percent annual charge for 42 days or 2.5%*(42/365) = 0.288 percent. Applying this funding cost to the single MWh charge of $141.42 gives $0.41/MWh.

The components of the AEMO prudential costs for the Ergon NSLP are shown in Table 4.9. The estimated AEMO prudential costs for the Ergon NSLP are $0.30/MWh.

TABLE 4.9 AEMO PRUDENTIAL COSTS FOR ERGON NSLP – 2019-20

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price	$84.57	$57.39	$56.59
Participant Risk Adjustment Factor	0.9675	0.9815	0.9683
OS Volatility factor	1.70	1.28	1.38
PM Volatility factor	3.51	1.75	2.23
OSL	$5,268	$2,750	$2,865
PML	$1,054	$550	$573
MCL	$6,322	$3,300	$3,438
Average MCL		$4,347	

SOURCE: ACIL ALLEN ANALYSIS, AEMO

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 1.5 percent. 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 percent on average for a base contract, 20 percent for a peak contract and 26 percent for a cap contract
— the intra monthly spread charge currently set at $12,300 for a base contract of 1 MW for a quarter, $13,600 for a peak contract and $5,900 for a cap contract
— the spot isolation rate currently set at $1,500 for a base contract, $1,500 for a peak contract and $600 for a cap contract.

Prior to the 2018-19 Determination, ACIL Allen used baseload contracts as proxies for hedge prudential costs. For the 2018-19 Determination we refined the methodology to take into account the relative proportion of each type of contract used in the hedge model and any over-contracting modelled in the hedge model, and we have continued to use this refinement for the 2019-20 Draft Determination.

Using the annual average futures price and applying the above factors gives an average initial margin for each quarter (rounded up) as shown in Table 4.10. This is divided by the average hours in a quarter. Then applying the assumed funding cost of 8.21[17] percent but adjusted for an assumed 1.5 percent return on cash lodged with the clearing (giving a net funding cost of 6.71 percent) results in the prudential cost per MWh for each contract type as shown in Table 4.10.

TABLE 4.10 HEDGE PRUDENTIAL FUNDING COSTS BY CONTRACT TYPE

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$67.51	$27,000	$0.83
Peak	$82.52	$30,000	$2.21
Cap	$6.46	$11,000	$0.34

SOURCE: ACIL ALLEN ANALYSIS, ASX ENERGY, RBA, QCA

However, the hedge model used is designed to conservatively cover all load at the extremes and so results in an over-contracted position against the average load. The volume of hedges (MWh) in each category have been calculated as a proportion of the average annual load in the Energex NSLP to give a proportional factor. The product of the prudential cost per MWh for each contract type and the proportion of each contract in the hedge model profile provides the total hedge prudential cost per MWh associated with each contract type. These are then summed to establish the total hedge prudential costs as shown in Table 4.11. The same process was undertaken for the Ergon NSLP and is summarised in Table 4.12.

TABLE 4.11 HEDGE PRUDENTIAL FUNDING COSTS FOR ENERGEX NSLP

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.83	1.0555	$0.87
Peak	$2.21	0.2171	$0.48
Cap	$0.34	1.2586	$0.42
Total cost		**$1.78**	

SOURCE: ACIL ALLEN ANALYSIS

[17] QCA provided ACIL Allen with the funding cost to be used in the analysis.

TABLE 4.12 HEDGE PRUDENTIAL FUNDING COSTS FOR ERGON NSLP

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.83	1.0445	$0.86
Peak	$2.21	0.1038	$0.23
Cap	$0.34	0.3746	$0.13
Total cost		**$1.22**	

SOURCE: ACIL ALLEN ANALYSIS

Total prudential costs

Adding the AEMO and hedge prudential costs gives a total prudential requirement as set out in Table 4.13. Prudential costs for the 2019-20 Draft Determination are lower than the 2018-19 Final Determination due to lower hedge prices and lower price volatility.

TABLE 4.13 TOTAL PRUDENTIAL COSTS ($/MWH) - 2019-20

Cost category	Energex NSLP	Ergon NSLP
AEMO pool	$0.41	$0.30
Hedge	$1.77	$1.22
Total	**$2.18**	**$1.52**

SOURCE: ACIL ALLEN ANALYSIS

4.4.4 Summary of estimated total other costs

Adding these component costs gives a total other cost requirement as set out in Table 4.14 for the 2019-20 Draft Determination and is compared to the costs from the Final Determination for 2018-19.

TABLE 4.14 TOTAL OF OTHER COSTS ($/MWH) – ENERGEX NSLP

Cost category	Draft Determination 2019-20	Final Determination 2018-19
NEM management fees	$0.63	$0.53
Ancillary services	$0.37	$0.43
Hedge and pool prudential costs	$2.18	$2.95
Total	**$3.18**	**$3.91**

TABLE 4.15 TOTAL OF OTHER COSTS ($/MWH) – ERGON NSLP

Cost category	Draft Determination 2019-20	Final Determination 2018-19
NEM management fees	$0.63	$0.53
Ancillary services	$0.37	$0.43
Hedge and pool prudential costs	$1.52	$2.09
Total	**$2.52**	**$3.05**

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 results in a transmission loss factor of 1.008 for Energex and 0.962 for the Ergon Energy east zone. These estimates are based on AEMO's MLFs for 2018-19 weighted by the 2017-18 energy for the TNIs.[18]

The distribution loss factor by settlement class for the Energex area and the Ergon energy east zone are taken from AEMO's Distribution Loss Factors for 2018-19.

The estimation of transmission and distribution loss factors for the settlement classes to be used in calculating energy costs for the Draft Determination for 2019-20[19] is shown in Table 4.16.

TABLE 4.16 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	1.053	1.008	1.062
Energex - Control tariff 9000	1.053	1.008	1.062
Energex - Control tariff 9100	1.053	1.008	1.062
Ergon Energy - NSLP - SAC HV, CAC and ICC	1.036	0.962	0.996
Ergon Energy - NSLP - SAC demand and street lighting	1.087	0.962	1.045

SOURCE: ACIL ALLEN ANALYSIS BASED ON QUEENSLAND TNI ENERGY FOR 2017-18, MLFS FOR 2018-19 AND ENERGEX AND ERGON ENERGY EAST ZONE DLFS FOR 2018-19 FROM AEMO

For the Draft Determination for 2019-20 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[20], 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 and estimates from the previous sections of this report, ACIL Allen's estimates of the 2019-20 total energy costs (TEC) for the Draft Determination for each of the settlement classes are presented in Table 4.17.

[18] In previous Draft Determinations, updated TNI data was not readily available

[19] These estimates will be updated for the Final Determination taking into account AEMO's MLFs and DLFs for 2019-20 to be published in March 2019.

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

TABLE 4.17 ESTIMATED TEC FOR 2019-20 DRAFT DETERMINATION

Settlement class	WEC at Qld reference node ($/MWh)	Renewable energy costs at Qld reference node ($/MWh)	Other costs Qld reference node ($/MWh)	Total transmission and distribution loss factor (MLF x DLF)	Network losses ($/MWh)	TEC at the customer terminal ($/MWh)	Change from 2018-19 Final Determination ($/MWh)	Change from 2018-19 Final Determination (%)
Energex - NSLP - residential and small business	$89.08	$16.32	$3.18	1.062	$6.73	$115.31	-$14.86	-11.42%
Energex - Controlled load tariff 9000 (31)	$64.89	$16.32	$3.18	1.062	$5.23	$89.62	-$0.36	-0.40%
Energex - Controlled load tariff 9100 (33)	$72.49	$16.32	$3.18	1.062	$5.70	$97.69	-$10.77	-9.93%
Energex - NSLP - unmetered supply	$89.08	$16.32	$2.52	1.062	$6.73	$115.31	-$14.86	-11.42%
Ergon Energy - NSLP - CAC and ICC	$75.39	$16.32	$2.52	0.996	-$0.38	$93.85	-$17.16	-15.46%
Ergon Energy - NSLP - SAC demand and street lighting	$75.39	$16.32	$2.52	1.045	$4.24	$98.47	-$17.97	-15.44%

SOURCE: ACIL ALLEN ANALYSIS

A AEMC 2018 RESIDENTIAL ELECTRICITY PRICE TRENDS REVIEW

The AEMC's report, *2018 Residential Electricity Price Trends Review,* was released in December 2018 (the review). Analysis and projections underpinning the review were completed with assistance from Ernst & Young (EY). ACIL Allen notes that the review does not form part of a regulatory determination process but has the purpose of providing consumers and governments with an understanding of the cost components of the electricity supply chain and the expected trends of the components.

Provided below are some key differences in the approach adopted by EY and the AEMC compared with ACIL Allen's methodology.

A.1 Wholesale energy costs

The review suggests wholesale energy costs[21] will decrease by 25.6 per cent in south east Queensland between 2018–19 and 2019–20 – larger than what is estimated by ACIL Allen.

EY's approach to estimating wholesale energy costs is broadly similar to the approach adopted by ACIL Allen. However, there are some key differences:

— <u>Hedge portfolio</u>:
  - EY appear to use a portfolio of quarterly base, peak and cap hedges to cover the NSLP, as do ACIL Allen, but do not provide the mix of these products or the extent that the portfolio of hedges covers the NSLP profile.

— <u>Hedge or contract prices</u>:
  - EY use a 12-month and a 2-year build-up of hedges for small and large retailers respectively. ACIL Allen does not distinguish between small and large retailers.
  - EY's portfolio build-up is assumed to be completed by April 2019, as is ACIL Allen[22], but uses an assumed exponential build up path.
  - EY do not use the observable trade volumes as the weights to calculate the weighted average cost of each product, and instead use an exponential build-up of the portfolio of hedges.
  - Because of this approach, and the fact that EY's analysis was completed in October 2018 or earlier, this means that 6 months of actual ASX Energy prices are unable to be included in the analysis for 2019-20 (with the six-month period being October 2018 to April 2019).
  - For the 6 months of missing ASX Energy data, EY have used their modelled price outcomes. Based on information in the review reports, this means that in deriving the final estimate of the contract prices for each quarterly product for 2019-20, EY essentially use an approximate

[21] It is worth noting that EY's definition of the WEC includes the costs of market operator fees, network losses and ancillary services charges, whereas ACIL Allen report these elements separately from the WEC.
[22] Noting the cut-off date for the 2019-20 Final Determination is April 2019.

weighting of 46 per cent for the ASX Energy data and 54 per cent for the EY modelled spot prices for a large retailer.

- Rather than prespecifying or forcing a particular pattern in the hedge book build up, ACIL Allen uses all trades back to the first trade recorded by ASX Energy for the given product, which generally more closely reflects, in practice, how retailers build up their portfolio of hedging contracts over time.
- A different weighting between actual ASX Energy prices and modelled spot prices could yield a very different result using EY's approach.

A.2 Renewable energy target costs

The AEMC's review projects that LRET costs for south-east Queensland to be about $2/MWh lower than ACIL Allen's estimate using a market-based approach.

For large retailers, EY do not use observable traded LGC prices to estimate the cost of LGCs. Instead they estimate the subsidy required for a new entrant renewable generator to enter into a PPA to recover its fixed and variable costs for the period spanning the commissioning of the plant to the end of the LRET (2030).

EY take the NPV of the fixed and variable costs of the new entrant out to 2030, and deduct the projected wholesale electricity revenue it receives out to 2030.

EY note that the LGC spot and forward markets are thinly traded. However, EY's approach is based on a theoretical new entrant with assumed costs, rather than observable market data. Further, the LRET is fully satisfied so there is no need for further investment in renewable energy projects to meet the LRET.

EY note that the LGC price estimated using the forward market may be less than that paid by retailers for long term PPAs in the past (given the decline in capital costs for renewable technology), and therefore appear to assume that older PPAs require a subsidy of $40/LGC (fourth column in table 7 on page 33 of the EY report). EY then take a weighted average of the $40 and the modelled required subsidy for a new entrant to derive the estimate of the LGC price.

For small retailers, EY use what appears to be the spot price for LGCs as at 8 August 2018. In other words, they use a single point in time value. As noted in section 4.3.1, LGC spot prices can be reasonably volatile and hence the choice of day on which to make the observation can vary the resulting estimate noticeably.

Although the LGC spot and forward markets maybe not be as deeply traded as the wholesale electricity futures market, the forward market is an active market and provides a sound basis for the value of LGCs at the margin. There are several observable sources of forward market data – including several brokers and trading platforms (the existence of which in itself suggests the market is sufficiently traded). Our approach uses the observed average price of trades made in the two-year period leading up to the determination period – rather than a single point in time observation.

The $40 price EY adopts for LGCs under PPA is rounded and likely to have a large error bound. To arrive at a detailed estimate would require knowledge of all PPAs (prices, volumes and terms) in order to estimate the weighted average shortfall after accounting for long term projected wholesale electricity price revenue for each renewable project. Even if this was possible, this approach is at odds with a market-based approach used by EY for wholesale electricity costs, and is analogous to using the LRMC approach for wholesale electricity costs.

The ACIL Allen approach results in estimates that reflect the state of the market in the given determination year – rather than what might or might not happen in the market out to 2030.