ACIL ALLEN CONSULTING

REPORT TO
QUEENSLAND COMPETITION AUTHORITY

21 FEBRUARY 2018

ESTIMATED ENERGY COSTS

2018-19 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 2018-19 RETAIL TARIFFS: DRAFT DETERMINATION, ACIL ALLEN, JANUARY 2018

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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 2018-19.

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 2018-19. 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, 2014-15, 2015-16, 2016-17 and 2017-18 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.

This report also 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 2018–19* (December 2017), where those submissions refer to the methodology used to estimate the cost of energy in regulated retail electricity prices.

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 2018 to 30 June 2019.

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, 2014-15, 2015-16, 2016-17 and 2017-18 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, 2014-15, 2015-16, 2016-17 and 2017-18 reviews, ACIL Allen continues to use the market hedging approach for estimating the WEC for 2018-19.

We have utilised our:

— stochastic demand model to develop 47 weather influenced simulations of hourly demand traces for each of the tariff profiles – using temperature data from 1970-71 to 2016-17 and demand data for 2013-14 to 2016-17
— stochastic outage model to develop 11 hourly power station availability simulations
— energy market models to run 517 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 2018-19 provided in AEMO's 2017 Electricity Forecasting Insights (EFI) continues to be 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 sets out the key assumption changes for existing power stations in the NEM adopted in the market simulations, and Table 2.2 provides a summary of the near term new entrants that ACIL Allen considers committed projects which have been included in the market simulations.

At this stage, the market modelling does not include a restructure of the Queensland Government's assets and the formation of a CleanCo. The Queensland Government is currently investigating establishing a separate CleanCo generator to operate its existing renewable and low-emissions energy generation assets and develop new renewable energy projects as part of its 50 per cent renewable energy policy. The new renewable projects to be developed under the 50 per cent renewable energy policy will not be commissioned until after 2018-19.

CleanCo would include the Wivenhoe pumped storage facility. For the 2018-19 period, the key impact of the CleanCo could be a change in operation of Wivenhoe. Historically, Wivenhoe has operated with an annual capacity factor of about one per cent. However, if the facility was to be operated more aggressively, as part of a smaller generation portfolio, then it would likely place downward pressure on peak price outcomes. Conversely, Wivenhoe could operate to firm up the intermittent supply of the renewable projects developed as part of the 50 per cent renewable energy target, in which case the price impact would be less noticeable. It is unclear at this stage as to whether the Government envisages a change in role of Wivenhoe if it is part of CleanCo. If there is more transparency on this matter over the coming months then ACIL Allen will adopt any necessary changes in the market simulations for the Final Determination.

TABLE 2.1 CHANGES TO EXISTING SUPPLY

Project name	Generation technology	Capacity (MW)	Region	Nature and date of change
Bayswater & Liddell	Black coal steam turbine	4,820	NSW	Bidding with a higher coal cost in 2018-19
Mt Piper	Black coal steam turbine	1,340	NSW	Bidding with a higher coal cost in 2018-19
Smithfield	Natural gas CHP	105	NSW	Closing Q2 2018
Tallawarra	Natural gas CCGT	430	NSW	Mothball Q1 2019
Condamine	Natural gas CCGT	140	QLD	Opportunistic operation from Q3 2017
Darling Downs	Natural gas CCGT	630	QLD	Opportunistic operation from Q3 2017
Gladstone	Black coal steam turbine	1,680	QLD	One unit offline
Swanbank E	Natural gas CCGT	385	QLD	Restart Q1 2018
Newport	Natural gas steam turbine	510	VIC	Close Q2 2019

SOURCE: ACIL ALLEN ANALYSIS

TABLE 2.2 NEAR-TERM ADDITION TO SUPPLY

Project name	Generation technology	Capacity (MW)	Region	Date added
Bodangora	Wind	113	NSW	Q1 2019
Crookwell 2	Wind	91	NSW	Q2 2018
Griffith	Solar PV	30	NSW	Q1 2018
Gullen Range	Solar PV	10	NSW	Q4 2017
Manildra	Solar PV	49	NSW	Q2 2018
Parkes	Solar PV	55	NSW	Q1 2018
Sapphire stage 1	Wind	100	NSW	Q2 2018
Sapphire stage 2	Wind	170	NSW	Q3 2018
Silverton	Wind	200	NSW	Q3 2018
White Rock	Solar PV	20	NSW	Q2 2018
White Rock stage 1	Wind	175	NSW	Q3 2017
Clare	Solar PV	100	QLD	Q1 2018
Clermont	Solar PV	89	QLD	Q4 2018
Collinsville	Solar PV	42	QLD	Q2 2018
Coopers Gap	Wind	453	QLD	Q1 2019
Darling Downs	Solar PV	110	QLD	Q1 2019
Daydream	Solar PV	150	QLD	Q3 2018
Emerald	Solar PV	68	QLD	Q4 2018
Hamilton	Solar PV	58	QLD	Q2 2018

Project name	Generation technology	Capacity (MW)	Region	Date added
Hayman	Solar PV	50	QLD	Q3 2018
Kennedy Energy	Solar PV / Wind	14/43	QLD	Q3 2018
Kidston stage 1	Solar PV	50	QLD	Q1 2018
LilyVale	Solar PV	100	QLD	Q3 2018
Mt Emerald	Wind	180	QLD	Q1 2018
Oakey	Solar PV	80	QLD	Q3 2018
Ross River	Solar PV	148	QLD	Q3 2018
SunMetals	Solar	125	QLD	Q2 2018
Whitsunday	Solar PV	58	QLD	Q2 2018
Barket Inlet	Natural gas reciprocating engine	210	SA	Q1 2019
Bungala	Solar PV	220	SA	Q1 2018
Hornsdale Power Reserve	Battery	30	SA	Q1 2018
Hornsdale stage 3	Wind	109	SA	Q3 2019
Lincoln Gap	Wind	126	SA	Q2 2019
Willogoleche	Wind	118	SA	Q1 2019
Bannerton	Solar PV	88	VIC	Q3 2018
Crowlands	Wind	80	VIC	Q2 2019
Gannawarra	Solar PV	50	VIC	Q2 2018
Kiata	Wind	30	VIC	Q1 2018
Mt Gellibrand stage 1	Wind	132	VIC	Q1 2019
Murra Warra	Wind	226	VIC	Q4 2018
Salt Creek	Wind	58	VIC	Q3 2018
Stockyard Hill	Wind	530	VIC	Q1 2020
Wemen	Solar PV	110	VIC	Q4 2018
Yaloak South	Wind	29	VIC	Q3 2018

SOURCE: ACIL ALLEN ANALYSIS

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 TFS, 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 2018 and 2019 calendar years, with the costs averaged to estimate the 2018-19 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 AFMA[3] and TFS[4]
- Mandated LRET targets for 2018 and 2019 of 28,637 GWh and 31,244 GWh, respectively
- Estimated RPP values for 2018 and 2019 of 15.81 per cent and 16.9 per cent, respectively[5]
- Non-binding STP values for 2018 and 2019 of 8.06 per cent and 7.52 per cent, respectively[6]
- CER clearing house price for 2018 and 2019 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 2017-18 MLFs published by AEMO. It is expected that AEMO will have published the 2018-19 MLF estimates in time for them to be used in our revised analysis for input to the Final Determination in mid-April 2018.

3 AFMA data includes weekly prices up to and including 29 September 2016, after which the data ceased to be published

4 TFS data includes prices up to and including 10 January 2018.

5 2018 and 2019 RPP values were estimated using liable electricity acquisitions implied in the non-binding STP values for 2018 and 2019, as published by CER.

6 The non-binding 2018 and 2019 STP estimates are based on the modelling prepared for CER for the 2017 STP, as published by CER.

3 RESPONSES TO SUBMISSIONS TO INTERIM CONSULTATION PAPER

3.1 Introduction

The QCA forwarded to ACIL Allen a total of 12 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 2018-19 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	Confidential submission	Nil	Nil	Nil	Nil	Nil	Nil
2	Canegrowers Isis	Yes	Nil	Nil	Nil	Nil	Nil
3	Caravanning Queensland	Nil	Nil	Nil	Nil	Nil	Nil
4	Chamber of Commerce and Industry Queensland	Nil	Nil	Nil	Nil	Nil	Nil
5	Cloncurry Shire Council	Nil	Nil	Nil	Nil	Nil	Nil
6	Queensland Consumers' Association	Yes	Nil	Nil	Nil	Nil	Nil
7	Queensland Farmers' Federation	Nil	Nil	Nil	Nil	Nil	Nil
8	Queensland Electricity Users Network	Nil	Nil	Nil	Nil	Nil	Nil
9	CANEGROWERS	Nil	Nil	Yes	Nil	Yes	Nil
10	Queensland Council of Social Service (QCOSS)	Nil	Nil	Nil	Nil	Nil	Nil
11	Origin Energy	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
12	Energy Queensland Limited	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 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 note on page 2 of their submission:

In our view yes, extending the energy cost data cut-off date to the end of January should be considered 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, the Queensland Consumers Association notes on page one of their submission:

We support extending the energy cost data cut-off date to the end of January.

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 cost estimates by mid-January 2018, we have extended the data cut-off date to 10 January 2018 for contract price and volume data. Compared with a cut-off date of mid-November 2016 for the 2017-18 Draft Determination, we now include an additional two months' of contract price and volume data in our analysis for the 2018-19 Draft Determination.

3.3 Prudential costs

CANEGROWERS in their submission recommended that the Ergon NSLP be used to calculate the prudential costs.

ACIL Allen agrees with this approach, and has been instructed by the QCA to include this modification in its analysis for the 2018-19 Draft Determination.

3.4 Large-scale Generation Certificate prices

CANEGROWERS on page three of their submission noted:

In the determination for 2017-18 QCA increased the allowance for LGCs in its prices by a punitive 49.9%.

The methodology relied on by QCA appears to assume Ergon retail is a marginal retailer with no long-term offtake contracts in place and no investments in renewable energy capacity. In the context of the Queensland government's policy push towards renewables it is likely that an efficient prudent retailer, such as Ergon Retail, with evergreen customer contracts would actively manage this exposure by being long on investment with respect to renewables.

LGC prices have increased notably in recent years reflecting the tightness in supply and potential for shortfalls in LGCs, as a result of the hiatus in renewable investment during the 2015-2016 period due to policy uncertainty. Similarly, the substantial increase in renewable energy investment that is committed to occur over the next 12 months or so is likely to result in lower LGC prices post 2018, and particularly from 2020.

The issue raised by CANEGROWERS was also raised by retailers for the 2014-15 determination – except during that time retailers were suggesting the use of a modelled Long run Marginal Cost (LRMC) approach because LGC prices had collapsed, and hence were too low, due to the uncertainty of the LRET policy at that time.

It is important that the methodology is only changed if there is a fundamental issue that can be objectively addressed to improve the estimates, and not because the estimates work for or against a particular stakeholder (or group of stakeholders) – thus avoiding cherry-picking.

As we have indicated in the past there are issues with using a LRMC approach for LGC prices. LRMC is a long run and forward looking concept and in the case of LGCs would largely relate to future wind and solar costs and longer term future wholesale electricity prices (over the life of the renewable energy assets and thus well beyond the 2018-19 Determination period).

Consistent with previous determinations, in the absence of confidential data showing the actual position of Ergon (or other retailers in south-east Queensland), we maintain the view that transparent market prices provide a much better indicator of current prices compared with any modelled outcomes. A modelled price should only be used where market pricing is not available. No material was supplied in the submissions to persuade us to change this view.

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 2018-19.

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 five 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).

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.

In relation to each profile, we note the following:

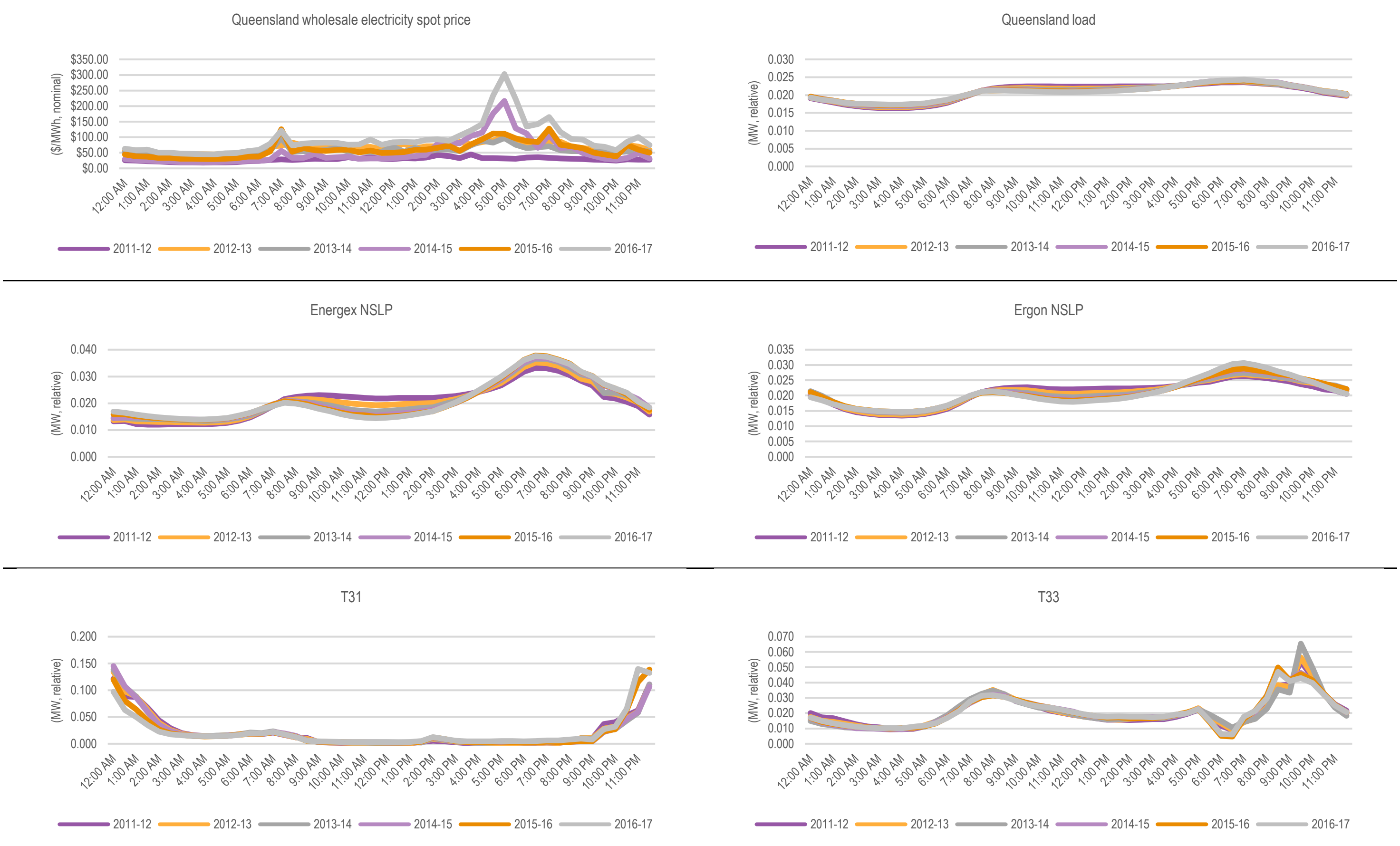
— The annual time of day price profile has been volatile over the past five years – with the overall level and shape of the price profile changing from one year to the next. For example, in 2011-12 the time of day profile was very flat compared with 2014-15. In 2012-13 and 2013-14, prices increased largely 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.

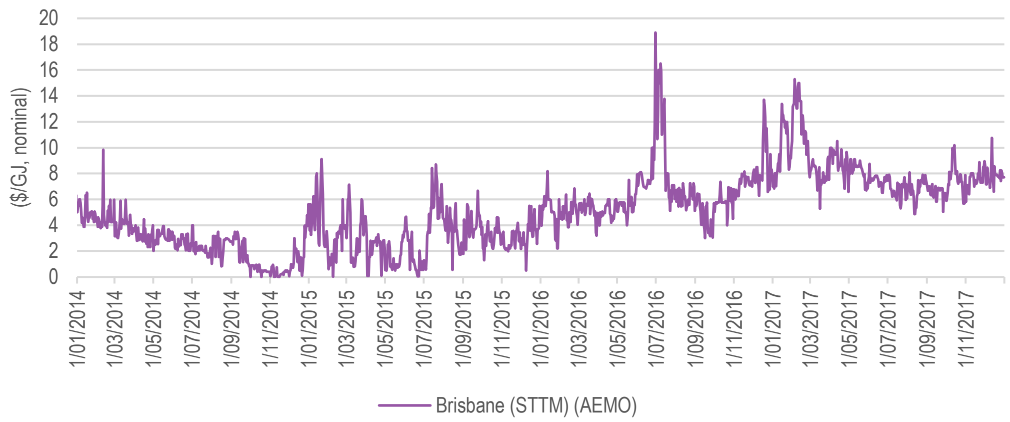
FIGURE 4.1 ACTUAL AVERAGE TIME OF DAY QLD WHOLESALE SPOT PRICE ($/MWH, NOMINAL) AND LOAD PROFILE (MW, RELATIVE) – 2011-12 TO 2016-17



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.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

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

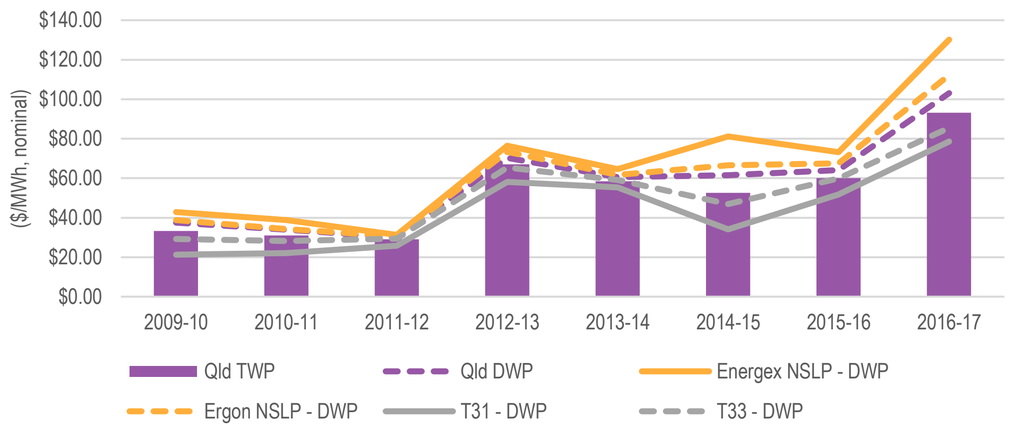


SOURCE: AEMO DATA

Figure 4.3 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 eight 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, the flat half-hourly price profile resulted in the three tariffs having relatively similar wholesale spot prices. However, from 2014-15, 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.

The increase in spot price outcomes in 2016-17 is quite apparent, with prices on an average time weighted basis of about $95/MWh – compared with $60/MWh in 2015-16 (representing an increase of just under 60 per cent).

FIGURE 4.3 ACTUAL ANNUAL AVERAGE DEMAND WEIGHTED PRICE ($/MWH, NOMINAL) BY TARIFF AND QUEENSLAND TIME WEIGHTED AVERAGE PRICE ($/MWH, NOMINAL) – 2009-10 TO 2016-17



Note: Values reported are spot (or uncontacted) prices.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

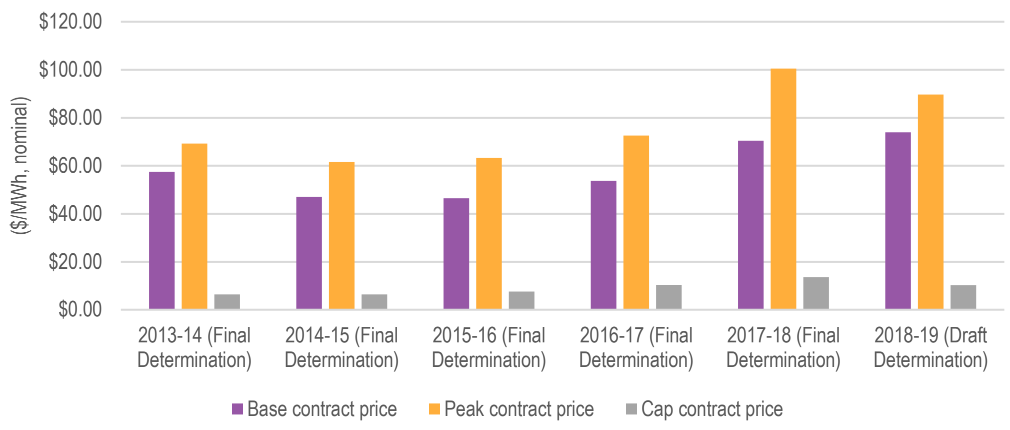
The volatility of spot prices (timing and incidence) in the Queensland region of the NEM provides the incentive to a retailer to hedge their load, since hedging of the loads reduces a retailer's exposure to the volatility. The suite of contracts (as defined by base/peak, swap/cap and quarter) available 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 4.4.

The market modelling undertaken by ACIL Allen, and reported in this chapter, aligns with the market's expectations of price outcomes in 2018-19. Compared with the 2017-18 Final Determination, futures contract prices for 2018-19, on an annualised and trade weighted basis to date, have:

— increased by about $3.50/MWh for base contracts
— decreased by about $11.00/MWh for peak contracts
— decreased by about $3.50/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 2018-19 (as shown in Table 2.2). About 5,000 MW of renewable investment will enter the NEM over the next 18 months – about 1,800 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 (and on a trade weighted basis are higher than for 2017-18). Continuing strong gas prices as well as prolonged coal supply issues for some of the NSW coal fired plant has influenced the market's view and hence has acted as a lower bound on base contract prices for 2018-19 to date.

FIGURE 4.4 QUARTERLY BASE, PEAK AND CAP CONTRACT PRICES ($/MWH) – DRAFT DETERMINATION 2018-19 AND PREVIOUS FINAL DETERMINATIONS



SOURCE: ACIL ALLEN

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 10 January 2018.

Table 4.1 shows the estimated quarterly swap and cap contract prices for the 2018-19 Draft Determination and compares them with the estimates under the 2017-18 Final Determination.

TABLE 4.1 ESTIMATED CONTRACT PRICES (MWH)

	Q3	Q4	Q1	Q2
Draft Determination 2018-19				
Base	$70.25	$70.24	$90.09	$65.03
Peak	$85.38	$84.53	$115.69	$72.90
Cap	$5.27	$10.33	$19.51	$5.17
Final Determination 2017-18				
Base	$63.13	$66.46	$89.73	$62.33
Peak	$78.56	$89.23	$142.45	$91.62
Cap	$6.87	$13.47	$27.41	$6.75
% change from Final Determination 2017-18				
Base	11.3%	5.7%	0.4%	4.3%
Peak	8.7%	-5.3%	-18.8%	-20.4%
Cap	-23.2%	-23.3%	-28.8%	-23.3%

SOURCE: ACIL ALLEN ANALYSIS USING ASX ENERGY DATA UP TO 10 JANUARY 2018

Trade weighted peak contract prices for 2018-19 are on average 11 per cent lower than 2017-18 and trade weighted cap contract prices for 2018-19 are on average 26 per cent lower than 2017-18. The lower peak and cap contract prices reflect the market's expectation that price volatility will reduce in 2018-19 due to:

— the Queensland Government's directive to Stanwell in June 2017 to adjust their bidding behaviour in order to put downward pressure on wholesale prices
— the large amount of new renewable capacity that is expected to enter the market in 2018-19
— possibly the change in operation of Wivenhoe.

Trade weighted base contract prices for 2018-19 are on average 5 per cent higher than 2017-18. The higher base contract prices reflect the market's expectation that the underlying price will remain elevated during 2018-19 due to the coal supply constraints in NSW.

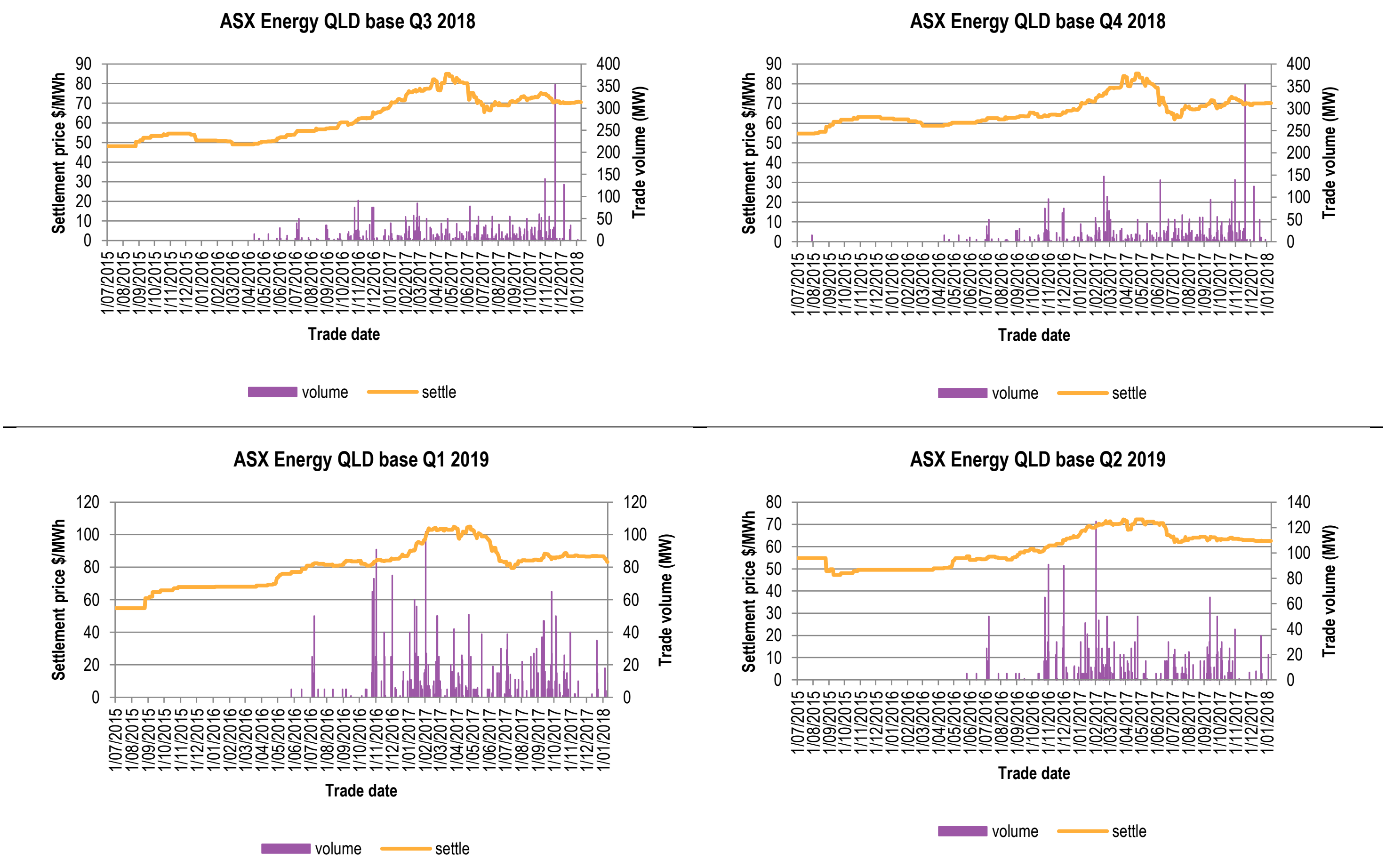
The following charts show daily settlement prices and trade volumes for ASX Energy quarterly base futures, peak futures and cap contracts up to 10 January 2018.

Base futures have traded strongly, with total volumes of 4,573 MW (Q3 2018), 5,034 MW (Q4 2018), 2,770 MW (Q1 2019), and 2,392 MW (Q2 2019).

Peak futures have also traded strongly with 122 MW (Q3 2018), 122 MW (Q4 2018), 51 MW (Q1 2019) and 60 MW (Q2 2019).

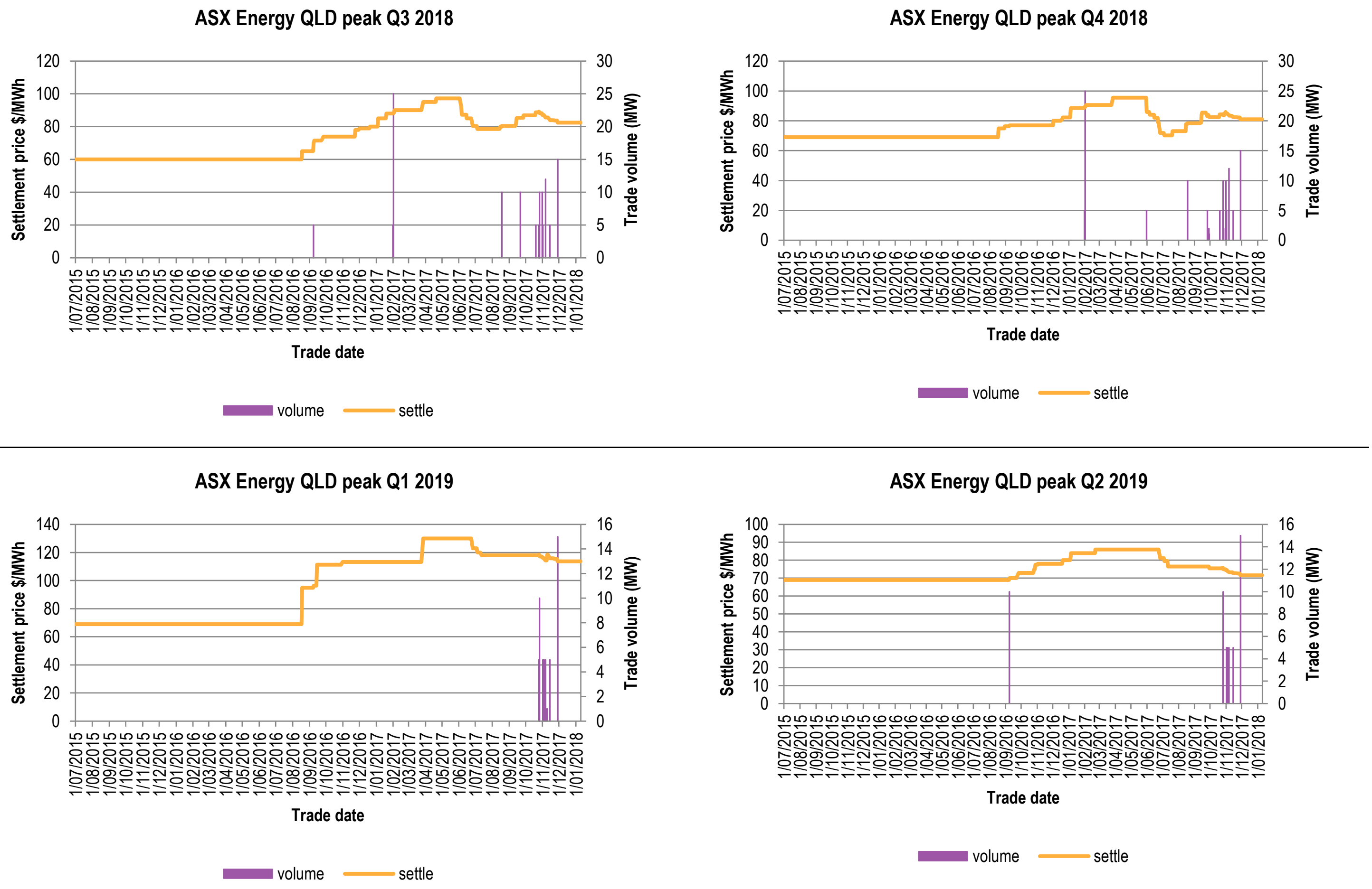
Cap contract trade volumes have also traded strongly with 983 MW (Q3 2018), 1,125 MW (Q4 2018), 730 MW (Q1 2019) and 582 MW (Q2 2019).

FIGURE 4.5 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY QUEENSLAND BASE FUTURES



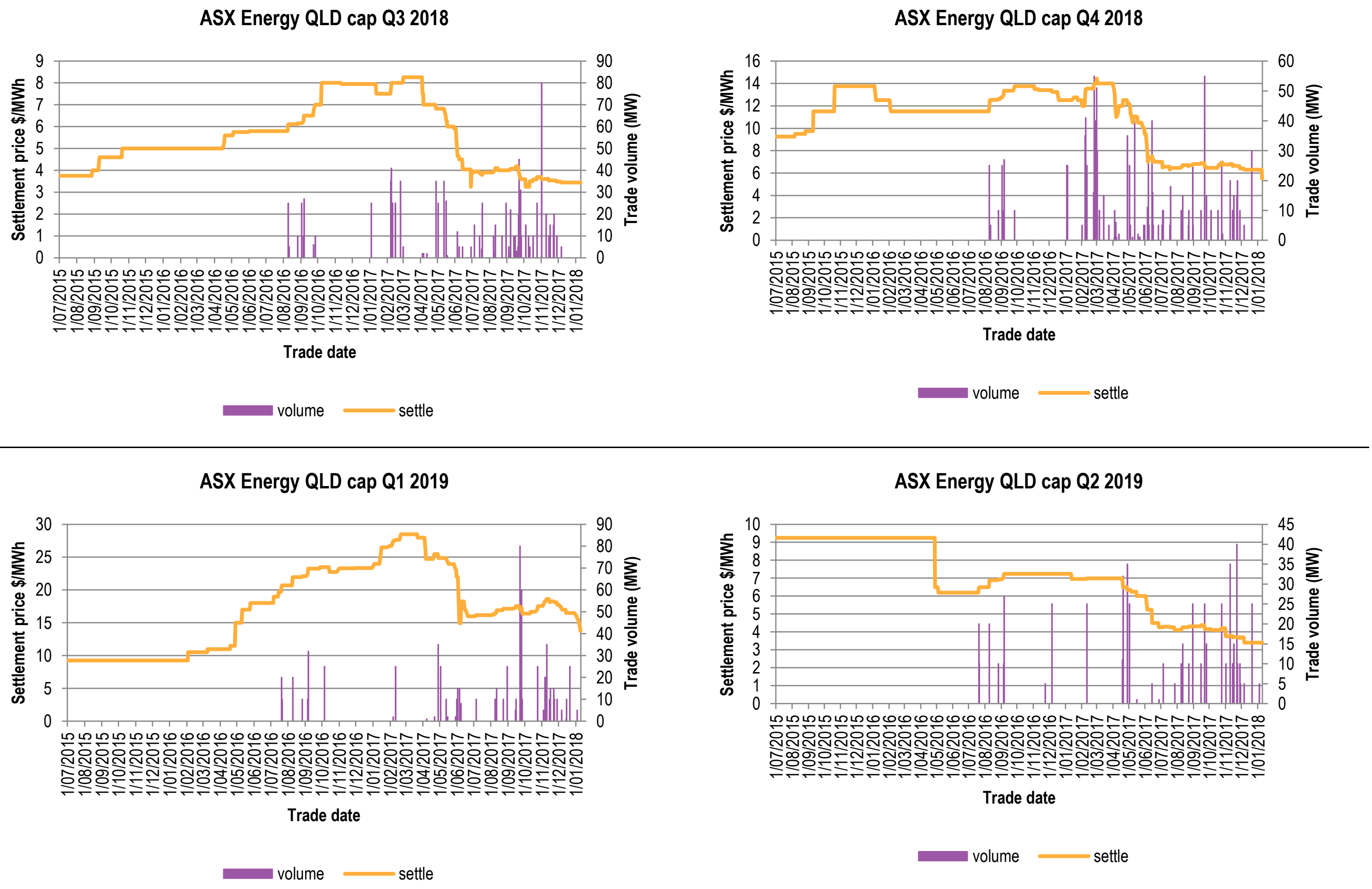
SOURCE: ASX ENERGY DATA UP TO 10 JANUARY 2018

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



SOURCE: ASX ENERGY DATA UP TO 10 JANUARY 2018

FIGURE 4.7 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY QUEENSLAND $300 CAP CONTRACTS



SOURCE: ASX ENERGY DATA UP TO 10 JANUARY 2018

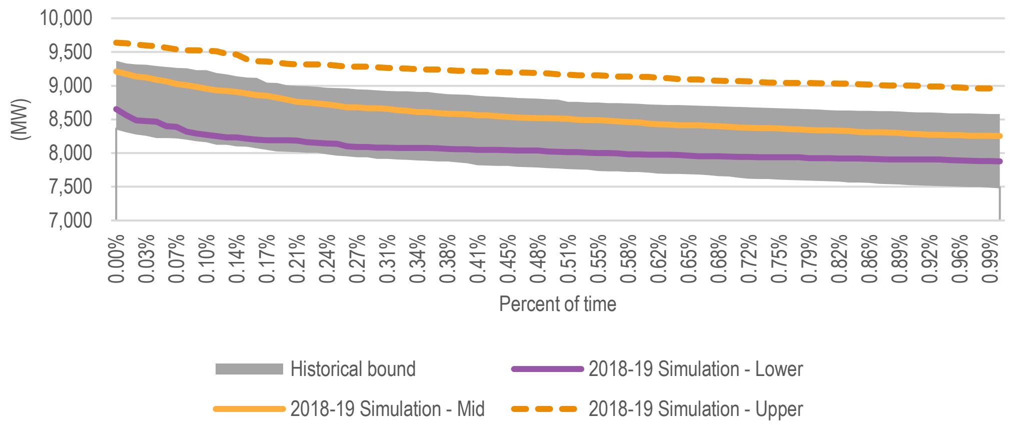
4.2.2 Estimating wholesale spot prices

ACIL Allen's proprietary electricity model, *PowerMark* was run to estimate the hourly pool prices for 2018-19 for the 517 simulations (47 demand and 11 outage sets).

Figure 4.8 shows the range of the upper one percent segment of the demand duration curves for the 47 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 47 simulated sets. It can be seen that the demand duration curves of the simulated demand sets for 2018-19 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[7]. This variation in demand contributes to the variation in modelled pool price outcomes as discussed further in this section.

[7] The simulated demand sets for 2018-19 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 4.8 TOP ONE PERCENT HOURLY DEMANDS – QUEENSLAND

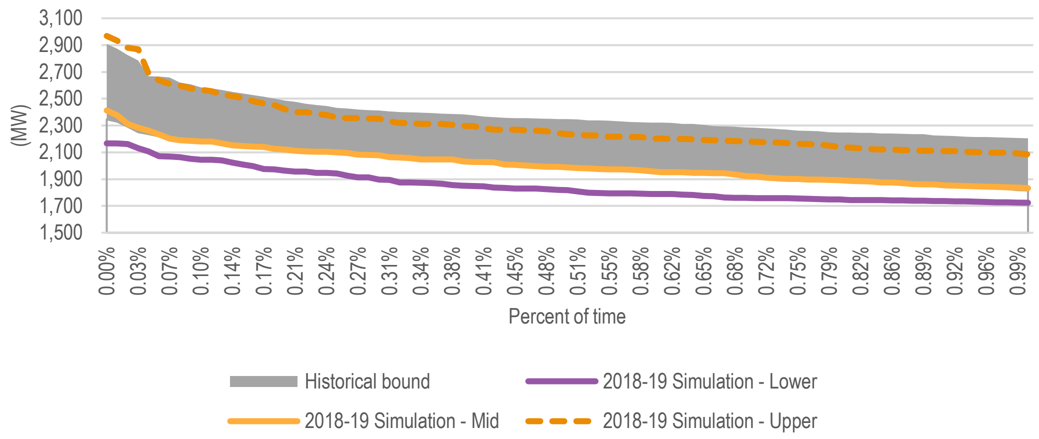


SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

Figure 4.9 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[8] of the 2018-19 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. 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 4.9 TOP ONE PERCENT HOURLY DEMANDS – ENERGEX NSLP



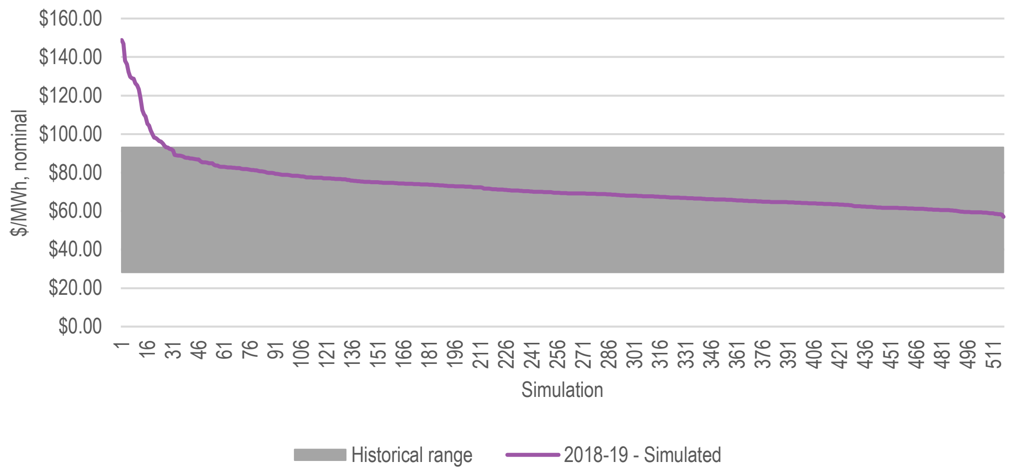
SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

[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.

The modelled annual time weighted pool prices (TWP) for Queensland in 2018-19 from the 517 simulations range from a low of $57.02/MWh to a high of $148.82/MWh. This compares with the lowest recorded Queensland TWP in the last 15 years of $28.12/MWh in 2005-06 to the highest of $93.13/MWh in 2016-17. The average TWP simulated for 2018-19 is $72.36/MWh – about 22 per cent less than 2016-17.

Figure 4.10 compares the modelled Queensland TWP for the 517 simulations for 2018-19 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 2018-19 when compared with the past 17 years of history. The lower part of the distribution of simulated outcomes sits above a number of the actual outcomes (particularly for the earlier years of the market), but by 2018-19 gas prices are projected to be around $11/GJ, compared with $3 - $4/GJ in previous 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. ACIL Allen is satisfied that in an aggregate sense the distribution of the 517 simulations for 2018-19 cover an adequately wide range of possible annual pool price outcomes.

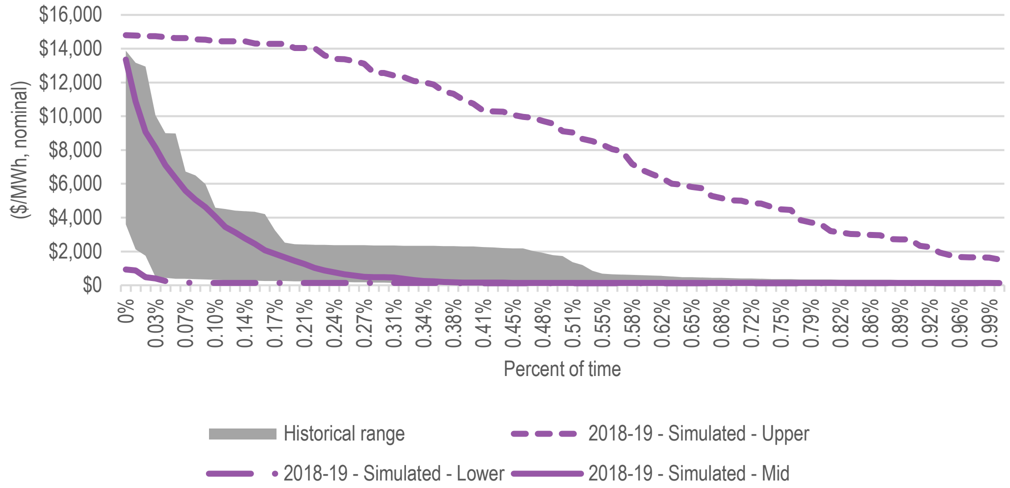
FIGURE 4.10 ANNUAL TWP FOR QUEENSLAND FOR 517 SIMULATIONS FOR 2018-19 COMPARED WITH ACTUAL ANNUAL OUTCOMES IN PAST YEARS



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

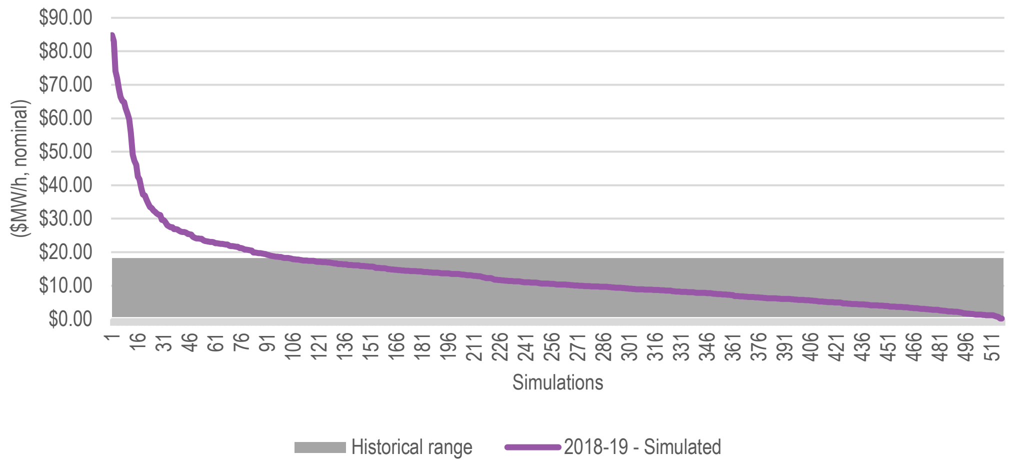
FIGURE 4.11 COMPARISON OF UPPER 1 PERCENT TAIL OF SIMULATED HOURLY PRICE DURATION CURVES FOR QUEENSLAND AND HISTORICAL OUTCOMES



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 517 simulations. The range in annual average contribution to the TWP, of hourly prices above $300/MWh, for the 517 simulations is consistent with those recorded in history as shown in Figure 4.12.

FIGURE 4.12 ANNUAL AVERAGE CONTRIBUTION TO THE QUEENSLAND TWP BY PRICES ABOVE $300/MWH FOR QUEENSLAND IN 2018-19 FOR 517 SIMULATIONS COMPARED WITH ACTUAL OUTCOMES IN PAST YEARS



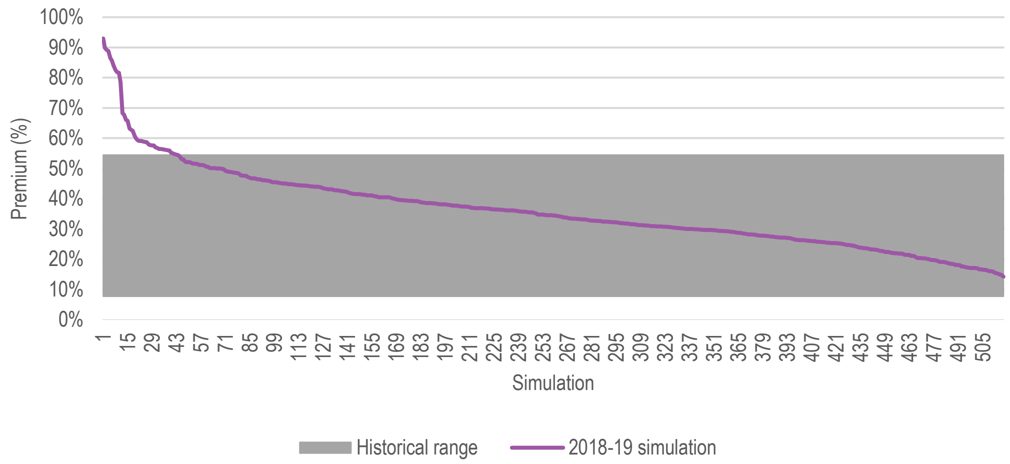
SOURCE: AEMO HISTORIC POOL PRICE DATA AND ACIL ALLEN RESULTS FROM POWERMARK MODELLING

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 4.13 shows that, for the past seven 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 to a high of 54 percent in 2014-15. In the 517 simulations for 2018-19, this percentage varies from 14 percent to 93 percent.

The comparison with actual outcomes over the past seven years in Figure 4.13 demonstrates that the relationship between the Energex NSLP demand and Queensland pool prices in the 517 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 2018-19. It also provides a sound cross check on the shape of the NSLP demand and its relationship with the Queensland demand.

FIGURE 4.13 ANNUAL DWP FOR ENERGEX NSLP AS PERCENTAGE PREMIUM OF ANNUAL TWP FOR QUEENSLAND FOR 517 SIMULATIONS FOR 2018-19 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 517simulations cover the range of expected price outcomes for 2018-19 in terms of annual averages and distributions. These comparisons clearly show that the 47 simulated demand traces combined with the 11 plant outage scenarios provide a sound basis for modelling the expected future spot market outcomes for 2018-19.

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 continue to be 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 47 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 47 demand sets minus the base contract volumes for the quarter.

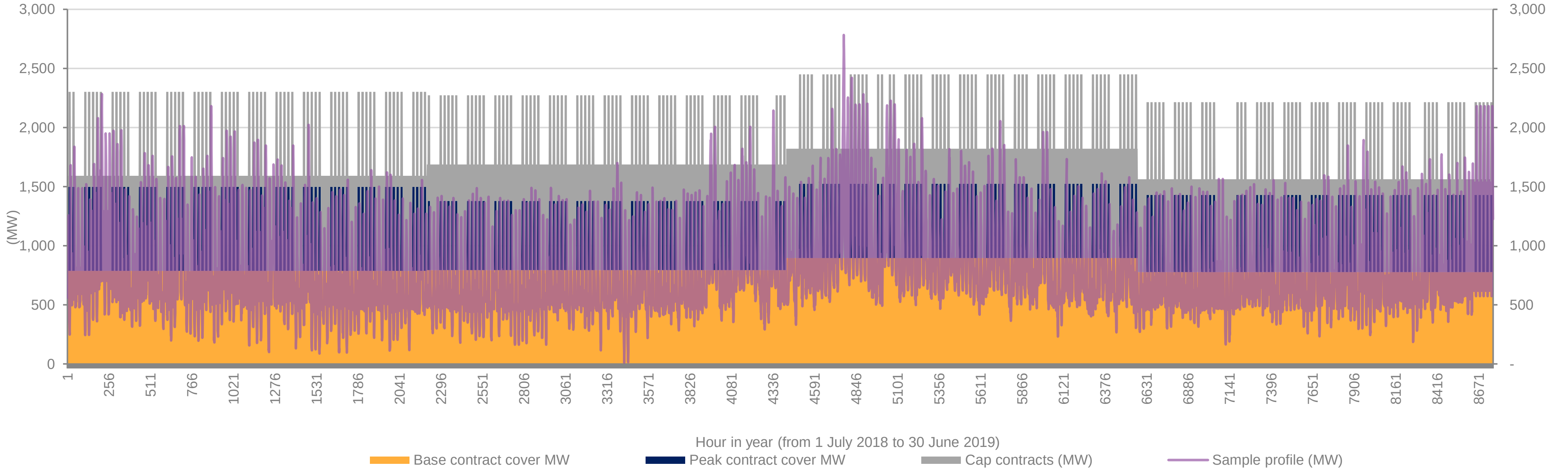
— The cap contract volume is set at 105 per cent of the median of the annual peak demands across the 47 demand sets minus the base and peak contract volumes.

In other words, the same hourly hedge volumes (in MW terms) apply to each of the 47 demand sets for a given settlement class, and hence to each of the 517 simulations. To be clear, we are not altering the hedge volume (in MW terms) on an ex-post basis for each of the 47 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 517 simulations when calculating the wholesale energy cost. The contract volumes used are shown in Figure 4.14.

For the 2018-19 Draft Determination, ACIL Allen recommends reducing slightly the base contract volume to 70th percentile of the off-peak hourly demands. The reason for this is that as more rooftop PV is installed, the Energex NSLP continues to be carved out during daylight hours, whereas the 80th percentile has remained reasonably constant. This means that continuing to use the 80th percentile will result in substantial over contracting during daylight hours. For example, in Figure 4.14, using the 80th percentile would result in base contract cover levels of about 1,000 MW which sits well above the majority of the load profile during the day.

FIGURE 4.14 CONTRACT VOLUMES USED IN HEDGE MODELLING OF 517 SIMULATIONS FOR 2018-19 FOR ENERGEX NSLP

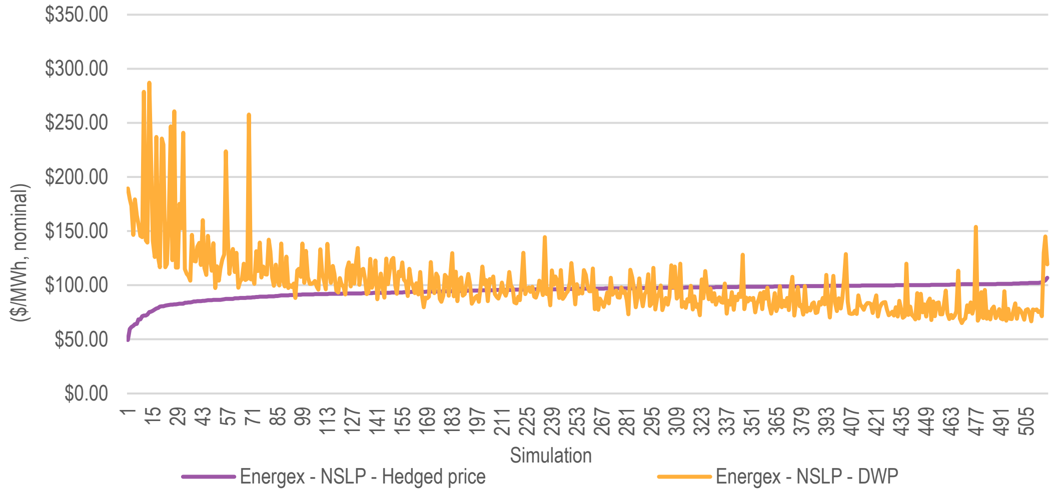


SOURCE: ACIL ALLEN

As hedge benefits are inversely related to pool prices, simulations with higher demand-weighted pool prices usually produce lower hedged prices. Figure 4.15 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 4.15 ANNUAL HEDGED PRICE AND DWP ($/MWH, NOMINAL) FOR ENERGEX NSLP FOR THE 517 SIMULATIONS – 2018-19



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 517 annual hedged prices. ACIL Allen's estimate of the WEC for each tariff class for the 2018-19 Draft Determination are shown in Table 4.2.

TABLE 4.2 ESTIMATED WEC ($/MWH, NOMINAL) FOR 2018-19 AT THE QUEENSLAND REFERENCE NODE

Settlement classes	2018-19 – Draft Determination	2017-18 – Final Determination	Change from 2017-18 to 2018-19 (%)
Energex - NSLP - residential and small business	$101.22	$103.11	-1.83%
Energex - Controlled load tariff 9000 (31)	$61.46	$56.76	8.28%
Energex - Controlled load tariff 9100 (33)	$79.17	$75.38	5.03%
Energex - NSLP - unmetered supply	$101.22	$103.11	-1.83%
Ergon Energy - NSLP - CAC and ICC	$89.64	$92.75	-3.35%
Ergon Energy - NSLP - SAC demand and street lighting	$89.64	$92.75	-3.35%

SOURCE: ACIL ALLEN ANALYSIS

Compared with the 2017-18 Final Determination, the estimated WEC for 2018-19 for the NSLPs has decreased by about $2-3/MWh, and the control load tariffs have increased by about $4-5/MWh.

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 5,000 MW of utility scale solar and wind capacity in the NEM, with around 1,800 MW of this new capacity committed to enter the Queensland market. The projected decrease in price volatility is also due to the Queensland Government's directive to Stanwell in June 2017 to adjust their bidding behaviour in order to put downward pressure on wholesale prices.

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.

Section **4.2.1** shows that baseload contract prices have increased slightly between 2017-18 and 2018-19. Hence, given that the control loads tend to be weighted more towards the off-peak periods, it seems reasonable that their respective WECs have increased slightly.

4.2.5 Comparison with AEMC price trends report

In December 2017 the Australian Energy Market Commission (AEMC) released its report *Residential Electricity Price Trends*. The report explores trends in the cost components of the electricity supply chain that contribute to the overall price paid by residential consumers over the period from 2016-17 to 2019-20.

The AEMC report suggests that between 2017-18 and 2018-19 wholesale electricity costs will decrease by 15.7 per cent for Queensland households. This is noticeably a larger decrease than that presented above in Table 4.2 based on the hedging approach. As a direct point of comparison, ACIL Allen's projected DWP for the Energex NSLP for 2018-19 (assuming no hedging) is about 12 per cent below our DWP estimate for 2017-18.

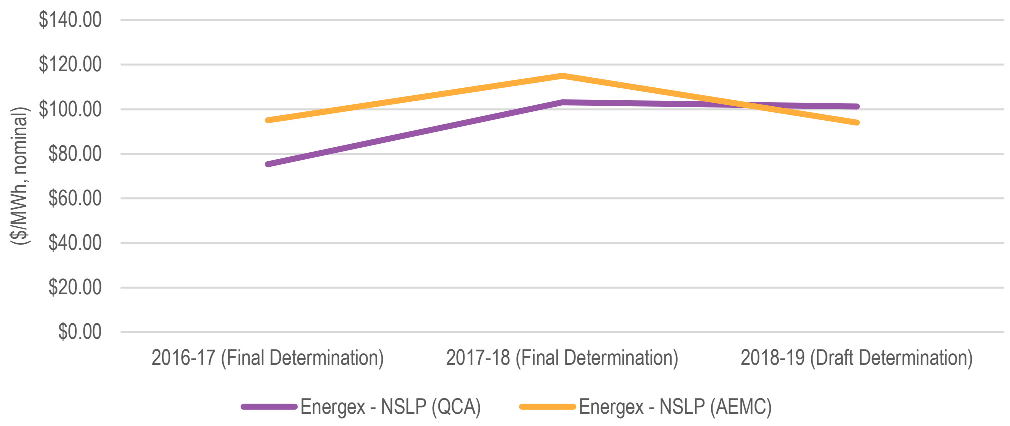
The AEMC approach appears to take modelled spot prices for 2018-19 and apply a five per cent premium to the projected spot prices to estimate the contact prices and uses an undefined hedging strategy to estimate the WEC. In other words, the AEMC approach does not contemplate a prudent hedging strategy in which retailers build up a portfolio of hedges over a period of time ahead of 2018-19.

In effect, the AEMC approach assumes retailers do not actively trade in the futures market or hedge their retail load in advance.

Section **4.2.1** shows that although there has been a reasonable decline in contract prices for 2018-19, the traded volume weighted average has not declined by the same extent. Contracts that were procured earlier were done so at higher prices for 2018-19 because at that time the market expected 2018-19 to have higher prices. This information is not taken into account in the AEMC approach.

Although it may be appealing to change approach and use the projected spot prices (with some premium) to estimate the contract prices rather than the ASX Energy trade volume weighted contract prices for 2018-19, and thus have a lower estimate of the WEC, the risk is that in other years this approach may result in a higher WEC. Figure 4.16 shows a comparison of the estimated WECs from the two approaches. Using the AEMC's approach would have resulted in much higher WECs in the 2016-17 and 2017-18 determinations. Further, the 15.7 per cent decline in WEC projected by the AEMC for 2018-19 is off the much higher based WEC in 2017-18.

FIGURE 4.16 COMPARISON OF ESTIMATED WEC ($/MWH, NOMINAL) FOR ENERGEX NSLP



SOURCE: ACIL ALLEN ANALYSIS AND AEMC

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] and TFS[11]
— Mandated LRET targets for 2018 and 2019 of 28,637 GWh and 31,244 GWh, respectively
— Estimated RPP values for 2018 and 2019 of 15.81 per cent and 16.9 per cent, respectively[12]
— Non-binding STP values for 2018 and 2019 of 8.06 per cent and 7.52 per cent, respectively[13]
— CER clearing house price for 2018 and 2019 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.

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 29 September 2016, after which the data ceased to be published
11 TFS data includes prices up to and including 10 January 2018.
12 2018 and 2019 RPP values were estimated using liable electricity acquisitions implied in the non-binding STP values for 2018 and 2019, as published by CER.
13 The non-binding 2018 and 2019 STP estimates are based on the modelling prepared for CER for the 2017 STP, as published by CER.

ACIL Allen has estimated the average LGC price using forward looking weekly market prices for LGCs published by the Australian Financial Markets Association (AFMA) up until September 2016 [14] and LGC forward prices provided by broker TFS from October 2016 to January 2018. In September 2016, AFMA ceased publishing LGC prices due to inadequate contributions by survey participants. TFS data has been used for the period after the AFMA data ceased. We have examined LGC forward prices prior to September 2016, and are satisfied that they are consistent with the AFMA prices.

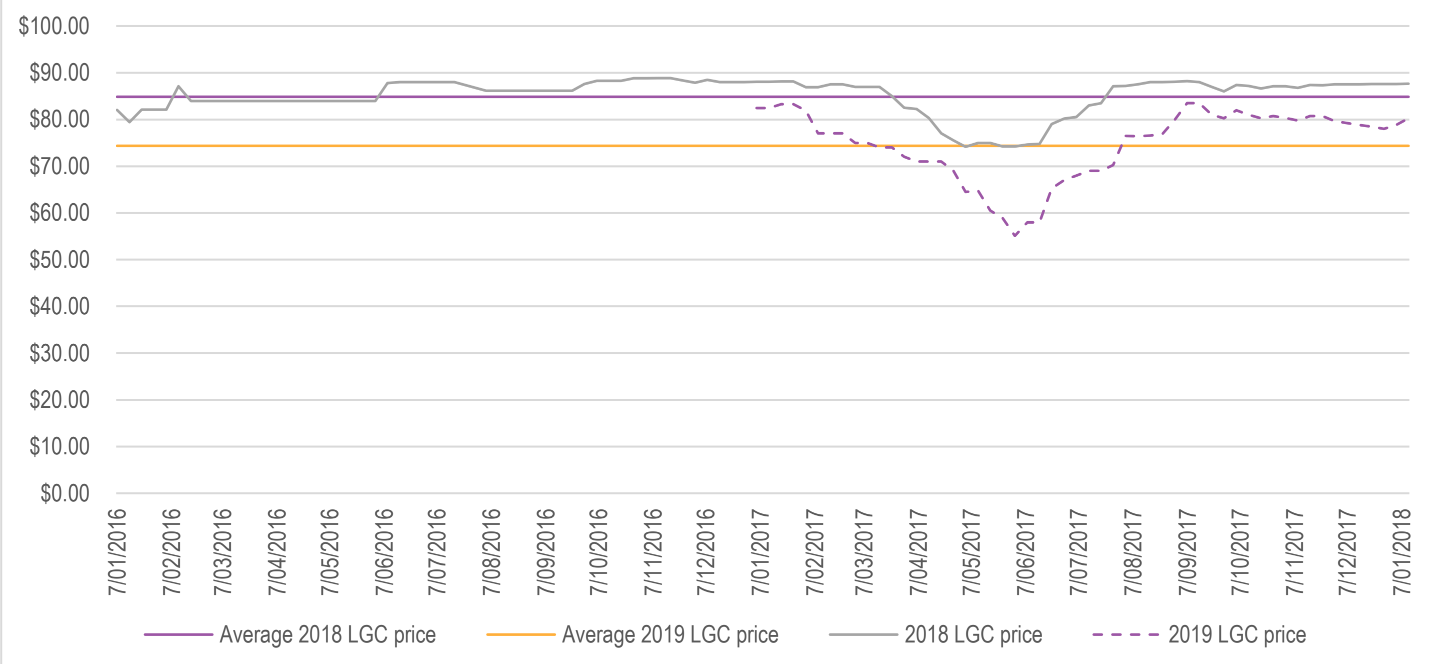
The LGC price used in assessing the cost of the scheme for 2018-19 is found by averaging the forward prices for the 2018 and 2019 calendar years, during the two years prior to the commencement of 2018 and 2019. This assumes that LGC coverage is built up over a two year period (see Figure 4.17). The average LGC prices calculated from the AFMA and TFS data are $84.85/MWh for 2018 and $74.36/MWh for 2019**.** Since the 2017-18 Final Determination, LGC forward prices have softened slightly due to:

— A number of renewable projects reaching financial close in recent months with most of the projects expected to be commissioned during 2018

— The mix of near-term renewable projects skewed more towards solar than wind, with solar having a shorter lead time to commissioning

Notably the 2019 average LGC price is lower than the 2018 average LGC price, reflecting the increased likelihood that the LRET scheme will be fully subscribed by 2020.

FIGURE 4.17 LGC PRICES FOR 2018 AND 2019 ($/LGC, NOMINAL)



SOURCE: AFMA, TFS AND ACIL ALLEN ANALYSIS

The 2018 and 2019 RPP values of 15.81 per cent and 16.91 per cent, respectively, were estimated using the mandated targets for 2018 and 2019 and the total estimated electricity consumption implied in the non-binding STP values for 2018 and 2019.

Key elements of the 2018 and 2019 RPP estimation are shown in Table 4.3.

[14] 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.

TABLE 4.3 ESTIMATING THE 2018 AND 2019 RPP VALUES

	2018	2019
Non-binding STP (CER)	8.06%	7.52%
Projected STCs (CER)	14,600,000	13,900,000
Implied total estimated electricity consumption	181,141,439	184,840,426
LRET target	28,637,000	31,244,000
Estimated RPP using implied total estimated electricity consumption	15.81%	16.90%

[a] Implied total estimated electricity consumption is 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 2018 and 2019 by multiplying the RPP values for 2018 and 2019 by the average LGC prices for 2018 and 2019, respectively. The cost of complying with the LRET in 2018-19 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be $12.99/MWh in 2018-19 as shown in Table 4.4

TABLE 4.4 ESTIMATED COST OF LRET – 2018-19

	2018	2019	Cost of LRET 2018-19
RPP %	15.81%	16.90%	
Average LGC price ($/LGC, nominal)	$84.85	$74.36	
Cost of LRET ($/MWh, nominal)	$13.41	$12.57	$12.99

SOURCE: CER, AFMA, ACIL ALLEN ANALYSIS

4.3.2 SRES

The cost of the SRES for calendar years 2018 and 2019 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 2018-19.

The STPs published by CER are as follows:

— Non-binding 2018 and 2019 STP values of 8.06 per cent and 7.52 per cent, respectively

ACIL Allen estimates the cost of complying with SRES to be $3.12/MWh in 2018-19 as set out in Table 4.5Table 4.5.

TABLE 4.5 ESTIMATED COST OF SRES – 2018-19

	2018	2019	Cost of SRES 2018-19
STP %	8.06%	7.52%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of SRES ($/MWh, nominal)	$3.22	$3.01	$3.12

SOURCE: CER, 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 2017-18.

TABLE 4.6 TOTAL RENEWABLE ENERGY POLICY COSTS ($/MWH) –DRAFT DETERMINATION 2018-19 AND FINAL DETERMINATION 2017-18

	Draft Determination 2018-19	Final Determination 2017-18
LRET	$12.99	$11.97
SRES	$3.12	$3.01
Total	$16.11	$14.98

SOURCE: ACIL ALLEN ANALYSIS

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.

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)[15].

Based on projected fees in AEMO's *Electricity Final Budget & Fees 2017-18*, the total fee for 2018-19 is $0.53/MWh. The breakdown of total fees is shown in Table 4.7.

TABLE 4.7 NEM MANAGEMENT FEE ($/MWH) – 2018-19

Cost category	Fees ($/MWh)
NEM fees (admin, registration, etc.)	$0.41
FRC - electricity	$0.072
NTP - electricity	$0.024
ECA - electricity	$0.027
Total NEM management fees	**$0.53**

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA, AER STATE OF THE ENERGY MARKET 2017

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 2018-19, the cost of ancillary services is estimated to be $0.42/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:

[15] ECA requirements are measured in terms of connection points for small customers. It is not clear in AEMO's *Electricity Final Budget and Fees 2017-18* 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.

- 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 $10,493.

TABLE 4.8 AEMO PRUDENTIAL COSTS FOR ENERGEX NSLP – 2018-19

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price	$121.59	$100.77	$68.54
Participant Risk Adjustment Factor	1.5192	1.5867	1.2881
OS Volatility factor	1.83	1.31	1.52
PM Volatility factor	4.27	1.93	2.70
OSL	$13,014	$8,064	$5,167
PML	$2,603	$1,613	$1,033
MCL	$15,617	$9,677	$6,200
Average MCL		$10,493	

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 $10,493/42 = $249.84/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 $249.84 gives $0.72/MWh.

For the 2018-19 determination, the QCA instructed ACIL Allen to calculate the prudential costs for the Ergon NSLP, the components of which are shown in Table 4.9. The estimated AEMO prudential costs for the Ergon NSLP are $0.49/MWh.

TABLE 4.9 AEMO PRUDENTIAL COSTS FOR ERGON NSLP – 2018-19

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price	$106.09	$87.06	$63.68
Participant Risk Adjustment Factor	1.1566	1.1843	1.1118
OS Volatility factor	1.83	1.31	1.52
PM Volatility factor	4.27	1.93	2.70

Factor	Summer	Winter	Shoulder
Loss Factor	1.014	1.014	1.014
OSL	$8,646	$5,200	$4,143
PML	$1,729	$1,040	$829
MCL	$10,375	$6,240	$4,972
Average MCL		$7,190	

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 13 percent on average for a base contract, 25 percent for a peak contract and 24 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.

In previous years ACIL Allen used baseload contracts as proxies for hedge prudential costs. We have refined the methodology this year 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.

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[16] 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	$70.84	$35,000.00	$1.07
Peak	$89.53	$37,000.00	$2.64
Cap	$10.04	$12,000.00	$0.37

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

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

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	$1.07	0.7679	$0.82
Peak	$2.64	0.4641	$1.22
Cap	$0.37	1.0739	$0.39
Total cost		**$2.44**	

SOURCE: ACIL ALLEN 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	$1.07	1.0693	$1.15
Peak	$2.64	0.1688	$0.45
Cap	$0.37	0.5005	$0.18
Total cost		**$1.78**	

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.

TABLE 4.13 TOTAL PRUDENTIAL COSTS ($/MWH) - 2018-19

Cost category	Energex NSLP	Ergon NSLP
AEMO pool	$0.72	$0.49
Hedge	$2.44	$1.78
Total	**$3.16**	**$2.27**

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 2018-19 Draft Determination and is compared to the costs from the Final Determination for 2017-18.

TABLE 4.14 TOTAL OF OTHER COSTS ($/MWH) – DRAFT DETERMINATION 2018-19 AND FINAL DETERMINATION 2017-18

Cost category	Energex NSLP - Draft Determination 2018-19	Ergon NSLP - Draft Determination 2018-19	Final Determination 2017-18
NEM management fees	$0.53	$0.53	$0.53
Ancillary services	$0.42	$0.42	$0.34
Hedge and pool prudential costs	$3.16	$2.27	$2.53
Total	**$4.11**	**$3.22**	**$3.41**

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 results in a transmission loss factor of 1.008 for Energex and 0.985 for the Ergon Energy east zone. These estimates are based on AEMO's MLFs for 2017-18 weighted by the 2014-15 energy for the TNIs [17].

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 2017-18.

The estimation of transmission and distribution loss factors for the settlement classes to be used in calculating energy costs for the Draft Determination for 2018-19 is shown in Table 4.15.

TABLE 4.15 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	1.056	1.008	1.065
Energex - Control tariff 9000	1.056	1.008	1.065
Energex - Control tariff 9100	1.056	1.008	1.065
Ergon Energy - NSLP - SAC HV, CAC and ICC	1.030	0.985	1.014
Ergon Energy - NSLP - SAC demand and street lighting	1.096	0.985	1.079

SOURCE: ACIL ALLEN ANALYSIS BASED ON QUEENSLAND TNI ENERGY FOR 2014-15, MLFS FOR 2017-18AND ENERGEX AND ERGON ENERGY EAST ZONE DLFS FOR 2017-18 FROM AEMO

[17] Updated energy data for the TNIs will not be available for the calculation of loss factors for the 2017-18 Determination, due to a restriction by AEMO on the provision of this data.

For the Draft Determination for 2018-19 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[18], 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 2018-19 total energy costs (TEC) for the Draft Determination for each of the settlement classes are presented in Table 4.16.

TABLE 4.16 ESTIMATED TEC FOR 2018-19 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 ($/MWh)	Change from 2017-18 Final Determination ($/MWh)	Change from 2017-18 Final Determination (%)
Energex - NSLP - residential and small business	$101.22	$16.11	$4.11	1.065	$7.89	$129.33	-$0.06	-0.05%
Energex - Controlled load tariff 9000 (31)	$61.46	$16.11	$4.11	1.065	$5.31	$86.99	$6.97	8.71%
Energex - Controlled load tariff 9100 (33)	$79.17	$16.11	$4.11	1.065	$6.46	$105.85	$6.00	6.01%
Energex - NSLP - unmetered supply	$101.22	$16.11	$3.22	1.065	$7.89	$129.33	-$0.06	-0.05%
Ergon Energy - NSLP - CAC and ICC	$89.64	$16.11	$3.22	1.014	$1.53	$110.50	-$2.19	-1.94%
Ergon Energy - NSLP - SAC demand and street lighting	$89.64	$16.11	$3.22	1.079	$8.61	$117.58	-$2.33	-1.94%

SOURCE: ACIL ALLEN ANALYSIS

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

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