ACIL ALLEN

31 May 2021

Report to Queensland Competition Authority

Estimated energy costs

For use by the Queensland Competition Authority in its Final Determination of 2021-22 retail electricity tariffs

About ACIL Allen

ACIL Allen is a leading independent economics, policy and strategy advisory firm, dedicated to helping clients solve complex issues.

Our purpose is to help clients make informed decisions about complex economic and public policy issues.

Our vision is to be Australia's most trusted economics, policy and strategy advisory firm. We are committed and passionate about providing rigorous independent advice that contributes to a better world.

Suggested citation for this report

Estimated energy costs for 2021-22 retail electricity tariffs: Final Determination, ACIL Allen, May 2021

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Introduction 1

ACIL Allen has been engaged by the Queensland Competition Authority (the QCA) to provide advice on the energy related costs likely to be incurred by a retailer to supply customers on notified retail prices for the 2021-22 regulatory period.

Retail prices generally consist of three components:

— network costs

— energy costs

— costs associated with retailing to end users.

ACIL Allen's engagement relates to the energy costs component only. In accordance with the Ministerial Delegation (the Delegation), and the Consultancy Terms of Reference (TOR) provided by the QCA, the methodology developed by ACIL Allen provides an estimate of energy costs to be incurred by a retailer to supply customers on notified prices for 2021-22. Although the QCA's determination is to apply only to the area outside of the Energex distribution area, the TOR specifically requests that ACIL Allen's analysis cover the same tariff classes as covered in the analyses for the 2013-14 to 2020-21 determinations, and therefore includes the load profiles for residential and small business customers in south east Queensland.

Hence, we are required to provide estimates for:

— Energex's net system load profile (NSLP)

— Ergon Energy's NSLP

— load control profiles for small customers in the Energex distribution area

— load control profiles for large business customers in the Ergon distribution area.

This report provides estimates of the energy costs for use by the QCA in its Final Determination.

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 QCA's *Draft Determination: Regulated retail electricity prices for 2021–22* (March 2021), where those submissions refer to the methodology used to estimate the cost of energy in regulated retail electricity prices.

— Chapter 4 summarises our derivation of the energy cost estimates.

— Finally, Appendix A summarises our high-level comparison with the AEMC's 2020 Residential Electricity Price Trends Report released in December 2020.

2 Overview of approach

2.1 Introduction

In preparing advice on the estimated energy costs, ACIL Allen is required to have regard to the actual costs of making, producing or supplying the goods or services which in this case are the customer retail services to be supplied to customers on notified prices for the tariff year 1 July 2021 to 30 June 2022.

2.2 Components of the total energy cost estimates

ACIL Allen is required to estimate the Total Energy Costs (TEC) component of the retail tariffs. Total Energy Costs comprise of the following components (as shown in Figure 2.1):

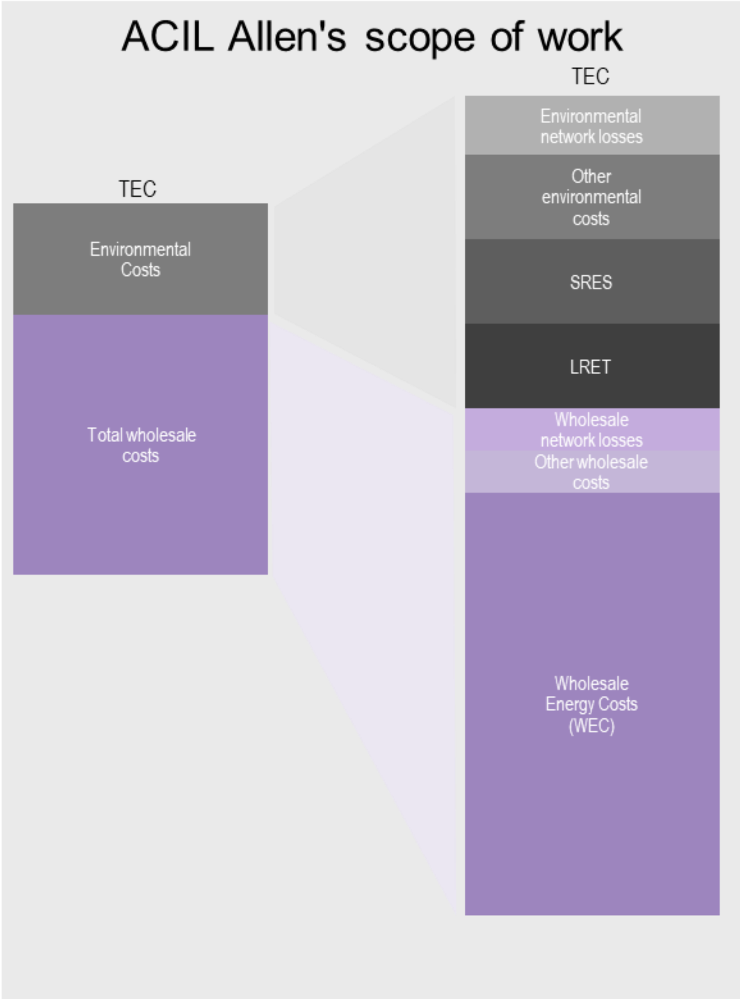
— Wholesale energy costs (WEC) for various demand profiles

— Environmental Costs: costs of complying with state and federal government policies, including the Renewable Energy Target (RET).

— Other wholesale costs: including 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.

Figure 2.1 Components of TEC



Source: ACIL Allen

2.3 Methodology

ACIL Allen's methodology follows the methodology used to provide advice to the QCA for the 2013-14 to 2020-21 determinations.

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. The methodology includes undertaking 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 Estimating the WEC - 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.

At the core of the market-based approach is an assumed contracting strategy that an efficient retailer would use to manage its electricity market risks. Such risks and the strategy used to mitigate them are an important part of electricity retailing. The contracting strategy adopted generally assumes that the retailer is partly exposed to the wholesale spot market and partly protected by the procured contracts.

The methodology simulates the cost of hedging by building up a portfolio of hedges consisting of base and peak swap contracts, and cap contracts (and this is discussed in more detail below).

Conceptually, in a given half-hourly settlement period, the retailer:

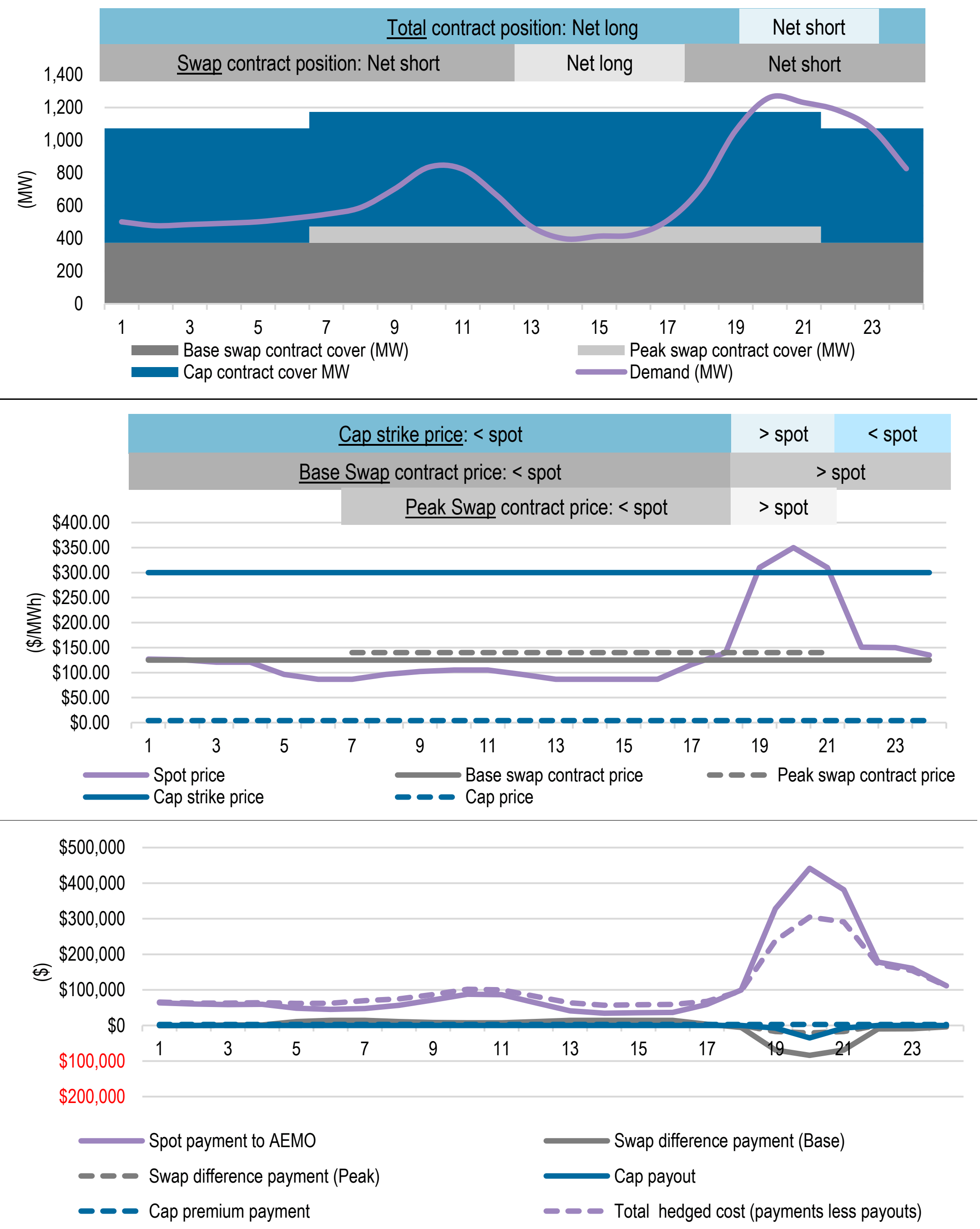
— Pays AEMO the spot price multiplied by the demand.
— Pays the contract counterparty the difference between the swap contract strike price and the spot price, multiplied by the swap contract quantity. This is the case for the base swap contract regardless of time of day, and for the peak swap contract during the periods classified as peak. If the spot price is greater than the contract strike price than the counter party pays the retailer.
— Pays the contract counterparty the cap price multiplied by the cap contract quantity.
— If the spot price exceeds $300/MWh, receives from the contract counter party the difference between the spot price and $300, multiplied by the cap contract quantity.

Figure 2.2 shows an illustrative example of a hedging strategy for a given load across a 24-hour period.

In this example:

— The demand profile:
  – Varies between 400 MW and 1,300 MW.
  – Peaks between 6 pm and 10 pm, with a smaller morning peak between 9 am and 11 am.
— The hedging strategy:
  – Consists of 375 MW of base swaps, 100 MW of peak period swaps, and 700 MW of caps.
  – Means that demand exceeds the total of the contract cover between 7 pm and 10 pm by about 100 MW. Hence during these periods, the retailer is exposed to the spot price for 100 MW of the demand, and the remaining demand is covered by the hedges.
  – Demand is less than the hedging strategy for all other hours. Hence, during these periods the retailer in effect sells the excess hedge cover back to the market at the going spot price (and if the spot price is less than the contract price this represents a net cost to the retailer, and vice versa).

Figure 2.2 Illustrative example of hedging strategy, prices and costs



Source: ACIL Allen

With this in mind, the WEC for a given demand profile for a given year is therefore generally a function of four components, the:

1. demand profile
2. wholesale electricity spot prices
3. forward contract prices
4. hedging 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 long term value of the generation anticipated at the time of commitment when the investor was faced with a variety of uncertain futures. 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.

Use of load profiles in estimating the WEC

The following load profiles are required for the given determination year:

— system load for each region of the NEM (that is, the load to be satisfied by scheduled and semi-scheduled generation) – used to model the regional wholesale electricity spot prices
— Net System Load Profiles (NSLPs) for the Energex and Ergon distribution networks
— controlled load profiles (CLPs) for small customers in the Energex distribution network
— CLPs for small business customers on a primary load control tariff in the Energex distribution network
— CLPs for large business customers in the Ergon distribution network.

Historical load data is available from AEMO – as shown in Table 2.1. The exception is the load data for the small business primary CLP in the Energex distribution network, which is derived from 2019-20 Ergon Energy Agricultural Tariff Trial data set[1].

The NSLP is used as the representative load profile for residential and small business customers because the majority (about 85 per cent) of residential and small business customers in Queensland are on accumulation (or basic) meters. And those customers with digital (or interval) meters are in the minority. Therefore, a single WEC is estimated for residential and small business customers.

Table 2.1 Sources of load data

Distribution Network	Load Type	Load	Source
NA	System Load	QLD1	MMS
Energex	NSLP	NSLP, ENERGEX	MSATS
Ergon	NSLP	NSLP, ERGON	MSATS
Energex	CLP – small customers	QLDEGXCL31, ENERGEX	MSATS

[1] Details of this data set and our treatment of it can be found in our report to the QCA as part of the 2020-21 Supplementary Pricing Review (https://www.qca.org.au/wp-content/uploads/2020/10/rle_j0426-acil-allen-report-for-final-determination-28-sep-2020.pdf).

Distribution Network	Load Type	Load	Source
Energex	CLP – small customers	QLDEGXCL33, ENERGEX	MSATS
Energex	CLP – small business primary load control tariff	2019-20 Ergon Energy Agricultural Tariff Trial	Energy Queensland
Ergon	CLP – large business primary and secondary load control tariffs	QLDEGXCL33, ENERGEX	MSATS

Source: AEMO

Key steps to estimating the WEC

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

1. Forecast the 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 50 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.
2. Use a stochastic availability model to develop 11 annual simulations of hourly thermal power station availability.
3. Forecast hourly wholesale electricity spot prices by using ACIL Allen's proprietary wholesale energy market model, *PowerMark*. *PowerMark* produces 550 (i.e. 50 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. The book build is based on the observed trade volumes and the price estimate is equal to the trade volume weighted average price.
5. Adopt an assumed hedging strategy – the hedging 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.
6. Calculate the spot and contracting cost for each hour and aggregate for each of the 550 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.

Choosing the appropriate hedging strategy

As mentioned above, multiple hedging strategies are tested by varying the mix of base/peak/cap contracts for each quarter. This is done by running the hedge model for a large number[2] of simulations for each strategy and analysing the resulting distribution of WECs for each given strategy – and in particular, keeping note of the 95th percentile WEC for each strategy. We select a strategy that is robust and plausible for each load profile, and minimises the 95th percentile WEC, 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 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 seasonal peak demand and annual energy forecasts for the regional demand profiles are referenced to the neutral scenarios from the latest available Electricity Statement of Opportunities (ESOO) published by AEMO 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 seasonal peak load, and energy forecasts from the AEMO neutral scenario to produce multiple simulated representations of the hourly load profile for the given determination year using a Monte Carlo analysis. These multiple simulations 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 three 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 50 years of weather data and uses a matching algorithm to produce 50 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 three years to represent a given day in the past.

[2] When testing the different strategies, we do not run the full set of 550 simulations as this is time prohibitive. However, we run the full set of 550 simulations once the strategy has been chosen.

- The set of 50 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 50 simulations equals the energy forecast, and the distribution of annual seasonal peak loads across the 50 simulations generally matches the distribution of peak loads inferred by the P10, P50 and P90 seasonal 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 50 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 50 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

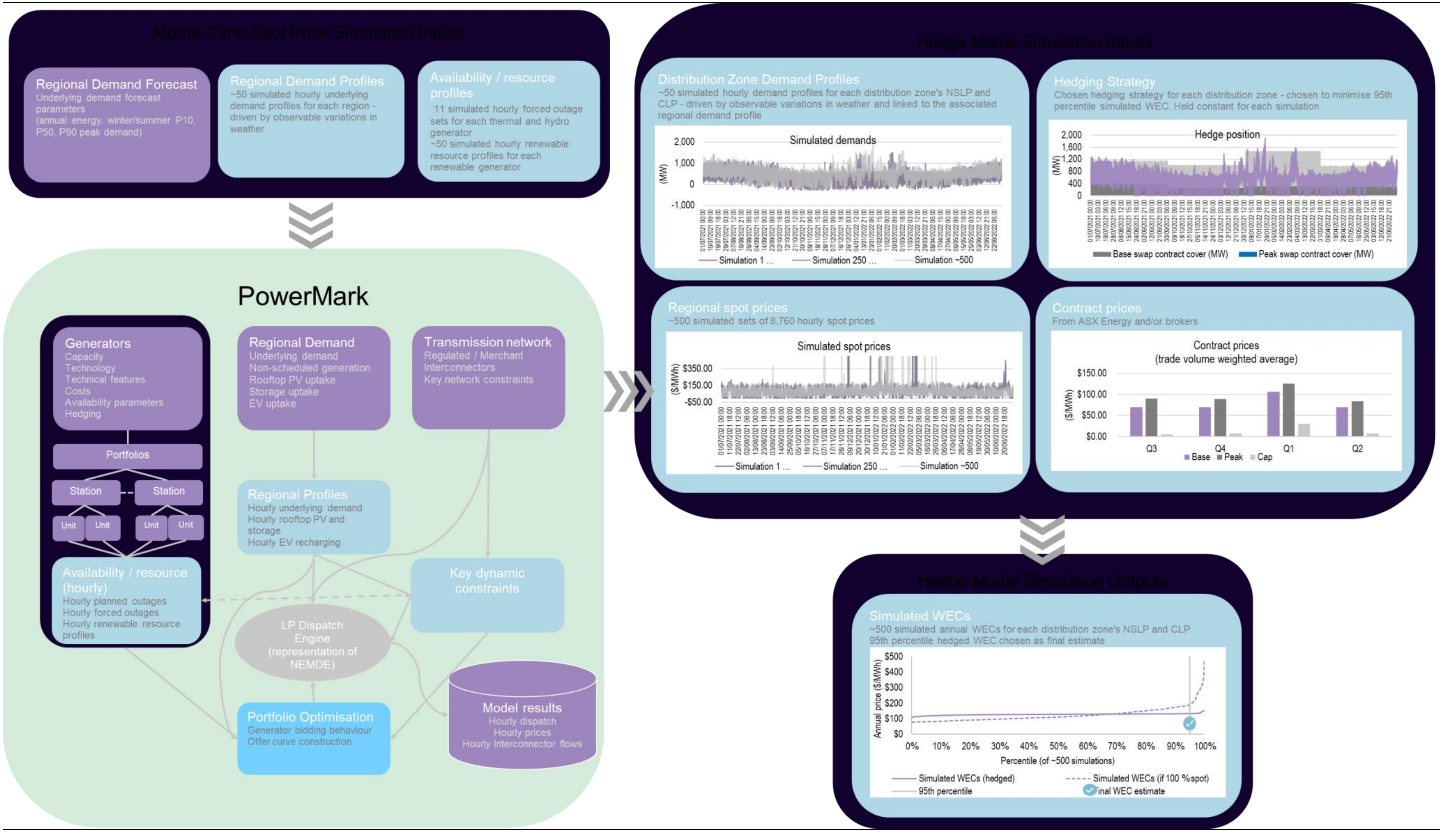
ACIL Allen maintains a Reference case projection of the NEM, which it updates each quarter in response to supply changes announced in the market in terms of new investment, retirements, fuel costs, and plant availability. In this analysis, for 2021-22 we use our December 2020 Reference case projection settings which are closely aligned with AEMO's Integrated System Plan (ISP) for the Final Determination.

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.

Summary infographic of the approach to estimate the WEC

Figure 2.3 provides an infographic type summary of the data, inputs, and flow of the market-based approach to estimating the WEC.

Figure 2.3 Estimating the WEC – market-based approach



2.3.2 Other wholesale costs

Market fees and ancillary services costs

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

NEM fees

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

The approach uses for estimating market fees is to make use of AEMO's budget report. For the most part, the budget report includes forecasts of fees for four or more years.

It is worth noting that in previous determinations, the National Transmission Planner (NTP) was included in this cost category. However, the recovery of this item has recently been transferred from AEMO to each of the Transmission Network Service Providers (TNSPs) directly, forming part of the TUOS charge. Therefore, the NTP cost is excluded from our analysis for 2021-22.

Ancillary services charges

Ancillary services charges cover the costs of services used by AEMO to manage power system safety, security and reliability. AEMO recovers the costs of these services from market participants. These fees are published by AEMO on its website on a weekly basis.

The approach uses for estimating ancillary services costs is to average the most recent 52 weeks of costs to recover ancillary services from customers, which is published on the AEMO website.

To date ACIL Allen has taken the approach of using the ancillary service costs data published by AEMO, and summing the costs across the NEM and then dividing by the total energy across the NEM to get a cost per MWh that is the same in each region. Although this approach is reasonable when there is no islanding of the regions, it is likely that in the future there will be more islanding events as a result of the large investment in semi-scheduled renewable energy projects which may well result in price separation of ancillary services.

ACIL Allen continues to use the same data set, but for the 2021-22 determination derives these costs on a region-by-region basis.

Prudential costs

Prudential costs, for AEMO, as well as representing the 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.

Prudential costs are calculated for each NSLP. The prudential costs for the NSLP are then used as a proxy for prudential costs for the controlled load profiles.

AEMO publishes volatility factors two years in advance. Similarly, ASX Energy publishes initial margin parameters two years in advance.

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

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.

Hedge prudential costs

ACIL Allen relies 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 0.10 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 is set for each of the base, peak and cap contract types
— the intra monthly spread charge and is set for each of the base, peak and cap contract types
— the spot isolation rate and is set for each of the base, peak and cap contract types.

Using the annual average futures price and applying the above factors gives an average initial margin for each quarter. This is divided by the average hours in the given quarter. Then applying an assumed funding cost but adjusted for an assumed return on cash lodged with the clearing results in the prudential cost per MWh for each contract type.

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 use the RERT costs as published by AEMO for the 12-month period prior to the Final Determination. 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.

Retailer Reliability Obligation

The Retailer Reliability Obligation (RRO) started on 1 July 2019 to help manage the risk of declining reliability of supply in response to the recent large amounts of investment in intermittent renewable projects coupled with recent and potential closures of thermal power stations.

If the RRO is triggered for a given quarter and region of the NEM, then retailers need to secure sufficient *qualifying contracts* to cover their share of a one-in-two-year peak demand.

The RRO has not been triggered for 2021-22, and hence we are not required to account for the RRO in the wholesale costs for 2021-22. However, it is worth noting that this cost component should be included as part of the wholesale cost if the RRO is triggered in future determinations.

We think that entering into a mix of firm base, peak, and cap contracts satisfies the qualifying contract definition. As part of the current WEC estimation methodology, an algorithm is run to determine the optimal hedge cover for a given distribution zone for each quarter of the given determination period.

The total optimal cover is expressed as a percentage of the P50 annual peak demand for the given quarter – which is analogous to a one-in-two-year peak demand referred to in the RRO.

Our proposed approach to account for the triggering of the RRO in the estimated WEC is:

— If the overall level of the optimal contract cover is less than 100 per cent of the P50 annual peak demand, then increase the overall level of contract cover to 100 per cent. This will result in an increase in the WEC value since the cost of the additional contracts will be included.

— If the overall level of the optimal contract cover is equal to or greater than 100 per cent of the P50 annual peak demand then no change is required, and hence the RRO has no impact on the WEC.

2.3.3 Environmental costs

Large-scale Renewable Energy Target (LRET)

By 31 March each compliance year, the Clean Energy Regulator (CER) publishes the Renewable Power Percentage (RPP), which translates the aggregate LRET target into the number of Large-scale Generation Certificates (LGCs) that liable entities must purchase and acquit under the scheme.

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 multiplying the RPP and 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 electricity tariffs.

Market-based approach

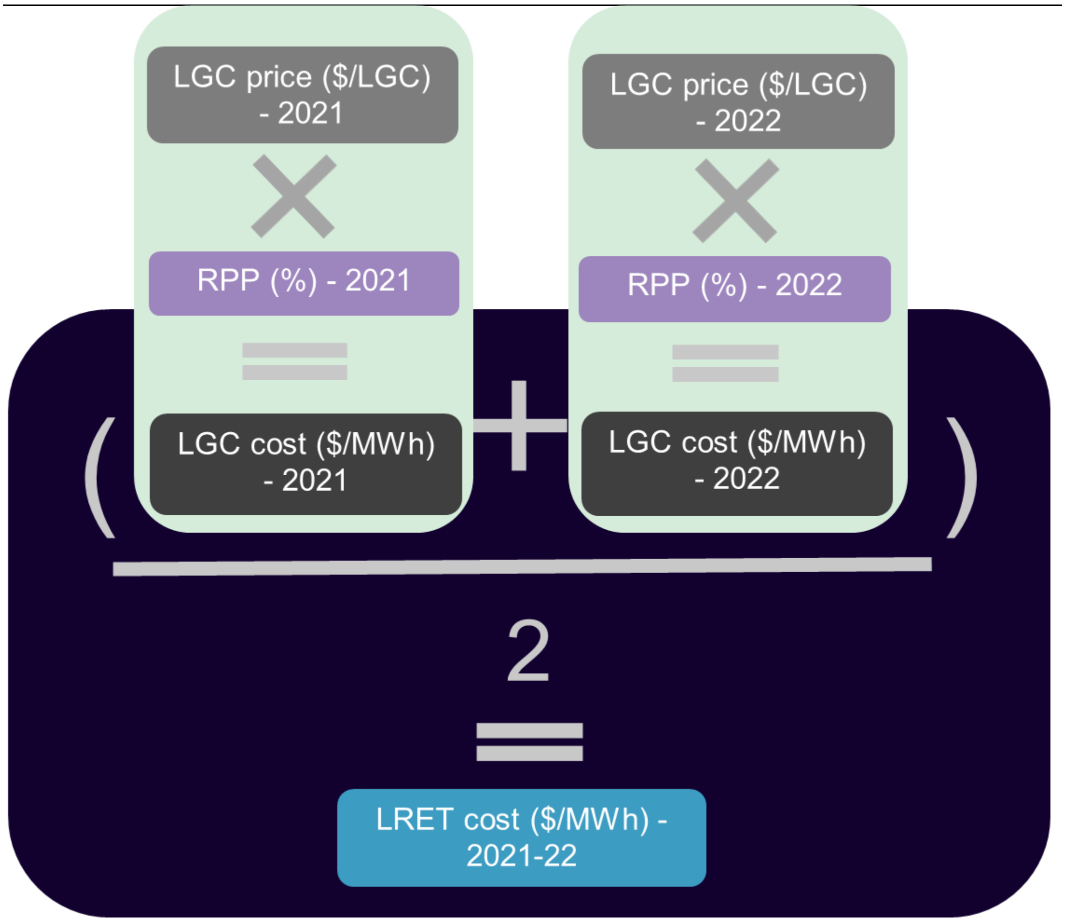
A market-based approach is used to determine the price of a LGC, which assumes that an efficient and prudent electricity retailer builds up LGC coverage prior to each compliance year.

This approach involves estimating the average LGC price using LGC forward prices for the two relevant calendar compliance years in the determination period. Specifically, for each calendar compliance year, the trade-weighted average of LGC forward prices since they commenced trading is calculated.

To estimate the costs to retailers of complying with the LRET for 2021-22, ACIL Allen uses the following elements:

— The average of the trade-weighted average of LGC forward prices for 2021 and 2022 from brokers TFS
— the Renewable Power Percentages (RPPs) for 2021, published by the CER[3]
— estimated RPP values for 2022[4].

Figure 2.4 Steps to estimate the cost of LRET



Source: ACIL Allen

Small-scale Renewable Energy Scheme (SRES)

Similar to the LRET, by 31 March each compliance year, the CER publishes the binding Small-scale Technology Percentage (STP) for a year and non-binding STPs for the next two years.

[3] It is worth noting that the 2021 RPP changed slightly between the 2020-21 Final Determination and the 2021-22 Final Determination due to a slight revision in the estimated electricity acquisitions.

[4] The estimated RPP value for 2022 is estimated using ACIL Allen's estimate of liable acquisitions and the CER-published mandated LRET targets for 2022.

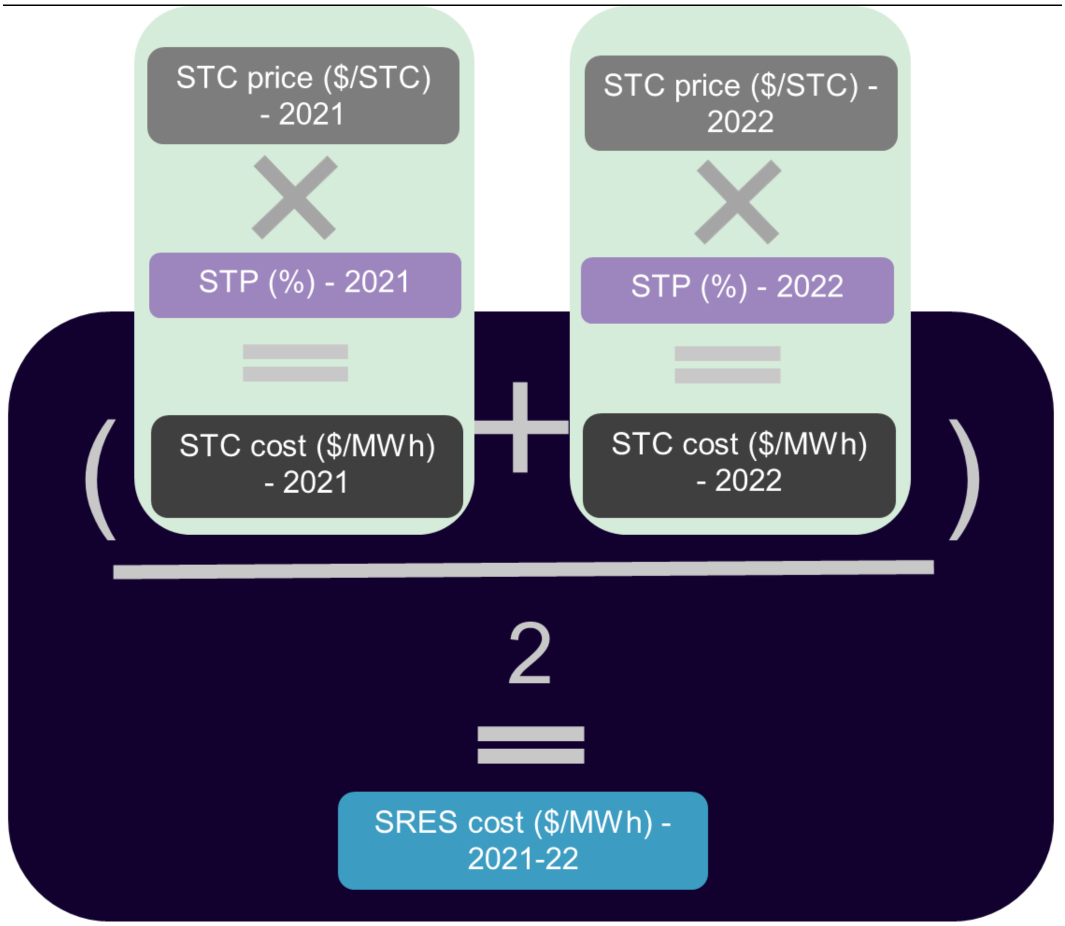
The STP is determined ex-ante by the CER and represents the relevant year's projected supply of Small-scale Technology Certificates (STCs) as a percentage of the estimated volume of liable electricity consumption throughout Australia in that year.

The estimated cost of compliance with the SRES is derived by multiplying the estimated STP value.

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

— the binding Small-scale Technology Percentages (STPs) for 2021 to be published by the CER
— an estimate of the STP value for 2022[5]
— CER clearing house price[6] for 2021 and 2022 for Small-scale Technology Certificates (STCs) of $40/MWh.

Figure 2.5 Steps to estimate the cost of SRES



Source: ACIL Allen

[5] The STP value for 2022 is estimated using estimates of STC creations and liable acquisitions in 2022, taking into consideration the CER's non-binding estimate.

[6] 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.

2.3.4 Energy losses

Some electricity is lost when it is transported over transmission and distribution networks to customers. As a result, retailers must purchase additional electricity to allow for these losses when supplying customers.

The components of the wholesale and environmental costs are expressed at the relevant regional reference node (RRN). Therefore, prices expressed at the regional reference node must be adjusted for losses in the transmission and distribution of electricity to customers – otherwise the wholesale and environmental costs are understated. The cost of network losses associated with wholesale and environmental costs is separate to network costs and are not included in network tariffs.

Distribution Loss Factors (DLF) for each distribution zone and average Marginal Loss Factors (MLF) for transmission losses from the node to major supply points in the distribution networks are applied to the wholesale energy cost estimates to incorporate losses.

The loss factors used are published by AEMO one year in advance for all NEM regions. Average transmission losses by network area are estimated by allocating each transmission connection point to a network based on their location. Average distribution losses are already summarised by network area in the AEMO publication.

As described by AEMO[7], 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 Price * (MLF * DLF)*

The MLFs used to estimate losses for the Final Determination for 2021-22 are based on the final 2021-22 MLFs published by AEMO on 1 April 2021. The DLFs used to estimate losses for 2021-22 are based on the final DLFs published by AEMO on 1 April 2021.

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

Responses to submissions to Draft Determination 3

The QCA forwarded to ACIL Allen a total of seven submissions in response to its Draft Determination. ACIL Allen reviewed the submissions to identify issues that related to our methodology and required our consideration for the 2021-22 Final Determination. A summary of the review is shown below in Table 3.1.

The issues raised in the submissions cover the following broad areas:

— estimating separate WECs for irrigation
— five-minute settlement and its impact on the availability of cap contracts
— estimating NEM fees
— placing a cap on the TEC or WEC.

Table 3.1 Review of issues raised in submissions in response to the Draft Determination

ID	Stakeholder	Wholesale energy costs	Contract prices /hedge model	Renewable energy policy costs	NEM fees	Prudential costs	Energy losses
1	AgForce	Nil	Nil	Nil	Nil	Nil	Nil
2	CANEGROWERS	Yes	Nil	Nil	Nil	Nil	Nil
3	Cotton Australia	Nil	Nil	Nil	Nil	Nil	Nil
4	Energy Queensland Limited	Yes	Yes	Nil	Yes	Nil	Nil
5	Etrog Consulting (submission funded by Energy Consumers Australia)	Nil	Nil	Nil	Nil	Nil	Nil
6	QEUN	Yes	Nil	Nil	Nil	Nil	Nil
7	Queensland Farmers' Federation	Yes	Nil	Nil	Nil	Nil	Nil

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

3.1 Estimating separate WECs for irrigation

CANEGROWERS on page two of its submission suggests the WEC for irrigation should reflect the structure of the network tariff

CANEGROWERS reiterates its call for the peak charging windows for the three new transitional retail tariffs to be limited to 4pm to 9pm, Monday to Friday, with deeply discounted off-peak charges applying at all other times. Reflecting the falling electricity cost *structure, we are keen to ensure the state's irrigators have access to competitively priced electricity that takes account of the fact that irrigators are typically low-cost users of both electricity network capacity and volume weighted average wholesale electricity prices..*

The QCA has not explicitly asked ACIL Allen to consider additional WECs for specific loads as part of our engagement. That said, we have explored this matter in previous determinations.

We acknowledge that price regulation is not perfect. The current methodology estimates the WEC based on the NSLP and CLPs published by AEMO (with the exception of the trial load data), which are used by the QCA when determining the wholesale cost components for the various retail tariffs. In effect the QCA is choosing one of the existing four load profiles to represent the load of customers on any given tariff.

This approach is adopted because AEMO bills retailers for energy consumed by customers on basic (accumulation or consumption) meters based on these profiles. In one sense it is the technology of the meters that has influenced the approach. Our understanding is that most irrigators are on accumulation meters, and hence the current approach is appropriate.

ACIL Allen also acknowledges that it is inevitable that different customers and customer types will have different load profiles. However, the approach needs to be pragmatic, transparent, consistent, and manageable. If a separate WEC is estimated for irrigation, then this would mean that a separate WEC ought to be estimated for each customer or customer group, which is simply not practical.

3.2 Five-minute settlement and its impact on the availability of cap contracts

EQ on pages nine and 10 its submission notes that five-minute settlement (5MS) caps have only recently commenced trading on ASX Energy and suggest consideration be given to an alternate hedging strategy:

Energy Queensland notes the heavy weighting of cap contracts used in the ACIL Allen hedge modelling. For example, in Figure 4.11 of the ACIL Allen Estimated Energy Cost Report, approximately 700 megawatts (MW) of cap contracts are assumed in the modelling for July-September 2021. At the time of writing, total open interest for Queensland caps for this quarter is 367 MW on the Australian Stock Exchange (ASX) with less than four months to the commencement of the quarter. The total open interest position would need to nearly double for ACIL Allen's assumed volume of cap contracts without any other market participant having a bought cap contract position on the ASX. Even after considering over-the-counter contracts, Energy Queensland questions whether actual cap contract liquidity supports a high weighting of cap contracts in the modelled hedge portfolio...

Further, EQ on page 10 suggests the actual traded weighted price of 5MS caps traded to date would be a better estimate of cap prices rather than using the method that approximates the cap price based on the movement in base contract prices.

As noted in section 4.2.1, we have considered that if it was apparent that trade volumes of other contract products had changed because of 5MS then this ought to be taken into account. To date the volume of 2021-22 base contracts traded has converged to the volume traded for 2020-21. This suggests that there appears to be no further reliance on base contracts as a replacement for cap contracts.

ACIL Allen acknowledges that the cumulative level of trades for 5MS is low given trading only started on 22 March 2021. But it is worth noting the cumulative trade volumes for the post 5MS quarters range between 11 per cent and 42 per cent of the cumulative trade volumes of the July-September 2021 quarter. However, the level of trades for the post 5MS quarters during the four weeks that they have been available is comparable with, or even higher than, the level of trades for the July-September 2021 quarter.

ACIL Allen agrees with EQ that the ASX data is the latest indicator of the value of caps post 5MS. Hence it is prudent to use the trade volume weighted average price to estimate the cap price for the post 5MS quarters for the Final Determination. There is no doubt uncertainty, or at the very least a range of views, amongst market participants as to the eventual impact 5MS will have on the market and this uncertainty is reflected in the ASX 5MS cap prices and ought to be accounted for the WEC.

3.3 NEM fees

EQ on page 10 of its submission notes:

the QCA reports a reduction in the National Electricity Market (NEM) management fees by around 31 per cent ($0.22/MWh), reflecting a decline in costs related to operating the NEM and the exclusion of costs associated with the Australian Energy Market Operator's (AEMO's) function as the National Transmission Planner. This is not our experience. Rather, we are seeing NEM management fees remain constant, and will provide evidence of this in our confidential submission to the QCA.

ACIL Allen has estimated the NEM fees using *AEMO's Electricity Final Budget & Fees 2020-21*, which is the same approach as previous determinations. However, we have identified and excluded NEM fees that are not charged to customers (but are instead charged to generators and market network service providers).

3.4 Placing a cap on the WEC or TEC

Two submissions called for a cap on the WEC or TEC.

Queensland Farmers Federation (QFF) suggest a cap be placed on the TEC on page two of its submission:

Equitable pricing for the agricultural sector continues to be a problem as prices continue to rise to unsustainable levels. QFF continues to call on the Government to implement policy to ensure that there is an effective price ceiling of 8 cents per kWh for electrons and 8 cents for distribution, therefore for a total of 16 cents per kWh maximum.

QEUN suggest a cap be placed on the WEC on page 27 of its submission:

Cap the wholesale electricity price at $60/MWh for Ergon Retail regulated retail tariffs ...

It is not clear whether QFF are suggesting a cap for the agricultural sector only, or for all consumers. Regardless, neither submission provides a sound and transparent basis or methodology for calculating the price cap. Nor do the submissions demonstrate why the proposed price cap values are valid. In this sense, the proposed price caps are arbitrary.

Arbitrary price caps represent market intervention in its grossest form. Arbitrary price caps run the risk of understating the true costs faced by a retailer – particularly during periods when the market is in transition, and prices are changing substantially from one year to the next.

Further, continuous application of an arbitrary price cap over successive determinations may result in an ever-widening gap between the price cap and the actual energy costs incurred.

The methodology to estimate the TEC (and its WEC component) has been used for the past eight or so years by the QCA, and the past three years by the Australian Energy Regulator (AER) for determining its Default Market Offer (DMO). Where appropriate, during this period, minor refinements have been made to the methodology based on feedback from stakeholders, and in response to changes in the market rules and regulatory framework. As such, the methodology has, quite rightly, been subject to, and withstood a high degree of examination from a range of stakeholders in three regions of the NEM (New South Wales, South Australia and Queensland) over a long period of time.

The methodology is similar to that used by the Victorian Essential Services Commission (ESC) in setting its Victoria Default Offer (VDO).

ACIL Allen also notes the Australian Energy Market Commission (AEMC) adopts an almost identical methodology when undertaking its analysis for its annual price trends reports (discussed in detail in Appendix A-1).

In summary, the TEC estimation methodology used for the QCA's determination is robust, transparent, well understood by most stakeholders, and consistent with that used by other regulators, thus ensuring comparable estimates of the TEC for regulated tariffs across the NEM.

Estimation of energy costs 4

4.1 Introduction

In this chapter we apply the methodology described in Chapter 2, and summarise the estimates of each component of the Total Energy Cost (TEC) for each of the NSLPs and CLPs for 2021-22.

4.1.1 Historic demand and energy price levels

Figure 4.1 shows the average time of day pool (spot) price for the Queensland region of the NEM, and the associated average time of day load profiles for the past nine 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 Queensland. 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.

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

Prices in 2018-19 increased by about $8/MWh compared with 2017-18 to about $80/MWh. This is largely driven by an increase in morning and evening peak prices due to an increase in gas prices, and an increase in prices at other times due to an increase in the export coal price (which affects NSW and some Queensland coal fired power stations), rather than an increase in price volatility.

Compared with 2018-19, wholesale spot prices in 2019-20 have decreased by about $25/MWh in Queensland. This is largely a result of the continued commissioning of large-scale renewable generation across the NEM, as well as a decline in gas prices due to a slightly better global supply outlook, which has meant LNG exporters have made more supply available to the domestic market due to depressed international prices. South-east Queensland temperature outcomes in January and February 2020 were comparatively milder than January and February 2019 – with temperature about equal to the long-term average. South-east Queensland rainfall over the same period in 2020 was above average, and in contrast to the dry summer of 2018-19.

In relation to each profile, we note the following:

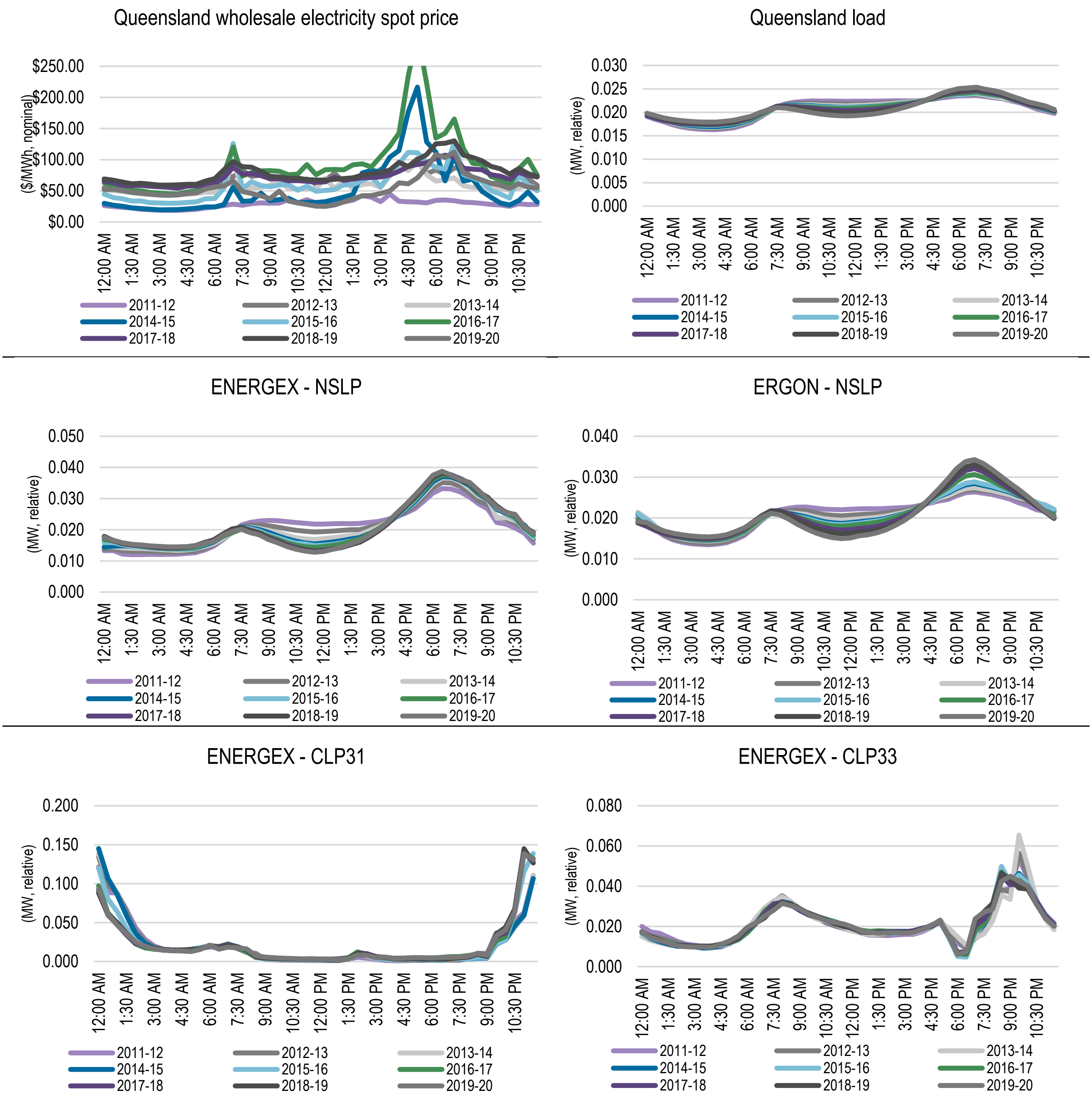
— The annual time of day price profile has been volatile over the past eight years – with the overall level and shape of the price profile changing from one year to the next. For example, in 2011-12 the time of day profile was very flat compared with 2014-15. In 2012-13 and 2013-14, prices increased largely because of the carbon tax. Between 2016-17 and 2018-19 price volatility has decreased – particularly during the evening peak periods. Prices have generally peaked in the afternoon and evening, whereas in some years there is also a morning peak. In short, the profile of prices varies from one year to the next – noting that these are the annual profiles (seasonal profiles are even more variable over time).

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

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

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

Figure 4.1 Actual average time of day wholesale electricity spot price ($/MWh, nominal) and load profiles (MW, relative) – Queensland – 2011-12 to 2019-20



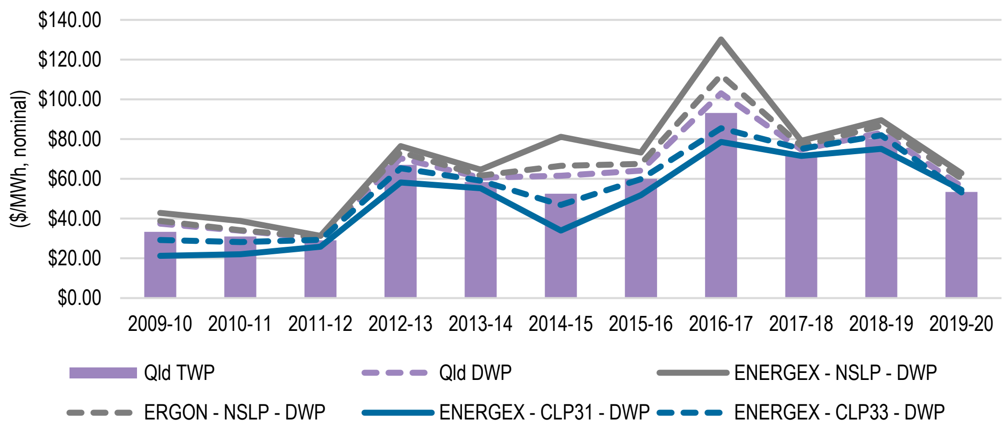
Note: The term relative MW means the loads for each tariff and year have been scaled so they sum to one. This removes differences in absolute scale between the different tariffs and changes in absolute size over time. This is an appropriate representation of the loads since it is the relative shape of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

Source: ACIL Allen analysis of AEMO data

Figure 4.2 shows the actual annual demand weighted spot price (DWP) for each of the tariff loads compared with the time weighted average spot price in Queensland (TWP) over the past 10 years. As expected, the DWPs for tariffs 31 and 33 are below the DWP for the NSLPs in each year, with tariff 31 having the lowest price. Although the rank order in prices by tariff has been consistent in each year, the dollar value differences between the prices has varied from one year to the next. For example, in 2011-12, 2017-18, and 2018-19, the relatively flatter half-hourly price profile resulted in the profiles having relatively similar wholesale spot prices. However, from 2014-15 and 2016-17, the increased price volatility across the afternoon period has resulted in the NSLP spot price diverging away from tariff 31 and 33. Conversely, the increase in off-peak spot prices in 2015-16 lifted the DWP of tariff 31 and 33 up towards that of the NSLP.

It is also worth noting that it has only been for four of the past 10 years that the control loads have noticeably lower DWPs when compared with the NSLPs. Certainly in 2017-18 the DWPs across all tariff classes were comparatively very similar. ACIL Allen raises this point as it is often questioned/noted in submissions that the wholesale energy costs for the control loads produced by our methodology are no longer substantially lower than those of the NSLPs. The control loads are subject to the DNSPs in that are used to manage network congestion – hence their shape is not purely a result of consumer behaviour.

Figure 4.2 Actual annual average demand weighted price ($/MWh, nominal) by profile and Queensland time weighted average price ($/MWh, nominal) – 2009-10 to 2019-20



Note: Values reported are spot (or uncontracted) prices.
Source: ACIL Allen analysis of AEMO data

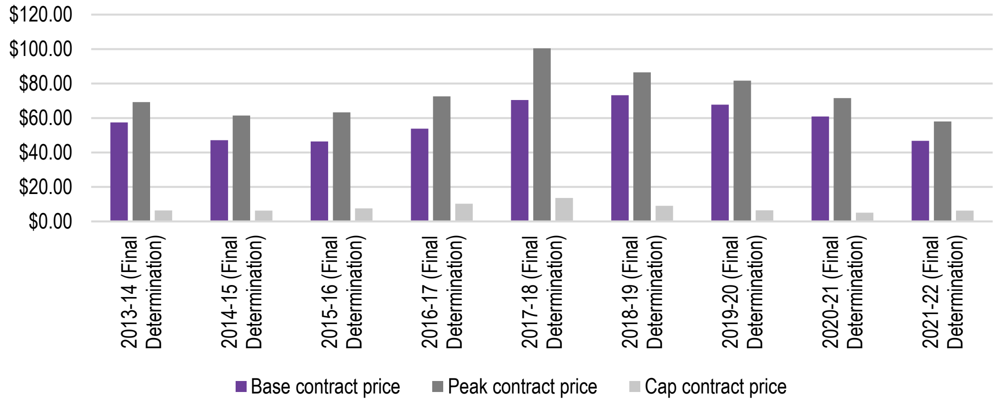
The volatility of spot prices (timing and incidence) provides the incentive to a retailer to hedge their load, since hedging of the loads reduces a retailer's exposure to the volatility. The suite of contracts (as defined by base/peak, swap/cap and quarter) used in the methodology does not change from one year to the next. However, the movement in contract price is the key contributor to movement in the estimated wholesale energy costs of the different profiles year on year, as is shown in Figure 4.3.

Compared with 2020-21, futures base and peak contract prices for 2021-22, on an annualised and trade weighted basis to date, have decreased by about $14.00/MWh and $13.50/MWh respectively for Queensland. Cap contract prices have increased by about $1.20/MWh – possibly reflecting the market's uncertainty on the impact of five-minute settlement on spot market outcomes.

The market is clearly expecting further softening in price outcomes (in addition to what has occurred in 2020, and 2021 to date) due to the continued strong increase in renewable investment coming on-line between 2019-20 and 2021-22. About 4,000 MW of renewable investment will enter the NEM over the next 12-18 months.

The decline in contract prices means that the trade weighted average price levels to date for 2021-22 are quite similar to those of 2014-15.

Figure 4.3 Queensland Base, Peak, and Cap trade weighted average contract prices ($/MWh, nominal) – 2013-14 to 2021-22



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 1 May 2021 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.

Box 4.1 Availability of cap contract products

At the time of the Draft Determination cap contracts had not traded beyond the July-September 2021 quarter due to the delayed commencement of five-minute settlement (5MS).

We have considered that if it was apparent that trade volumes of other contract products had changed because of 5MS then this ought to be taken into account. To date the volume of 2021-22 base contracts traded has converged to the volume traded for 2020-21. This suggests that at this there appears to be no further reliance on base contracts as a replacement for cap contracts.

ACIL Allen consulted with TFS regarding other contract products that might be used in response to 5MS. The only other product of note is the super peak contract – but TFS indicated that there has been negligible trade in this product to date.

For the Draft Determination, ACIL Allen estimated the cap prices beyond the July-September 2021 quarter (the post 5MS quarters) as a function of the percentage movement in the July-September cap contracts between 2020-21 and 2021-22. We note that a similar approach has been used by the ESC when determining the 2021 VDO.

ASX Energy commenced trading of its Australian Base Load Electricity 5 Minute Cap Futures Contract from 22 March 2021. ACIL Allen has analysed the 5MS contract prices on ASX Energy up to 1 May 2021 and found the annual trade weighted average cap contract prices were within $1-$3/MWh of the estimated cap contract price based on the estimation method used for the Draft Determination (with the ASX cap contract prices higher than those estimated by ACIL Allen for the Draft Determination).

The cumulative level of trades is low given trading only started on 22 March 2021. The cumulative trade volumes for the post 5MS quarters range between 11 per cent and 42 per cent of the cumulative trade volumes of the July-September 2021 quarter. However, the level of trades for the post 5MS quarters during the six weeks that they have been available is comparable with, or even higher than, the level of trades for the July-September 2021 quarter.

Therefore, a decision is required: do we continue with the approach used in the Draft Determination or do we adopt the trade volume weighted prices based the six weeks of actual trade data?

ACIL Allen's view is that the ASX data is the latest indicator of the value of caps post 5MS, and given the reasonable degree of agreement between the two approaches it is prudent to use the trade volume weighted average price to estimate the cap price for the post 5MS quarters. There is no doubt uncertainty, or at the very least a range of views, amongst market participants as to the eventual impact 5MS will have on the market and this uncertainty would be reflected in the ASX 5MS cap prices and ought to be accounted for the WEC.

Further, TFS also started brokering 5MS cap contracts at a similar time and display nearly perfect agreement with the ASX Energy data.

Finally, we note that this is a transitional issue.

On this basis, for the Final Determination ACIL Allen has used the trade weighted average ASX Energy prices for the cap contracts.

Table 4.1 shows the estimated quarterly swap and cap contract prices for 2020-21 and 2021-22. Base and peak contract prices decrease from 2020-21 to 2021-22 for all products and quarters. However, cap prices increase in all quarters. Further, the cap prices are generally higher in this Final Determination when compared with the Draft Determination.

Table 4.1 Estimated contract prices ($/MWh, nominal) - Queensland

	Q3	Q4	Q1	Q2
		2020-21		
Base	$58.16	$60.21	$73.12	$52.10
Peak	$68.15	$68.71	$88.81	$60.89
Cap	$2.18	$3.60	$12.16	$2.48
		2021-22		

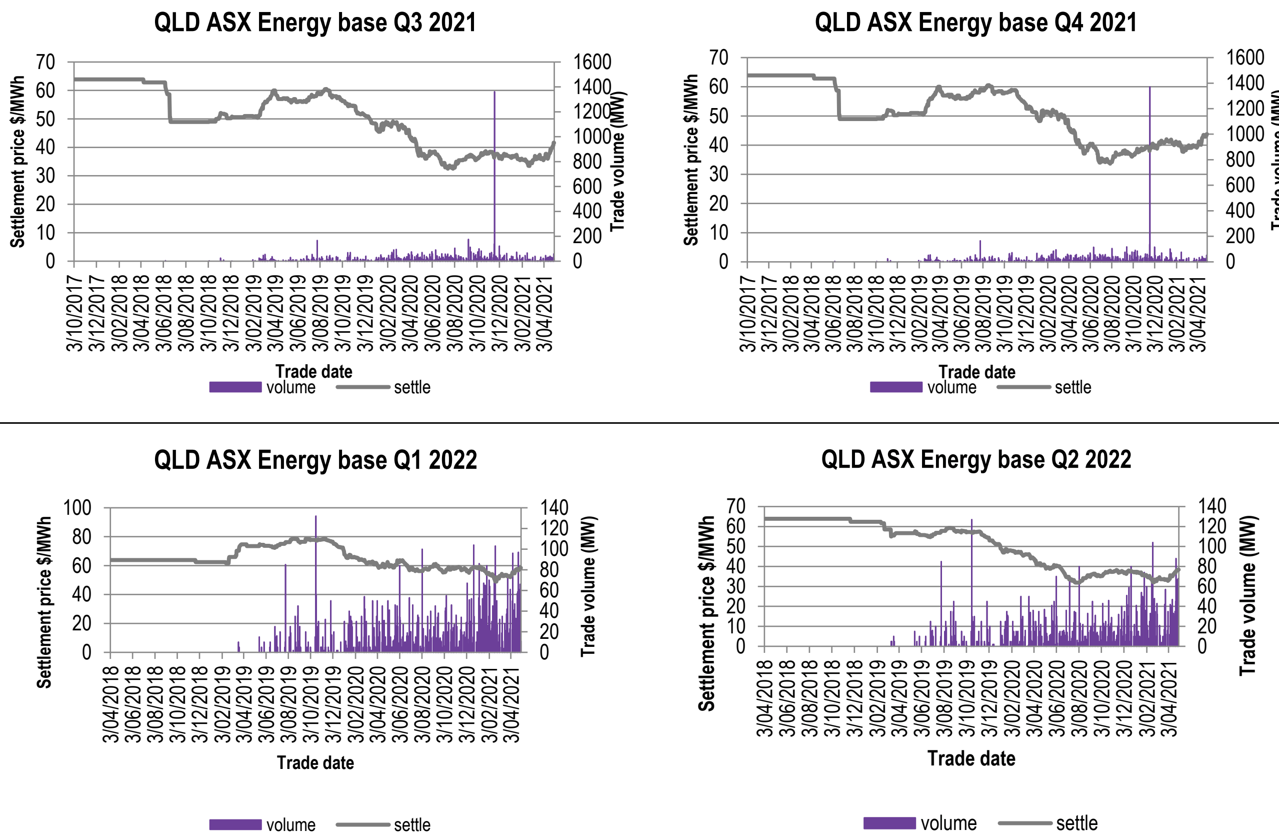
	Q3	Q4	Q1	Q2
Base	$42.03	$43.92	$60.50	$40.68
Peak	$55.38	$55.21	$76.75	$45.00
Cap	$2.18	$5.73	$13.99	$3.30
Percentage change from 2020-21 to 2021-22				
Base	-28%	-27%	-17%	-22%
Peak	-19%	-20%	-14%	-26%
Cap	0%	59%	15%	33%

Source: ACIL Allen analysis using ASX Energy and TFS data up to 1 May 2021 for 2021-22

In addition to the increase in renewable energy capacity, another driver of lower base contract prices in 2021-22 is the continuation of lower of gas prices for gas fired generation. Spot prices across the east coast gas market have maintained their lower levels over the past 12 months. As mentioned in our report for the 2020-21 Final Determination, this has been courtesy of a range of factors including reduced gas fired generation demand, improved supply performance from CSG fields in Queensland, and reduced international LNG export prices. A key consequence of reduced international LNG export prices is that the attractiveness of selling gas on the LNG spot market has appeared to have lessened. With surplus global LNG supply expected to keep international LNG prices lower over the next 12-18 months (excluding the peak of the northern hemisphere winter).

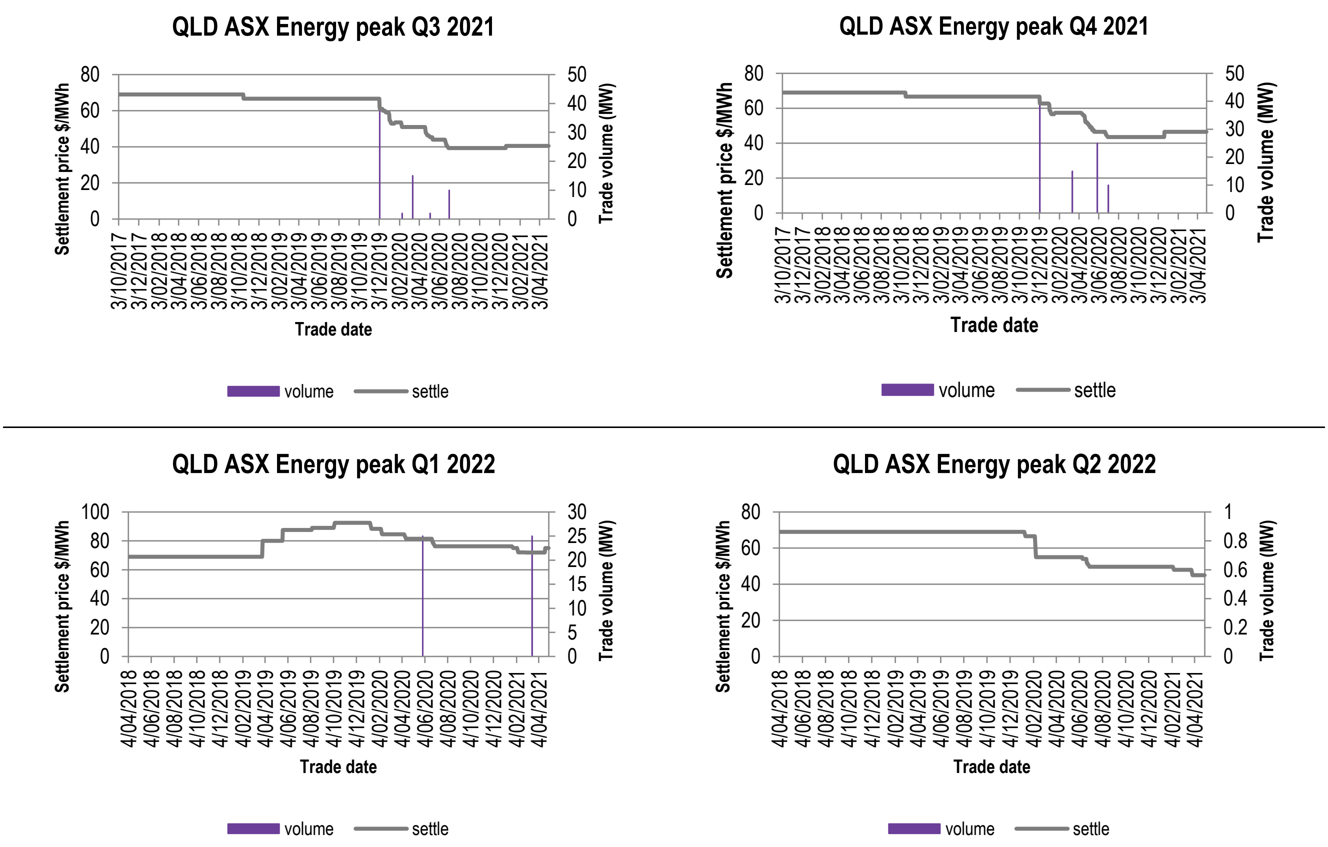
The following charts show daily settlement prices and trade volumes for 2021-22 ASX Energy quarterly base futures, peak futures and cap contracts up to 1 May 2021. It can be seen that the trading of these contracts tends to commence from mid to late 2018.

Figure 4.4 Time series of trade volume and price – ASX Energy base futures - Queensland



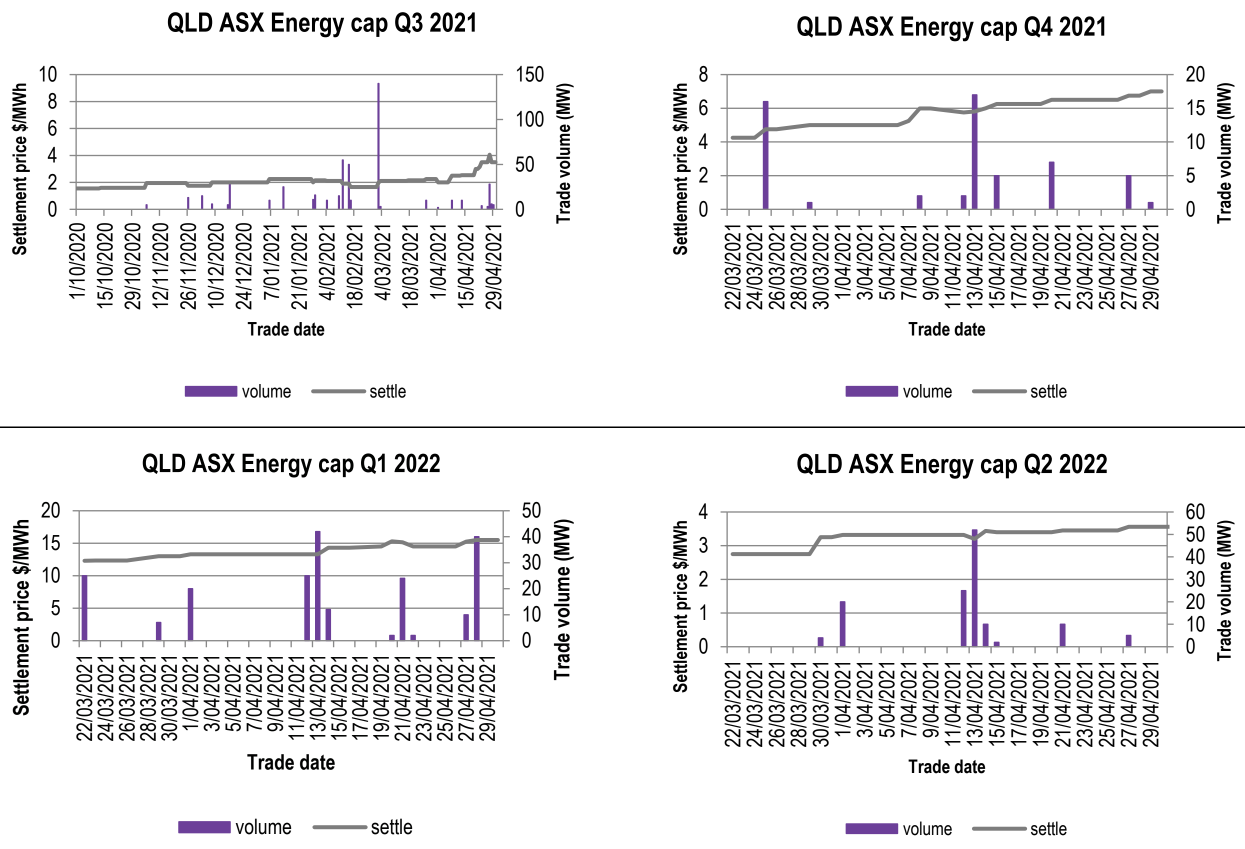
Source: ASX Energy data up to 1 May 2021

Figure 4.5 Time series of trade volume and price – ASX Energy peak futures - Queensland



Source: ASX Energy data up to 1 May 2021

Figure 4.6 Time series of trade volume and price – ASX Energy $300 cap futures - Queensland



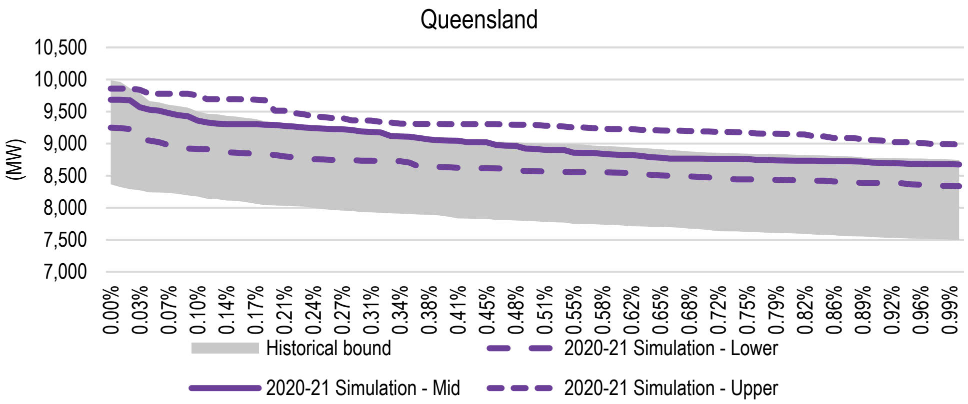
Source: ASX Energy data up to 1 May 2021

4.2.2 Estimating wholesale spot prices

ACIL Allen's proprietary electricity model, *PowerMark* was run to estimate the hourly pool prices for the 550 simulations (50 demand and 11 outage sets).

Figure 4.7 shows the range of the upper one percent segment of the demand duration curves for the 50 simulated Queensland system demand sets resulting from the methodology for 2021-22, 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 50 simulated sets. It can be seen that the demand duration curves of the simulated demand sets for 2021-22 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. This variation in demand contributes to the variation in modelled pool price outcomes as discussed further in this section.

Figure 4.7 Comparison of upper one per cent of hourly loads of 2021-22 simulated hourly demand sets with historical outcomes – Queensland



Source: ACIL Allen analysis and AEMO data

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 2021-22 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 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.

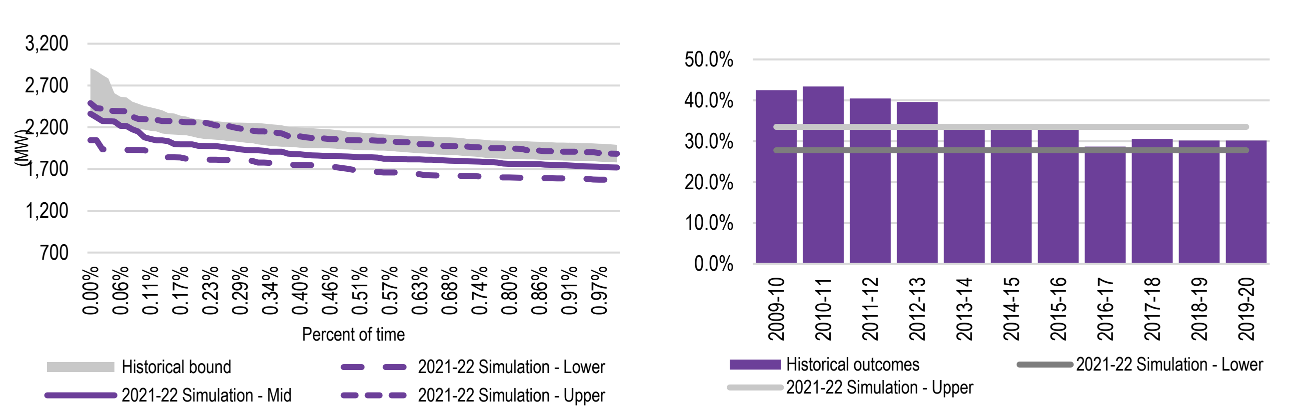
The left panel of Figure 4.8 shows the range of the simulated NSLP demands envelope recent actual outcomes. This variation results in the annual load factor[8] of the 2021-22 simulated demand sets ranging between 28 percent and 34 percent compared with a range of 29 percent to 43 percent for the actual Energex NSLP (as shown in the right panel of Figure 4.8). 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.

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

Figure 4.8 Comparison of upper one per cent of hourly loads and load factors of 2021-22 simulated hourly demand sets with historical outcomes – Energex NSLP

Upper one percent of hourly demands | Load factors



Source: ACIL Allen analysis and AEMO data

The chart in the upper left panel of Figure 4.9 compares the modelled annual regional TWP for the 550 simulations for 2021-22 with the regional TWPs from the past 20 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 2021-22 when compared with the past 20 years of history. Unlike the simulation results for 2020-21 Final Determination, the upper bound of the simulations for 2021-22 generally sits below the historic upper bound of actual outcomes. This is not surprising given the continued decline in gas prices and extensive commissioning of large-scale renewable energy capacity.

Comparing the upper one percent of hourly prices in the simulations with historical spot prices (the upper right panel in Figure 4.9) shows the spread of the hourly prices from the simulations also more than adequately covers the historical spread of spot prices. It is also notable, that as would be expected, the distribution of simulated price outcomes demonstrates a strong positive skewness.

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 550 simulations. The range in annual average contribution to the TWP, of hourly prices above $300/MWh (shown in the mid left panel of Figure 4.9) for the 550 simulations is consistent with those recorded in history.

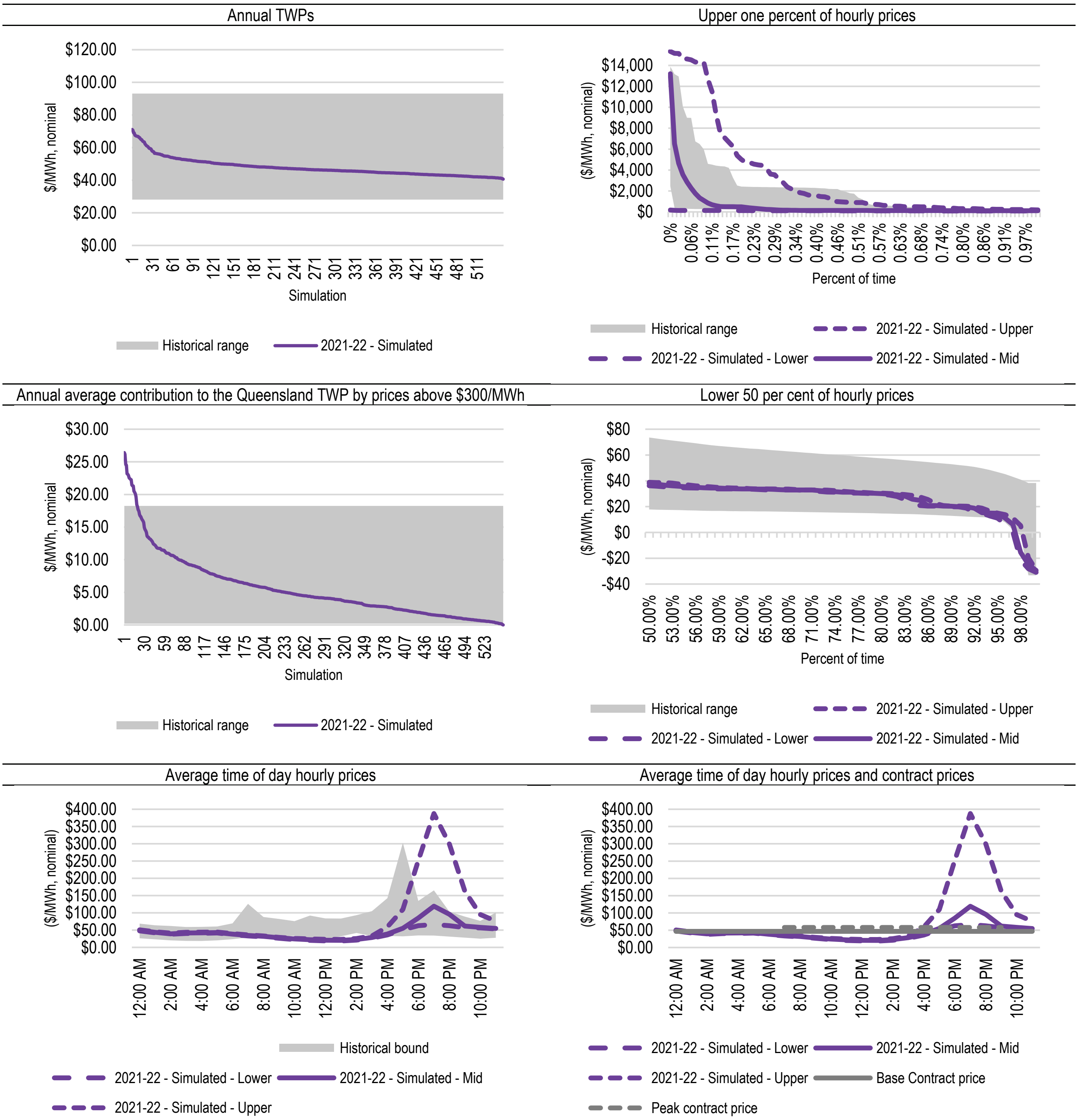
The mid right panel of Figure 4.9 compares the lower 50 per cent of hourly prices in the simulations with historical spot prices. The projected increase in uptake of rooftop PV coupled with the commissioning of the committed utility scale solar projects in Queensland by 2021-22 results in a slight increase in the proportion of hours in which the price is negative.

The lower left panel of Figure 4.9 compares the annual average time of day prices in the simulations with historical time of day spot prices. The continued increase in rooftop PV penetration and development of utility scale solar is projected to reduce price outcomes in 2021-22 during daylight hours as well as the range in price outcomes during daylight hours.

Simulated spot prices during daylight hours for 2021-22 are on average around $30/MWh – well below the annualised base contract price of about $47/MWh (as shown in the lower right panel of Figure 4.9). Indeed, simulated prices during daylight hours are slightly lower than prices between 1am and 4am (historically the period of lowest price outcomes prior to the development of utility scale solar). During these periods, retailers will be making hedge difference payments.

On the basis of these metrics, ACIL Allen is satisfied that in an aggregate sense the distribution of the 550 simulations for 2021-22 cover an adequately wide range of possible annual pool price outcomes.

Figure 4.9 Comparison of various metrics of hourly prices from the 2021-22 simulations with historical outcomes – Queensland



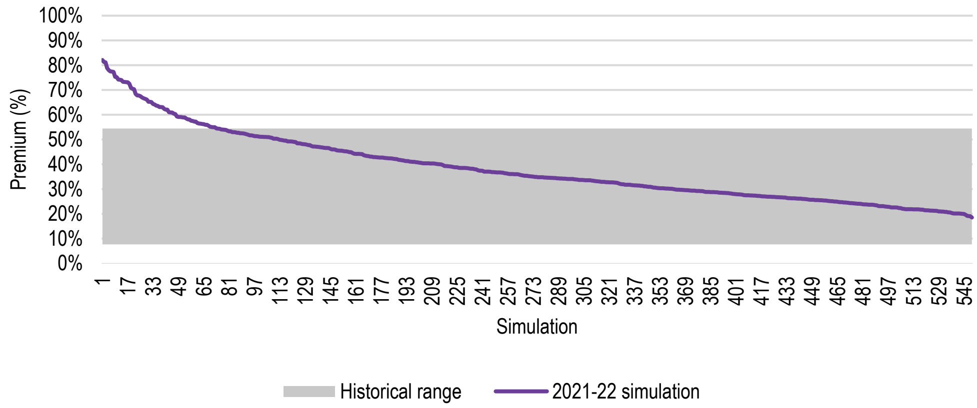
Source: ACIL Allen analysis and AEMO data

The maximum demand of the NSLP is not in isolation a critical feature in determining the cost of supply. The shape and volatility of the NSLP demand trace and its relationship to the shape and volatility 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 simulated 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 4.10 shows that, for the past 19 financial years, the DWP for the Energex NSLP as a percentage premium over the Queensland TWP has varied from a low of 8 percent in 2011-12 and 2017-18 to a high of 54 percent in 2014-15. In the 550 simulations for 2021-22 for each NSLP, this percentage varies from 22 percent to 82 percent. The modelling suggests a greater range in the premium for 2021-22 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 4,000 MW or so of renewable energy projects over the next 12 to18 months.

The comparison with actual outcomes over the past 10 years in Figure 4.10 demonstrates that the relationship between the NSLP demand and corresponding regional spot prices in the 550 simulations is sound.

Figure 4.10 Simulated annual DWP for Energex NSLP as percentage premium of annual TWP for 2021-22 compared with range of actual outcomes in past years



Source: ACIL Allen analysis and AEMO data

ACIL Allen is satisfied the modelled regional wholesale spot prices from the 550 simulations cover the range of expected price outcomes for 2021-22 across all three regions in terms of annual averages and distributions. These comparisons clearly show that the 50 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 2021-22.

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 2021-22 are calculated for each settlement class for each quarter as follows, and are unchanged (in percentage terms) from the 2020-21 determination:

Contract volumes are calculated for the tariff classes for each quarter as follows:

- The base contract volume is set to equal the 60th percentile of the off-peak period hourly demands across all 50 demand sets for the quarter.
- The peak period contract volume is set to equal the 70th percentile of the peak period hourly demands across all 50 demand sets minus the base contract volumes for the quarter.

— The cap contract volume is set at 100 per cent of the median of the annual peak demands across the 50 demand sets minus the base and peak contract volumes.

However, given the Energex small business primary load control tariff, is a primary tariff, the optimal contract volumes are calculated separately, and are:

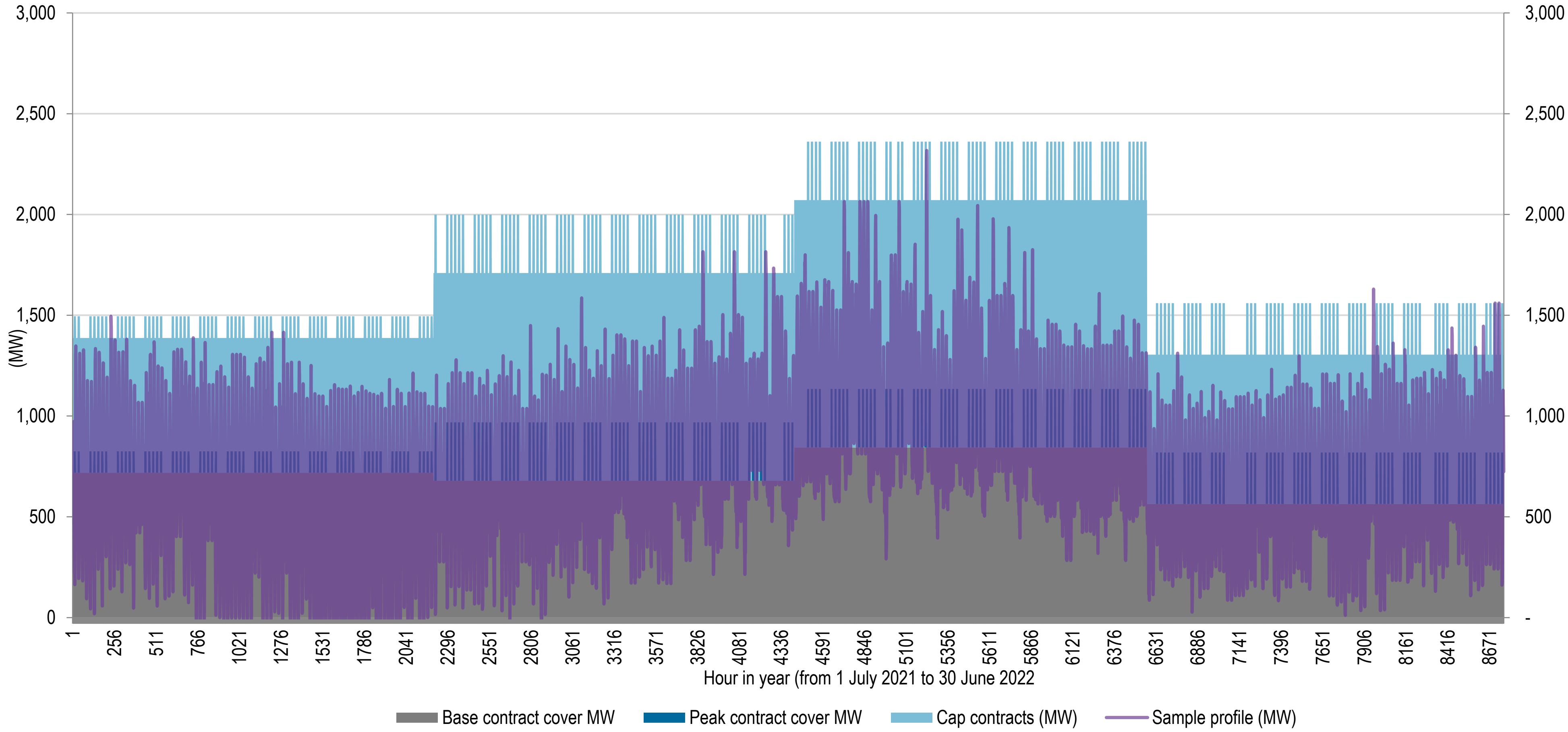
— The base contract volume is set to equal the 30th percentile of the off-peak period hourly demands across all 50 demand sets for the quarter.
— The optimal hedging strategy does not require peak contracts. This is likely due to the shape of the load profile which has relatively lower demand during daylight hours, and peaks later in the evening compared with the NSLPs.
— The cap contract volume is set at 70 per cent of the median of the annual peak demands across the 50 demand sets minus the base and peak contract volumes.

The same hourly hedge volumes (in MW terms) apply to each of the 50 demand sets for a given tariff class and year, and hence to each of the 550 simulations. To be clear, we are not altering the hedge volume (in MW terms) on an ex-post basis for each of the 50 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 550 simulations when calculating the wholesale energy cost. The contract volumes for the Energex NSLP used are shown in Figure 4.11.

Generally, the contracting strategies place little reliance on peak contracts. This is not surprising – the trade weighted price differential between base and peak contracts in Queensland is about $12/MWh (on an annual basis). The carve out of demand during daylight hours (which makes up a reasonable part of the peak hours on business days), and the corresponding low spot prices during those hours makes the peak contacts generally unappealing. It is during these periods that the load will be over contracted and hence in effect retailers will be selling back to the market the extent of this over contracted position at the much lower spot prices. Further, the strategy's very low reliance on peak contracts matches well with the very small volume of peak contracts traded relative to base contracts in the actual futures market.

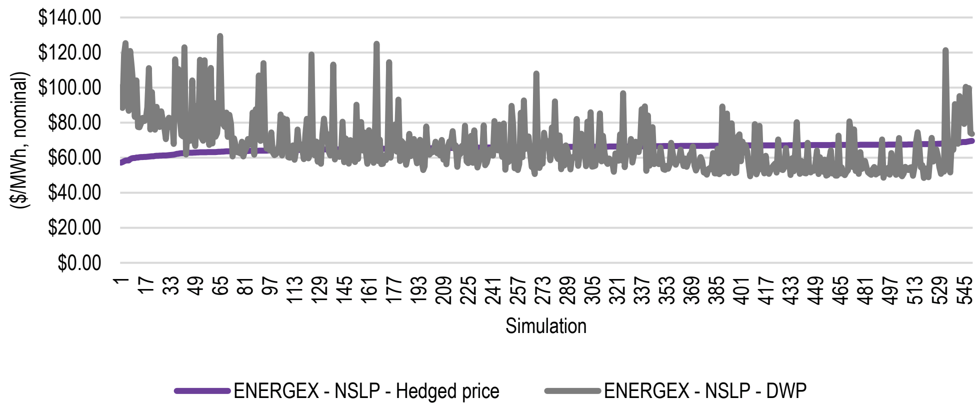
Figure 4.11 Contract volumes used in hedge modelling of 550 simulations for 2021-22 for Energex NSLP



Source: ACIL Allen analysis

Figure 4.12 shows that, by using the above contracting strategies, the variation in the annual hedged price for the 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 4.12 Annual hedged price and DWP ($/MWh, nominal) for Energex NSLP for the 550 simulations – 2021-22



Source: ACIL Allen analysis

4.2.4 Summary of estimated Wholesale Energy Cost

After applying the hedge model, the final WEC estimate is taken as the 95th percentile of the distribution containing 550 WECs (the annual hedged prices). ACIL Allen's estimate of the WEC for each tariff class for 2021-22 are shown in Table 4.2.

Table 4.2 Estimated WEC ($/MWh, nominal) for 2021-22 at the regional reference node

Settlement class	2020-21 – Final Determination	2021-22 – Final Determination	Change from 2020-21 to 2021-22 (%)
Energex - NSLP - residential and small business	$80.90	$67.76	-16.24%
Energex - Controlled load tariff 9000 (31)	$63.49	$53.34	-15.99%
Energex - Controlled load tariff 9100 (33)	$65.35	$54.83	-16.10%
Energex - NSLP - unmetered supply	$80.90	$67.76	-16.24%
Ergon Energy - NSLP - CAC and ICC	$72.41	$61.09	-15.63%
Ergon Energy - NSLP - SAC demand and street lighting	$72.41	$61.09	-15.63%
Energex – Small business primary load control tariff	$68.59	$58.75	-14.35%
Ergon – Large business primary and secondary load control tariffs	$65.35	$54.83	-16.10%

Source: ACIL Allen analysis

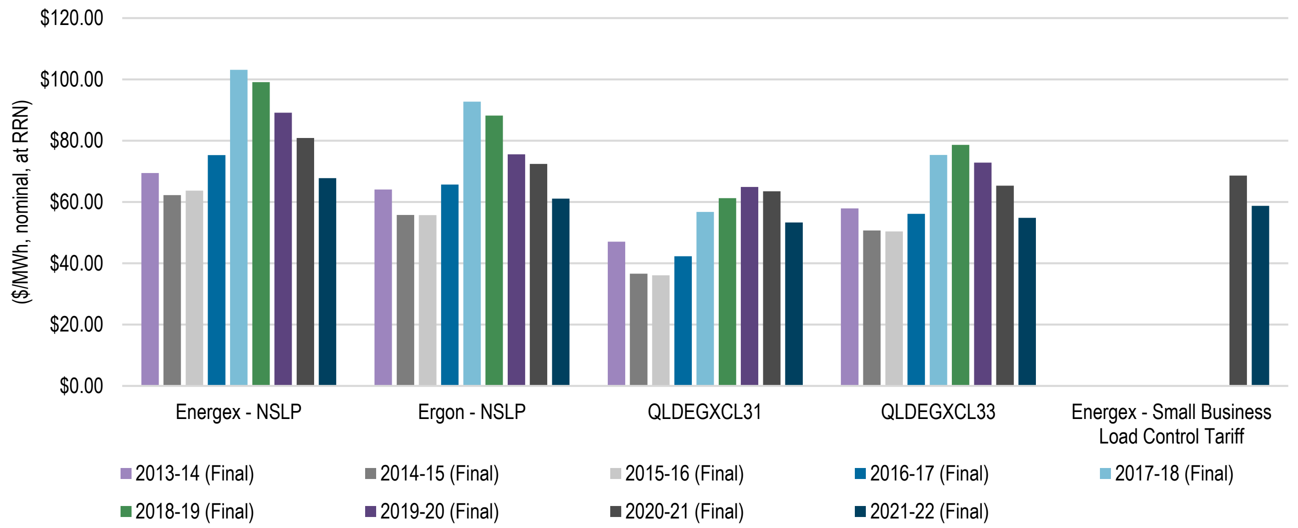
The 2021-22 WECs for the NSLPs and CLPs decrease by between 14 and 16 per cent compared with 2020-21 – reflecting the strong decrease on base contract prices due to the expected continued entry of around renewable investment over the next 18 months.

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

Unlike in recent previous determinations, the percentage decline in WEC of the CLPs is about the same as that of the NSLPS. This is largely due to a stabilising of the load shape of the CLPs over the past 12-24 months, and a stronger decline in percentage terms of the base contacts compared with the peak and cap contacts.

Figure 4.13 shows the trend in WEC over the past determinations. The decrease in the NSLP WECs between 2020-21 and 2021-22 represents the fourth consecutive decrease (from the high of 2017-18). Broadly, the estimated WECs for 2021-22 sit between the WECs of the 2015-16 and 2016-17 determinations.

Figure 4.13 Estimated WEC ($/MWh, nominal) for 2021-22 at the regional reference node in comparison with WECs from previous determinations



Source: ACIL Allen analysis

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[9]) 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. For the Draft Determination, ACIL Allen assessed the most up to date information available including 'non-binding' scheme parameters from the CER, and this information was revised for the Final Determination given the CER has published the final binding parameters.

Retailer compliance with these schemes operates on a calendar year basis and hence estimates are required 2021 and 2022 calendar years, with the costs averaged to estimate the 2021-22 financial year costs.

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

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

— historical Large-scale Generation Certificate (LGC) market forward prices for 2021 and 2022 from brokers TFS
— estimated Renewable Power Percentages (RPP) values for 2021 and 2022 of 18.54 per cent[10]
— the binding Small-scale Technology Percentage (STP) for 2021 of 28.80 per cent, as published by CER
— estimated STP value for 2022 of 28.80 per cent[11]
— CER clearing house price[12] for 2021 and 2022 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.

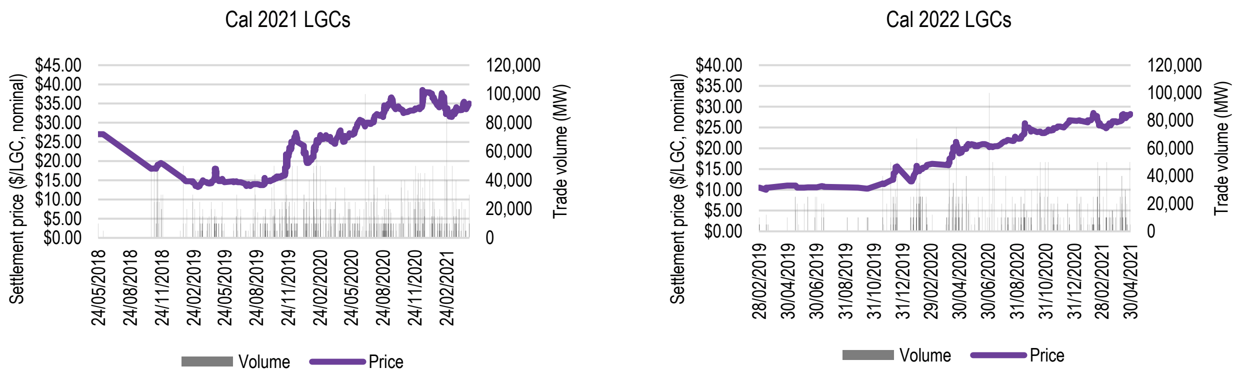
The LGC price used in assessing the cost of the scheme for 2021-22 is found by taking the trade-weighted average of the forward prices for the 2021 and 2022 calendar years, respectively, since the contracts commenced trading. This is typically about 2.5 years prior to the commencement of the compliance year (see Figure 4.14). The average LGC prices calculated from the TFS data are $25.71/MWh for 2021 and $20.61/MWh for 2022.

[10] The RPP values for 2021 and 2022 are based on the CER's published RPP for 2021, and assumes no change in liable acquisitions and the CER-published mandated LRET targets for 2021 and 2022.

[11] The STP value for 2022 assumes a similar level of STC creations, oversupply from the previous year and liable acquisitions in 2022 as in 2021.

[12] 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.

Figure 4.14 LGC prices for 2021 and 2022 for 2021-22 ($/LGC, nominal)



Source: ACIL Allen analysis of TFS data

The RPP value for 2021 was set by the CER on 1 April 2021 at 18.54 per cent. The RPP value for 2022 is estimated by using the mandated target for 2022 of 33 TWh and the CER's published cumulative adjustment and estimate of electricity acquisitions in 2021 of 175.9 TWh. In other words, ACIL Allen has assumed electricity acquisitions remain constant in 2022, and hence the RPP value for 2022 is also 18.54 per cent.

Key elements of the 2021 and 2022 RPP estimation are shown in Table 4.3.

Table 4.3 Estimating the 2021 and 2022 RPP values

	2021	2022
LRET target, MWh (CER)	32,616,792	32,616,792
Relevant acquisitions minus exemptions, MWh (CER)	175,900,000	175,900,000
Estimated RPP	18.54%	18.54%

Source: ACIL Allen analysis of CER and AEMO data

ACIL Allen calculates the cost of complying with the LRET in 2021 and 2022 by multiplying the RPP values for 2021 and 2022 by the trade volume weighted average LGC prices for 2021 and 2022, respectively. The cost of complying with the LRET in 2021-22 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be $4.29/MWh in 2021-22 as shown in Table 4.4**.**

Table 4.4 Estimated cost of LRET – 2021-22

	2021	2022	Cost of LRET 2021-22
RPP %	18.54%	18.54%	
Trade weighted average LGC price ($/LGC, nominal)	$25.71	$20.61	
Cost of LRET ($/MWh, nominal)	**$4.77**	**$3.82**	**$4.29**

Source: ACIL Allen analysis of CER and TFS data

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 2021-22.

The estimate for 2021-22, which incorporates all available information to date, uses the following inputs:

— The CER's binding 2021 STP of 28.80 per cent

— ACIL Allen's estimate of the STP value for 2022 of 28.80 per cent – assuming similar level of STC creation and oversupply from the previous year as in 2021. ACIL Allen has not used the CER's non-binding estimate of 22.40 per cent for 2022 given our spot price modeling assumes a similar level of rooftop PV installations in 2022 as in 2021. We also note that the binding STP has been greater than the CER's non-binding STP for eight of the past 10 years.

ACIL Allen estimates the cost of complying with SRES to be $11.52/MWh in 2021-22 as set out in Table 4.5.

Table 4.5 Estimated cost of SRES – 2021-22

	2021	2022	Cost of SRES 2021-22
STP %	28.80%	28.80%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of SRES ($/MWh, nominal)	**$11.52**	**$11.52**	**$11.52**

Source: ACIL Allen analysis of CER data

4.3.3 Summary of estimated LRET and SRES costs

Adding these component costs gives a total cost requirement for 2021-22 as set out in Table 4.6.

Since the 2020-21 estimate, the cost of LRET has decreased by around four per cent, driven by lower LGC prices in 2021-22, and the cost of SRES has increased by three per cent, driven by slightly higher expected installations in 2021 and 2022.

Table 4.6 Total renewable energy policy costs ($/MWh, nominal) – 2021-22

	2020-21	2021-22
LRET	$4.99	$4.29
SRES	$9.31	$11.52
Total	**$14.30**	**$15.81**

Source: ACIL Allen analysis

4.4 Estimation of other energy costs

The estimates of other energy costs for the Final 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), and the Energy Consumers Australia (ECA)[13].

It is worth noting that in previous final determinations the National Transmission Planner (NTP) was included in this cost category. However, the recovery of this item has since been transferred from AEMO to each of the Transmission Network Service Providers (TNSPs) directly, forming part of the TUOS charge. Therefore, the NTP cost is excluded from our analysis for 2021-22.

Based on projected fees in AEMO's *Electricity Final Budget & Fees 2020-21* the fees for 2021-22 are $0.49/MWh. The breakdown of total fees is shown in Table 4.7.

Table 4.7 NEM management fees ($/MWh, nominal) – 2021-22

Cost category	2020-21	2021-22
NEM fees (admin, registration, etc.)	$0.56	$0.37
FRC - electricity	$0.077	$0.078
NTP - electricity	$0.040	$0.00
ECA - electricity	$0.032	$0.040
Total NEM management fees	**$0.71**	**$0.49**

Source: ACIL Allen analysis of AEMO reports

4.4.2 Ancillary services

AEMO provides weekly aggregated settlements data for ancillary service payments in each interconnected region. Using the average costs in each region over the preceding 52 weeks of currently available NEM ancillary services data as a basis for 2021-22, the estimates cost of ancillary services is shown in Table 4.8.

Generally, there has been a decrease in weekly ancillary service costs as a result of additional supply being commissioned that can offer services to this relatively small market. This results in a reasonable decrease in ancillary service costs in Queensland.

Table 4.8 Ancillary services ($/MWh, nominal) – 2021-22

Region	2020-21	2021-22
Queensland	$1.53	$0.41

Source: ACIL Allen analysis of AEMO data

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:

[13] ECA requirements are measured in terms of connection points for small customers. It is not clear in AEMO's *Electricity Final Budget and Fees 2020-21* of the assumed number of connection points for small customers used in the estimate, therefore ACIL Allen has used DNSP customer numbers to estimate the cost of ECA requirements in $/MWh terms.

- — bank guarantees
- — reallocation certificates
- — prepayment of cash.

There is no fundamental requirement to reallocate prudential obligations – it is a retailer's choice to do so. Assuming no reallocation and no vertical integration (either owned generation or PPAs), a retailer is required to provide suitable guarantees to the AEMO assessed maximum credit limit (MCL) which is calculated as follows:

MCL = OSL + PML

Where for the Summer (December to March), Winter (May to August) and Shoulder (other months):

OSL = (Average daily load x Average future expected spot price x Participant Risk Adjustment Factor * OS Volatility factor x (GST + 1) x 35 days

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

Taking a 1 MWh average daily load and assuming the inputs in Table 4.9 for each season for the Energex NSLP gives an estimated MCL of $6,139.

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 Energex NSLP is $6,139/42 = $146.17/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 $148.64 gives $0.42/MWh for the Energex NSLP**.**

The components of the AEMO prudential costs for Ergon are shown in Table 4.10**.**

Table 4.9 AEMO prudential costs for Energex NSLP – 2021-22

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$73.70	$39.97	$42.14
Participant Risk Adjustment Factor	1.5503	1.3104	1.4308
OS Volatility factor	1.56	1.35	1.34
PM Volatility factor	2.90	1.81	1.91
OSL	$8,544	$3,116	$3,721
PML	$1,709	$623	$744
MCL	$10,253	$3,739	$4,465
Average MCL		$6,139	
AEMO prudential cost ($/MWh, nominal)		**$0.42**	

Source: ACIL Allen analysis of AEMO data

Table 4.10 AEMO prudential costs for Ergon NSLP – 2021-22

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$73.70	$39.97	$42.14
Participant Risk Adjustment Factor	1.2507	1.1924	1.2704
OS Volatility factor	1.56	1.35	1.34
PM Volatility factor	2.90	1.81	1.91
OSL	$6,192	$2,705	$3,113
PML	$1,238	$541	$623
MCL	$7,430	$3,246	$3,736
Average MCL		$4,795	
AEMO prudential cost ($/MWh, nominal)		**$0.33**	

Source: ACIL Allen analysis of AEMO data

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 0.10 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 8 percent on average for a base contract, 14 percent for a peak contract and 19 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 Queensland in Table 4.11. This is divided by the average hours in a quarter. Then applying the assumed funding cost of 6.45 per cent but adjusted for an assumed 0.10 per cent return on cash lodged with the clearing (giving a net funding cost of 6.35 percent) results in the prudential cost per MWh for each contract type.

Average initial margins for Queensland using the average contract prices and initial margin parameters results in a prudential cost per MWh for each contract type as shown in the right column of Table 4.11.

Table 4.11 Hedge Prudential funding costs by contract type – Queensland 2021-22

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$46.73	$22,000	$0.64
Peak	$58.02	$23,000	$1.55
Cap	$6.26	$10,000	$0.29

Source: ACIL Allen analysis of ASX Energy and RBA data

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 the Energex and Ergon NSLPs as shown in Table 4.12 and Table 4.13 respectively.

Table 4.12 Hedge Prudential funding costs for ENERGEX NSLP – 2021-22

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.64	1.0074	$0.64
Peak	$1.55	0.1460	$0.23
Cap	$0.29	1.3165	$0.38
Total cost		**$1.25**	

Source: ACIL Allen analysis

Table 4.13 Hedge Prudential funding costs for ERGON NSLP – 2021-22

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.64	1.0305	$0.66
Peak	$1.55	0.0831	$0.13
Cap	$0.29	0.8497	$0.25
Total cost		**$1.03**	

Source: ACIL Allen analysis

Total prudential costs

Adding the AEMO and hedge prudential costs gives a total prudential requirement for 2021-22 as set out in Table 4.14. Prudential costs for 2021-22 are generally lower than 2020-21 due to lower hedge prices and lower expected price volatility across 2021-22.

Table 4.14 Total prudential costs ($/MWh, nominal) – 2021-22

Jurisdiction	2020-21	2021-22
Energex NSLP	$1.75	$1.67
Ergon NSLP	$1.43	$1.36

Source: ACIL Allen analysis

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 take the RERT costs as published by AEMO for the 12-month period prior to the Final Determination.

AEMO has not activated the RERT for the 12-month period prior to the Final Determination in Queensland.

Therefore, the RERT costs are currently set of $0.00/MWh.

4.4.5 Summary of estimated total other costs

Adding these component costs gives a total other cost requirement as set out in Table 4.15 and Table 4.16, for the 2021-22 Final Determination and is compared with the costs for 2020-21.

Table 4.15 Total of other costs ($/MWH, nominal) – Energex NSLP – 2021-22

Cost category	2020-21	2021-22
NEM management fees	$0.71	$0.49
Ancillary services	$1.53	$0.41
Hedge and pool prudential costs	$1.75	$1.67
Reserve and Emergency Reserve Trader	$0.00	$0.00
Total	**$3.99**	**$2.57**

Source: ACIL Allen analysis

Table 4.16 total of other costs ($/MWH, nominal) – Ergon NSLP – 2021-22

Cost category	2020-21	2021-22
NEM management fees	$0.71	$0.49
Ancillary services	$1.53	$0.41
Hedge and pool prudential costs	$1.43	$1.36
Reserve and Emergency Reserve Trader	$0.00	$0.00
Total	**$3.67**	**$2.26**

Source: ACIL Allen analysis

4.5 Estimation of energy losses

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

The transmission loss factors from the Queensland reference node to the distribution network for Energex and Ergon Energy's east zone area are based on the average energy-weighted marginal loss factors (MLFs) for the Energex and Ergon Energy east zone Transmission Node Identities (TNIs). This analysis results in a transmission loss factor of 1.006 for Energex and 0.986 for the Ergon Energy east zone. These estimates are based on AEMO’s final MLFs for 2021-22 (published on 1 April 2021) weighted by the 2019-20 energy for the TNIs. The DLFs used to estimate losses are based on the final DLFs published by AEMO on 1 April 2021.

The estimation of transmission and distribution loss factors for the settlement classes to be used in calculating energy costs for 2021-22 is shown in Table 4.17.

Table 4.17 Estimated transmission and distribution losses

	2020-21			2021-22		
	Distribution loss factor (DLF)	Transmission marginal loss factor (MLF)	Total loss factors (MLFxDLF)	Distribution loss factor (DLF)	Transmission marginal loss factor (MLF)	Total loss factors (MLFxDLF)
Energex – NSLP - residential and small business	1.052	1.007	1.060	1.059	1.006	1.066
Energex – Controlled load tariff 9000 (31)	1.052	1.007	1.060	1.059	1.006	1.066
Energex – Controlled load tariff 9100 (33)	1.052	1.007	1.060	1.059	1.006	1.066
Energex – NSLP - unmetered supply	1.052	1.007	1.060	1.059	1.006	1.066
Ergon Energy – NSLP - CAC and ICC	1.031	0.964	0.993	1.036	0.986	1.022
Ergon Energy - NSLP - SAC demand and street lighting	1.093	0.964	1.053	1.077	0.986	1.062
Energex – Small business primary load control tariff	1.052	1.007	1.060	1.059	1.006	1.066
Ergon – Large business primary and secondary load control tariffs	1.093	0.964	1.053	1.077	0.986	1.062

Source: ACIL Allen analysis of AEMO data

As described by AEMO[14], 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)*

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

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 2021-22 total energy costs (TEC) for the Final Determination for each of the profiles are presented in Table 4.18.

Table 4.18 Estimated TEC for 2021-22 Final Determination

Settlement class	WEC at Qld reference node ($/MWh)	Renewable energy costs at Qld reference node ($/MWh)	Other costs Qld reference node ($/MWh)	Total transmission and distribution loss factor (MLF x DLF)	Network losses ($/MWh)	TEC at the customer terminal ($/MWh)	Change from 2020-21 Final Determination ($/MWh)	Change from 2020-21 Final Determination (%)
Energex – NSLP - residential and small business	$67.76	$15.81	$2.57	1.066	$5.69	**$91.83**	-$13.31	-12.66%
Energex – Controlled load tariff 9000 (31)	$53.34	$15.81	$2.57	1.066	$4.73	**$76.45**	-$10.24	-11.81%
Energex – Controlled load tariff 9100 (33)	$54.83	$15.81	$2.57	1.066	$4.83	**$78.04**	-$10.62	-11.98%
Energex – NSLP - unmetered supply	$67.76	$15.81	$2.57	1.066	$5.69	**$91.83**	-$13.31	-12.66%
Ergon Energy – NSLP - CAC and ICC	$61.09	$15.81	$2.26	1.022	$1.74	**$80.90**	-$8.85	-9.86%
Ergon Energy - NSLP - SAC demand and street lighting	$61.09	$15.81	$2.26	1.062	$4.91	**$84.07**	-$11.10	-11.67%
Energex – Small business primary load control tariff	$58.75	$15.81	$2.57	1.066	$5.09	**$82.22**	-$9.87	-10.72%
Ergon – Large business primary and secondary load control tariffs	$54.83	$15.81	$2.26	1.062	$4.52	**$77.42**	-$10.32	-11.77%

Source: ACIL Allen analysis

AEMC 2020 Residential electricity price trends report

A

The AEMC's report, *2020 Residential Electricity Price Trends,* was released in December 2020 (the AEMC report). 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.

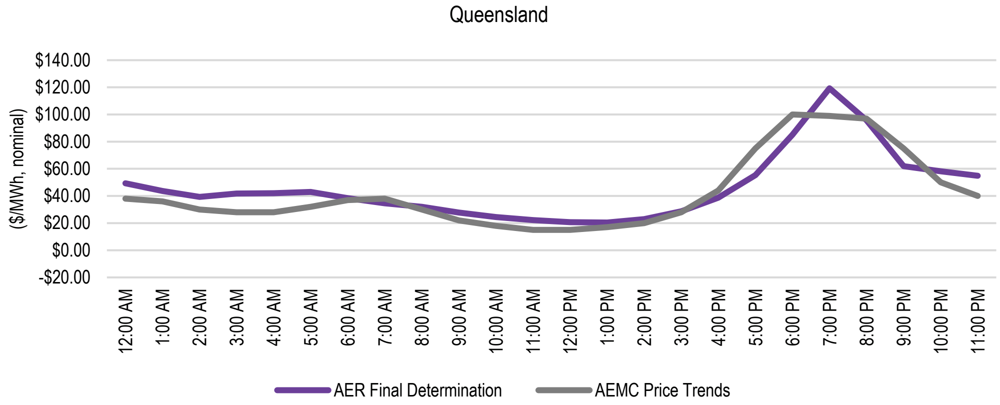
A.1 Wholesale energy costs

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 ACIL Allen's understanding the AEMC does not adjust the historic NSLPs to take into account changes in the shape in the future due to further uptake of rooftop PV.
  – If this understanding is correct, then not adjusting the profiles will result in lower wholesale costs estimates (all other things equal).
  – It also appears that the AEMC aggregate the NSLP and control load produce an aggregate WEC for Queensland.

— Spot market modelling:
  – The AEMC appears to use historic bids (offer curves) when undertaking its spot price modelling. These appear to be adjusted for assumed changes in underlying costs (such as fuel prices) from the latest available ESOO. 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 4,000 MW of renewable capacity between now and 2021-22, as well as changes in underlying costs). AEMC acknowledges that bidding behaviour may change in the future and therefore affect their results. In our analysis for 2021-22 we use our December 2020 Reference case projection settings which are closely aligned with AEMO's 2020 ISP and 2020 ESOO.
  – The projected time of day spot price outcomes presented in the AEMC report appear to be relatively similar to those developed by ACIL Allen as shown in Figure A.1.

Figure A.1 Project Queensland average time of day spot price ($/MWh, nominal) – 2021-22



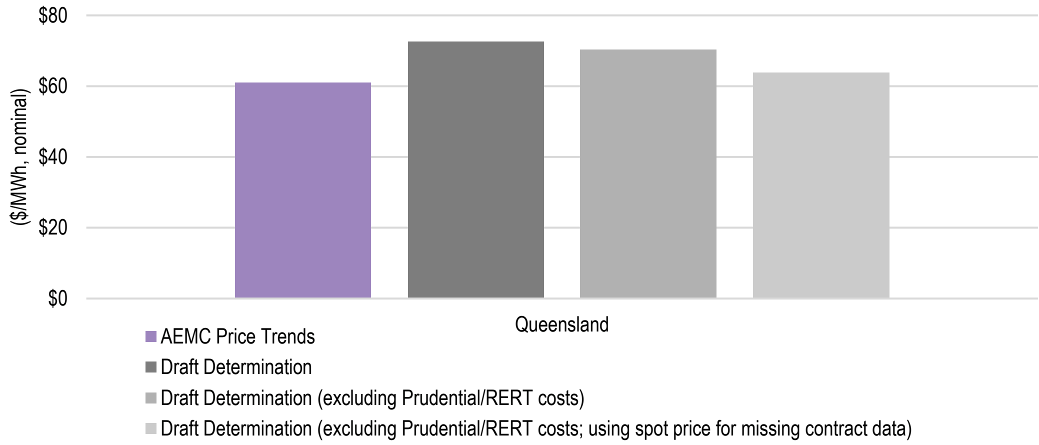
Note: AEMC prices inferred from charts in AEMC 2020 Price Trends Report

Source: ACIL Allen analysis and AEMC Residential electricity price trends report 2020

— Other wholesale costs:
  – ACIL Allen has confirmed with the AEMC that the AEMC wholesale cost estimates exclude prudential and RERT costs. These costs amount to about $2/MWh in Queensland (after accounting for losses).
— Hedge portfolio:
  – AEMC use a portfolio of quarterly base, peak and cap hedges to cover the NSLP, as does 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 2 November 2020.
  – It appears AEMC's portfolio build-up is assumed to be completed by April 2021, as is ACIL Allen's for the Final Determination.
  – This means that six months of actual ASX Energy prices are unable to be included in the AEMC analysis for 2021-22 (with the five-month period being November 2020 to end of April 2021).
  – 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 six months of missing ASX Energy contract data, the AEMC have used their modelled spot price outcomes as a substitute for contract prices. This means that in deriving the final estimate of the contract prices for each quarterly product for 2021-22, AEMC is missing at least, an assumed, 55 per cent of ASX Energy trade volumes and corresponding prices, and is using their modelled spot prices to represent the missing 55 per cent of trade volumes and contract prices.
    - Further, given that there was no cap contract data available for the post 5MS quarters at the time AEMC undertook its analysis, cap prices for these quarters are likely to be based entirely on modelled spot prices.
  – Rather than pre-specifying 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 have noted in earlier reports that the cumulative shape in actual volume of trades can be quite different to an exponential curve in some years.

- 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.
- This is the key difference between our methodology and the AEMC methodology for estimating the WEC:
  - We use actual contract data because the final estimates of the WEC are derived at the end of April 2021 for the Final Determination, whereas AEMC had to make their final estimates at the beginning of November 2020 (so in effect the AEMC has had to fill in a contract price and volume data gap of six months with projected spot prices). For the Draft Determination we do did explicitly predict the volume or price level of trades in contracts between January and April 2021 – instead, we simply close the contract data as of 1 February 2021.
- The projected wholesale costs for Queensland presented in the AEMC report for 2021-22 are lower than those of this Final Determination. This is mainly a result of the difference in the hedge book build approach. As a sensitivity for the Draft Determination, ACIL Allen adopted the AEMC hedging approach by using our projected spot prices to inform what the contract prices might be for the next five months. Figure A.2 shows that by doing this there is much better agreement such that the estimates of the total wholesale costs are within five per cent of the AEMC. Or put another way, actual contract prices have not declined and traded to the extent assumed in the AEMC analysis.

Figure A.2 Total wholesale costs ($/MWh, nominal) – 2021-22 – Queensland



Source: ACIL Allen analysis and AEMC

- ACIL Allen maintains the view that there is no net benefit in filling in the missing contract data for the Draft Determination since the actual data is available for the Final Determination. As we noted in our Draft Determination report, the wholesale costs estimated for the Final Determination may well be different to those of the Draft Determination depending on volume and price level of trades in contracts that occur between the Draft and Final Determination. If actual contracts continued to be traded at volumes observed in previous years, and contract prices decreased further, between the Draft Determination and the Final Determination, then a further decrease in the WECs would be expected for the Final Determination. However, it is apparent that between the Draft Determination and the Final Determination, actual contract prices have not declined to the extent assumed by AEMC.

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