ACIL ALLEN CONSULTING

REPORT TO
AUSTRALIAN ENERGY REGULATOR

5 FEBRUARY 2020

DEFAULT MARKET OFFER

ESTIMATING WHOLESALE ENERGY AND ENVIRONMENTAL COSTS

PHASE 2: APPLICATION OF METHODOLOGY FOR 2020-21 DRAFT DETERMINATION

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EXECUTIVE SUMMARY

ACIL Allen Consulting (ACIL Allen) has been engaged by the Australian Energy Regulator (AER) to support the AER in estimating specific cost inputs required for the determination of Default Market Offer (DMO) prices. Specifically, ACIL Allen is required to provide consultancy services to the AER to estimate the underlying wholesale and environmental cost inputs to inform the determination for 2020-21. These estimates are to be based on the relevant cost drivers for a retailer supplying electricity to residential and small business customers in non-price regulated jurisdictions (excluding Victoria).

This report relates to Phase 2 of our engagement, and provides estimates of the wholesale energy, environmental, and other costs for use by the AER in its Draft Determination, using the methodology proposed in our Phase 1 methodology report.

In addition, we are required to estimate the same cost components for 2019-20, retrospectively, using the same methodology.

Methodology

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, Reliability and Emergency Reserve Trader (RERT) costs, and costs of meeting prudential requirements

— energy losses incurred during the transmission and distribution of electricity to customers.

The ACIL Allen methodology estimates costs from a retailing perspective. This includes running wholesale energy market simulations to estimate expected spot market costs and volatility, and the hedging of the spot market price risk by entering into hedging contracts with prices represented by the observable futures market data. Environmental and other energy costs are added to the wholesale energy costs and the total is then adjusted for network losses.

Wholesale energy costs - market-based approach

Energy purchase costs are incurred by a retailer when purchasing energy from the NEM spot market to satisfy their retail load. However, given the volatile nature of wholesale electricity spot prices, which is an important and fundamental feature of an energy-only market (i.e. a market without a separate capacity mechanism), and that retailers charge their customers based on fixed rate tariffs (for a given period), a prudent retailer is incentivised to hedge its exposure to the spot market.

Hedging can be achieved by a number of means – a retailer can own or underwrite a portfolio of generators (the gen-tailer model), enter into bilateral contracts directly with generators, purchase over the counter (OTC) contracts via a broker, or take positions on the futures market.

The market-based approach adopted for estimating the WEC makes use of financial derivative data to estimate contract prices, given that it is readily available and transparent.

The WEC for a given year is therefore generally a function of four components:

1. load profile
2. wholesale electricity spot prices
3. forward contract prices
4. contracting strategy.

Key steps

The key steps to estimating the WEC for a given load and year are:

1. Use a stochastic demand and renewable energy resource model to develop 49 weather influenced annual simulations of hourly demand (system and customer load) and renewable energy resource traces.
2. Use a stochastic availability model to develop 11 annual simulations of hourly thermal power station availability.
3. Forecast hourly wholesale electricity spot prices to produce 539 (i.e. 49 by 11) simulations of hourly spot prices of the NEM using the stochastic demand and renewable energy resource traces and power station availabilities as inputs.
4. Estimate the forward contract price using ASX Energy contract price data, verified with broker data.
5. Adopt an assumed contracting strategy – the contracting strategy represents a strategy that a retailer would undertake to hedge against risk in the spot price in a given year. It is generally assumed that a retailer's risk management strategy would result in contracts being entered into progressively over a two- to three-year period, resulting in a mix (or portfolio) of base (or flat), peak and cap contracts.
6. Calculate the spot and hedging cost for each hour and aggregate for each of the 539 simulations – for a given simulation, for each hour calculate the spot purchase cost, contract purchase costs (adopting a fixed strategy from step 5), and different payments, and then aggregate to get an annual cost which is divided by the annual load to get a price in $/MWh terms.

The distribution of outcomes produced by the above approach is then analysed to provide a risk assessed estimate of the WEC. ACIL Allen adopts the 95th percentile WEC from the distribution of WECs as the final estimate. Choosing the 95th percentile reduces the risk of understating the true WEC, since only five per cent of WEC estimates exceed this value.

Environmental costs

Energy costs associated with the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES) have been estimated using price information from brokers, information published by the Clean Energy Regulator (CER) and modelling by ACIL Allen. ACIL Allen has estimated the average LGC price using LGC forward prices provided by broker TFS.

Energy costs associated with the NSW Energy Savings Scheme (ESS) have been estimated using price information from brokers and information published by the Independent Pricing and Regulatory Tribunal (IPART).

Retailer compliance with these schemes operates on a calendar year basis and hence estimates are required for 2019, 2020 and 2021 calendar years, with the costs averaged to estimate the 2019-20 and 2020-21 financial year costs.

Energy costs associated with the South Australian Retailer Energy Efficiency Scheme (REES) has been estimated using costs published in the AEMC's Pricing Trends Report, in the absence of publicly available cost data on the scheme.

Other costs

Other energy costs associated with participating in the NEM include NEM management fees, ancillary services charges, prudential costs and the Reliability and Emergency Reserve Trader. These costs have been estimated using data published by the market operator, AEMO.

Results

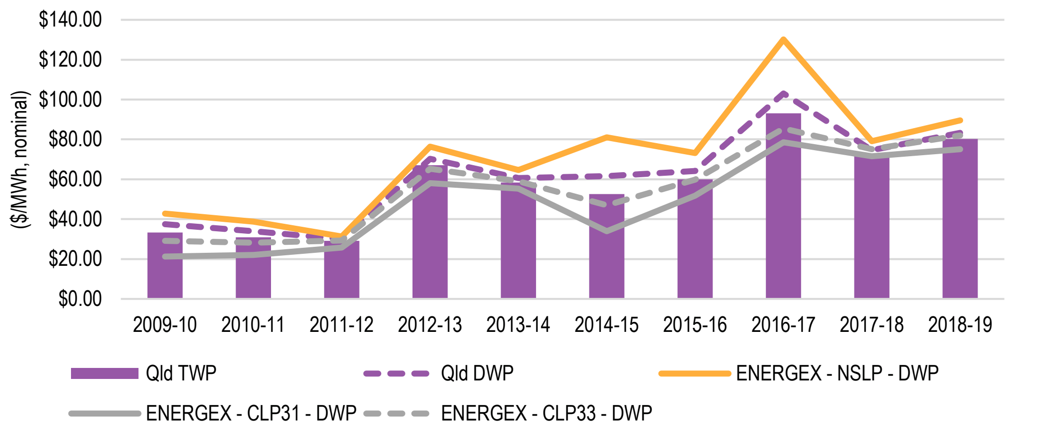
Wholesale energy costs

Over the past few years, the Queensland and South Australian NSLP load profiles, and to some degree, the New South Wales NSLPs, 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 and consequently, the demand weighted spot prices (DWP) for the NSLP load profiles have increased relative to the corresponding regional time weighted average spot price (TWP) as shown in **Figure ES 1** to **Figure ES 3**. Although the increased penetration of rooftop PV is placing some downward pressure wholesale spot prices during daylight hours, price volatility during the evening peak has persisted. The carving out of the NSLP during daylight hours increases the relative weighting of the load profile during the higher priced evening peak and reduces the relative weighting during the lower priced daylight hours.

As expected, the DWPs for the CLPs are below the DWP for the NSLPs in each year. Although the rank order in prices by profile within each region 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 across all three regions resulted in the profiles having relatively similar wholesale spot prices (within their respective region). Conversely, in 2016-17, the increased price volatility across the afternoon period resulted in the NSLP DWPs diverging away from the CLP DWPs.

It is also worth noting that it has only been for four of the past 10 years that the CLPs have noticeably lower DWPs when compared with the NSLPs. ACIL Allen raises this point as it is often noted that the WECs for the control loads are no longer substantially lower than those of the NSLPs.

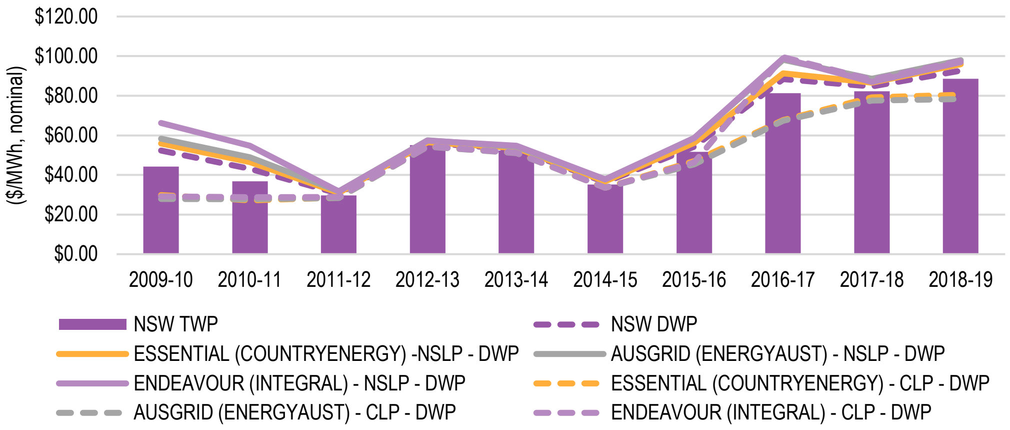
FIGURE ES 1 ACTUAL ANNUAL AVERAGE DEMAND WEIGHTED SPOT PRICE ($/MWH, NOMINAL) BY PROFILE AND QUEENSLAND TIME WEIGHTED AVERAGE SPOT PRICE ($/MWH, NOMINAL) – 2009-10 TO 2018-19



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

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

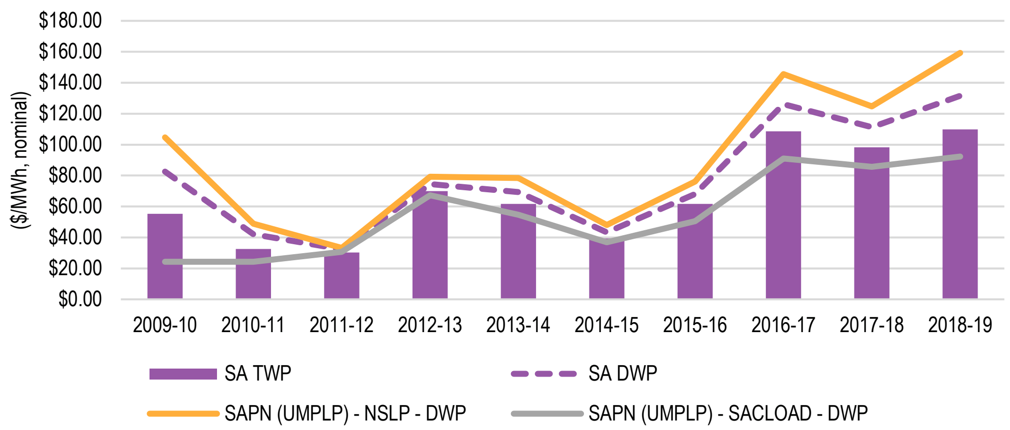
FIGURE ES 2 ACTUAL ANNUAL AVERAGE DEMAND WEIGHTED SPOT PRICE ($/MWH, NOMINAL) BY PROFILE AND NEW SOUTH WALES TIME WEIGHTED AVERAGE SPOT PRICE ($/MWH, NOMINAL) – 2009-10 TO 2018-19



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

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

FIGURE ES 3 ACTUAL ANNUAL AVERAGE DEMAND WEIGHTED SPOT PRICE ($/MWH, NOMINAL) BY PROFILE AND SOUTH AUSTRALIA TIME WEIGHTED AVERAGE SPOT PRICE ($/MWH, NOMINAL) – 2009-10 TO 2018-19



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

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

The market is clearly expecting some softening in price outcomes due to the strong increase in renewable investment coming on-line between 2019-20 and 2020-21 – with annualised base contract prices decreasing in all three regions. About 5,200 MW of renewable investment will enter the NEM over the next 18 months. Interestingly, cap prices, on a trade weighted basis have decreased marginally on an annual basis between 2019-20 and 2020-21 – suggesting that overall the market is not expecting the 5,200 MW of additional renewable capacity to increase price volatility.

FIGURE ES 4 BASE, PEAK AND CAP CONTRACT PRICES ($/MWH, NOMINAL) – 2019-20 AND 2020-21

SOURCE: ACIL ALLEN ANALYSIS OF ASX ENERGY DATA UP TO 6 JANUARY 2020

ACIL Allen's estimate of the WEC for each profile for 2019-20 and 2020-21 is shown in **Table ES 1**.

TABLE ES 1 ESTIMATED WEC ($/MWH, NOMINAL) FOR 2019-20 AND 2020-21 AT THE REGIONAL REFERENCE NODE

Settlement classes	2019-20	2020-21	Change from 2019-20 to 2020-21 (%)
Ausgrid – NSLP	$102.99	$104.12	1.10%
Endeavour – NSLP	$99.94	$104.05	4.11%
Essential – NSLP	$94.69	$96.90	2.33%
Ausgrid - CLP1	$76.74	$67.98	-11.42%
Ausgrid - CLP2	$72.46	$66.31	-8.48%
Endeavour – CLP	$90.44	$96.51	6.71%
Essential – CLP	$87.08	$82.63	-5.11%
Energex – NSLP	$89.16	$85.21	-4.43%
Energex - CLP1	$64.91	$65.93	1.57%
Energex - CLP2	$72.85	$67.47	-7.39%
SAPN – NSLP	$141.39	$135.53	-4.14%
SAPN – CLP	$92.23	$81.40	-11.74%

SOURCE: ACIL ALLEN ANALYSIS

The WECs for the New South Wales NSLPs increase slightly between 2019-20 and 2020-21. This is despite a marginal decrease overall in the contract prices between these two years. However, contract prices in quarter one and four (the summer quarters) increase slightly – and it is these quarters that tend to display the great level of volatility in terms of demand and spot price outcomes. Further, the projected continued uptake of rooftop PV installations for customers in these networks is resulting in the profiles becoming sufficiently peakier so as to increase the cost of hedging the NSLP profiles (all other things equal). Further, the WEC for the Endeavour NSLP increases at a slightly higher rate than the Ausgrid and Essential NSLPs. Historical data shows the time of day shape of the Endeavour NSLP tends to exhibit a higher degree of volatility which will be influencing the projected estimates.

The WECs for the NSLPs in Queensland and South Australia decline between 2019-20 and 2020-21 as a result of stronger declines in contract prices (compared with New South Wales) and less change in the demand profiles since the penetration of rooftop PV is much greater already in these two regions compared with New South Wales.

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.

The change in WEC for the CLPs is a mixed result – with some increasing and others decreasing between 2019-20 and 2020-21. The change in WEC of the CLPs is reflecting the change in shape of the load profiles. For example, the Endeavour CLP WEC increases by about seven per cent between 2019-20 and 2020-21 – this is largely a result of the change in its shape as discussed earlier. It is worth noting that it is the distribution network service providers more than consumer behaviour that control the shape of the CLPs.

Environmental costs

LRET

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 and 2020-21 is found by averaging the forward prices for the 2019, 2020 and 2021 calendar years, respectively during the two years prior to the commencement of the compliance years. 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 and 2020
  - The surge in investment in renewables have been driven by falling costs of renewables, demand for PPAs from corporates and increased appetite of renewable investors to take on merchant exposure.
- The significantly lower average price for 2020 reflects the high likelihood that the LRET scheme will be fully subscribed by 2020.Although this reduction has been tempered since around August 2019 due to delays in committed renewable projects reflecting current difficulties experienced by developers in obtaining grid connection.

ACIL Allen estimates the cost of complying with the LRET scheme to be $9.38/MWh in 2019-20 and $4.56/MWh in 2020-21.

SRES

The cost of the SRES is calculated by applying the estimated STP value to the STC price in each compliance (calendar year). The average of these calendar year costs is then used to obtain the estimated costs for 2019-20 and 2020-21.

ACIL Allen estimates the cost of complying with SRES to be $7.26/MWh in 2019-20, and $9.72/MWh in 2020-21. The estimate for 2020-21 accounts for an uplift of 8 million STCs due to an estimated carryover of overflow STCs from 2019 and an expectation that SGU installations in 2020 will be at similar levels to 2019.

TABLE ES 2 TOTAL RENEWABLE ENERGY TARGET SCHEME COSTS ($/MWH, NOMINAL)

	2019-20	2020-21	Change
LRET	$9.38	$4.56	($4.82)
SRES	$7.26	$9.72	$2.46
Total	$16.64	$14.28	($2.36)

SOURCE: ACIL ALLEN ANALYSIS

State schemes

Energy Savings Scheme

The Energy Savings Scheme (ESS) is a New South Wales Government program to assist households and businesses reduce their energy consumption. It is a certificate trading scheme in which retailers are required to fund energy efficiency through the purchase of certificates.

The cost of the ESS is calculated by applying the estimated ESS target to the ESC price in each compliance (calendar year). The average of these calendar year costs is then used to obtain the estimated costs for 2019-20 and 2020-21. ACIL Allen estimates the cost of complying with ESS to be $1.80/MWh in 2019-20, and $2.03/MWh in 2020-21.

Retailer Energy Efficiency Scheme

The Retailer Energy Efficiency Scheme (REES) is a South Australian Government energy efficiency scheme that provides incentives for South Australian households and businesses to save energy. It does this via energy efficiency and audit targets to be met by electricity and gas retailers with customers in South Australia.

Given the limited availability of public data on the cost of meeting the REES and given that the cost as estimated by AEMC in its price trends reports is a very small component of the overall cost of the retail bill, ACIL Allen has adopted the estimates of the cost of REES provided in the latest AEMC price trends report, which is $2.50/MWh in both 2019-20 and 2020-21.

Other costs

The estimates of other energy costs for the Draft Determination consist of:

- Market fees and charges including:
  - NEM management fees
  - Ancillary services costs.
- Pool and hedging prudential costs
- The Reliability and Emergency Reserve Trader (RERT).

Adding these component costs gives a total other cost requirement as set out in **Table ES 3,** for the 2020-21 Draft Determination and is compared with the costs for 2019-20.

TABLE ES 3 TOTAL OF OTHER COSTS ($/MWH, NOMINAL)

	2019-20	2020-21
AUSGRID	$3.17	$3.65
ENDEAVOUR	$3.01	$3.46
ESSENTIAL	$2.82	$3.07
ENERGEX	$3.18	$3.12
SAPN	$6.55	$6.04

SOURCE: ACIL ALLEN ANALYSIS

Summary of estimated energy costs

Drawing together the analyses and estimates of the various cost components, ACIL Allen's estimates of the 2019-20 and 2020-21 total energy costs (TEC) for the Draft Determination for each of the profiles are presented in **Table ES 5** and **Table ES 6**.

TABLE ES 4 ESTIMATED TEC FOR 2019-20 DRAFT DETERMINATION ($/MWH, NOMINAL)

Profile	Total wholesale costs at the customer terminal ($/MWh, nominal)	Total environmental costs at the customer terminal ($/MWh, nominal)	Total energy costs at the customer terminal ($/MWh, nominal)
Ausgrid - NSLP	$111.36	$19.34	$130.70
Endeavour - NSLP	$108.61	$19.45	$128.06
Essential - NSLP	$103.17	$19.51	$122.68
Ausgrid - CLP1	$84.15	$19.42	$103.57
Ausgrid - CLP2	$79.64	$19.42	$99.06
Endeavour - CLP	$98.59	$19.45	$118.04
Essential - CLP	$95.11	$19.51	$114.62
Energex - NSLP	$98.34	$17.72	$116.06
Energex – CLP31	$72.52	$17.72	$90.24
Energex – CLP33	$80.97	$17.72	$98.69
SAPN - NSLP	$164.21	$21.25	$185.46
SAPN - CLP	$109.65	$21.25	$130.90

SOURCE: ACIL ALLEN ANALYSIS

TABLE ES 5 ESTIMATED TEC FOR 2020-21 DRAFT DETERMINATION ($/MWH, NOMINAL)

Profile	Total wholesale costs at the customer terminal ($/MWh, nominal)	Total environmental costs at the customer terminal ($/MWh, nominal)	Total energy costs at the customer terminal ($/MWh, nominal)
Ausgrid - NSLP	$113.48	$17.17	$130.65
Endeavour - NSLP	$113.32	$17.19	$130.51
Essential - NSLP	$105.27	$17.17	$122.44
Ausgrid - CLP1	$75.64	$17.22	$92.86
Ausgrid - CLP2	$73.88	$17.22	$91.10
Endeavour - CLP	$105.37	$17.19	$122.56
Essential - CLP	$90.24	$17.17	$107.41
Energex - NSLP	$94.07	$15.21	$109.28
Energex – CLP31	$73.54	$15.21	$88.75
Energex – CLP33	$75.18	$15.21	$90.39
SAPN - NSLP	$157.14	$18.63	$175.77
SAPN - CLP	$97.06	$18.63	$115.69

SOURCE: ACIL ALLEN ANALYSIS

TABLE ES 6 CHANGE IN ESTIMATED TEC FOR 2019-20 AND 2020-21 ($/MWH, NOMINAL) - DRAFT DETERMINATION

Profile	2019-20 Total energy costs at the customer terminal ($/MWh, nominal)	2020-21 Total energy costs at the customer terminal ($/MWh, nominal)	Change from 2019-20 to 2020-21 ($/MWh, nominal)	Change from 2019-20 to 2020-21 (%, nominal)
Ausgrid - NSLP	$130.70	$130.65	($0.05)	-0.04%
Endeavour - NSLP	$128.06	$130.51	$2.45	1.91%
Essential - NSLP	$122.68	$122.44	($0.24)	-0.20%
Ausgrid - CLP1	$103.57	$92.86	($10.71)	-10.34%
Ausgrid - CLP2	$99.06	$91.10	($7.96)	-8.04%
Endeavour - CLP	$118.04	$122.56	$4.52	3.83%
Essential - CLP	$114.62	$107.41	($7.21)	-6.29%
Energex - NSLP	$116.06	$109.28	($6.78)	-5.84%
Energex – CLP31	$90.24	$88.75	($1.49)	-1.65%
Energex – CLP33	$98.69	$90.39	($8.30)	-8.41%
SAPN - NSLP	$185.46	$175.77	($9.69)	-5.22%
SAPN - CLP	$130.90	$115.69	($15.21)	-11.62%

SOURCE: ACIL ALLEN ANALYSIS

1 INTRODUCTION

ACIL Allen Consulting (ACIL Allen) has been engaged by the Australian Energy Regulator (AER) to support the AER in estimating specific cost inputs required for the determination of Default Market Offer (DMO) prices. Specifically, ACIL Allen is required to provide consultancy services to the AER to estimate the underlying wholesale and environmental cost inputs to inform the determination for 2020-21.

These estimates are to be based on the relevant cost drivers for a retailer supplying electricity to residential and small business customers in non-price regulated jurisdictions (excluding Victoria).

ACIL Allen's work is broadly divided into two phases:

- **Phase 1**: Initial scoping and assessment of forecasting options
  - The services in this phase include identifying, scoping and developing a methodology to estimate underlying wholesale and environmental cost inputs to forecast changes in retail electricity costs. The deliverables in this phase formed part of the position paper for the DMO (Position Paper), which was published by the AER in September 2019. Our report for this phase of work is available on the AER's website[1] (and is referred to in this current report as the methodology report).
- **Phase 2**: Estimating the underlying costs to inform the DMO 2020-21 determination
  - The services in this phase include estimating the underlying cost inputs for the DMO determination based on the methodology developed in Phase 1. The deliverables in this phase will form part of draft DMO prices (Draft Determination) and the final DMO prices (Final Determination). This current report presents our analysis and findings for Phase 2.

This report relates to Phase 2 of our engagement, and provides estimates of the wholesale energy, environmental, and other costs for use by the AER in its Draft Determination, using the methodology proposed in our Phase 1 methodology report.

The report is presented as follows:

- Chapter 2 summarises our methodology.
- Chapter 3 provides responses to submissions made by various parties following the release of the AER's *Position Paper: Default Market Offer Price 2020-21* (September 2019), where those submissions refer to the methodology used to estimate the wholesale, environmental, and other costs.
- Chapter 4 summarises our derivation of the energy cost estimates.
- Finally, Appendix A summarises our high-level comparison with the AEMC's 2019 Residential Electricity Price Trends Report released in December 2019.

[1] https://www.aer.gov.au/system/files/ACIL%20Allen%20Consulting%20-%20DMO%20Estimating%20wholesale%20energy%20and%20environmental%20costs%20%28phase%201%29%20-%2010%20September%202019_0.pdf

2 OVERVIEW OF APPROACH

2.1 Introduction

In determining the DMO, the Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019 (the Regulations) requires the AER to determine the annual consumption and annual retail bill amounts based on the following principles and policy objectives:

— an electricity retailer should be able to make a reasonable profit in relation to supplying electricity in the region
— to reduce the unjustifiably high level of standing offer prices for consumers who are not engaged in the market
— to set DMO prices at a level that provides consumers and retailers with incentives to participate in the market
— to allow retailers to recover their efficient costs in servicing customers.

The overall objective of estimating the DMO is to ensure that the projected change in costs is as accurate as possible.

ACIL Allen is required to estimate the wholesale energy, environmental, and other energy related costs for 2020-21. In addition, we are required to estimate the same cost components for 2019-20. The same methodology is used for both years to maintain internal consistency between the two sets of estimates, which allows the AER to consider, if required, percentage changes in each of the cost components. Importantly, we are to estimate the cost components for 2019-20 retrospectively, as if we were undertaking the exercise for 2019-20 in April 2019 for the Final Determination (that is, without the benefit of knowing actual outcomes to date for 2019-20).

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, Reliability and Emergency Reserve Trader costs, and costs of meeting prudential requirements
— energy losses incurred during the transmission and distribution of electricity to customers.

As the energy purchase costs are broader than the wholesale energy and environment costs, we have referred to them as wholesale and environment costs in this report.

2.3 Methodology

The methodology adopted by ACIL Allen is described in detail in Chapter 6 of our methodology report and is summarised below.

The ACIL Allen methodology estimates costs from a retailing perspective. This involves estimating the energy and environmental costs that an electricity retailer would be expected to incur in a given determination year. This includes wholesale energy market simulations to estimate expected spot market costs and volatility and the hedging of the spot market price risk by entering into electricity contracts with prices represented by the observable futures market data. Environmental and 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 - market-based approach

Energy purchase costs are incurred by a retailer when purchasing energy from the NEM spot market to satisfy their retail load. However, given the volatile nature of wholesale electricity spot prices, which is an important and fundamental feature of an energy-only market (i.e. a market without a separate capacity mechanism), and that retailers charge their customers based on fixed rate tariffs (for a given period), a prudent retailer is incentivised to hedge its exposure to the spot market.

Hedging can be achieved by a number of means – a retailer can own or underwrite a portfolio of generators (the gen-tailer model), enter into bilateral contracts directly with generators, purchase over the counter (OTC) contracts via a broker, or take positions on the futures market. Typically, a retailer will employ a number of these hedging approaches. In addition, a retailer may choose to leave a portion of their load exposed to the spot market.

In estimating the wholesale energy costs incurred by a retailer, it is generally assumed that the retailer is partly exposed to the wholesale spot market and partly protected through a contract hedging strategy.

The market-based approach includes an assumed contracting strategy that a prudent retailer would use to manage its electricity market risks or some estimation of contract premiums. Such risks and the strategy used to mitigate them are an important part of electricity retailing.

The WEC for a given year is therefore generally a function of four components:

7. load profile
8. wholesale electricity spot prices
9. forward contract prices
10. contracting strategy.

Use of financial derivatives in estimating the WEC

As discussed above, retailers purchase electricity in the NEM at the spot price and use a number of strategies to manage their risk. Market-based approaches adopted by regulators for estimating the WEC make use of financial derivative data given that it is readily available and transparent. This is not to say regulators are of the view that retailers only use financial derivatives to manage risk – it simply reflects the availability and transparency of data.

Some retailers also use vertical integration and Power Purchase Agreements (PPAs) to manage their risk. However, the associated costs, terms and conditions of these approaches are not readily available in the public domain. Further, smaller retailers may not be in a position to use vertical integration or PPAs and hence rely solely on financial derivatives.

Additionally, the value of long-dated assets associated with vertical integration and PPAs is determined by conditions in the market at a given point in time. The price in a PPA or the annualised historical cost of generation reflects the value of the generation anticipated at the time of commitment when the investor was faced with a variety of uncertain futures. Once an investment is committed, the costs are sunk. As time proceeds, the value of the generation asset is determined by the actual future that eventuates and may be quite different to the value expected at the time of commitment. As a consequence, there are considerable difficulties in using the price of PPAs or the annualised historical cost of generation as a basis for estimating current hedging costs.

Key steps

The key steps to estimating the WEC for a given load and year are:

11. Forecast the half-hourly load profile – generally as a function of the underlying demand forecast as published by the Australian Energy Market Operator (AEMO), and accounting for further uptake of rooftop solar PV. A stochastic demand and renewable energy resource model to develop 49 weather influenced annual simulations of hourly demand and renewable energy resource traces which are developed so as to maintain the appropriate correlation between the various regional and NSLP/CLP demands, and various renewable energy zone resources.
12. Use a stochastic availability model to develop 11 annual simulations of hourly thermal power station availability.
13. Forecast hourly wholesale electricity spot prices by using ACIL Allen's proprietary wholesale energy market model, *PowerMark*. *PowerMark* produces 539 (i.e. 49 by 11) simulations of hourly spot prices of the NEM using the stochastic demand and renewable energy resource traces and power station availabilities as inputs.
14. Estimate the forward contract price using ASX Energy contract price data, verified with broker data. The book build is based on the observed trade volumes and the price estimate is equal to the trade volume weighted average price.
15. Adopt an assumed contracting strategy – the contracting strategy represents a strategy that a retailer would undertake to hedge against risk in the spot price in a given year. It is generally assumed that a retailer's risk management strategy would result in contracts being entered into progressively over a two- or three-year period, resulting in a mix (or portfolio) of base (or flat), peak and cap contracts.
16. Calculate the spot and contracting cost for each hour and aggregate for each of the 539 simulations – for a given simulation, for each hour calculate the spot purchase cost, contract purchase costs, and different payments, and then aggregate to get an annual cost which is divided by the annual load to get a price in $/MWh terms.

The above steps produce a distribution of estimated WECs which vary due to variations in demand, and spot prices. Wholesale electricity spot prices will vary depending on the actual load (which will vary based on weather conditions), renewable generator resource (which also varies with weather outcomes), and availability of thermal power stations. It is this variability, and associated risk, that incentivises retailers to enter into hedging arrangements. However, this variability also changes the values of the spot purchase costs and difference payments incurred by a retailer (even though the contract prices and strategy are fixed).

The distribution of outcomes produced by the above approach is then analysed to provide a risk assessed estimate of the WEC. ACIL Allen adopts the 95th percentile WEC from the distribution of WECs as the final estimate. In practice, the distribution of WECs from the simulations exhibits a relatively narrow spread when compared to estimates based on the load being 100 per cent exposed to the spot market, which is to be expected since they are hedged values. Choosing the 95th percentile reduces the risk of understating the true WEC, since only five per cent of WEC estimates exceed this value.

As mentioned above, multiple hedging strategies are tested by varying the mix of base/peak/cap contracts for each quarter. We select a strategy that is robust and plausible for each load profile, noting that:

— some strategies may be effective in one year but not in others
— in practice, retailers do not necessarily make substantial changes to the strategy from one year to the next
— our approach is a simplification of the real world, and hence we are mindful not to over-engineer the approach and give a false sense of precision.

The hedging strategy for each contract product that results in the lowest 95th percentile annual WEC for 2019-20 and 2020-21 is adopted. The hedging strategy is not necessarily varied for every determination year – it tends to change when there is a sufficient change in either the shape of the load profile (for example, due to the continued uptake of rooftop PV) or a change in the relationship between contract prices for the different contract products (for example, in some years base contract prices increase much more than peak contract prices, which can influence the strategy).

Demand-side settings

The 2020-21 peak demand and energy forecasts for the regional demand profiles are referenced to the neutral scenarios from the Electricity Statement of Opportunities (ESOO) published by AEMO in August 2019 (and the 2018 ESOO for 2019-20) and take into account past trends and relationships between the NSLPs and the corresponding regional demand.

It is usual practice to use a number of years of historical load data together with the P10, P50 and P90 peak load, and energy forecasts from the AEMO neutral scenario to produce multiple simulated representations of the half hourly load profile for the given determination year using a Monte Carlo analysis. These multiple simulations will include a mix of mild and extreme representations of demand – reflecting different annual weather conditions (such as mild, normal and hot summers).

The key steps in developing the demand profiles are:

— The half-hourly demand profiles of the past four years are obtained. The profiles are adjusted by ‘adding’ back the estimated rooftop PV generation for the system demand and each NSLP (based on the amount of rooftop PV in each distribution network).
— A stochastic demand model is used to develop about 50 weather influenced simulations of hourly demand traces for the NSLPs, each regional demand, and each renewable resource – importantly maintaining the correlation between each of these variables. The approach takes the past three years of actual demand data, as well as the past 49 years of weather data and uses a matching algorithm to produce 49 sets of weather-related demand profiles of 17,520 half-hourly loads. This approach does not rely on attempting to develop a statistical relationship between weather outcomes and demand – instead it accepts there is a relationship and uses a matching algorithm to find the closest matching weather outcomes for a given day across the entire NEM from the past four years to represent a given day in the past.
— The set of 49 simulations of regional system demands is then grown to the AEMO demand forecast using a non-linear transformation so that the average annual energy across the 49 simulations equals the energy forecast, and the distribution of annual peak loads across the 49 simulations generally matches the distribution of peak loads inferred by the P10, P50 and P90 peaks from the AEMO demand forecast.
— A relationship between the variation in the NSLPs and the corresponding regional demand from the past four years is developed to measure the change in NSLP as a function of the change in regional demand. This relationship is then applied to produce 49 simulations of weather related NSLP profiles of 17,520 half-hourly loads which are appropriately correlated with system demand, but also exhibit an appropriate level of variation in the NSLP across the 49 simulations.
— The projected uptake of rooftop PV for the determination year is obtained (using our internal rooftop PV uptake model).
— The half-hourly rooftop PV output profile is then grown to the forecast uptake and deducted from the system demand and NSLPs.

Supply side settings

ACIL Allen maintains a Reference case projection of the NEM, which it updates each quarter in response to supply changes announced in the market in terms of new investment, retirements, fuel costs, and plant availability. In this analysis, for 2020-21 we have used our September 2019 Reference case projection settings which are closely aligned with the ISP. For the 2019-20 estimates we have used our March 2019 Reference case (since we are completing the 2019-20 analysis retrospectively at the time of the Final Determination for 2019-20).

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 assumed changes to existing supply included in the 2020-21 market simulations.

TABLE 2.1 CHANGES TO EXISTING SUPPLY

Project name	Generation technology	Capacity (MW)	Region	Nature and date of change
Gladstone	Black coal steam turbine	1,680	QLD	Five units in operation and one off-line
Torrens Island A	Natural gas steam turbine	480	SA	Gradual closure from Q4 2020 to Q4 2022
Liddell	Black coal steam turbine	2,000	NSW	Three units in operation and one off-line; Retires Q2 2023
Bayswater	Black coal steam turbine	2,740	NSW	25 MW upgrade to each of the 4 units, works beginning 2019 ending 2022
Mt Piper	Black coal steam turbine	1,400	NSW	30 MW upgrade to each of the 2 units, works beginning 2020 and ending 2021
Temporary Generation North and South	Liquid fuelled aero-derivative gas turbines	277	SA	Change of classification from market non-scheduled to market scheduled, to reflect 25- year leases secured by Infigen and Nexif. Assumed to transition to natural gas by 2021
Mackay GT	Liquid fuelled gas turbine	34	QLD	Closes in Q2 2021

SOURCE: ACIL ALLEN ANALYSIS

Table 2.2 provides near term entrants that ACIL Allen considers committed projects for the 2020-21 simulations.

TABLE 2.2 NEAR TERM ADDITION TO SUPPLY

Region	Name	Generation Technology	Capacity (MW)	Expected Entry
NSW1	Bango WF	Wind	244	Q1 2021
NSW1	Bomen Solar Farm	Solar	100	Q1 2021
NSW1	Collector WF	Wind	226.8	Q1 2021
NSW1	Crudine Ridge WF	Wind	135	Q4 2019
NSW1	Darlington Point Solar Farm	Solar	275	Q3 2020
NSW1	Goonumbla Solar Farm	Solar	67	Q4 2020
NSW1	Limondale Solar Farm 1	Solar	220	Q1 2020
NSW1	Limondale Solar Farm 2	Solar	29	Q2 2020
NSW1	Nevertire Solar Farm	Solar	105	Q1 2020
NSW1	Sunraysia Solar Farm	Solar	200	Q1 2020
NSW1	Wyalong Solar Farm	Solar	70	Q3 2020
QLD1	Brigalow Solar Farm	Solar	34.5	Q3 2020
QLD1	Chinchilla Solar Farm	Solar	100	Q3 2020

Region	Name	Generation Technology	Capacity (MW)	Expected Entry
QLD1	Kennedy Energy Park	Battery - Discharge	2	Q1 2020
QLD1	Kennedy Energy Park	Solar	15	Q1 2020
QLD1	Kennedy Energy Park	Wind	43	Q1 2020
QLD1	Kidston Pumped Hydro	Pump - Discharge	250	Q3 2023
QLD1	Oakey Solar Farm Stage 2	Solar	55	Q4 2019
QLD1	Teebar Solar Farm	Solar	52.5	Q3 2020
QLD1	Warwick Solar Farm	Solar	64	Q2 2020
QLD1	Yarranlea Solar Farm	Solar	102.5	Q1 2020
SA1	Barker Inlet	Natural gas	52.5	Q4 2019
SA1	Hallett Aeroderivative GT	Natural gas	27.5	Q1 2020
SA1	Lake Bonney Battery	Battery - Discharge	25	Q4 2019
SA1	Lincoln Gap WF Stage 2	Wind	86	Q4 2020
TAS1	Granville Harbour WF	Wind	112	Q3 2019
TAS1	Wild Cattle Hill WF	Wind	144	Q2 2020
VIC1	Berrybank WF	Wind	180	Q1 2020
VIC1	Bulgana Power Hub	Battery - Discharge	20	Q4 2019
VIC1	Bulgana Power Hub	Wind	194	Q4 2019
VIC1	Carwarp Solar Farm	Solar	99	Q4 2020
VIC1	Cherry Tree WF	Wind	57.6	Q2 2020
VIC1	Cohuna Solar Farm	Solar	27.27	Q4 2020
VIC1	Dundonnell WF	Wind	336	Q2 2020
VIC1	Elaine WF	Wind	86	Q3 2020
VIC1	Kiamal Solar Farm	Solar	200	Q2 2020
VIC1	Moorabool WF	Wind	312	Q4 2019
VIC1	Mortlake South WF	Wind	157.5	Q4 2020
VIC1	Stockyard Hill WF	Wind	530	Q1 2020
VIC1	Winton Solar Farm	Solar	85	Q4 2020
VIC1	Yatpool Solar Farm	Solar	81	Q2 2020

Note: Renewable plant 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 also includes the restructure of the Queensland Government's assets and the formation of CleanCo. 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, which operates more aggressively, reflecting its position in the new, smaller portfolio, and thus acting more so as a price taker than a price maker.

The modelling assumes that new renewable projects associated with the Queensland Government's 50 per cent renewable energy policy, including the recently re-activated Renewables 400 reverse auction, will not be commissioned until beyond 30 June 2021.

Similarly, the modelling assumes new renewable projects associated with the Victorian Renewable Energy Target, beyond the winning projects of the first round of the auction process, will not be commissioned until beyond 30 June 2021.

2.3.2 Renewable energy policy costs

Renewable energy scheme (RET)

Energy costs associated with the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES) have been estimated using price information from brokers TFS, information published by the Clean Energy Regulator (CER) and modelling by ACIL Allen. Retailer compliance with these schemes operates on a calendar year basis and hence estimates are required for 2019, 2020 and 2021 calendar years, with the costs averaged to estimate the 2019-20 and 2020-21 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 forward prices for 2019, 2020 and 2021 from brokers TFS[2]
— the Renewable Power Percentage (RPP) for 2019 of 18.60 per cent as published by the CER
— mandated LRET targets for 2020 and 2021 of 33,850 GWh and 33,000 GWh, respectively
— estimated RPP values for 2020 and 2021 of 19.61 per cent and 19.44 per cent, respectively[3]
— the binding Small-scale Technology Percentage (STP) for 2019 of 21.73 per cent as published by the CER
— non-binding STP value for 2020 of 14.56 per cent (for use in the retrospective 2019-20 estimate), as published by the CER
— estimated STP values for 2020 and 2021 (for use in the 2020-21 estimate) of 26.42 per cent and 22.15 per cent, respectively[4]
— CER clearing house price[5] for 2020 and 2021 for Small-scale Technology Certificates (STCs) of $40/MWh.

New South Wales Energy Savings Scheme (ESS)

The Energy Savings Scheme (ESS) is a New South Wales Government program to assist households and businesses reduce their energy consumption. It is a certificate trading scheme in which retailers are required to fund energy efficiency through the purchase of certificates.

To estimate the cost of complying with the ESS, ACIL Allen uses the following elements:

— Energy Savings Scheme Target for 2019, 2020 and 2021 of 8.5 per cent, as published by IPART
— Historical Energy Savings Certificate (ESC) market forward prices for 2019, 2020 and 2021 from brokers TFS

South Australia Retailer Energy Efficiency Scheme (REES)

The Retailer Energy Efficiency Scheme (REES) is a South Australian Government energy efficiency scheme that provides incentives for South Australian households and businesses to save energy. It does this via energy efficiency and audit targets to be met by electricity and gas retailers with customers in South Australia.

In the AEMC's 2018 price trends methodology report, the cost of the REES was sourced using data from the relevant jurisdiction, although there is no link to the exact location of this data.[6]

In the AEMC's report, the estimated cost of REES, which is expected to be generally flat in nominal terms over the reporting period, comprises less than 10 per cent of the cost of environmental policies,

[2] For 2019-20 and 2020-21, TFS data includes prices up to and including 10 April 2019 and 6 January 2020, respectively.
[3] The RPP values for 2020 and 2021 were estimated using ACIL Allen's estimate of liable acquisitions for 2020 and 2021 and the mandated LRET targets as published by CER.
[4] The STP value for 2020 and 2021 were estimated using ACIL Allen's estimates of STC creations and liable acquisitions in 2020 and 2021
[5] Although there is an active market for STCs, ACIL Allen is not compelled to use market prices. This is mainly because historical prices might not be the best indicators of future prices as the market is designed to clear every year – so in theory prices could be $40 or at least very close to it. This assumes that the CER provides an accurate forecast of created certificates underpinning the STP for the next year.
[6] Table 8.5, page 49 at https://www.aemc.gov.au/sites/default/files/2018-12/AEMC%202018%20Residential%20Electricity%20Price%20Trends%20Methodology%20Report%20-%20CLEAN.pdf

and less than one per cent of the total retail bill in South Australia during the four-year reporting period.

In the AEMC's 2019 price trends report[7], the cost of REES appears to be unchanged from the 2018 report.

Given the limited availability of public data on the cost of meeting the REES and given that the cost as estimated by AEMC is a very small component of the overall cost of the retail bill, ACIL Allen has used the estimates of the cost of REES provided in the latest AEMC price trends report.

2.3.3 Other energy costs

Market fees and ancillary services costs

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

Prudential costs

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.

Reliability and Emergency Reserve Trader (RERT)

Given the RERT is called upon under extreme circumstances only, ACIL Allen is of the opinion that it is difficult to project into the future. Although it may be possible to make use of previous costs of the RERT and relate these to AEMO's projection of USE in the ESOO, there is little data available at this point to take this approach.

Therefore, as with the ancillary services, we have used the RERT costs as published by AEMO for the 12-month period prior to the determination year. At the time of writing this report for the Draft Determination, the costs of the RERT for 2019-20 have not yet been reported and therefore we have used the costs for 2018-19 as a proxy. We note that the ESC uses this approach in the VDO. However, the ESC expresses the RERT cost on a per customer basis. Instead, ACIL Allen expresses the cost based on energy consumption, by taking the reported cost in dollar terms from AEMO for the given region and prorating the cost across all consumers in the region on a consumption basis.

2.3.4 Energy losses

The estimated wholesale energy costs resulting from the analysis is referenced to the 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 each network area 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 to estimate losses for 2019-20 are based on the updated draft 2019-20 MLFs published by AEMO on 1 April 2019.

[7] Published on 9 December 2019 at: https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2019

The MLFs used to estimate losses for the Draft Determination for 2020-21 are based on the final 2019-20 MLFs published by AEMO on 21 June 2019.

For the Final Determination for 2020-21, we propose to use AEMO's 2020-21 MLFs, which are due to be published by 1 April 2020.

3 RESPONSES TO SUBMISSIONS TO POSITION PAPER

The AER forwarded to ACIL Allen a total of 13 submissions in response to its Position Paper. ACIL Allen reviewed the submissions to identify issues that related to our methodology and required our consideration for the 2020-21 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 POSITION PAPER

ID	Stakeholder	Wholesale energy cost	Environmental costs	Other costs
1	Australian Energy Council (AEC)	Nil	Yes	Nil
2	AGL	Yes	Yes	Yes
3	Alinta	Nil	Nil	Nil
4	Australian Small Business and Family Enterprise Ombudsman (ASBFEO)	Nil	Nil	Nil
5	Ausgrid	Nil	Nil	Nil
6	Energy Consumers Australia (ECA)	Nil	Nil	Nil
7	Energy Australia (EA)	Yes	Yes	Nil
8	Origin	Yes	Yes	Nil
9	Public Interest Advocacy Centre (PIAC)	Nil	Nil	Nil
10	Powershop MEA Group	Yes	Yes	Nil
11	Queensland Council of Social Services (QCOSS)	Nil	Nil	Nil
12	Red Lumo	Yes	Nil	Nil
13	Simply Energy	Nil	Nil	Nil

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

SOURCE: ACIL ALLEN ANALYSIS OF AER SUPPLIED DOCUMENTS

3.1 Wholesale energy cost

The submissions raised issues in relation to following sub-components of the wholesale energy cost (WEC):

— Market modelling
— Load profiles
— Hedging
— Market data cut-off date.

The issues raised have been addressed for each of these sub-components below.

3.1.1 Market modelling

In the submissions, stakeholders are generally in agreement with ACIL Allen's proposed market-based approach to estimating the WEC and are in support of incorporating the latest available data and market information.

AGL on page 3 of their submission stated:

The use of a market based hedging approach is also reasonable. As with any modelling, however, the outputs of the model will depend on the inputs and assumptions. They should reflect recent changes in wholesale market conditions such as the closure of Hazelwood Power Station in 2017 and more supply from renewable energy resources

Energy Australia on page 2 of their submission noted:

Wholesale cost methods and data sources should be examined to ensure cost trends and more recent market developments are accurately captured.

Red and Lumo on page 2 of their submission stated:

The market based approach proposed by ACIL Allen and the AER is reasonable and consistent with previous and current determinations from other jurisdictions (with the Victorian Default Offer as a recent example). Noting that retailers operating within a volatile wholesale market, ACIL Allen should ensure its analysis and conclusions reflect the best and most recent information available about the current and expected state of the markets.

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

On the supply-side, ACIL Allen incorporates changes to existing generators where companies have formally announced the changes – mothballing, closure, upgrades and change in operating approach. Near-term named new generators are included where they are considered to be committed projects. ACIL Allen's modelling has also applied delays of 6-12 months to some of these committed renewable generators to reflect the difficulties experienced by market participants to connect to the grid.

On the demand-side, ACIL Allen uses as a starting point the Central scenario from AEMO's 2019 Electricity Statement of Opportunities (ESOO), with an adjustment to the official projections to take account of differences in views with respect to the level of uptake of rooftop solar PV. ACIL Allen's projections for uptake of rooftop PV systems, are a function of payback periods for residential and business customers taking into consideration the number of suitable dwellings, roof-space and saturation levels. Inputs for the uptake model consist of system costs, retail electricity prices and government feed-in-tariffs and upfront subsidies. ACIL Allen's projections for uptake of rooftop PV systems are in line with recent trends of high uptake.

3.1.2 Load profiles

AGL and Energy Australia support the use of the NSLP and CLP to forecast the half-hourly load profiles.

AGL on page 3 of their submission stated:

Retailers are likely to hedge according to their own customers' load profile. However, as each retailer will have a different profile the Net System Load Profile (NSLP) and Controlled Load Profile (CLP) will be a useful proxy to model a representative load profile. The use of NSLP and CLP is particularly relevant when retailers are seeking to acquire customers where their consumption profile is unknown.

Energy Australia on page 3 of their submission stated:

Subject to there not being material difference across these customers types, we would support having the same DMO and reference prices apply as this would add simplicity and transparency for retailers and customers.

However, some stakeholders suggest that the NSLP should be separated into different customer types.

Origin on page 4 of their submission stated:

Contrary to the AER, Origin considers it important that load data for residential and small business customers is separated. We consider that using a combined load profile does not adequately reflect the variance between maximum and average usage for residential customers. The aggregate of small business and residential profiles also creates a flatter profile than either segment individual, i.e. the analysis only represents the demand for a retailer that holds a balanced small business/residential customer portfolio. We consider that the use of separate load profiles provides a more cost reflective outcome. Origin would be pleased to provide the AER with the associated load profile data if required.

Red and Lumo on page 3 of their submission stated:

Similarly, assumptions about load profile may in fact the profiles of certain retailers' customer base but not others. Some retailers for example, have more volatile profiles as they have a relatively high proportion of solar customers. …. Finally, we do not share the AER's view that there is limited value in separating the NSLP into residential and small business customer profiles. …. We think that further analysis is required by the AER to identify the extent of significant difference in load profile between these two broad categories and how it impacts retailers' exposure to volatility of that load.

Powershop on page 2 of their submission stated:

Powershop does not agree that there is limited value in separating the NSLP into residential and small business customer profiles. As seen during the Essential Service Commission of Victoria's (ESC) calculation of the Victorian Default Price (VDO) separating the load profiles had a significant impact on both the residential and business VDO prices.

ACIL Allen acknowledges that it is inevitable that different retailers will have different mixes of customers and that different customer types will have different profiles. However, the approach needs to be pragmatic, transparent, consistent, and manageable.

First, ACIL Allen's view is that splitting the load into residential and non-residential does not improve accuracy and is largely arbitrary. It ignores, and does not account for, the large variety of non-residential load profile shapes that exist and the different mixes of these profiles that each retailer may have, and for some non-residential customers their profile may well be closer related to a residential profile given the nature of their business and hours of operation.

Splitting the profiles into segments requires reliable and transparent data collected from interval and smart meters. For networks in which the rollout of interval or smart meters is limited, there is an issue of representativeness which raises the following questions:

— How do we know that these customers are representative of customers that do not have interval or smart meters?
— And how do we apply a method that is consistent across all jurisdictions?

ACIL Allen notes that the half hourly load profile data for the NSLP and CLP for Queensland, New South Wales and South Australia, as currently published by AEMO, does not differentiate between small business and residential customers. Nor does it differentiate between customers with and without rooftop PV.

It is likely there is insufficient data in Queensland, New South Wales and South Australia to be split into residential and small business profiles, or to be split into customers with and without rooftop PV, because unlike in Victoria, these regions have not had mandatory roll out of interval meters.

ACIL Allen acknowledges that there are some jurisdictions which would have interval meter data. For example, since December 2017, all new and replacement meters in the New South Wales Ausgrid network have been replaced with smart meters. However, a consistent approach across all regions is required. In addition, there is a risk of small samples not being representative of the overall customer load.

Splitting the profiles into segments also raises valid questions of the extent to which the profile is segmented:

— How many segments do we split the profile into?
— What is the basis for segmentation?

ACIL Allen notes that the load profiles used in the Victorian Default Offer (VDO) were based on the Victorian Manually Read Interval Meter (MRIM) data, which AEMO filtered and split into residential and small business customers with consumption less than 40 MWh per annum[8]. Presumably AEMO was able to split the Victorian data because there has been mandatory roll out of interval ('smart') meters in all 5 distribution regions in Victoria between 2013 and 2016.

Evidence from the VDO suggests that the difference between residential and business WECs estimated by Essential Services Commission (ESC) for the draft 2020 VDO is varied and typically about six per cent.

In summary, ACIL Allen's view is that the NSLP and CLP are relevant and representative at the aggregate level.

Some stakeholders suggested that a shorter time frame should be used when analysing historical half-hourly load profiles or that recent years should be given more weighting than the earlier years.

Red and Lumo on page 2-3 of their submission state:

In light of this, we note that historic NSLP and CLP are "historic". These are not necessarily the best indicators of future load profiles and ACIL Allen should give greater weight to more recent profiles that reflect the current state of the market.

Powershop on page 3 of their submission stated:

ACIL Allen's methodology utilises 4 years of half-hourly demand profiles however, it is not clear whether these are weighted evenly of if more weighting is given to more recent years. Applying such a long timeframe for the historical data can reduce the impact of recent trends and does not account for the rapid changes taking place in the market. Powershop suggests a smaller timeframe should be applied.

AGL on page 3 of their submission stated:

Due to the rapid penetration of rooftop solar, the correlation of weather and demand in the past may not be suitable for the future.

Origin on page 4 of their submission stated:

In addition, it is important that the load profile analysis takes into account the increasing level of behind the meter technology, such as rooftop solar PV.

ACIL Allen appropriately accounts for the recent historical and projected future penetration of rooftop PV when it creates the 50 synthetic load profiles. As part of this process, ACIL Allen 'adds back' the historical rooftop PV output to the past three years of historical demand traces, creates the 50 synthetic demand profiles using the weather matching technique described section 2.3.1, and then deducts the projected future rooftop PV profile from these profiles.

Using this approach means that we do not need to arbitrarily apply weightings to the historical data.

3.1.3 Hedging

A number of stakeholders highlighted that the increased penetration of rooftop PV has resulted in a deteriorating load factor and an increase in spot price volatility, which increases the cost of hedging such a load.

Energy Australia on page 2 of their submission stated:

[8] According to page 23 of the Victorian Default Offer to apply from 1 January 2020 Draft Determination, available at: https://www.esc.vic.gov.au/sites/default/files/documents/Victorian%20Default%20Offer%20to%20apply%20from%201%20January%202020%20-%20Draft%20decision%2020190920_0.PDF

Load and price volatility is increasing, particularly in QLD and SA due to the influx of solar PV, bringing associated changes in shaping costs incurred by retailers.

Origin on page 4 of their submission stated:

In principle, Origin is comfortable with AER's proposed hedging strategy. However, we stress that any strategy needs to sufficiently account for volatility and the linkage between high electricity pool prices and high demand. ….. The significant increase in solar PV systems requires the collective trend to be included in future projections. Without the inclusion of this data, daytime load factor deteriorates with retailers bearing more under/over hedging as flat swap products are used to hedge a more sculpted load.

ACIL Allen notes that there has been an observable fall in the load factor in the actual NSLP for most DNSP areas 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) for most NSLPs but continues to reduce the average 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 hedging costs will increase.

Several stakeholders highlighted the importance of estimating a WEC that appropriately accounts for the various risks faced by a retailer.

AGL on page 2 of their submission state:

There is no allowance for volume risk resulting from customer churn.

Powershop on page 3 of their submission stated:

Powershop believes the hedging strategy is unsuitable for minimising the range of outcomes in wholesale energy costs faced by a retailer. Retailers face uncertainty over customer numbers and load in any particular time period. With increasing time there is an increased amount of uncertainty. Customer loads can change due to a number of reasons, including but not limited to the competitive landscape, regulatory interventions and seasonal behaviours. Hedging with perfect foresight obviously reduces the possible range of cost outcomes but adapting portfolios and delta-hedging as required can drastically change costs, and therefore, margin outcomes.

Powershop questions the basis for 10 and 5 percentile increments for base/peak and cap products, respectively. It appears there is no data supporting these percentiles.

Red and Lumo on page 2 of their submission stated:

ACIL Allen's modelling will also need to include realistic assumptions about a prudent retailer's hedging strategy, namely, appropriate weightings for the different types of products available and some reasonable level of exposure to spot prices. We would welcome the opportunity to work with ACIL Allen and the AER as they develop their assumptions and gather the inputs to their modelling.

ACIL Allen's approach assumes that a retailer builds their book of hedges ahead of the start of the DMO period. ACIL Allen uses all trades (generally 2-3 years) back to the first trade recorded by ASX Energy for the given product, which generally more closely reflect, in practice, how retailers build up their portfolio of hedging contracts over time – taking into account their evolving view on their market share and customer load (including customer churn).

ACIL Allen's hedging strategy methodology involves testing multiple mixes of base/peak/cap contracts for each quarter. Ideally this testing is undertaken for a number of years to ensure a reasonably robust and risk averse hedging strategy is adopted.

ACIL Allen considers it important to estimate the WEC under a range of simulations. As such a number of simulations (around 500) are run to understand the range of potential spot price and demand outcomes. The distribution of these outcomes is then analysed to provide a risk assessed estimate of the WEC.

ACIL Allen uses the 95th percentile of these 500 simulations as the final value of the WEC, rather than the median and average value, to minimise the risk of understating the actual wholesale energy costs incurred by a retailer. Using the 95th percentile allows for residual risk to be incorporated into the wholesale energy costs estimate, which could represent, for example, a deviation from expected customer volumes.

3.1.4 Market data cut-off date

Red and Lumo on page 2 of their submission stated:

Any modelling that draws on market data should reflect retailers' hedging strategies to manage their exposure to wholesale costs over a reasonable period of time, while also capturing pricing data as close to the final determination date as possible.

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 market data cut-off date are the contract prices and trade volumes, which we obtain from ASX Energy. For the Draft Determination, the market data cut-off date is 6 January 2020. This will be extended to March 2020 for the Final Determination, which is expected to be finalised in April 2020.

3.2 Environmental costs

The submissions raised issues in relation to following sub-components of the environmental and other costs:

— Large-scale Renewable Energy Target (LRET)
— Small-scale Renewable Energy Scheme (SRES)
— Retailer Energy Efficiency Scheme (REES)
— Reliability and Emergency Reserve Trader (RERT).

The issues raised have been addressed for each of these sub-components below.

3.2.1 LRET

A number of stakeholders suggested that cost of LRET should be based on the long run cost to retailers rather than the market price of LGCs.

AGL on page 3 of their submission stated:

LCG costs should reflect the long term industry costs by considering the range of historical PPA prices.

Energy Australia on page 2 of their submission stated:

Approaches that rely heavily or entirely on the market price of LGCs as an estimate of costs under the large-scale renewable energy target (LRET) do not reflect the prudent practice of retailers and will give a poor estimate of retail costs trends.

Origin on page 4 of their submission stated:

The AER should carefully consider whether its approach of using the market price will adequately compensate retailers for their prudent LGC costs over the remaining years of the scheme.

Powershop on page 3 of their submission stated:

Limiting the use of simple averages and more consideration of environmental hedging time frames may help to provide a better estimate of costs likely to be incurred by retailers in the procurement of environmental products.

It is likely that LGC prices will continue to 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 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.

A PPA price reflects the value of generation expected by an investor at the time of commitment when faced with a variety of uncertain futures. A PPA entered into 10 or so years ago may have had a higher expectation of value of an LGC, whereas a PPA entered into over the past 5 years may have had an expectation of reducing value of an LGC.

A price of a PPA, just like an investment in a physical power station, represents a sunk cost once the investment has been made, and subject to the future evolution of the electricity market. Similarly, a PPA is not a regulated investment, and as such does not provide a guaranteed return, nor does it represent a guaranteed value. Hence, the value of an LGC within a PPA is determined by market conditions that actually eventuate at a given point in time – rather than at the time the investment decision was made.

In any case, a reasonable proportion of PPAs, if not the majority of those not expired, do not split out LGC prices, rather the price is a bundled price. This raises the challenge of ascribing a value to the LGC component of a PPA price.

In summary, ACIL Allen's view is that a market-based approach using contemporary forward LGC prices represents most reliable indicator of the current market consensus view of the price of LGCs in the near-term. This is also consistent with a market-based approach for wholesale electricity costs.

3.2.2 SRES

A number of stakeholders suggested that the cost of SRES should incorporate an alternative to the CER's non-binding estimate for 2021 calendar year.

AGL on page 3-4 of their submission stated:

AGL has concerns with the use of the non-binding STPs as they have significantly underestimated the final binding STPs over the past 9 years and particularly, more recently, in 2018 and 2019. … In the final determination in April 2020, AGL anticipates that the AER will take account of the final binding 2020 STP which should be set by 31 March 2020. In relation to the 2021 STP, the AER (and ACIL Allen) should consider if there are more robust estimates than the non-binding target.

Origin on page 5 of their submission stated:

With respect to SRES, small scale solar installations continue to experience a rapid growth in the rate of installation. This growth has outstripped the CER's estimates of the volume of small-scale certificates (STC) created. We note that the most recent update from the CER in December 2018, indicates a significant surplus of STCs created in calendar year 2018 estimate at around 6-8 million STCs. This represents a variance of over 20 per cent above the published STP. We suggest the AER consults with the CER to better estimate a revised STP for inclusion in the AER's draft determination. Further, as the calendar 2020 STP is also relevant to this determination, we suggest that the AER also consider the CER's current non-binding STP.

ACIL Allen recognises that historically, some of the non-binding STP values have underestimated the final binding STPs. This is due to actual creation of STCs exceeding projected STC creation and the long lead time between estimation of the non-binding STPs and release of the binding STC.

ACIL Allen's view is that the current non-binding estimates for 2020 and 2021 are likely to be too low.

Based on year to date installations for 2019, there is likely to be an excess of STCs over the amount implied in the binding STP for 2019.

ACIL Allen also expects continued high levels of STC creation in 2020 and 2021. The CER has also confirmed a similar expectation in its October 2019 small-scale certificate market update.

For the Draft Determination, we have provided our own estimates of the 2020 and 2021 STPs, which will include an estimated excess of 8 million STCs in 2019 to be carried over to the 2020 STP value, and the assumption that STC creations in 2020 and 2021 are similar levels to 2019.

3.2.3 REES

Australian Energy Council on page 3 of their submission stated:

The AEC also notes that the South Australian government recently released a Direction Paper on the review of its Retailer Energy Efficiency Scheme (REES). This review asks what direction the REES should take after it ends in 2020. The outcome of this review should be monitored given it may influence the environmental costs in South Australia.

The current stage of the REES ends in 2020 with an updated REES proposed to commence on 1 January 2021, according to the Directions Paper.[9]

It is not clear how the proposed changes will affect the cost of the REES, or indeed whether all of the proposed changes will be implemented. ACIL Allen will monitor the outcome of the review during our estimation of the REES in for the Draft and Final Determinations.

3.3 Other costs

3.3.1 RERT

AGL on page 3 of their submission stated:

AEMO has invited Expressions of Interests for the Short and Medium Notice RERT for 2020. AGL believes an allowance should be made for these costs in the DMO, as well as the cost of directions especially in South Australia.

ACIL Allen proposes to take the RERT costs as published by AEMO for the 12-month period prior to the determination year and express the cost based on energy consumption. This would require taking the reported cost in dollar terms from AEMO for the given period and prorating the cost across all consumers in the region on a consumption basis.

[9] Government of South Australia Department for Energy and Mining, *Review into the South Australian Retailer Energy Efficiency Scheme, Directions Paper,* October 2019, can be accessed at: http://www.energymining.sa.gov.au/__data/assets/pdf_file/0005/350366/REES_Directions_Paper_October_2019.pdf

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 profiles for 2019-20 and 2020-21.

4.1.1 Historic energy price levels

Figure 4.1 to Figure 4.3 show the average time of day pool (spot) price for the Queensland, New South Wales, and South Australia regions of the NEM respectively, and the associated average time of day load profiles for the past eight years. The graphs are useful in understanding the dynamics of the absolute and relative wholesale electricity price changes in the profiles.

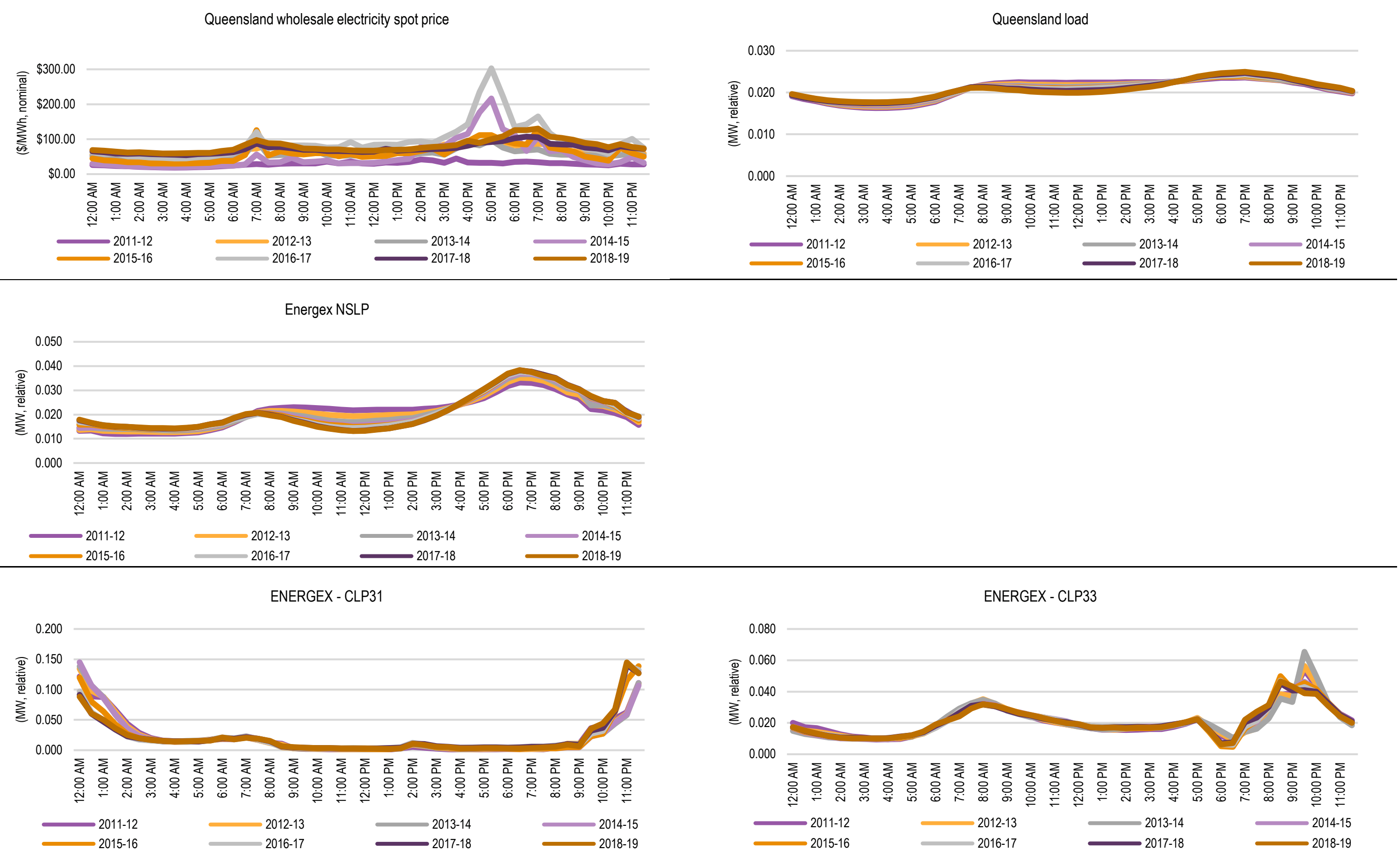
It is worth noting the uplift in spot prices between 2014-15, and 2016-17, across most periods of the day. During this period, wholesale spot prices increased by about $40/MWh in New South Wales and Queensland, and by about $60/MWh in South Australia. This is a result of coal station closures (Wallerawang in New South Wales in 2014, Northern in South Australia in 2016, and Hazelwood in Victoria in 2017), 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 across the NEM, and an increase export coal prices in New South Wales and Queensland, as well as coal supply constraints into coal fired power stations in New South Wales.

Between 2016-17 and 2018-19 annual average prices remained reasonably flat in New South Wales and South Australia and reduced slightly in Queensland in 2017-18.

Compared with 2018-19, wholesale spot prices to date in 2019-20 have decreased by about $15/MWh in New South Wales, decreased by about $10/MWh in New South Wales, and remain reasonably constant in South Australia.

Over the past few years, the Queensland and South Australian NSLP load profiles, and to some degree, the New South Wales NSLPs, 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 and consequently, the demand weighted spot prices (DWP) for the NSLP load profiles have increased relative to the corresponding regional time weighted average spot price (TWP). Although the increased penetration of rooftop PV is placing some downward pressure wholesale spot prices during daylight hours, price volatility during the evening peak has persisted. The carving out of the NSLP during daylight hours increases the relative weighting of the load profile during the higher priced evening peak and reduces the relative weighting during the lower priced daylight hours.

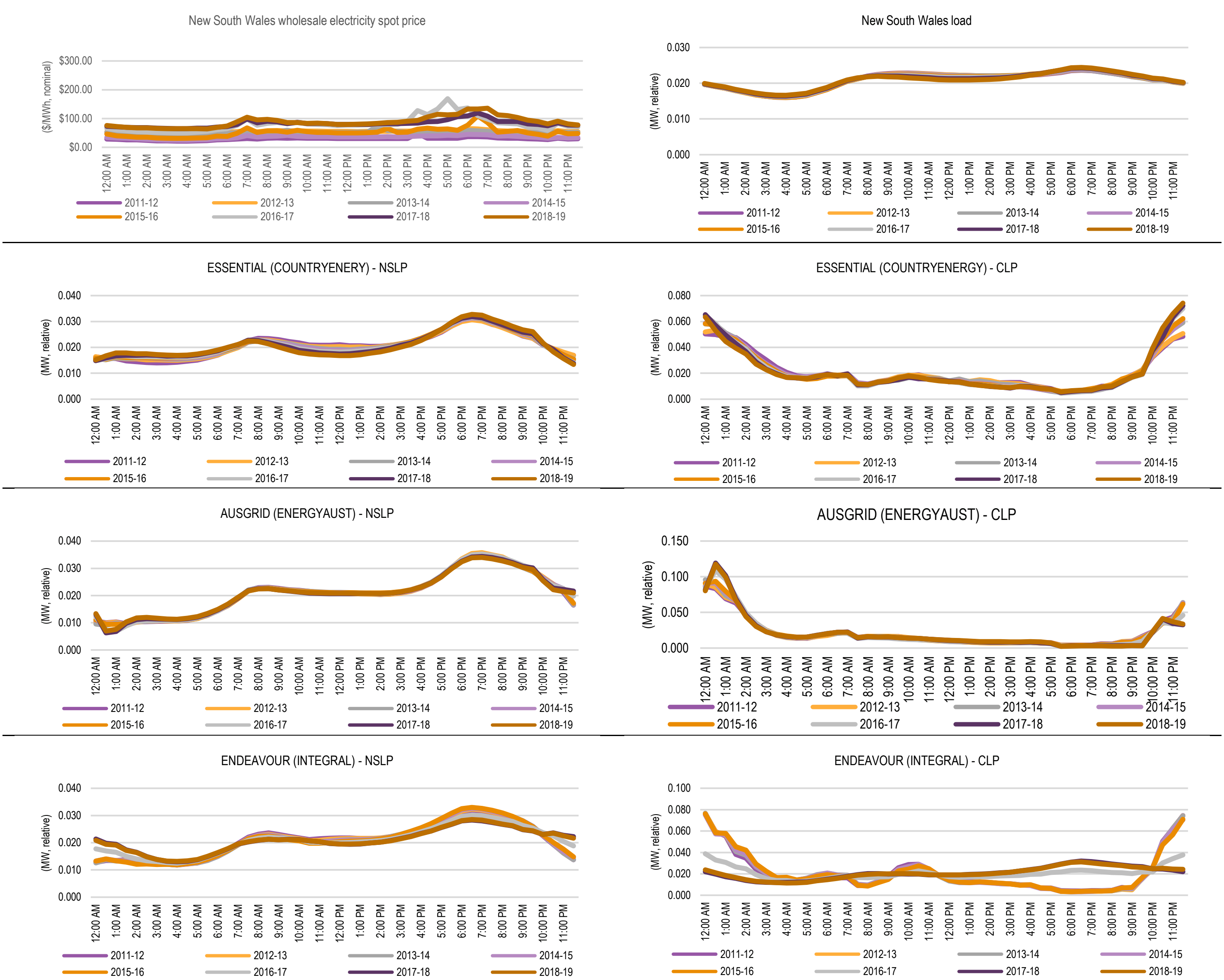
FIGURE 4.1 ACTUAL AVERAGE TIME OF DAY WHOLESALE SPOT PRICE ($/MWH, NOMINAL) AND LOAD PROFILE (MW, RELATIVE) – QUEENSLAND – 2011-12 TO 2018-19



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

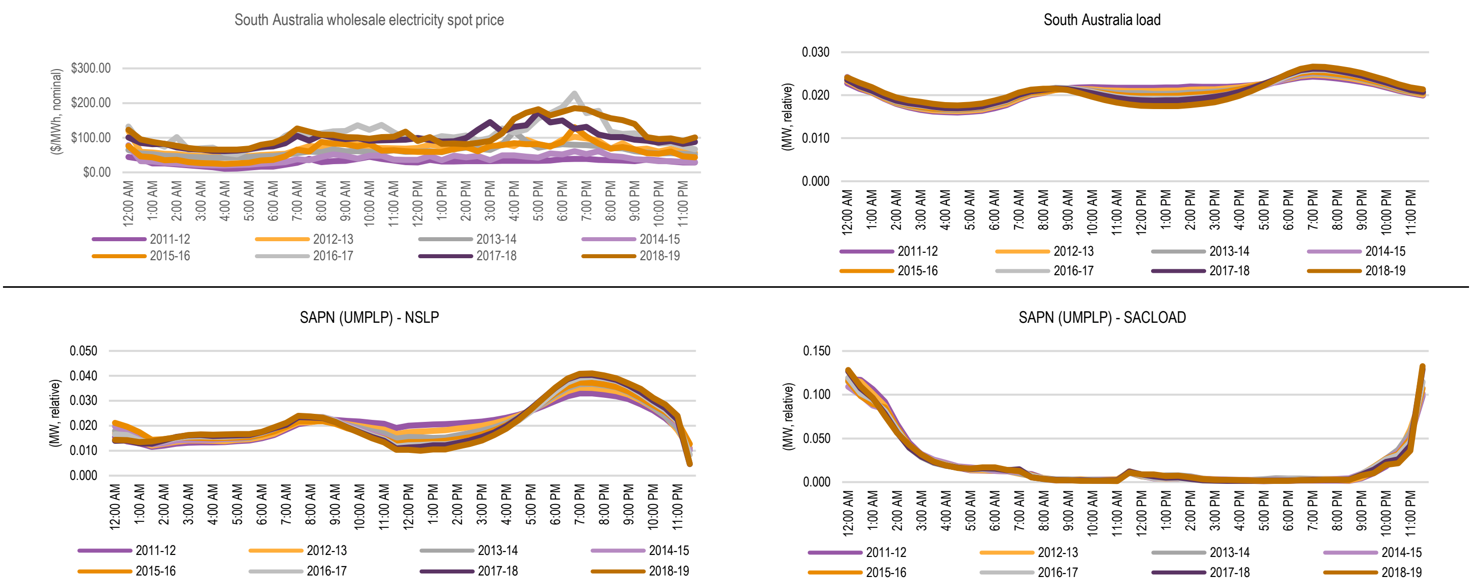
FIGURE 4.2 ACTUAL AVERAGE TIME OF DAY WHOLESALE SPOT PRICE ($/MWH, NOMINAL) AND LOAD PROFILE (MW, RELATIVE) – NEW SOUTH WALES – 2011-12 TO 2018-19



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 4.3 ACTUAL AVERAGE TIME OF DAY WHOLESALE SPOT PRICE ($/MWH, NOMINAL) AND LOAD PROFILE (MW, RELATIVE) – SOUTH AUSTRALIA – 2011-12 TO 2018-19



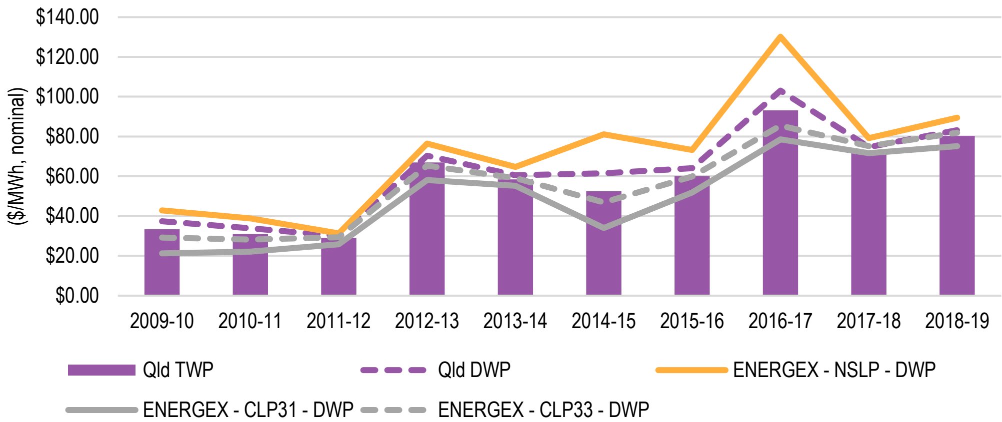
Note: The term relative MW means the loads for each tariff and year have been scaled so they sum to one. This removes differences in absolute scale between the different tariffs and changes in absolute size over time. This is an appropriate representation of the loads since it is the relative shape of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

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

Figure 4.4 to Figure 4.6 show the actual annual demand weighted spot price (DWP) for each of the profiles compared with the regional time weighted average spot price (TWP) over the past 10 years. As expected, the DWPs for the CLPs are below the DWP for the NSLPs in each year. Although the rank order in prices by profile within each region 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 across all three regions resulted in the profiles having relatively similar wholesale spot prices (within their respective region). Conversely, in 2016-17, the increased price volatility across the afternoon period resulted in the NSLP DWPs diverging away from the CLP DWPs.

It is also worth noting that it has only been for four of the past 10 years that the CLPs have noticeably lower DWPs when compared with the NSLPs. ACIL Allen raises this point as it is often noted that the WEC for the control loads produced by our methodology are no longer substantially lower than those of the NSLPs. For example, the change in shape of the Endeavour CLP over the past three years has resulted in it having a DWP about equal to the DWP of the corresponding Endeavour NSLP.

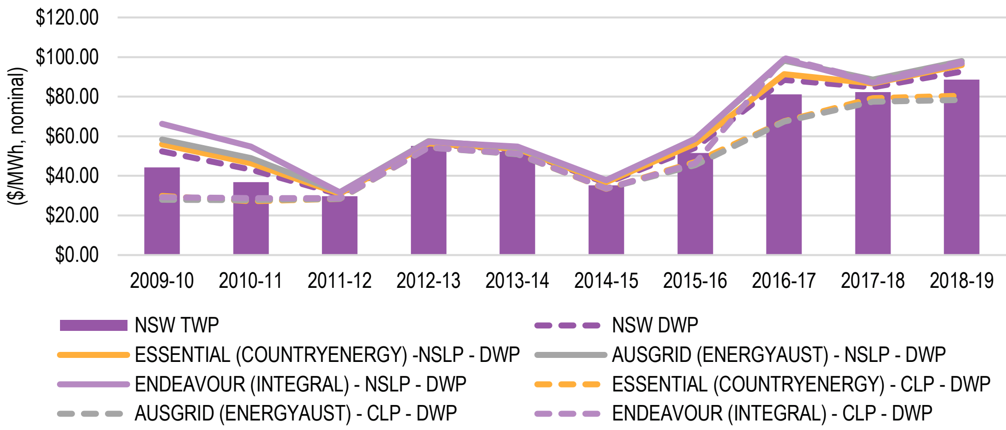
FIGURE 4.4 ACTUAL ANNUAL AVERAGE DEMAND WEIGHTED PRICE ($/MWH, NOMINAL) BY PROFILE AND QUEENSLAND TIME WEIGHTED AVERAGE PRICE ($/MWH, NOMINAL) – 2009-10 TO 2018-19



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

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

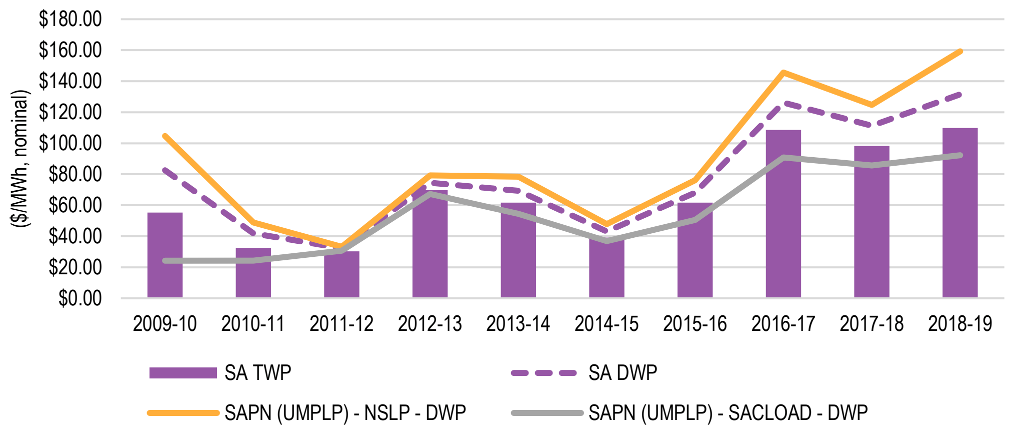
FIGURE 4.5 ACTUAL ANNUAL AVERAGE DEMAND WEIGHTED PRICE ($/MWH, NOMINAL) BY PROFILE AND NEW SOUTH WALES TIME WEIGHTED AVERAGE PRICE ($/MWH, NOMINAL) – 2009-10 TO 2018-19



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

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

FIGURE 4.6 ACTUAL ANNUAL AVERAGE DEMAND WEIGHTED PRICE ($/MWH, NOMINAL) BY PROFILE AND SOUTH AUSTRALIA TIME WEIGHTED AVERAGE PRICE ($/MWH, NOMINAL) – 2009-10 TO 2018-19



Note: Values reported are spot (or uncontracted) prices.
SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

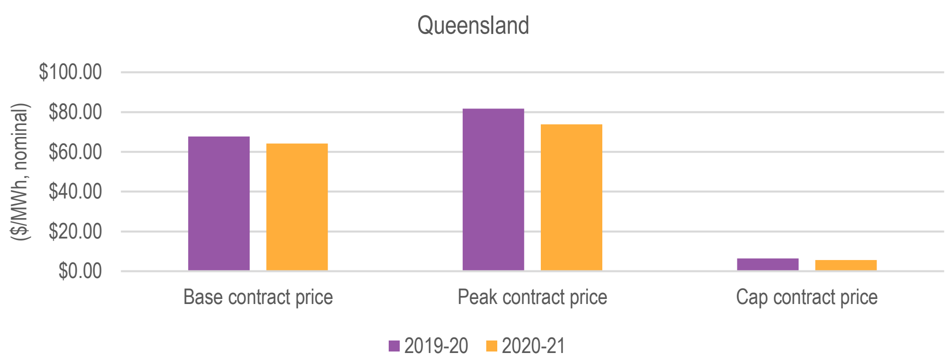
The volatility of spot prices (timing and incidence) provides the incentive to a retailer to hedge their load, since hedging of the loads reduces a retailer's exposure to the volatility. The suite of contracts (as defined by base/peak, swap/cap and quarter) used in the methodology does not change from 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 profiles year on year, as is shown in Figure 4.7.

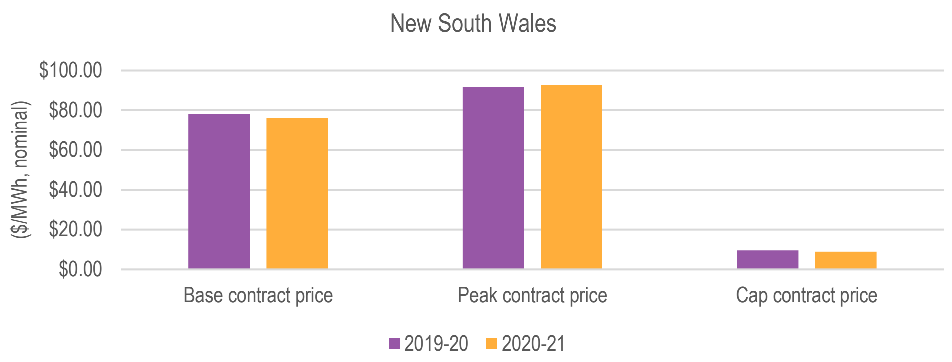
Compared with the 2019-20, futures base contract prices for 2020-21, on an annualised and trade weighted basis to date, have:

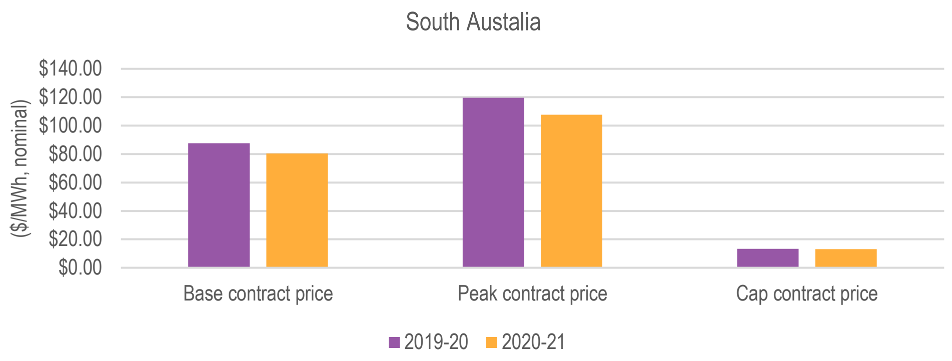
— decreased by about $3.60/MWh for Queensland
— decreased by about $2.10/MWh for New South Wales
— decreased by about $7.30/MWh for South Australia.

The market is clearly expecting some softening in price outcomes due to the strong increase in renewable investment coming on-line between 2019-20 and 2020-21. About 5,200 MW of renewable investment will enter the NEM over the next 18 months. Interestingly, cap prices, on a trade weighted basis have decreased marginally on an annual basis between 2019-20 and 2020-21 – suggesting that overall the market is not expecting the 5,200 MW of additional renewable capacity to increase price volatility.

FIGURE 4.7 BASE, PEAK AND CAP CONTRACT PRICES ($/MWH, NOMINAL) – 2019-20 AND 2020-21







SOURCE: ACIL ALLEN ANALYSIS OF ASX ENERGY DATA

4.2 Estimation of the Wholesale Energy Cost

4.2.1 Estimating contract prices

Contract prices were estimated using the trade-weighted average of ASX Energy daily settlement prices since the contract was listed up until 6 January 2020 inclusive. These were supplemented with broker data in the case of peak contracts. We note there was high agreement between the ASX Energy prices and the broker data – with the difference in prices from the two sources typically less than 0.5 per cent.

Table 4.1 shows the estimated quarterly swap and cap contract prices for 2019-20 and 2020-21.

TABLE 4.1 ESTIMATED CONTRACT PRICES ($/MWH, NOMINAL) - QUEENSLAND

	Q3	Q4	Q1	Q2
		2019-20		
Base	$68.22	$63.79	$80.07	$59.23
Peak	$76.10	$72.08	$106.56	$72.35
Cap	$2.89	$5.01	$14.87	$3.11
		2020-21		
Base	$60.40	$62.20	$78.51	$56.00
Peak	$68.22	$68.71	$93.79	$65.02
Cap	$2.44	$3.94	$13.43	$2.65
		Percentage change from 2019-20 to 2020-21		
Base	-11%	-2%	-2%	-5%
Peak	-10%	-5%	-12%	-10%

	Q3	Q4	Q1	Q2
Cap	-15%	-21%	-10%	-15%

SOURCE: ACIL ALLEN ANALYSIS USING ASX ENERGY DATA UP TO 10 APRIL 2019 FOR 2019-20, AND UP TO 6 JANUARY 2020 FOR 2020-21

TABLE 4.2 ESTIMATED CONTRACT PRICES ($/MWH, NOMINAL) – NEW SOUTH WALES

	Q3	Q4	Q1	Q2
		2019-20		
Base	$80.79	$71.48	$88.22	$72.40
Peak	$94.83	$85.29	$108.40	$78.21
Cap	$6.17	$7.53	$18.44	$6.15
		2020-21		
Base	$73.47	$73.74	$90.12	$67.26
Peak	$80.07	$83.02	$124.00	$84.00
Cap	$4.81	$7.30	$19.04	$4.91
		Percentage change from 2019-20 to 2020-21		
Base	-9%	3%	2%	-7%
Peak	-16%	-3%	14%	7%
Cap	-22%	-3%	3%	-20%

SOURCE: ACIL ALLEN ANALYSIS USING ASX ENERGY DATA UP TO 10 APRIL 2019 FOR 2019-20, AND UP TO 6 JANUARY 2020 FOR 2020-21

TABLE 4.3 ESTIMATED CONTRACT PRICES ($/MWH, NOMINAL) –SOUTH AUSTRALIA

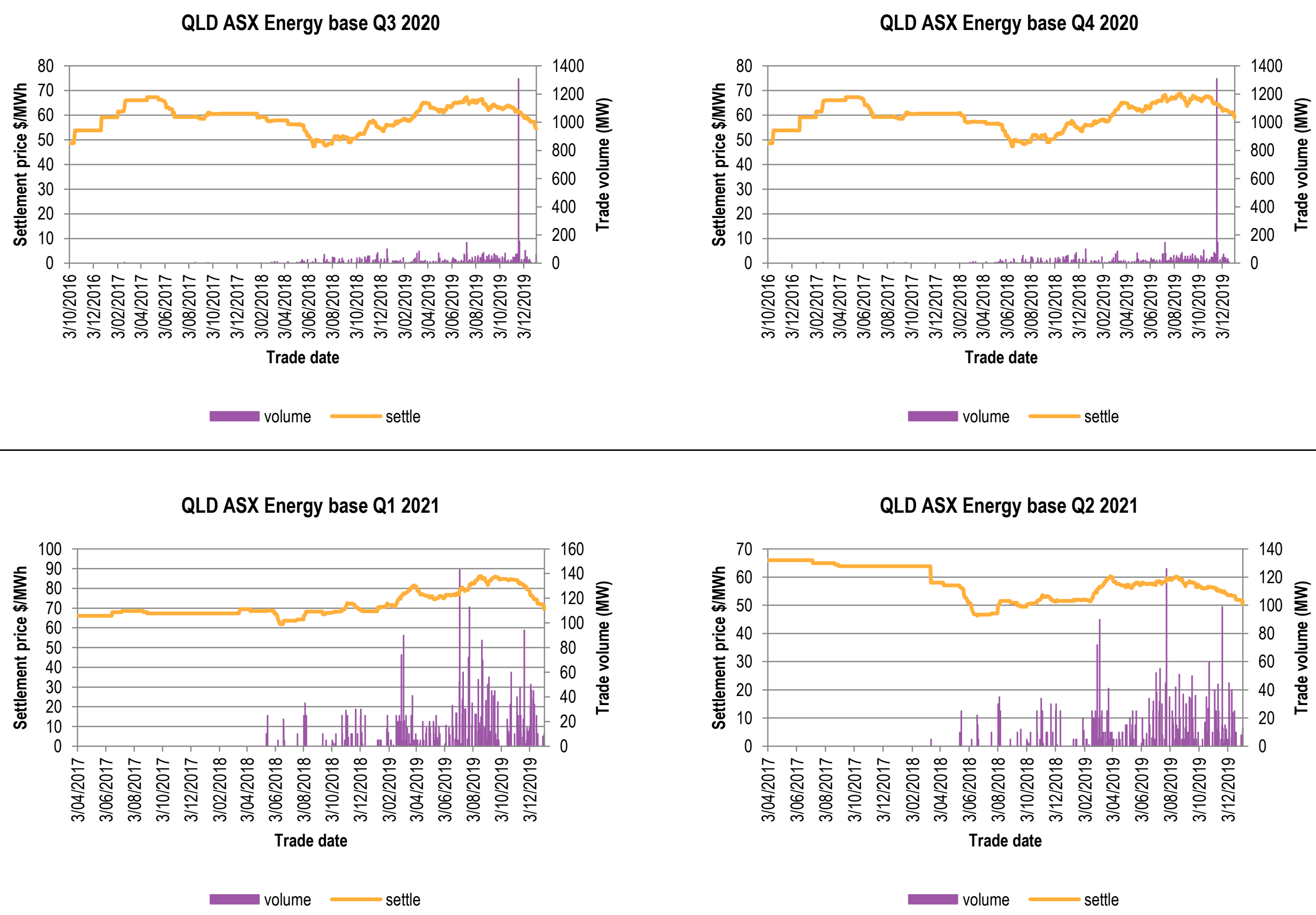
	Q3	Q4	Q1	Q2
		2019-20		
Base	$87.26	$78.16	$111.89	$73.86
Peak	$108.56	$102.67	$170.00	$98.00
Cap	$6.94	$8.94	$30.18	$7.60
		2020-21		
Base	$72.39	$70.68	$108.31	$70.85
Peak	$97.56	$93.45	$157.00	$83.40
Cap	$7.14	$7.25	$30.41	$7.70
		Percentage change from 2019-20 to 2020-21		
Base	-17%	-10%	-3%	-4%
Peak	-10%	-9%	-8%	-15%
Cap	3%	-19%	1%	1%

SOURCE: ACIL ALLEN ANALYSIS USING ASX ENERGY DATA UP TO 10 APRIL 2019 FOR 2019-20, AND UP TO 6 JANUARY 2020 FOR 2020-21

Contract prices decrease for 2019-20 to 2020-21 for all products and quarters in Queensland, although less so for quarter one. In New South Wales, although prices decrease overall, they increase in quarter one, when compared with 2019-20 – with base prices increasing by 2 per cent, and cap prices increasing by 3 per cent. Similarly, in South Australia, quarter one prices exhibit the smallest decrease compared with other quarters. However, base contracts decrease for all four quarters in South Australia for 2020-21. It appears the market is of the view that an increase renewable energy penetration, at this stage, will not reduce prices to the same extent in quarter one as in other quarters, or is less certain that prices in quarter one will decrease.

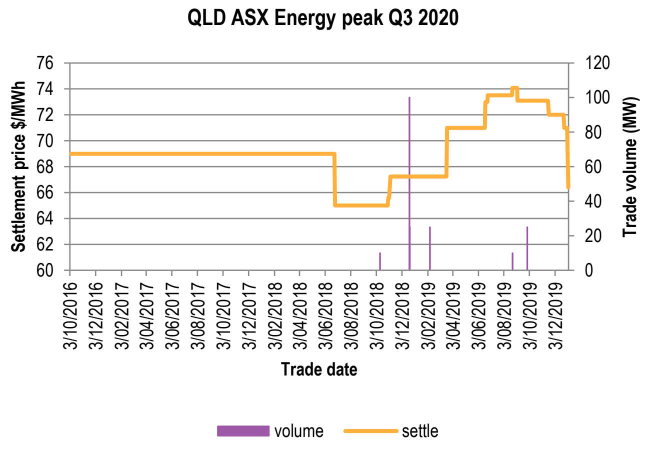
The following charts show daily settlement prices and trade volumes for 2020-21 ASX Energy quarterly base futures, peak futures and cap contracts up to 6 January 2020. It can be seen that the of trading of these contracts tends to commence from about June 2018.

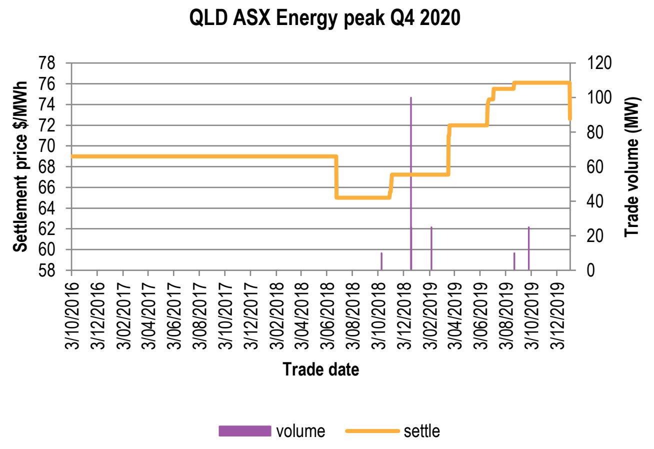
FIGURE 4.8 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY BASE FUTURES - QUEENSLAND

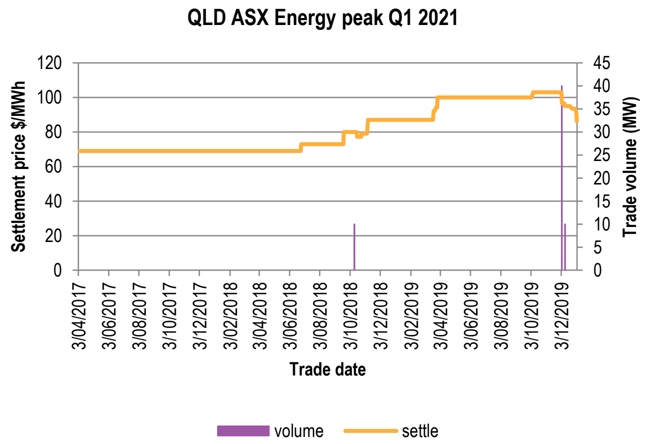


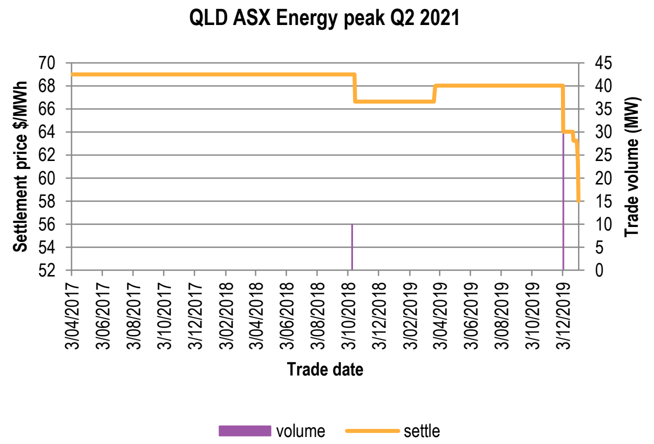
SOURCE: ASX ENERGY DATA UP TO 6 JANUARY 2020

FIGURE 4.9 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY PEAK FUTURES - QUEENSLAND



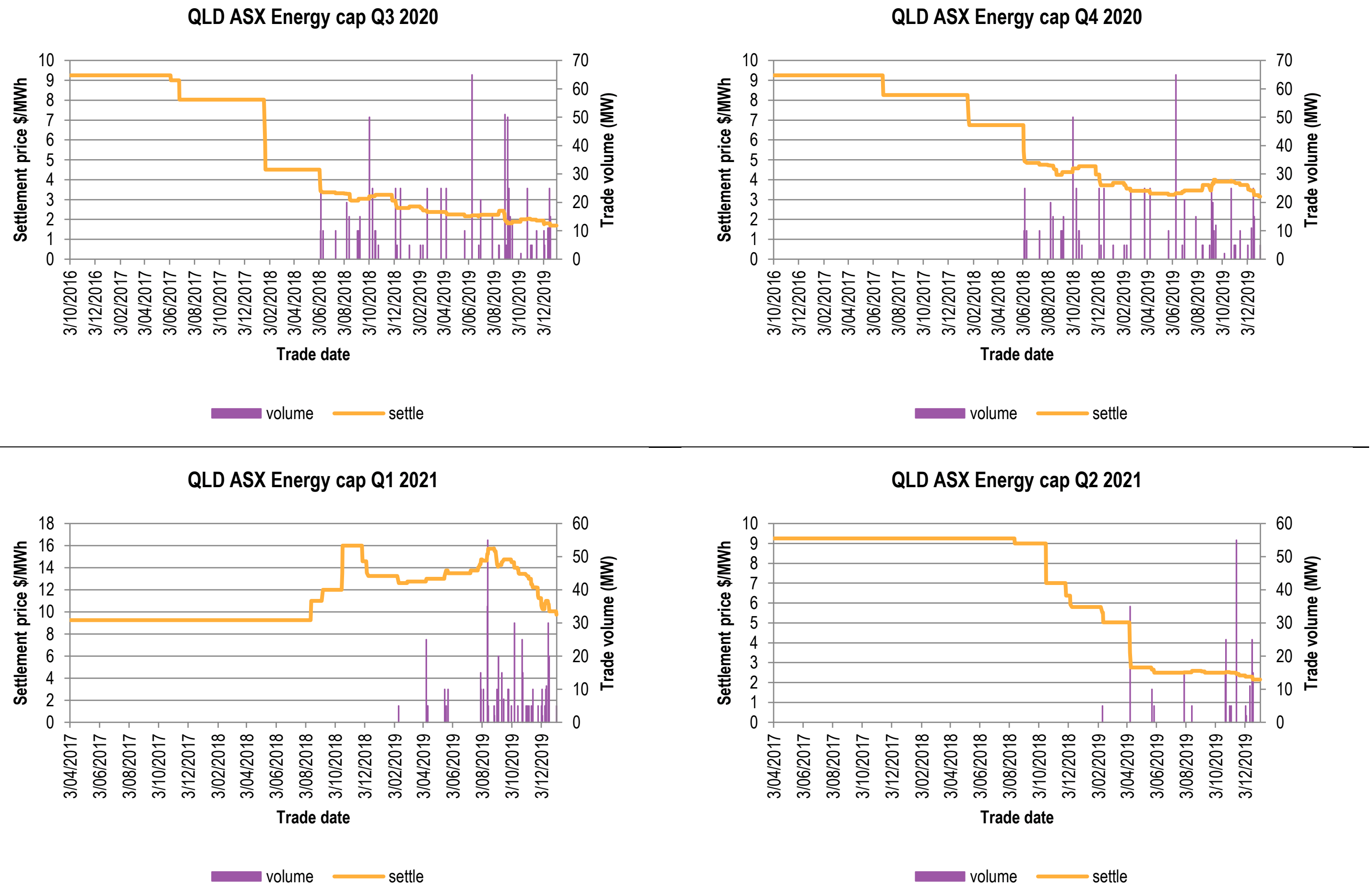






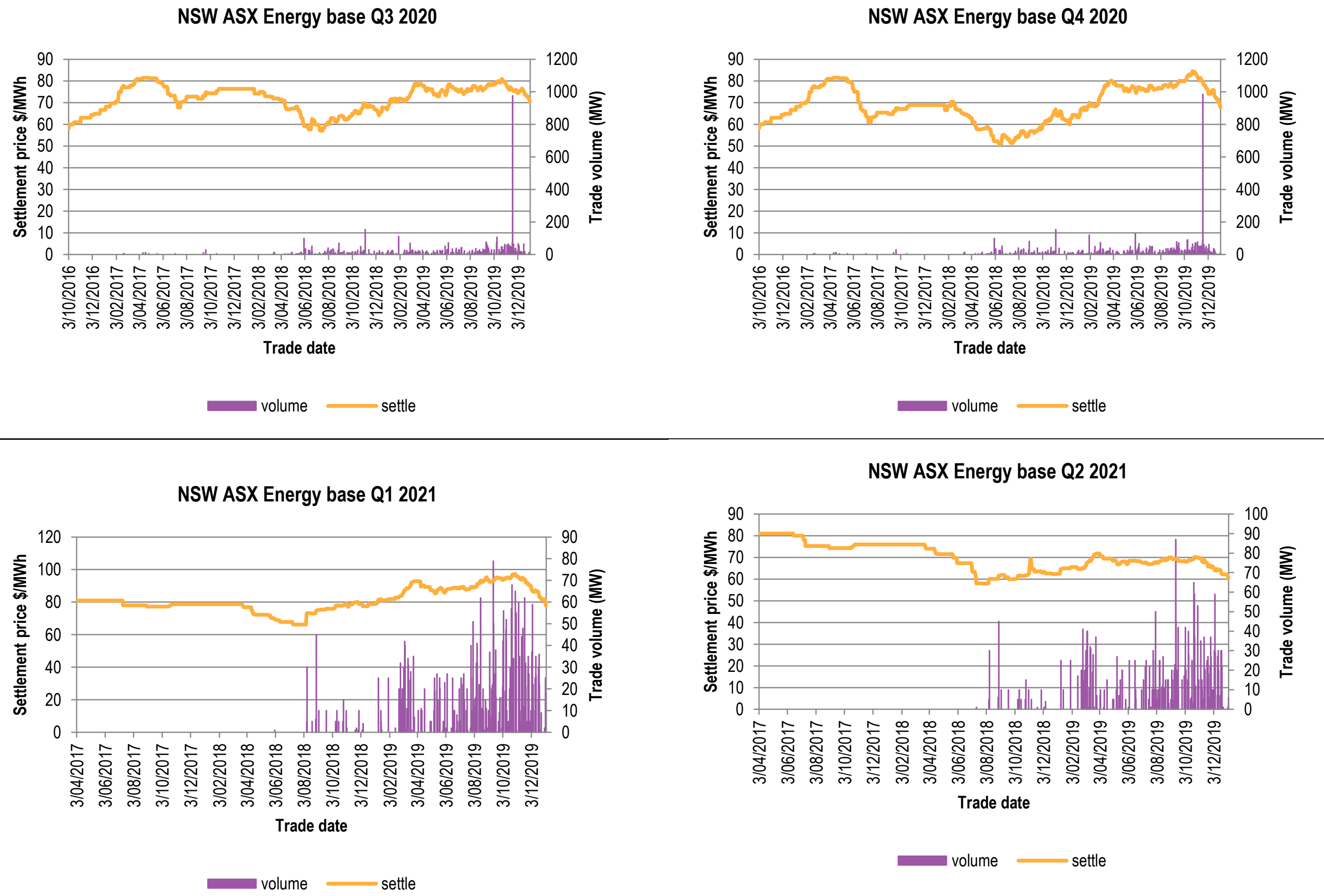
SOURCE: ASX ENERGY DATA UP TO 6 JANUARY 2020

FIGURE 4.10 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY $300 CAP CONTRACTS - QUEENSLAND



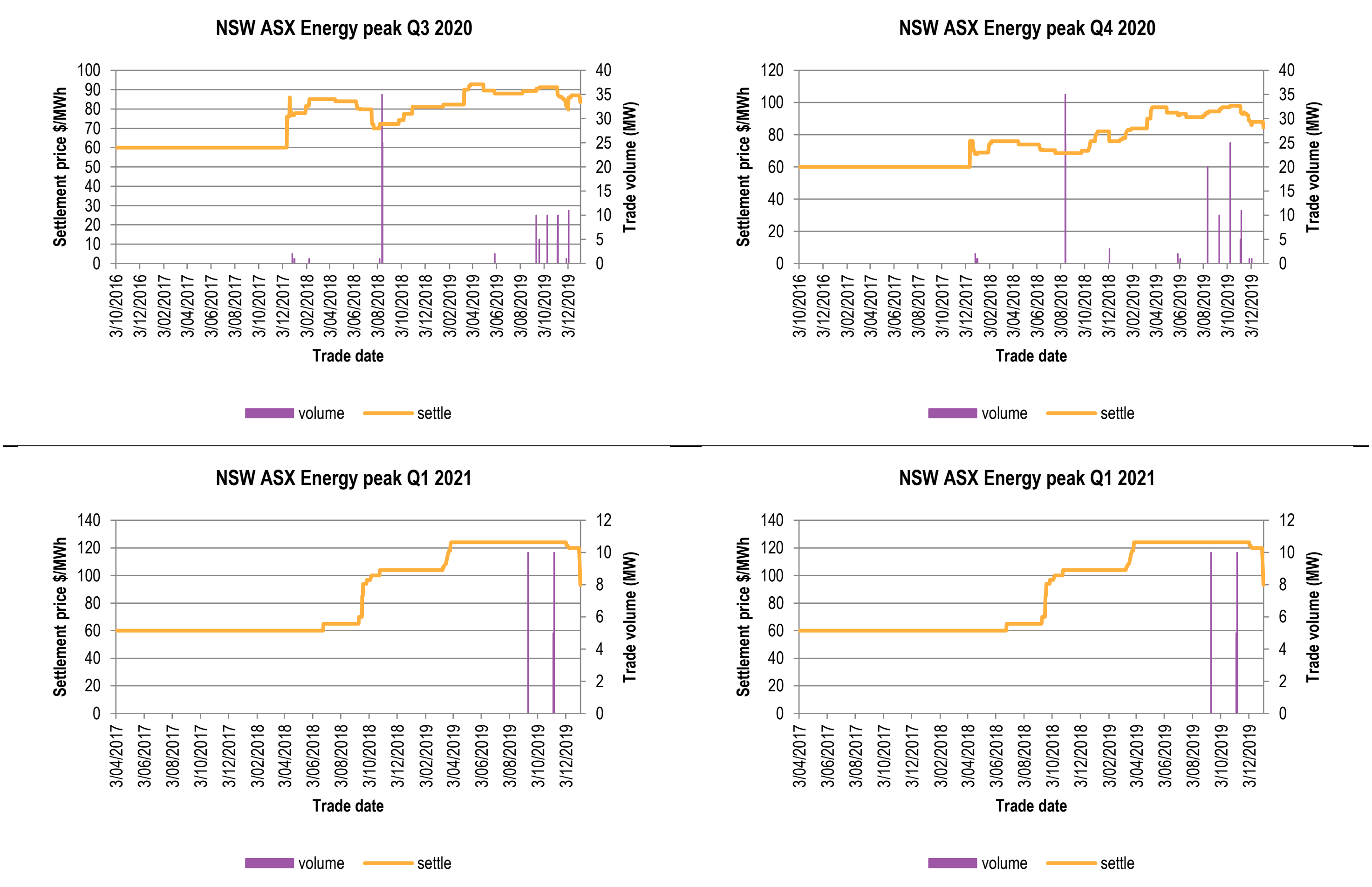
SOURCE: ASX ENERGY DATA UP TO 6 JANUARY 2020

FIGURE 4.11 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY BASE FUTURES – NEW SOUTH WALES



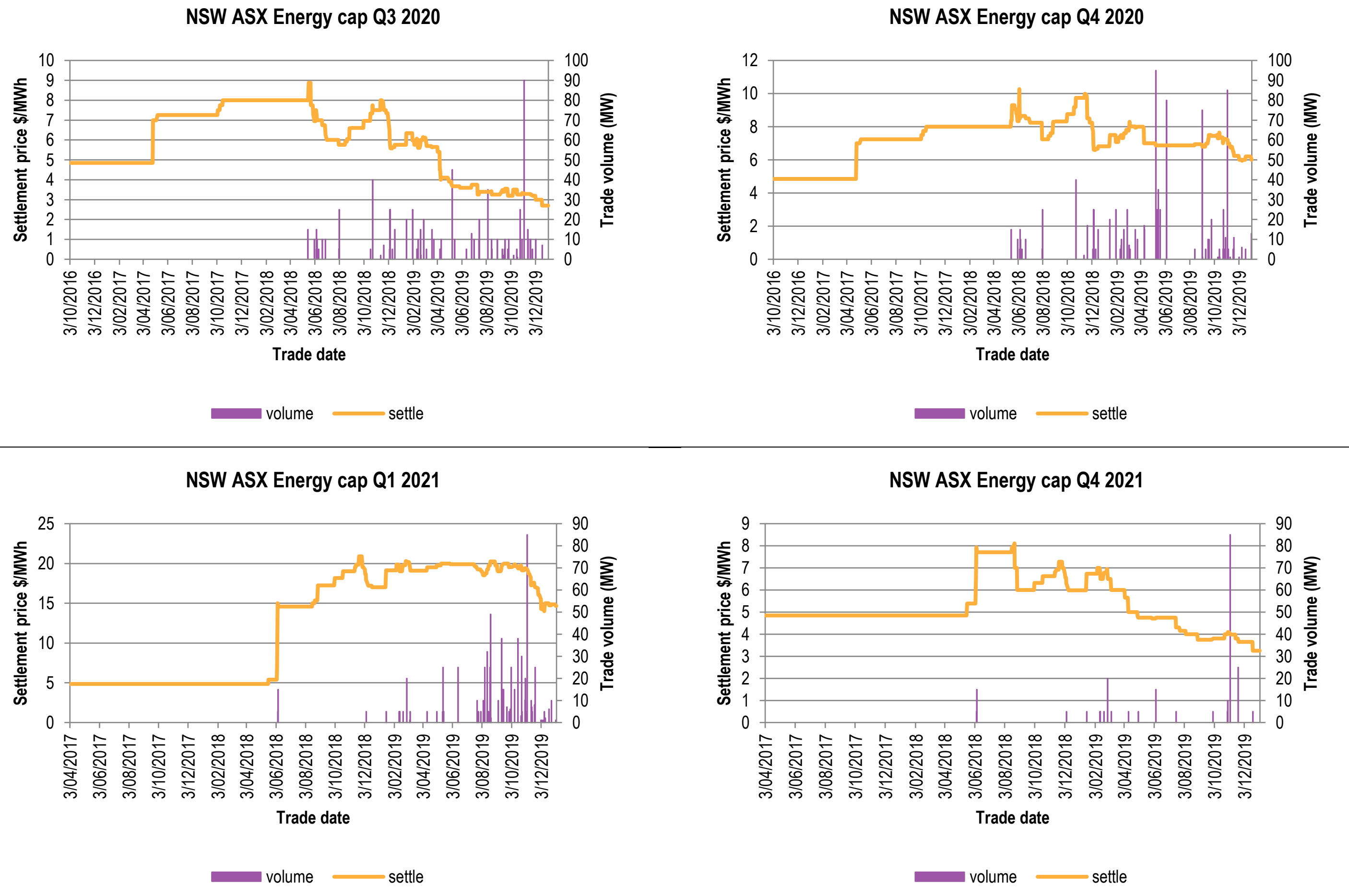
SOURCE: ASX ENERGY DATA UP TO 6 JANUARY 2020

FIGURE 4.12 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY PEAK FUTURES – NEW SOUTH WALES



SOURCE: ASX ENERGY DATA UP TO 6 JANUARY 2020

FIGURE 4.13 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY $300 CAP CONTRACTS – NEW SOUTH WALES

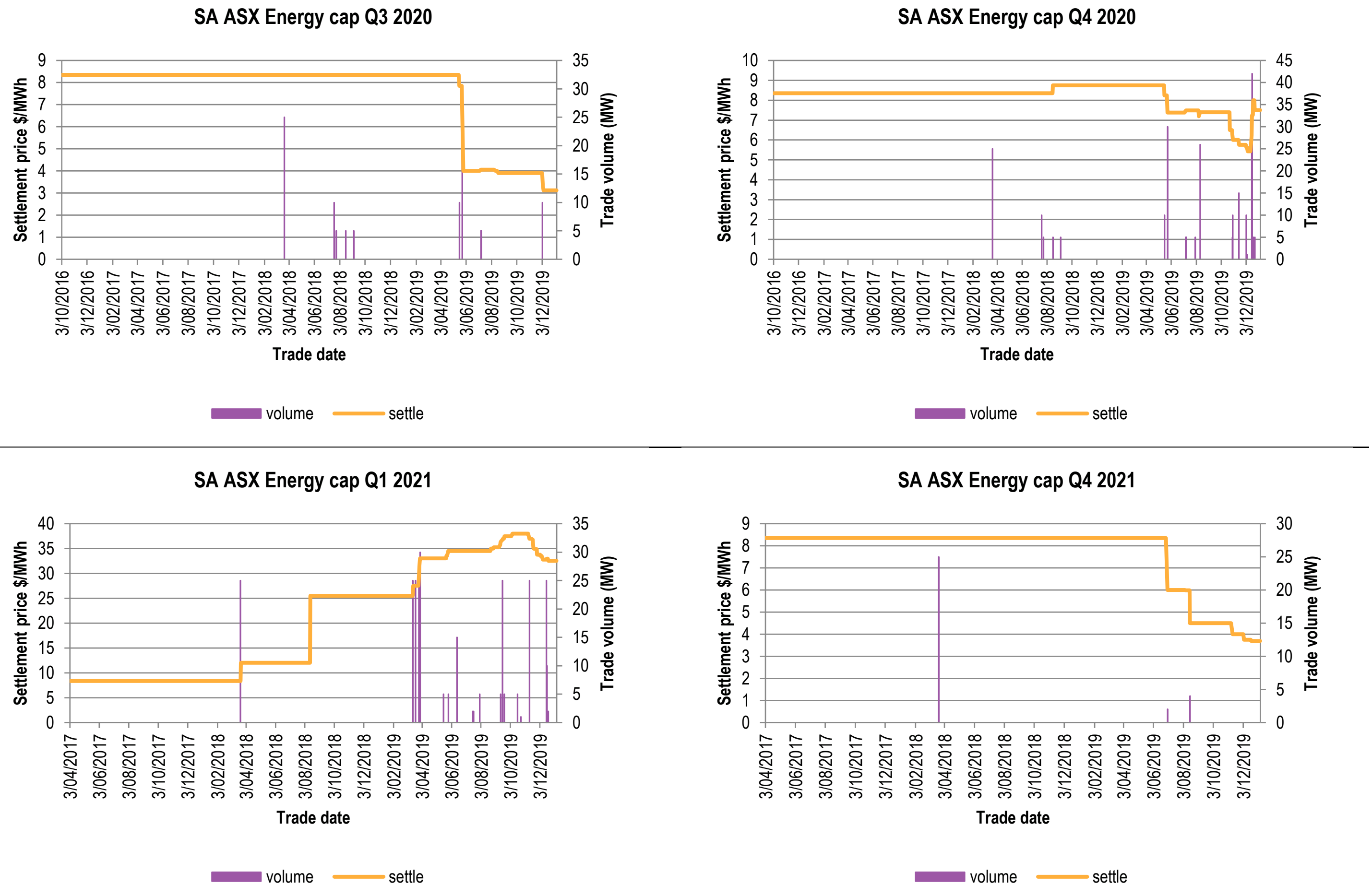


SOURCE: ASX ENERGY DATA UP TO 7 JANUARY 2020

FIGURE 4.14 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY BASE FUTURES – SOUTH AUSTRALIA

SOURCE: ASX ENERGY DATA UP TO 6 JANUARY 2020

FIGURE 4.15 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY $300 CAP CONTRACTS – SOUTH AUSTRALIA



SOURCE: ASX ENERGY DATA UP TO 6 JANUARY 2020

4.2.2 Estimating wholesale spot prices

ACIL Allen's proprietary electricity model, *PowerMark* was run to estimate the hourly pool prices for the 539 simulations (48 demand and 11 outage sets).

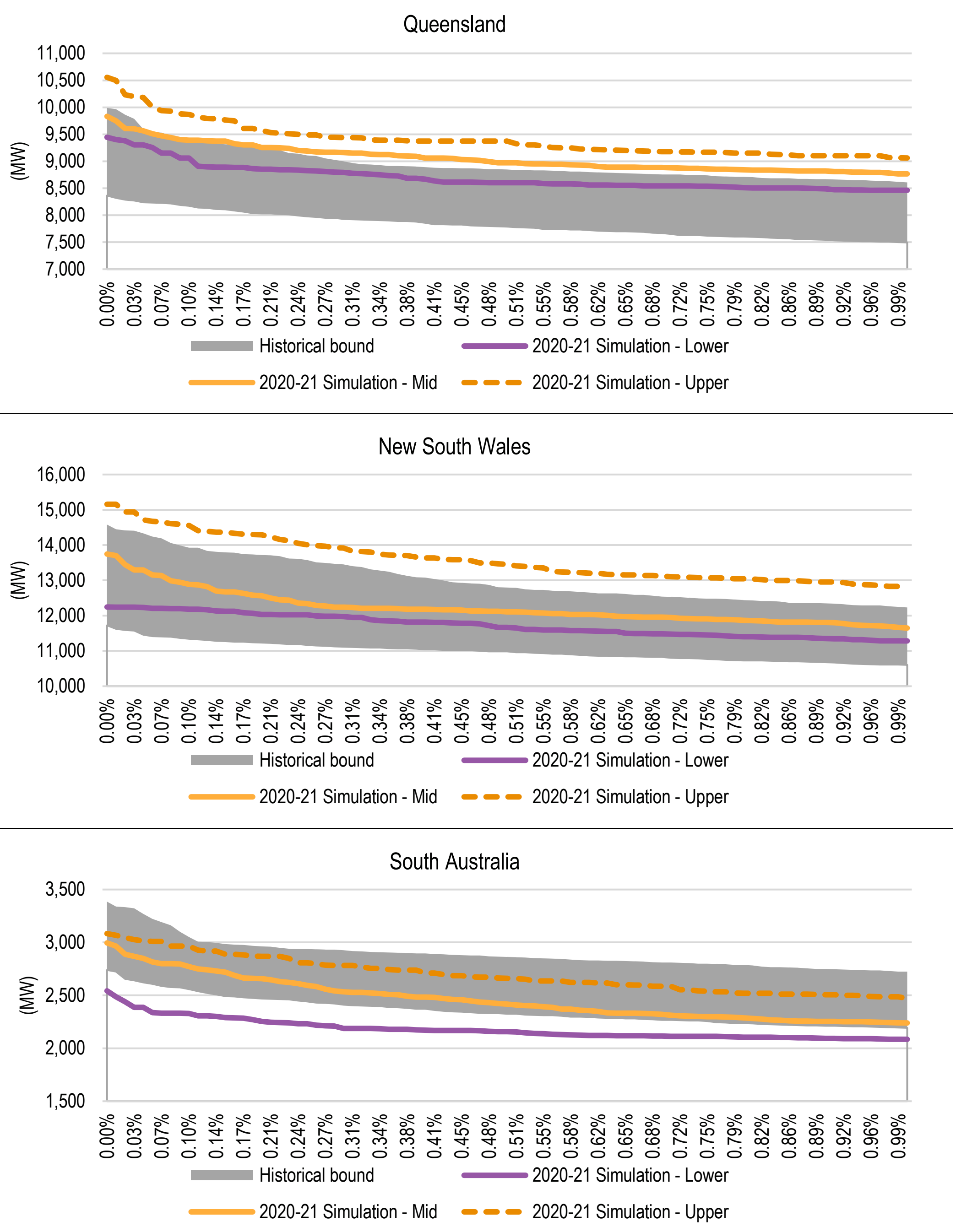
Figure 4.16 shows the range of the upper one percent segment of the demand duration curves for the 49 simulated Queensland, New South Wales and South Australia system demand sets resulting from the methodology for 2020-21, along with the range in historical demands since 2011-12. The simulated demand sets represent the upper, lower and middle of the range of demand duration curves across all 49 simulated sets. It can be seen that the demand duration curves of the simulated demand sets for 2020-21 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[10]. This variation in demand contributes to the variation in modelled pool price outcomes as discussed further in this section.

We do not expect the simulated demand sets to line up perfectly with the historical demand sets, in terms of their absolute location. For example, the simulated demand sets for 2020-21 are generally higher than the pre-2016-17 observed demand outcomes in Queensland due to the step increase in demand due to the in-field compression associated with the LNG export projects in Gladstone. What is

[10] The simulated demand sets for 2020-21 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.

important, is that the range in simulated outcomes reflects the range experienced in the past, indicating that the methodology is accounting for an appropriate degree of uncertainty.

FIGURE 4.16 TOP ONE PERCENT HOURLY SYSTEM DEMANDS



SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

Figure 4.17 shows the range of the simulated NSLP demands envelope recent. This variation results in the annual load factor[11] of the 2020-21 simulated demand sets ranging between:

— 26 percent and 35 percent compared with a range of 29 percent to 43 percent for the actual Energex NSLP between 2009-10 and 2018-19 (as shown in Figure 4.18)

[11] 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.

- 32 percent and 40 percent compared with a range of 41 percent to 51 percent for the actual Essential NSLP between 2009-10 and 2018-19
- 26 percent and 31 percent compared with a range of 31 percent to 36 percent for the actual Ausgrid NSLP between 2009-10 and 2018-19
- 25 percent and 34 percent compared with a range of 31 percent to 39 percent for the actual Endeavour NSLP between 2009-10 and 2018-19
- 20 percent and 27 percent compared with a range of 21 percent to 33 percent for the actual SAPN NSLP between 2009-10 and 2018-19.

With the exception of the Endeavour and Ausgrid NSLPs, 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.

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 4.17 TOP ONE PERCENT HOURLY DEMANDS - NSLPS

SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

FIGURE 4.18 COMPARISON OF LOAD FACTOR OF 2020-21 SIMULATED HOURLY DEMAND DURATION CURVES AND HISTORICAL OUTCOMES - NSLPS

SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

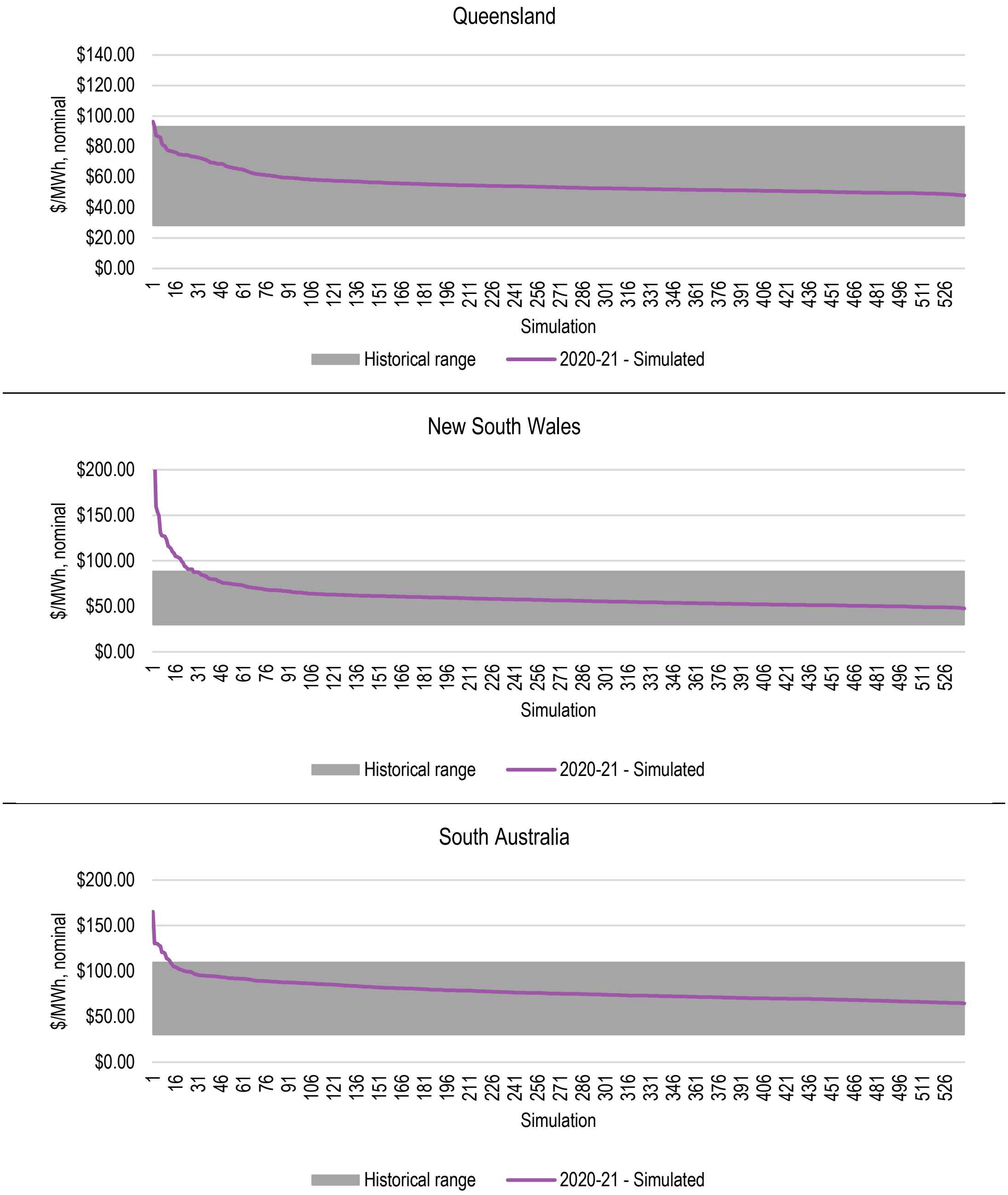
Figure 4.19 compares the modelled annual regional TWP for the 539 simulations for 2020-21 with the regional TWPs from the past 19 years. Although there have been changes to both the supply and demand side of the market, the graph clearly shows that the simulations cover a wide range in potential prices for 2020-21 when compared with the past 19 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 in Queensland, have the effect of influencing an increase in the lower bound of annual price outcomes.

The upper bound of the simulations for 2020-21 sits well above the historic upper bound of actual outcomes for New South Wales and South Australia, and at about the same level as the upper bound of historical outcomes in Queensland.

In Queensland, 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, which will place a natural cap on price outcomes. In New South Wales, the recent observed increase in variation in thermal power station availability has been included in the simulations which contributes to the increase in range of simulated annual price outcomes.

ACIL Allen is satisfied that in an aggregate sense the distribution of the 539 simulations for 2020-21 cover an adequately wide range of possible annual pool price outcomes for all three regions.

FIGURE 4.19 ANNUAL TWP FOR QUEENSLAND, NEW SOUTH WALES, AND SOUTH AUSTRALIA FOR 539 SIMULATIONS FOR 20-21 COMPARED WITH RANGE OF ACTUAL ANNUAL OUTCOMES IN PAST YEARS



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

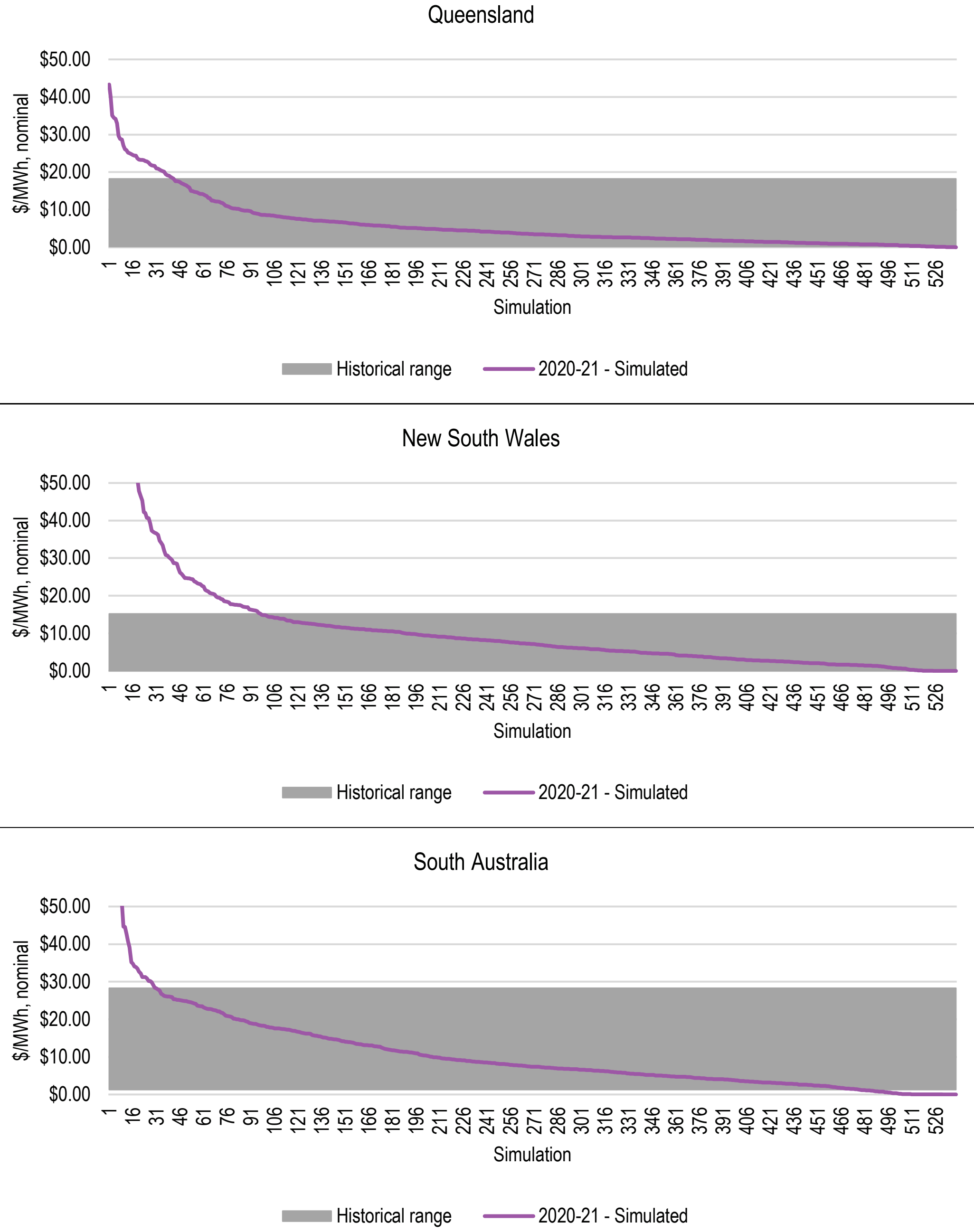
Comparing the upper one percent of hourly prices in the simulations with historical spot prices shows the spread of the hourly prices from the simulations also more than adequately covers the historical spread of spot prices, as shown in Figure 4.20. It is also notable, that as would be expected, the distribution of simulated price outcomes demonstrates a strong positive skewness.

FIGURE 4.20 COMPARISON OF UPPER 1 PERCENT TAIL OF SIMULATED HOURLY PRICE DURATION CURVES FOR QUEENSLAND, NEW SOUTH WALES AND SOUTH AUSTRALIA FOR 2020-21 AND RANGE OF 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 539 simulations. The range in annual average contribution to the TWP, of hourly prices above $300/MWh, for the 539 simulations is consistent with those recorded in history as shown in Figure 4.21.

FIGURE 4.21 ANNUAL AVERAGE CONTRIBUTION TO THE QUEENSLAND, NEW SOUTH WALES, AND SOUTH AUSTRALIA TWP BY PRICES ABOVE $300/MWH IN 2020-21 FOR 539 SIMULATIONS COMPARED WITH RANGE OF ACTUAL OUTCOMES IN PAST YEARS



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

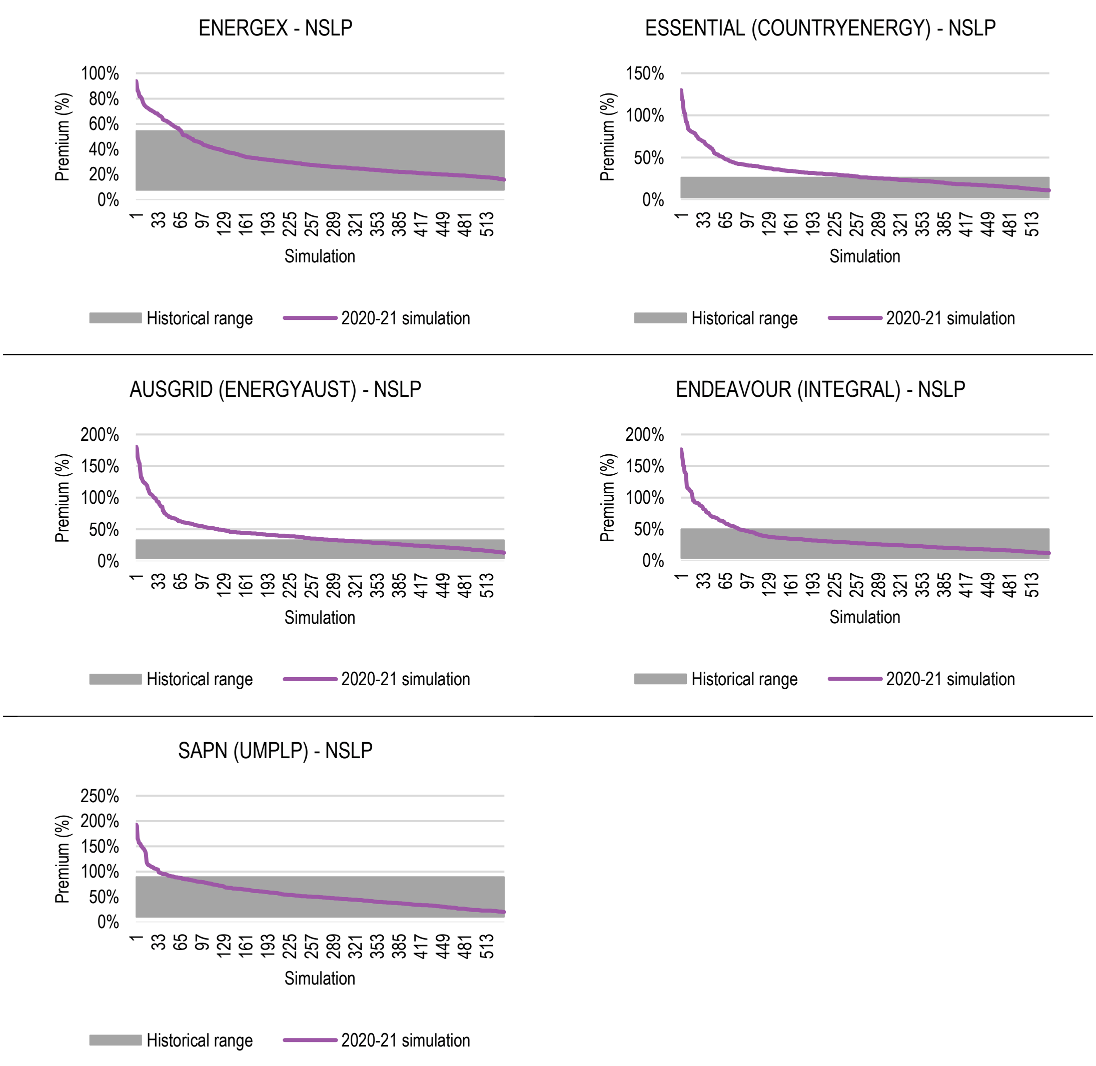
The maximum demand of the NSLP is not in isolation a critical feature in determining the cost of supply. The shape of the NSLP demand trace and its relationship to the shape of the regional demand/price traces is a critical factor in the cost of supplying the NSLP demand.

A test of the appropriateness of the NSLP demand shape and its relationship with the regional demand shape can be undertaken by comparing the annual demand weighted price (DWP) for the NSLP with the corresponding regional TWP. Figure 4.22 shows that, for the past 10 financial years, the DWP for NSLPs as a percentage premium over the corresponding regional TWPs has varied from a low of two percent in 2012-13 in New South Wales to a high of 89 percent in South Australia in

2009-10. In the 539 simulations for 2020-21 for each NSLP, this percentage varies from 12 percent to 193 percent. The modelling suggests a greater range in the premium for 2020-21 as a result of greater variability in thermal power station availability and the increasing influence of variability in renewable energy resource availability with the commissioning of the 5,00 MW or so of reenable energy projects between now and 2021.

The comparison with actual outcomes over the past 10 years in Figure 4.22 demonstrates that the relationship between the NSLP demand and corresponding regional spot prices in the 539 simulations is sound.

FIGURE 4.22 ANNUAL DWP FOR NSLP AS PERCENTAGE PREMIUM OF ANNUAL TWP FOR 539 SIMULATIONS FOR 2020-21 COMPARED WITH RANGE OF ACTUAL OUTCOMES IN PAST YEARS



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

ACIL Allen is satisfied the modelled regional wholesale spot prices from the 539 simulations cover the range of expected price outcomes for 2020-21 across all three regions in terms of annual averages and distributions. These comparisons clearly show that the 49 simulated demand and renewable energy resource traces combined with the 11 thermal power plant outage scenarios provide a sound basis for modelling the expected future range in spot market outcomes for 2020-21.

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 for 2020-21 are calculated for each NSLP for each quarter as follows:

- The base contract volume is set to equal the 50th (Essential, Endeavour, SAPN), 60th (Energex[12], Ausgrid) percentile of the off-peak period hourly demands across all 49 demand sets for the quarter.
- The peak period contract volume is set to equal the 50th (Ausgrid, Essential, Endeavour, SAPN), 70th (Energex) percentile of the peak period hourly demands across all 49 demand sets minus the base contract volumes for the quarter.
- The cap contract volume is set at 90 (SAPN), 100 (Energex, Essential, Endeavour), 110 (Ausgrid) per cent of the median of the annual peak demands across the 49 demand sets minus the base and peak contract volumes.

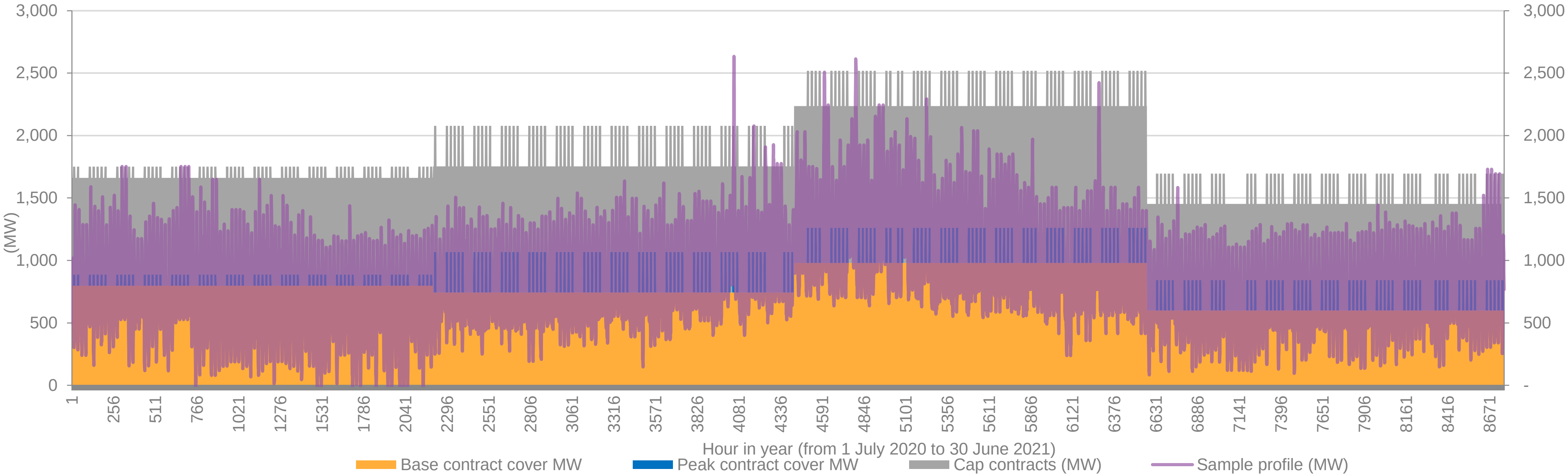
In other words, the same hourly hedge volumes (in MW terms) apply to each of the 49 demand sets for a given NSLP and year, and hence to each of the 539 simulations. To be clear, we are not altering the hedge volume (in MW terms) on an ex-post basis for each of the 49 demand sets. Therefore, the approach 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 weather-related outcomes.

Once established, these contract volumes are then fixed across all 539 simulations when calculating the wholesale energy cost. The contract volumes used are shown in Figure 4.23 to Figure 4.27.

Generally, the contracting strategies place little, if any, reliance on peak contracts – with the notable exception being the Energex NSLP. This is not surprising – the trade weighted price differential between base and peak contracts in Queensland is about $7/MWh (on an annual basis), compared with a differential of $16/MWh in New South Wales, and $26/MWh in South Australia. In other words, peak contracts in Queensland are relatively more attractive than in New South Wales and South Australia. As a consequence, the hedging strategy search algorithm finds there is benefit in entering into peak contract arrangements for the Energex NSLP. If the differential between peak and base contract prices in New South Wales and South Australia was smaller, then the resulting strategy may well include more peak contracts for the NSLPs in these regions.

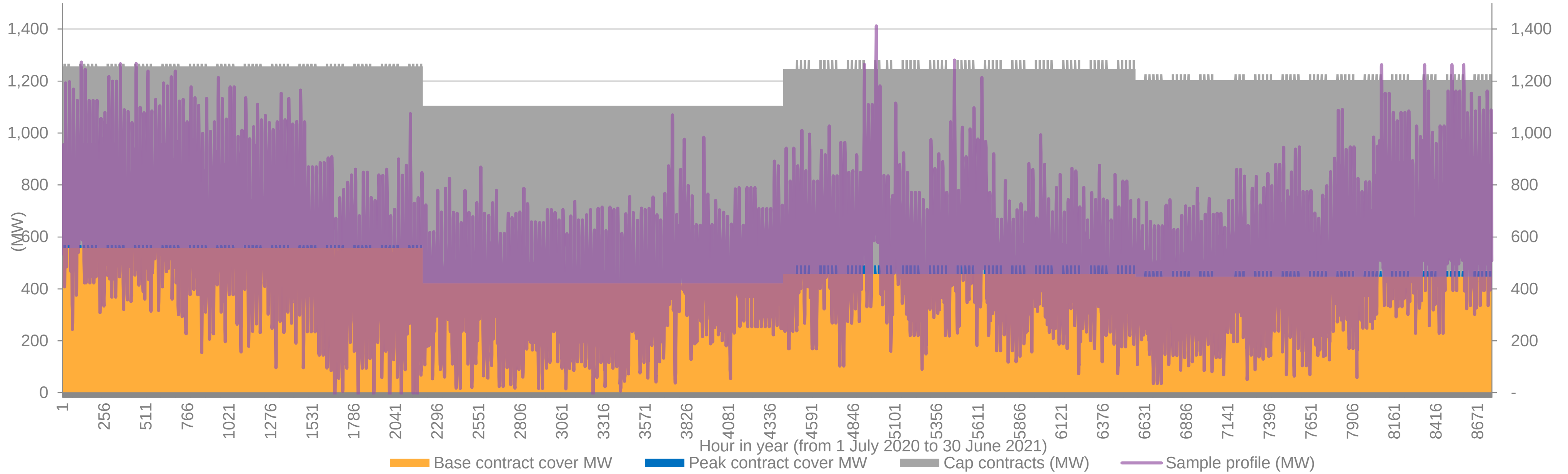
[12] For 2019-20, we have used the hedging strategy adopted for the QCA 2019-20 determination for the Energex NSLP – to remain consistent with that determination. However, given the continued strong uptake in rooftop PV over the past 12 months in Queensland, we have adjusted the strategy slightly for 2020-21.

FIGURE 4.23 CONTRACT VOLUMES USED IN HEDGE MODELLING OF 539 SIMULATIONS FOR 2020-21 FOR ENERGEX NSLP



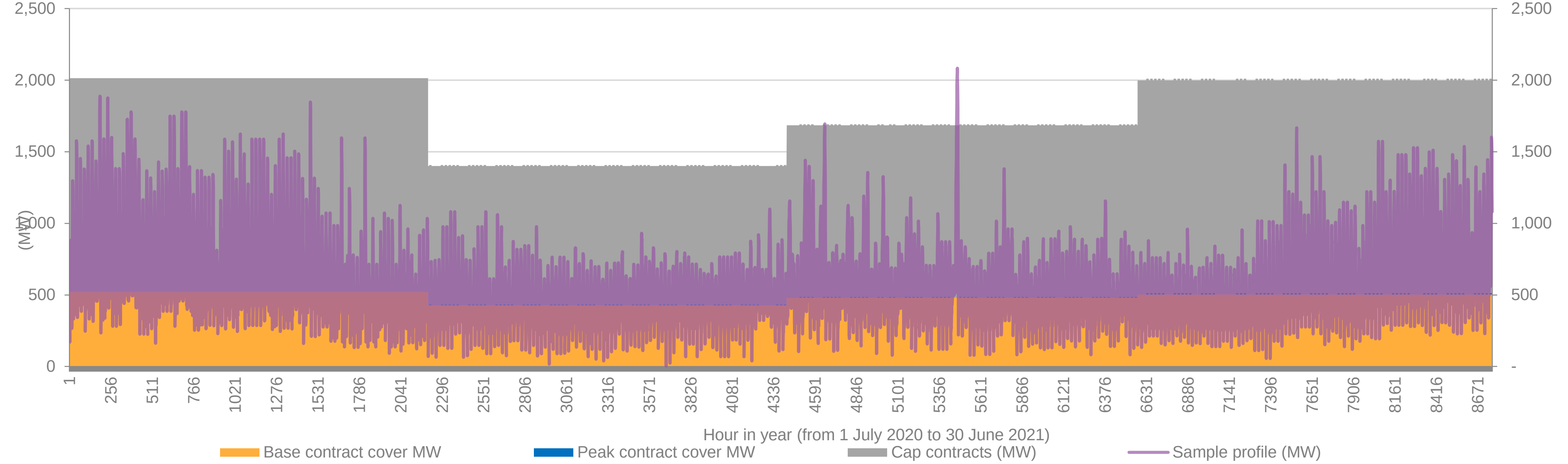
SOURCE: ACIL ALLEN

FIGURE 4.24 CONTRACT VOLUMES USED IN HEDGE MODELLING OF 539 SIMULATIONS FOR 2020-21 FOR ESSENTIAL (COUNTRYENERGY) NSLP



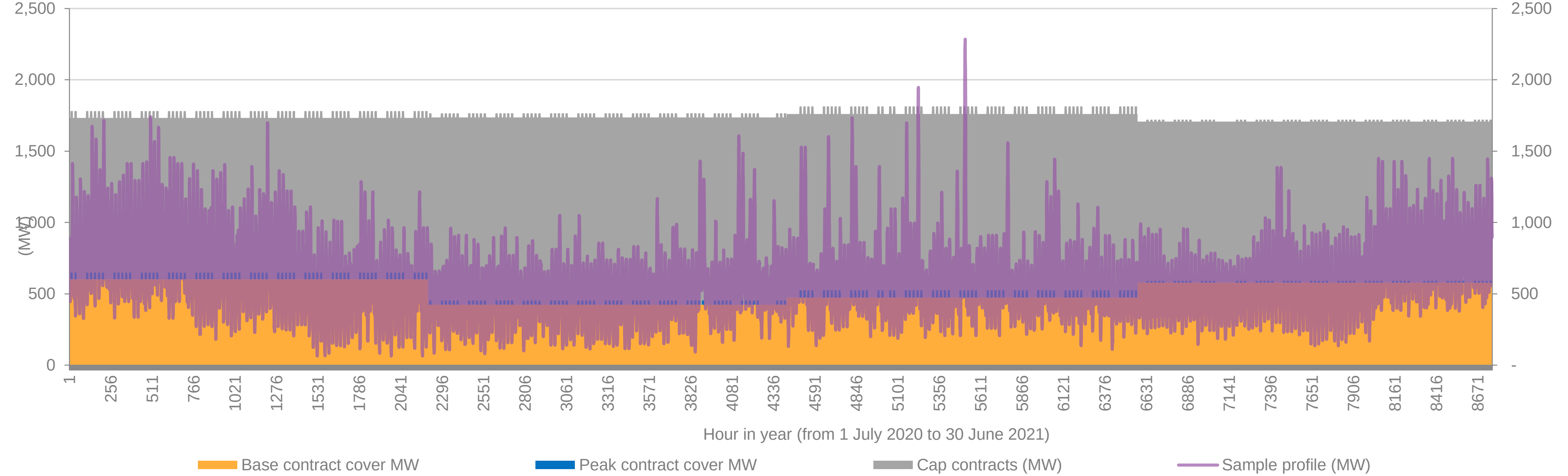
SOURCE: ACIL ALLEN

FIGURE 4.25 CONTRACT VOLUMES USED IN HEDGE MODELLING OF 539 SIMULATIONS FOR 2020-21 FOR AUSGRID (ENERGYAUST) NSLP



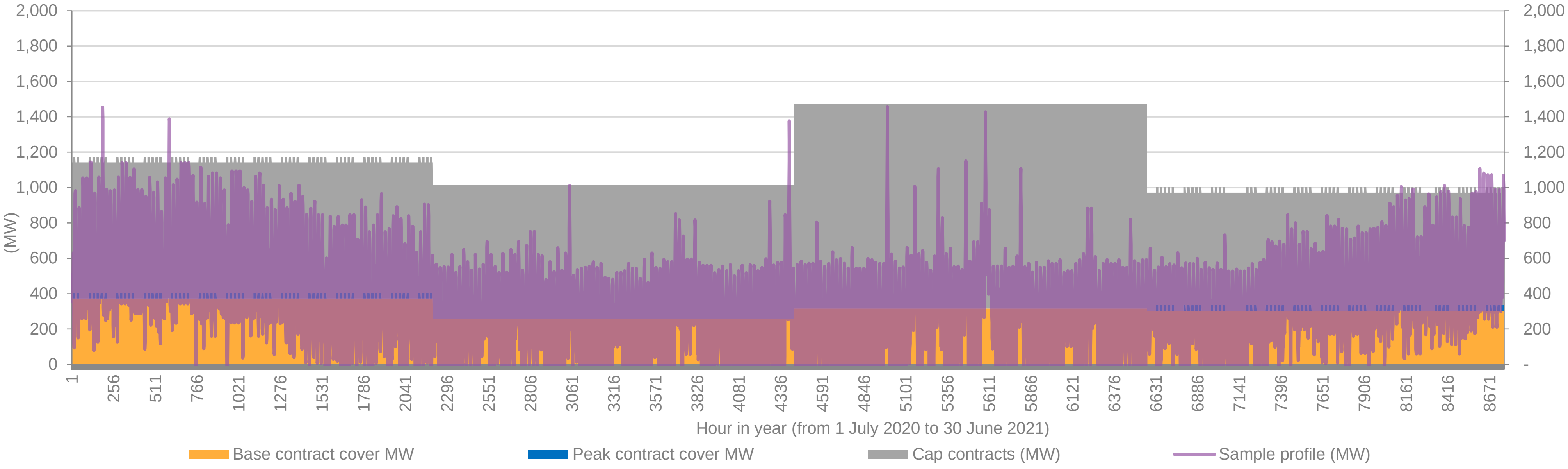
SOURCE: ACIL ALLEN

FIGURE 4.26 CONTRACT VOLUMES USED IN HEDGE MODELLING OF 539 SIMULATIONS FOR 2020-21 FOR ENDEAVOUR (INTEGRAL) NSLP



SOURCE: ACIL ALLEN

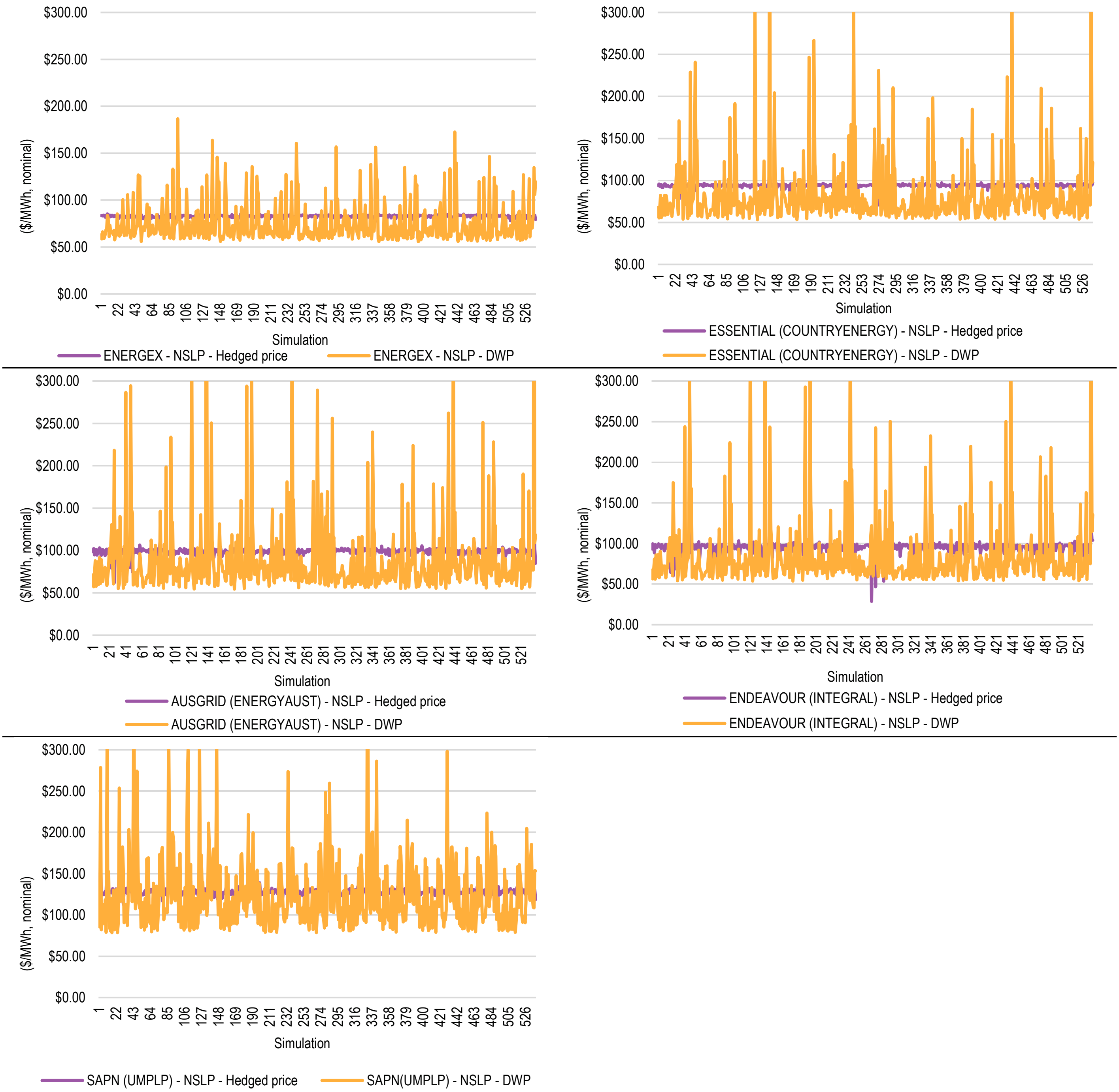
FIGURE 4.27 CONTRACT VOLUMES USED IN HEDGE MODELLING OF 539 SIMULATIONS FOR 2020-21 FOR SAPN (UMPLP) NSLP



SOURCE: ACIL ALLEN

Figure 4.28 shows that, by using the above contracting strategies, the variation in the annual hedged price for each NSLP is far less than the variation if the NSLP was to be supplied without any hedging and relied solely on spot price outcomes.

FIGURE 4.28 ANNUAL HEDGED PRICE AND DWP ($/MWH, NOMINAL) FOR NSLPS FOR THE 539 SIMULATIONS – 2020-21



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 539 annual hedged prices. ACIL Allen's estimate of the WEC for each profile for 2019-20 and 2020-21 are shown in Table 4.4.

TABLE 4.4 ESTIMATED WEC ($/MWH, NOMINAL) FOR 2019-20 AND 2020-21 AT THE REGIONAL REFERENCE NODE

Settlement classes	2019-20	2020-21	Change from 2019-20 to 2020-21 (%)
Ausgrid - NSLP	$102.99	$104.12	1.10%
Endeavour - NSLP	$99.94	$104.05	4.11%
Essential - NSLP	$94.69	$96.90	2.33%
Ausgrid - CLP1	$76.74	$67.98	-11.42%
Ausgrid - CLP2	$72.46	$66.31	-8.48%
Endeavour - CLP	$90.44	$96.51	6.71%
Essential - CLP	$87.08	$82.63	-5.11%
Energex - NSLP	$89.16	$85.21	-4.43%
Energex - CLP1	$64.91	$65.93	1.57%
Energex - CLP2	$72.85	$67.47	-7.39%
SAPN - NSLP	$141.39	$135.53	-4.14%
SAPN - CLP	$92.23	$81.40	-11.74%

SOURCE: ACIL ALLEN ANALYSIS

The WECs for the New South Wales NSLPs increase slightly between 2019-20 and 2020-21. This is despite a marginal decrease overall in the contract prices between these two years. However, contract prices in quarter one and four (the summer quarters) increase slightly – and it is these quarters that tend to display the great level of volatility in terms of demand and spot price outcomes. Further, the projected continued uptake of rooftop PV installations for customers in these networks is resulting in the profiles becoming sufficiently peakier so as to increase the cost of hedging the NSLP profiles (all other things equal). Further, the WEC for the Endeavour NSLP increases at a slightly higher rate than the Ausgrid and Essential NSLPs. Historical data (see **Figure 4.2**) shows the time of day shape of the Endeavour NSLP tends to exhibit a higher degree of volatility which will be influencing the projected WEC estimates.

The WECs for the NSLPs in Queensland and South Australia decline between 2019-20 and 2020-21 as a result of stronger declines in contract prices (compared with New South Wales) and less change in the demand profiles since the penetration of rooftop PV is much greater already in these two regions compared with New South Wales.

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.

The change in WEC for the CLPs is a mixed result – with some increasing and others decreasing between 2019-20 and 2020-21. The change in WEC of the CLPs is reflecting the change in shape of the load profiles. For example, the Endeavour CLP WEC increases by about seven per cent between 2019-20 and 2020-21 – this is largely a result of the change in its shape as discussed earlier. It is worth noting that it is the distribution network service providers more than consumer behaviour that control the shape of the CLPs.

4.3 Estimation of renewable energy policy costs

Renewable energy scheme (RET)

The RET scheme consists of two elements – the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). Liable parties (i.e. all electricity retailers[13]) are required to comply and surrender certificates for both LRET and SRES.

Energy costs associated with the LRET and the SRES have been estimated using price information from brokers TFS, information published by the Clean Energy Regulator (CER) and modelling by ACIL Allen. Retailer compliance with these schemes operates on a calendar year basis and hence estimates are required for 2019, 2020 and 2021 calendar years, with the costs averaged to estimate the 2019-20 and 2020-21 financial year costs.[14]

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 forward prices for 2019, 2020 and 2021 from brokers TFS[15]
— the Renewable Power Percentage (RPP) for 2019 of 18.60 per cent as published by the CER
— mandated LRET targets for 2020 and 2021 of 33,850 GWh and 33,000 GWh, respectively
— estimated RPP values for 2020 and 2021 of 19.61 per cent and 19.44 per cent, respectively[16]
— the binding Small-scale Technology Percentage (STP) for 2019 of 21.73 per cent as published by the CER
— non-binding STP value for 2020 of 14.56 per cent (for use in the 2019-20 estimate only), as published by the CER
— estimated STP values for 2020 (for use in the 2020-21 estimate only) and 2021 of 26.42 per cent and 22.15 per cent, respectively[17]
— CER clearing house price[18] for 2019, 2020 and 2021 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.

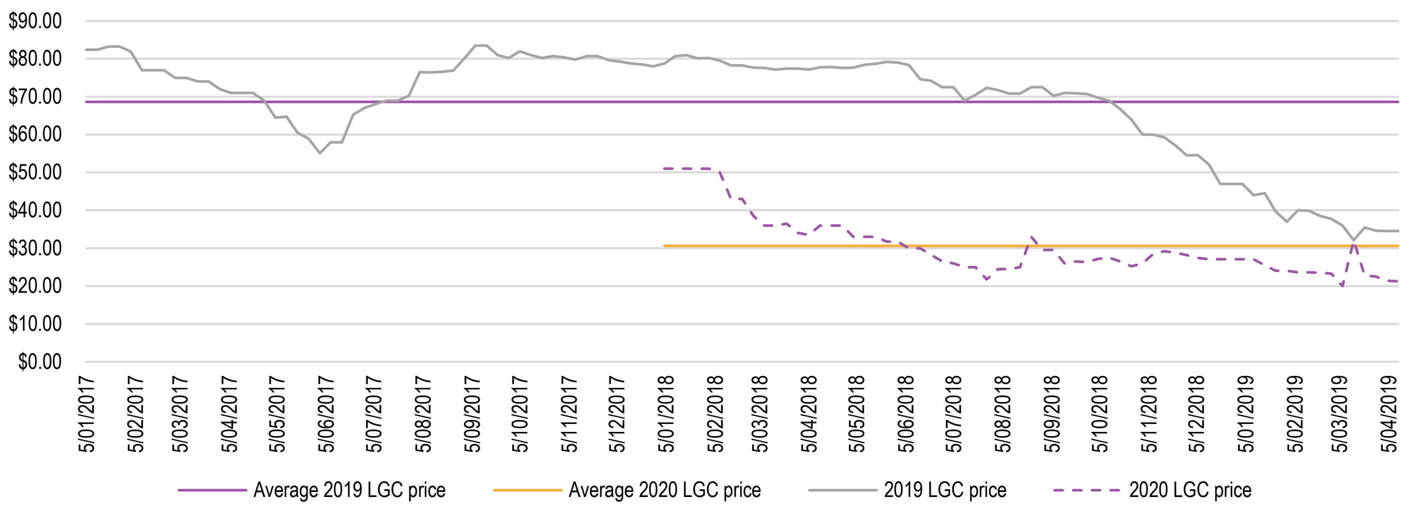
The LGC price used in assessing the cost of the scheme for 2019-20 and 2020-21 is found by averaging the forward prices for the 2019, 2020 and 2021 calendar years, respectively during the two years prior to the commencement of the compliance years. This assumes that LGC coverage is built up over a two-year period (see Figure 4.29 and Figure 4.30). The average LGC prices calculated from

[13] 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.
[14] Two estimates for 2020 have been presented – one for 2019-20, which is assumed to have been calculated in April 2019, and the other for 2020-21, which is calculated using data up to 20 November 2019.
[15] For 2019-20 and 2020-21, TFS data includes prices up to and including 10 April 2019 and 6 January 2020, respectively.
[16] The RPP values for 2020 and 2021 were estimated using ACIL Allen's estimate of liable acquisitions for 2020 and 2021 and the mandated LRET targets as published by CER.
[17] The STP value for 2020 and 2021 were estimated using ACIL Allen's estimates of STC creations and liable acquisitions in 2020 and 2021
[18] Although there is an active market for STCs, ACIL Allen is not compelled to use market prices. This is mainly because historical prices might not be the best indicators of future prices as the market is designed to clear every year – so in theory prices could be $40 or at least very close to it. This assumes that the CER provides an accurate forecast of created certificates underpinning the STP for the next year.

the TFS data are $68.64/MWh for 2019 and $30.61/MWh for 2020 for 2019-20, and $29.98/MWh for 2020 and $15.14/MWh for 2021 for 2020-21. Since the time of estimating the cost for 2019-20, 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 and 2020
  - The surge in investment in renewables have been driven by falling costs of renewables, demand for PPAs from corporates and increased appetite of renewable investors to take on merchant exposure
- The significantly lower average price for 2020 reflects the high likelihood that the LRET scheme will be fully subscribed by 2020.

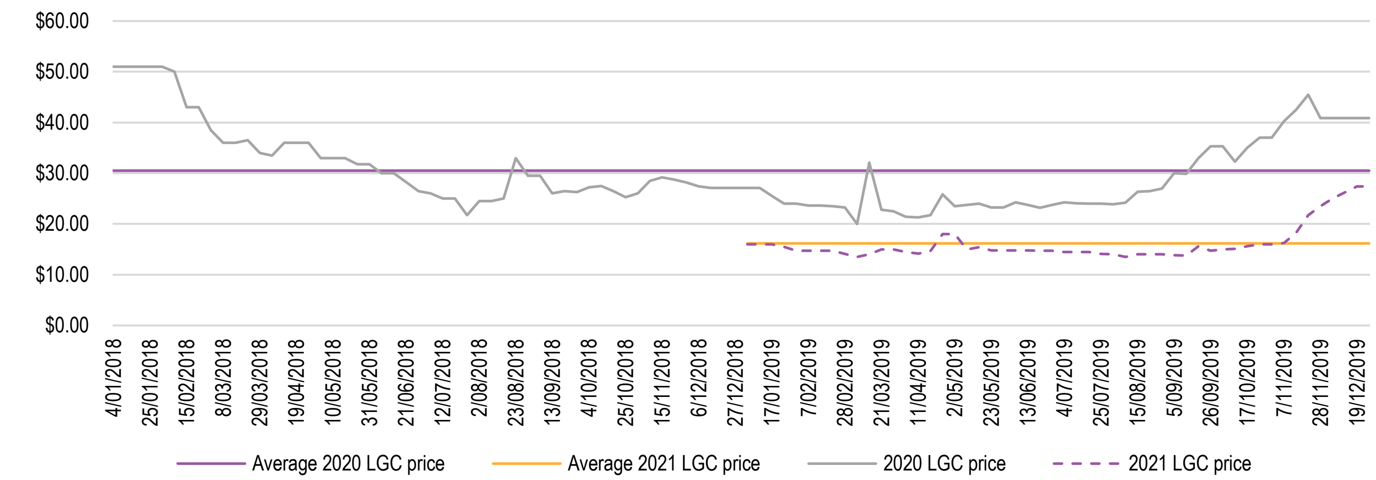
FIGURE 4.29 LGC PRICES FOR 2019 AND 2020 FOR 2019-20 ($/LGC, NOMINAL)



SOURCE: TFS AND ACIL ALLEN ANALYSIS

There has been a slight increase in LGC forward prices since around August 2019 and this is due to delays in committed renewable projects reflecting current difficulties experienced by developers in obtaining grid connection.

FIGURE 4.30 LGC PRICES FOR 2020 AND 2021 FOR 2020-21 ($/LGC, NOMINAL)



SOURCE: TFS AND ACIL ALLEN ANALYSIS

The 2019 RPP value of 18.60 per cent has been set by the CER and does not need to be estimated.

The 2020 and 2021 RPP values of 19.61 per cent and 19.44 per cent, respectively, were estimated using the mandated targets for 2020 and 2021 and ACIL Allen's estimates of electricity acquisitions in 2020 and 2021. Estimated electricity acquisitions have been estimated by ACIL Allen and they fall between 2020 and 2021 consistent with the trend in electricity demand forecasts in this year. Key elements of the 2020 and 2021 RPP estimation are shown in Table 4.5.

TABLE 4.5 ESTIMATING THE 2020 AND 2021 RPP VALUES

	2020	2021
LRET target, MWh (CER)	33,850,000	33,000,000
Estimated electricity acquisitions, MWh (ACIL Allen)	172,572,480	169,720,876
Estimated RPP	19.61%	19.44%

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 $9.38/MWh in 2019-20 as shown in Table 4.6.

TABLE 4.6 ESTIMATED COST OF LRET – 2019-20

	2019	2020	Cost of LRET 2019-20
RPP %	18.60%	19.61%	
Average LGC price ($/LGC, nominal)	$68.64	$30.61	
Cost of LRET ($/MWh, nominal)	$12.77	$6.00	$9.38

SOURCE: CER, TFS, ACIL ALLEN ANALYSIS

ACIL Allen calculates the cost of complying with the LRET in 2020 and 2021 by multiplying the RPP values for 2020 and 2021 by the average LGC prices for 2020 and 2021, respectively. The cost of complying with the LRET in 2020-21 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be $4.56/MWh in 2020-21 as shown in Table 4.7.

TABLE 4.7 ESTIMATED COST OF LRET – 2020-21

	2020	2021	Cost of LRET 2020-21
RPP %	19.61%	19.44%	
Average LGC price ($/LGC, nominal)	$30.51	$16.17	
Cost of LRET ($/MWh, nominal)	$5.98	$3.14	$4.56

SOURCE: CER, TFS, ACIL ALLEN ANALYSIS

4.3.2 SRES

The cost of the SRES is calculated by applying the estimated STP value to the STC price in each compliance (calendar year). The average of these calendar year costs is then used to obtain the estimated costs for 2019-20 and 2020-21.

As discussed earlier, the estimate for 2019-20 is assumed to have been calculated in April 2019, using the following inputs:

— The CER's binding 2019 STP of 21.73 per cent (equivalent to 37.5 million STCs as a proportion of total estimated electricity consumption for the 2019 year). This estimate includes an uplift of 7.9 million STCs due to the carryover of overflow STCs from 2018.

— The CER's non-binding 2020 STP of 14.56 per cent (equivalent to 20.8 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 and an expectation that demand for small-scale generating units (SGUs), such as rooftop solar PV, will be lower than 2019.

ACIL Allen estimates the cost of complying with SRES to be $7.26/MWh in 2019-20 as set out in Table 4.8.

TABLE 4.8 ESTIMATED COST OF SRES – 2019-20

	2019	2020	Cost of SRES 2019-20
STP %	21.73%	14.56%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of SRES ($/MWh, nominal)	$8.69	$5.82	$7.26

SOURCE: ACIL ALLEN ANALYSIS

The estimate for 2020-21, which incorporates all available information to date, uses the following inputs:

— ACIL Allen's estimate of the STP value for 2020 of 26.42 per cent - equivalent to 45.6 million STCs as a proportion of total estimated electricity consumption for the 2020 year. This estimate includes an uplift of 8 million STCs due to an estimated carryover of overflow STCs from 2019 and an expectation that SGU installations in 2020 will be at similar levels to 2019.

— ACIL Allen's estimate of the STP value for 2021 of 22.15 per cent - equivalent to 37.6 million STCs as a proportion of total estimated electricity consumption for the 2021 year. This is lower than the 2019 estimate due to an expectation that SGU installations will be at similar levels to 2020 and that the 2020 STP value is a reasonably accurate of estimate of actual STC creations in 2020 (i.e. no overflow from 2020 to 2021).

ACIL Allen estimates the cost of complying with SRES to be $9.72/MWh in 2020-21 as set out in Table 4.9. The cost of SRES in 2020-21 is estimated to be higher than in 2019-20

TABLE 4.9 ESTIMATED COST OF SRES – 2020-21

	2020	2021	Cost of SRES 2020-21
STP %	26.42%	22.15%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of SRES ($/MWh, nominal)	$10.57	$8.86	$9.72

SOURCE: ACIL ALLEN ANALYSIS

4.3.3 Summary of estimated LRET and SRES costs

Adding these component costs gives a total cost requirement for 2019-20 and 2020-21 as set out in Table 4.10.

Since the 2019-20 estimate, the cost of LRET has decreased by around 50 per cent, driven by lower LGC prices and the cost of SRES has increased by 35 per cent, driven by higher estimated STC creations. Overall, the renewable energy costs have decreased by about 15 per cent because the lower LGC prices offsets the increase in estimated STCs.

TABLE 4.10 TOTAL RENEWABLE ENERGY POLICY COSTS ($/MWH, NOMINAL)

	2019-20	2020-21	Change
LRET	$9.38	$4.56	($4.82)
SRES	$7.26	$9.72	$2.46
Total	$16.64	$14.28	($2.36)

4.3.4 New South Wales Energy Savings Scheme (ESS)

The Energy Savings Scheme (ESS) is a New South Wales Government program to assist households and businesses reduce their energy consumption. It is a certificate trading scheme in which retailers are required to fund energy efficiency through the purchase of certificates.

To estimate the cost of complying with the ESS, ACIL Allen uses the following elements:

— Energy Savings Scheme Target for 2019, 2020 and 2021 of 8.5 per cent, as published by IPART

— Historical Energy Savings Certificate (ESC) market forward prices for 2019, 2020 and 2021 from brokers TFS

The cost of the ESS is calculated by applying the estimated ESS target to the ESC price in each compliance (calendar year). The average of these calendar year costs is then used to obtain the estimated costs for 2019-20 and 2020-21, as set out in Table 4.11 and Table 4.12, respectively.

TABLE 4.11 ESTIMATED COST OF ESS ($/MWH, NOMINAL) – 2019-20

	2019	2020	Cost of ESS 2019-20
ESS target	8.5%	8.5%	
Average ESC price ($/MWh, nominal)	$21.49	$20.80	
Cost of ESS($/MWh, nominal)	$1.83	$1.77	$1.80

SOURCE: IPART, TFS

TABLE 4.12 ESTIMATED COST OF ESS ($/MWH, NOMINAL) – 2020-21

	2020	2021	Cost of ESS 2020-21
ESS target	8.5%	8.5%	
Average ESC price ($/MWh, nominal)	$23.12	$24.75	
Cost of ESS($/MWh, nominal)	$1.97	$2.10	$2.03

SOURCE: IPART, TFS

4.3.5 South Australia Retailer Energy Efficiency Scheme (REES)

The Retailer Energy Efficiency Scheme (REES) is a South Australian Government energy efficiency scheme that provides incentives for South Australian households and businesses to save energy. It does this via energy efficiency and audit targets to be met by electricity and gas retailers with customers in South Australia.

In the AEMC's 2018 price trends methodology report, the cost of the REES was sourced using data from the relevant jurisdiction, although there is no link to the exact location of this data.[19]

In the AEMC's 2019 price trends report[20], the cost of REES appears to be unchanged from the 2018 report.

[19] Table 8.5, page 49 at https://www.aemc.gov.au/sites/default/files/2018-12/AEMC%202018%20Residential%20Electricity%20Price%20Trends%20Methodology%20Report%20-%20CLEAN.pdf
[20] Published on 9 December 2019 at: https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2019

In the AEMC's report, the estimated cost of REES, which is expected to be generally flat in nominal terms over the reporting period, comprises less than 10 per cent of the cost of environmental policies, and less than one per cent of the total retail bill in South Australia during the four-year reporting period.

Given the limited availability of public data on the cost of meeting the REES and given that the cost as estimated by AEMC is a very small component of the overall cost of the retail bill, ACIL Allen has used the estimates of the cost of REES provided in the latest AEMC price trends report.

TABLE 4.13 ESTIMATED COST OF REES ($/MWH, NOMINAL)

	2019-20	2020-21
Cost of REES	$2.50	$2.50

SOURCE: AEMC

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
— The Reliability and Emergency Reserve Trader (RERT).

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)[21].

Based on projected fees in AEMO's *Electricity Final Budget & Fees 2018-19* and *Electricity Final Budget & Fees 2019-20*, the fees for 2019-20 and 2020-21 are $0.63/MWh and $0.70/MWh, respectively. The breakdown of total fees is shown in Table 4.14.

TABLE 4.14 NEM MANAGEMENT FEES ($/MWH, NOMINAL)

Cost category	2019-20	2020-21
NEM fees (admin, registration, etc.)	$0.50	$0.56
FRC - electricity	$0.080	$0.074
NTP - electricity	$0.025	$0.040
ECA - electricity	$0.029	$0.031
Total NEM management fees	**$0.63**	**$0.70**

SOURCE: AEMO, AER

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 2020-21, the cost of ancillary services is estimated to be $0.74/MWh.

Using the average costs over the 52 weeks preceding April 2019, the estimate for 2019-20 is $0.37/MWh.

[21] 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.

The increase in the estimate for 2020-21 is due a number of events that increased the demand for and price of FCAS services including, the Basslink outage in August 2019 to October 2019, the planned outage of the Heywood to Mortlake line in September 2019 and the South Australian islanding in November 2019.[22]

4.4.3 Prudential costs

Prudential costs have been calculated for each jurisdiction NSLP. The prudential costs for the NSLP are then used as a proxy for prudential costs for the controlled load profiles in the relevant jurisdiction.

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 4.15 for each season for Ausgrid NSLP gives an estimated MCL of $9,983.

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 in the Ausgrid NSLP is $9,983/42 = $237.70/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 $237.70 gives $0.68/MWh for Ausgrid NSLP, as shown in Table 4.15.

The components of the AEMO prudential costs for each of the other jurisdictions' NSLPs are shown in Table 4.16, Table 4.17, Table 4.18 and Table 4.19.

TABLE 4.15 AEMO PRUDENTIAL COSTS FOR AUSGRID NSLP – 2020-21

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$98.14	$65.01	$49.44
Participant Risk Adjustment Factor	1.9434	1.4395	1.1243
OS Volatility factor	1.62	1.24	1.35
PM Volatility factor	3.10	1.69	2.07
OSL	$16,583	$5,361	$3,063
PML	$3,317	$1,072	$613
MCL	$19,900	$6,433	$3,676

[22] For the purposes of FCAS recovery, the market is treated globally. Hence, for the purpose of recovery, participants are treated equally, regardless of region.

Factor	Summer	Winter	Shoulder
Average MCL		$9,983	
AEMO prudential cost ($/MWh, nominal)		**$0.68**	

SOURCE: ACIL ALLEN ANALYSIS, AEMO

TABLE 4.16 AEMO PRUDENTIAL COSTS FOR ENDEAVOUR NSLP – 2020-21

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$98.14	$65.01	$49.44
Participant Risk Adjustment Factor	1.7539	1.2434	1.1435
OS Volatility factor	1.62	1.24	1.35
PM Volatility factor	3.10	1.69	2.07
OSL	$14,219	$4,303	$3,142
PML	$2,844	$861	$628
MCL	$17,062	$5,164	$3,770
Average MCL		$8,646	
AEMO prudential cost ($/MWh, nominal)		**$0.592**	

SOURCE: ACIL ALLEN ANALYSIS, AEMO

TABLE 4.17 AEMO PRUDENTIAL COSTS FOR ESSENTIAL NSLP – 2020-21

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$98.14	$65.01	$49.44
Participant Risk Adjustment Factor	1.4838	1.2223	1.1421
OS Volatility factor	1.62	1.24	1.35
PM Volatility factor	3.10	1.69	2.07
OSL	$11,063	$4,194	$3,136
PML	$2,213	$839	$627
MCL	$13,276	$5,033	$3,763
Average MCL		$7,345	
AEMO prudential cost ($/MWh, nominal)		**$0.50**	

SOURCE: ACIL ALLEN ANALYSIS, AEMO

TABLE 4.18 AEMO PRUDENTIAL COSTS FOR ENERGEX NSLP – 2020-21

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$81.16	$45.94	$52.47

Factor	Summer	Winter	Shoulder
Participant Risk Adjustment Factor	1.5292	1.2993	1.2775
OS Volatility factor	1.62	1.24	1.35
PM Volatility factor	3.10	1.69	2.07
OSL	$9,572	$3,248	$3,938
PML	$1,914	$650	$788
MCL	$11,486	$3,898	$4,725
Average MCL		$6,688	
AEMO prudential cost ($/MWh, nominal)		**$0.46**	

SOURCE: ACIL ALLEN ANALYSIS, AEMO

TABLE 4.19 AEMO PRUDENTIAL COSTS FOR SAPN NSLP – 2020-21

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$125.13	$85.23	$70.94
Participant Risk Adjustment Factor	2.7020	1.1684	1.3026
OS Volatility factor	1.62	1.24	1.35
PM Volatility factor	3.10	1.69	2.07
OSL	$34,662	$5,139	$5,481
PML	$6,932	$1,028	$1,096
MCL	$41,594	$6,166	$6,577
Average MCL		$18,047	
AEMO prudential cost ($/MWh, nominal)		**$1.24**	

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 0.75 per cent. 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.

Using the annual average futures price and applying the above factors gives an average initial margin for each quarter (rounded up) as shown for each region in Table 4.20, Table 4.21 and Table 4.22. This is divided by the average hours in a quarter. Then applying the assumed funding cost of 6.80 per cent but adjusted for an assumed 0.75 per cent return on cash lodged with the clearing (giving a net funding cost of 6.05 percent) results in the prudential cost per MWh for each contract type for each region as shown in Table 4.20, Table 4.21 and Table 4.22.

TABLE 4.20 HEDGE PRUDENTIAL FUNDING COSTS BY CONTRACT TYPE – NEW SOUTH WALES 2020-21

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$76.09	$29,000	$0.80
Peak	$92.62	$25,000	$1.61
Cap	$8.97	$12,000	$0.33

SOURCE: ACIL ALLEN ANALYSIS, ASX ENERGY, RBA

TABLE 4.21 HEDGE PRUDENTIAL FUNDING COSTS BY CONTRACT TYPE – QUEENSLAND 2020-21

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$64.22	$26,000	$0.72
Peak	$73.85	$25,000	$1.61
Cap	$5.58	$9,000	$0.25

SOURCE: ACIL ALLEN ANALYSIS, ASX ENERGY, RBA

TABLE 4.22 HEDGE PRUDENTIAL FUNDING COSTS BY CONTRACT TYPE – SOUTH AUSTRALIA 2020-21

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$80.44	$45,000	$1.24
Peak	$107.65	$50,000	$3.21
Cap	$13.05	$20,000	$0.55

SOURCE: ACIL ALLEN ANALYSIS, ASX ENERGY, RBA

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 each jurisdiction 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 for each jurisdiction as shown in Table 4.23, Table 4.24, Table 4.25, Table 4.26 and Table 4.27.

TABLE 4.23 HEDGE PRUDENTIAL FUNDING COSTS FOR AUSGRID NSLP – 2020-21

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.80	0.9007	$0.72
Peak	$1.61	0.0049	$0.01
Cap	$0.33	2.4142	$0.80
Total cost		**$1.53**	

SOURCE: ACIL ALLEN ANALYSIS

TABLE 4.24 HEDGE PRUDENTIAL FUNDING COSTS FOR ENDEAVOUR NSLP – 2020-21

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.80	0.8800	$0.71
Peak	$1.61	0.0264	$0.04
Cap	$0.33	2.0538	$0.68
Total cost		**$1.43**	

SOURCE: ACIL ALLEN ANALYSIS

TABLE 4.25 HEDGE PRUDENTIAL FUNDING COSTS FOR ESSENTIAL NSLP – 2020-21

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.80	1.0825	$0.87
Peak	$1.61	0.0000	$0.00
Cap	$0.33	0.7764	$0.26
Total cost		**$1.12**	

SOURCE: ACIL ALLEN ANALYSIS

TABLE 4.26 HEDGE PRUDENTIAL FUNDING COSTS FOR ENERGEX NSLP – 2020-21

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.72	0.9931	$0.71
Peak	$1.61	0.1156	$0.19
Cap	$0.25	1.2956	$0.32
Total cost		**$1.22**	

SOURCE: ACIL ALLEN ANALYSIS

TABLE 4.27 HEDGE PRUDENTIAL FUNDING COSTS FOR SAPN NSLP – 2020-21

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.24	1.5345	$1.91
Peak	$3.21	0.0000	$0.00
Cap	$0.55	1.4994	$0.83
Total cost		**$2.74**	

SOURCE: ACIL ALLEN ANALYSIS

Total prudential costs

Adding the AEMO and hedge prudential costs gives a total prudential requirement for 2020-21 as set out in Table 4.28. The calculations have been made for 2019-20 and are also shown in Table 4.28 for comparison. Prudential costs for 2020-21 are generally lower than 2019-20 due to lower hedge prices and lower expected price volatility across 2020-21. Some of the New South Wales NSLPs show a slight increase in prudential costs which reflects higher expected volatility in Q1, which more than offsets lower expected volatility in the other quarters of 2020-21.

TABLE 4.28 TOTAL PRUDENTIAL COSTS ($/MWH, NOMINAL)

Jurisdiction	2019-20	2020-21
Ausgrid NSLP	$2.17	$2.21
Endeavour NSLP	$2.01	$2.02
Essential NSLP	$1.82	$1.63
Energex NSLP	$2.18	$1.68
SAPN NSLP	$4.92	$3.97

4.4.4 Reliability and Emergency Reserve Trader (RERT)

Given the RERT is called upon under extreme circumstances only, ACIL Allen is of the opinion that it is difficult to project into the future. Although it may be possible to make use of previous costs of the RERT and relate these to AEMO's projection of USE in the ESOO, there is little data available at this point to take this approach.

Therefore, as with the ancillary services, we propose to take the RERT costs as published by AEMO for the 12-month period prior to the determination year.

At the time of writing this report for the Draft Determination, the costs of the RERT for 2019-20 have not yet been reported and therefore we have used the costs for 2018-19 as a proxy.

ACIL Allen has expressed the cost based on energy consumption – which requires taking the reported cost in dollar terms from AEMO for the given region and prorating the cost across all consumers in the region on a consumption basis, as shown in Table 4.29

TABLE 4.29 ESTIMATED COST OF RERT – SOUTH AUSTRALIA ($/MWH, NOMINAL)

	2019-20	2020-21
Total RERT costs in 2018-19 ($'m)	$34.5	$34.5
SA energy in 2018-19 (GWh)	42,981	42,981
VIC energy in 2018-19 (GWh)	11,370	11,370
Total energy in 2018-19 (GWh)	54,352	54,352
RERT cost ($/MWh, nominal)	$0.63	$0.63

SOURCE: AEMO

4.4.5 Summary of estimated total other costs

Adding these component costs gives a total other cost requirement as set out in Table 4.33, for the 2020-21 Draft Determination and is compared with the costs for 2019-20.

TABLE 4.30 TOTAL OF OTHER COSTS ($/MWH, NOMINAL) – AUSGRID NSLP

Cost category	2019-20	2020-21
NEM management fees	$0.63	$0.70
Ancillary services	$0.37	$0.74
Hedge and pool prudential costs	$2.17	$2.21
Total	**$3.17**	**$3.65**

TABLE 4.31 TOTAL OF OTHER COSTS ($/MWH, NOMINAL) – ENDEAVOUR NSLP

Cost category	2019-20	2020-21
NEM management fees	$0.63	$0.70
Ancillary services	$0.37	$0.74
Hedge and pool prudential costs	$2.01	$2.02
Total	**$3.01**	**$3.46**

TABLE 4.32 TOTAL OF OTHER COSTS ($/MWH, NOMINAL) – ESSENTIAL NSLP

Cost category	2019-20	2020-21
NEM management fees	$0.63	$0.70
Ancillary services	$0.37	$0.74
Hedge and pool prudential costs	$1.82	$1.63
Total	**$2.82**	**$3.07**

TABLE 4.33 TOTAL OF OTHER COSTS ($/MWH, NOMINAL) – ENERGEX NSLP

Cost category	2019-20	2020-21
NEM management fees	$0.63	$0.70
Ancillary services	$0.37	$0.74
Hedge and pool prudential costs	$2.18	$1.68
Total	**$3.18**	**$3.12**

TABLE 4.34 TOTAL OF OTHER COSTS ($/MWH, NOMINAL) – SAPN NSLP

Cost category	2019-20	2020-21
NEM management fees	$0.63	$0.70
Ancillary services	$0.37	$0.74
Hedge and pool prudential costs	$4.92	$3.97
Reserve and Emergency Reserve Trader	$0.63	$0.63
Total	**$6.55**	**$6.04**

4.5 Estimation of energy losses

The estimated wholesale energy costs resulting from the analysis is referenced to the 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 each jurisdiction 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 to estimate losses for 2019-20 are based on the updated draft 2019-20 MLFs published by AEMO on 1 April 2019.

The MLFs used to estimate losses for the Draft Determination for 2020-21 are based on the final 2019-20 MLFs published by AEMO on 21 June 2019.

For the Final Determination for 2020-21, we will use AEMO's 2020-21 MLFs, which are due to be published by 1 April 2020.

The estimation of transmission and distribution loss factors for the settlement classes to be used in calculating energy costs for 2019-20 and 2020-21 is shown in Table 4.35.

TABLE 4.35 ESTIMATED TRANSMISSION AND DISTRIBUTION LOSSES

Settlement class	2019-20			2020-21		
	Distribution losses	Transmission losses	Total loss factor	Distribution losses	Transmission losses	Total loss factor
Ausgrid - NSLP	5.00%	-0.05%	1.049	5.00%	0.24%	1.053
Endeavour - NSLP	6.28%	-0.70%	1.055	6.28%	-0.83%	1.054
Essential - NSLP	6.91%	-1.06%	1.058	6.91%	-1.49%	1.053
Ausgrid - CLP1	5.32%	-0.05%	1.053	5.32%	0.24%	1.056
Ausgrid - CLP2	5.32%	-0.05%	1.053	5.32%	0.24%	1.056
Endeavour - CLP	6.28%	-0.70%	1.055	6.28%	-0.83%	1.054
Essential - CLP	6.91%	-1.06%	1.058	6.91%	-1.49%	1.053
Energex - NSLP	5.59%	0.84%	1.065	5.59%	0.84%	1.065
Energex – CLP31	5.59%	0.84%	1.065	5.59%	0.84%	1.065
Energex – CLP33	5.59%	0.84%	1.065	5.59%	0.84%	1.065
SAPN - NSLP	10.10%	0.82%	1.110	10.10%	0.78%	1.110
SAPN - CLP	10.10%	0.82%	1.110	10.10%	0.78%	1.110

SOURCE: AEMO, ACIL ALLEN ANALYSIS

As described by AEMO[23], 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 and 2020-21 total energy costs (TEC) for the Draft Determination for each of the profiles are presented in Table 4.36 to Table 4.38.

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

TABLE 4.36 ESTIMATED TEC FOR 2019-20 AND 2020-21 ($/MWH, NOMINAL) - DRAFT DETERMINATION

Profile	2019-20 Total energy costs at the customer terminal ($/MWh, nominal)	2020-21 Total energy costs at the customer terminal ($/MWh, nominal)	Change from 2019-20 to 2020-21 ($/MWh, nominal)	Change from 2019-20 to 2020-21 (%, nominal)
Ausgrid - NSLP	$130.70	$130.65	($0.05)	-0.04%
Endeavour - NSLP	$128.06	$130.51	$2.45	1.91%
Essential - NSLP	$122.68	$122.44	($0.24)	-0.20%
Ausgrid - CLP1	$103.57	$92.86	($10.71)	-10.34%
Ausgrid - CLP2	$99.06	$91.10	($7.96)	-8.04%
Endeavour - CLP	$118.04	$122.56	$4.52	3.83%
Essential - CLP	$114.62	$107.41	($7.21)	-6.29%
Energex - NSLP	$116.06	$109.28	($6.78)	-5.84%
Energex – CLP31	$90.24	$88.75	($1.49)	-1.65%
Energex – CLP33	$98.69	$90.39	($8.30)	-8.41%
SAPN - NSLP	$185.46	$175.77	($9.69)	-5.22%
SAPN - CLP	$130.90	$115.69	($15.21)	-11.62%

SOURCE: ACIL ALLEN ANALYSIS

TABLE 4.37 ESTIMATED TEC FOR 2019-20 DRAFT DETERMINATION ($/MWH, NOMINAL)

Profile	WEC at regional reference node ($/MWh, nominal)	Other wholesale costs at regional reference node ($/MWh, nominal)	Network loss factor	Wholesale network losses ($/MWh, nominal)	Total wholesale costs at the customer terminal ($/MWh, nominal)	LRET costs at regional reference node ($/MWh, nominal)	SRES costs at regional reference node ($/MWh, nominal)	Other environmental costs at regional reference node ($/MWh, nominal)	Environ mental network losses ($/MWh, nominal)	Total environmental costs at the customer terminal ($/MWh, nominal)	Total energy costs at the customer terminal ($/MWh, nominal)
Ausgrid - NSLP	$102.99	$3.17	1.049	$5.20	$111.36	$9.38	$7.26	$1.80	$0.90	$19.34	$130.70
Endeavour - NSLP	$99.94	$3.01	1.055	$5.66	$108.61	$9.38	$7.26	$1.80	$1.01	$19.45	$128.06
Essential - NSLP	$94.69	$2.82	1.058	$5.66	$103.17	$9.38	$7.26	$1.80	$1.07	$19.51	$122.68
Ausgrid - CLP1	$76.74	$3.17	1.053	$4.24	$84.15	$9.38	$7.26	$1.80	$0.98	$19.42	$103.57
Ausgrid - CLP2	$72.46	$3.17	1.053	$4.01	$79.64	$9.38	$7.26	$1.80	$0.98	$19.42	$99.06
Endeavour - CLP	$90.44	$3.01	1.055	$5.14	$98.59	$9.38	$7.26	$1.80	$1.01	$19.45	$118.04
Essential - CLP	$87.08	$2.82	1.058	$5.21	$95.11	$9.38	$7.26	$1.80	$1.07	$19.51	$114.62
Energex - NSLP	$89.16	$3.18	1.065	$6.00	$98.34	$9.38	$7.26	$0.00	$1.08	$17.72	$116.06
Energex - CLP1	$64.91	$3.18	1.065	$4.43	$72.52	$9.38	$7.26	$0.00	$1.08	$17.72	$90.24
Energex - CLP2	$72.85	$3.18	1.065	$4.94	$80.97	$9.38	$7.26	$0.00	$1.08	$17.72	$98.69
SAPN - NSLP	$141.39	$6.55	1.110	$16.27	$164.21	$9.38	$7.26	$2.50	$2.11	$21.25	$185.46
SAPN - CLP	$92.23	$6.55	1.110	$10.87	$109.65	$9.38	$7.26	$2.50	$2.11	$21.25	$130.90

SOURCE: ACIL ALLEN ANALYSIS

TABLE 4.38 ESTIMATED TEC FOR 2020-21 DRAFT DETERMINATION ($/MWH, NOMINAL)

Profile	WEC at regional reference node ($/MWh, nominal)	Other wholesale costs at regional reference node ($/MWh, nominal)	Network loss factor	Wholesale network losses ($/MWh, nominal)	Total wholesale costs at the customer terminal ($/MWh, nominal)	LRET costs at regional reference node ($/MWh, nominal)	SRES costs at regional reference node ($/MWh, nominal)	Other environmental costs at regional reference node ($/MWh, nominal)	Environ mental network losses ($/MWh, nominal)	Total environmental costs at the customer terminal ($/MWh, nominal)	Total energy costs at the customer terminal ($/MWh, nominal)
Ausgrid - NSLP	$104.12	$3.65	1.053	$5.71	$113.48	$4.56	$9.72	$2.03	$0.86	$17.17	$130.65
Endeavour - NSLP	$104.05	$3.46	1.054	$5.81	$113.32	$4.56	$9.72	$2.03	$0.88	$17.19	$130.51
Essential - NSLP	$96.90	$3.07	1.053	$5.30	$105.27	$4.56	$9.72	$2.03	$0.86	$17.17	$122.44
Ausgrid - CLP1	$67.98	$3.65	1.056	$4.01	$75.64	$4.56	$9.72	$2.03	$0.91	$17.22	$92.86
Ausgrid - CLP2	$66.31	$3.65	1.056	$3.92	$73.88	$4.56	$9.72	$2.03	$0.91	$17.22	$91.10
Endeavour - CLP	$96.51	$3.46	1.054	$5.40	$105.37	$4.56	$9.72	$2.03	$0.88	$17.19	$122.56
Essential - CLP	$82.63	$3.07	1.053	$4.54	$90.24	$4.56	$9.72	$2.03	$0.86	$17.17	$107.41
Energex - NSLP	$85.21	$3.12	1.065	$5.74	$94.07	$4.56	$9.72	$0.00	$0.93	$15.21	$109.28
Energex - CLP1	$65.93	$3.12	1.065	$4.49	$73.54	$4.56	$9.72	$0.00	$0.93	$15.21	$88.75
Energex - CLP2	$67.47	$3.12	1.065	$4.59	$75.18	$4.56	$9.72	$0.00	$0.93	$15.21	$90.39
SAPN - NSLP	$135.53	$6.04	1.110	$15.57	$157.14	$4.56	$9.72	$2.50	$1.85	$18.63	$175.77
SAPN - CLP	$81.40	$6.04	1.110	$9.62	$97.06	$4.56	$9.72	$2.50	$1.85	$18.63	$115.69

SOURCE: ACIL ALLEN ANALYSIS

A AEMC 2019 RESIDENTIAL ELECTRICITY PRICE TRENDS REPORT

The AEMC's report, *2019 Residential Electricity Price Trends,* was released in December 2019 (the AEMC report). ACIL Allen notes that the AEMC report does not form part of any 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 for the majority of customers in each region.

Provided below are some key differences in the approach adopted by the AEMC compared with ACIL Allen's methodology – noting that the AEMC report provides a high-level summary of the methodology only.

A.1 Wholesale energy costs

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

— Demand profiles:
  - It is unclear if the AEMC adjusts the historic NSLPs to take into account changes in the shape in the future due to further uptake of rooftop PV.
  - If the profiles are not adjusted this will result in wholesale costs estimates (all other things equal).
  - It also appears that the AEMC aggregate the NSLPs within each region to produce a state-based NSLP.

— Spot market modelling:
  - AEMC appear to have used some form of planning model to introduce a total of about 3,500 MW of additional capacity into the market, beyond the capacity of identified committed projects, between 2019-20 and 2021-22. There is no information given as to the timing and location of this additional capacity.
  - ACIL Allen does not introduce any additional capacity into the market, beyond the capacity of identified committed projects, between 2019-20 and 2020-21, since there is insufficient lead time for a current development project to reach financial close and be constructed and operational by 2020-21.
  - Inclusion of additional capacity would change the results of the spot price modelling, all other things equal.
  - AEMC appears to use historic bids (offer curves) when undertaking its spot price modelling for 2019-20 and 2020-21. These appear to be adjusted for assumed changes in underlying costs (such as fuel prices). ACIL Allen's *PowerMark* uses dynamic bidding (based on game theory) to account of changes in bidding behaviour incentivised by changes in market conditions (such as the addition of about 5,000 MW of renewable capacity between now and 2020-21, as well as changes in underlying costs). AEMC acknowledges that bidding behaviour may change in the future and therefore affect their results.

  - AEMC appears to run 32 simulations of the spot market for a given year (although it is not immediately clear whether there are 32 simulations of the spot market, or 8 simulations of the spot market coupled with 4 different NSLPs traces), compared with ACIL Allen's 539 simulations. The risk of the smaller number of simulations is that extreme events with a low probability of occurring are either overstated or understated.
- Hedge portfolio:
  - AEMC 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.
- Hedge or contract prices:
  - AEMC use a 2-year build-up of hedges using ASX Energy contract price data up to 3 September 2019.
  - It appears AEMC's portfolio build-up is assumed to be completed by April 2020, as does ACIL Allen.
  - This means that 7 months of actual ASX Energy prices are unable to be included in the analysis for 2020-21 (with the six-month period being September 2019 to April 2020).
  - AEMC 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.
  - For the 7 months of missing ASX Energy data, it is not clear whether the AEMC have used their modelled spot price outcomes as a substitute for contract prices (noting this was the approach adopted in the 2018 price review report). This means that in deriving the final estimate of the contract prices for each quarterly product for 2020-21, AEMC is either missing about 50 per cent of ASX Energy trade volumes and corresponding prices, or is using their modelled spot prices to represent 50 per cent of trade volumes and contract prices.
  - 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. We noted in our methodology report that the cumulative shape in actual volume of trades can be quite different to an exponential curve.
  - Forcing an exponential book build and using a different weighting between actual ASX Energy prices and modelled spot prices could yield a very different result using the AEMC's approach.

A.2 Renewable energy target costs

No information is provided in the AEMC report as to how the LGC prices are derived. It appears the AEMC uses the STP values as provided by the Clean Energy Regulator when calculating the SRES costs.

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