ACIL ALLEN

18 May 2022

Report to Queensland Competition Authority

Estimated energy costs

For use by the Queensland Competition Authority in its Final Determination of 2022-23 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 2022-23 retail electricity tariffs: Final Determination, ACIL Allen, May 2022

Contents

Contents

Tables

1 Introduction

ACIL Allen has been engaged by the Queensland Competition Authority (the QCA) to provide advice on the energy related costs likely to be incurred by a retailer to supply customers on notified retail prices for the 2022-23 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 2022-23. 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 analysis for the 2021-22 determination, and therefore includes the load profiles for residential and small business customers in south east Queensland.

Hence, we are required to provide cost 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 in regional Queensland 2022–23* (February 2022), 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 2021 Residential Electricity Price Trends Report released in November 2021.

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 2022 to 30 June 2023.

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):

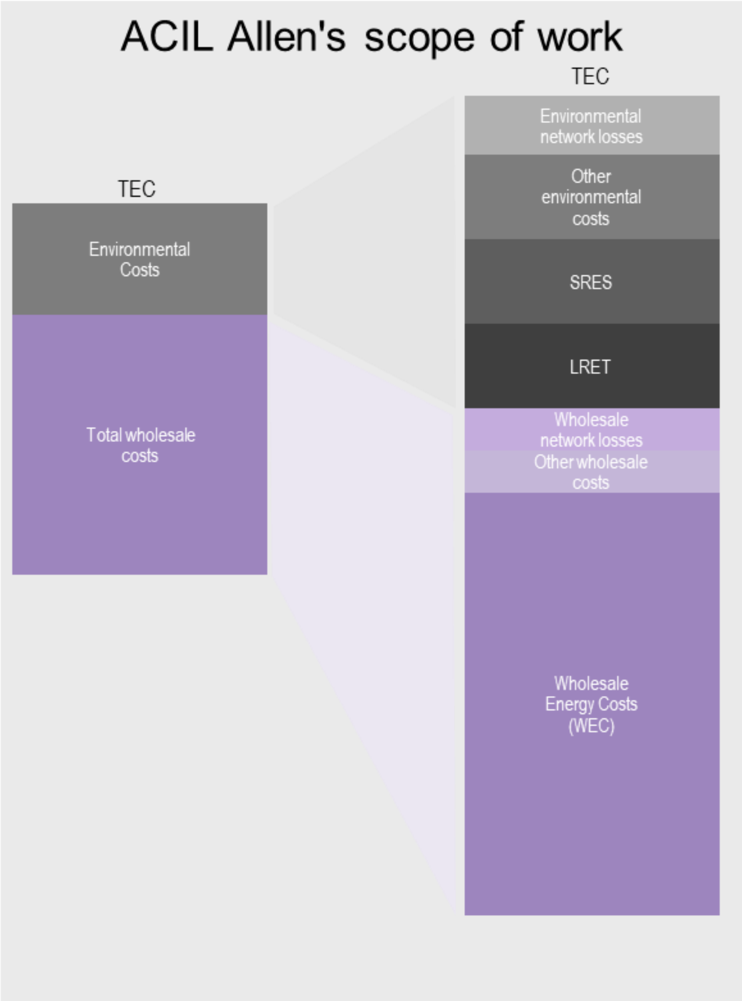
— Wholesale energy costs (WEC) for various demand profiles

— 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 2021-22 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:

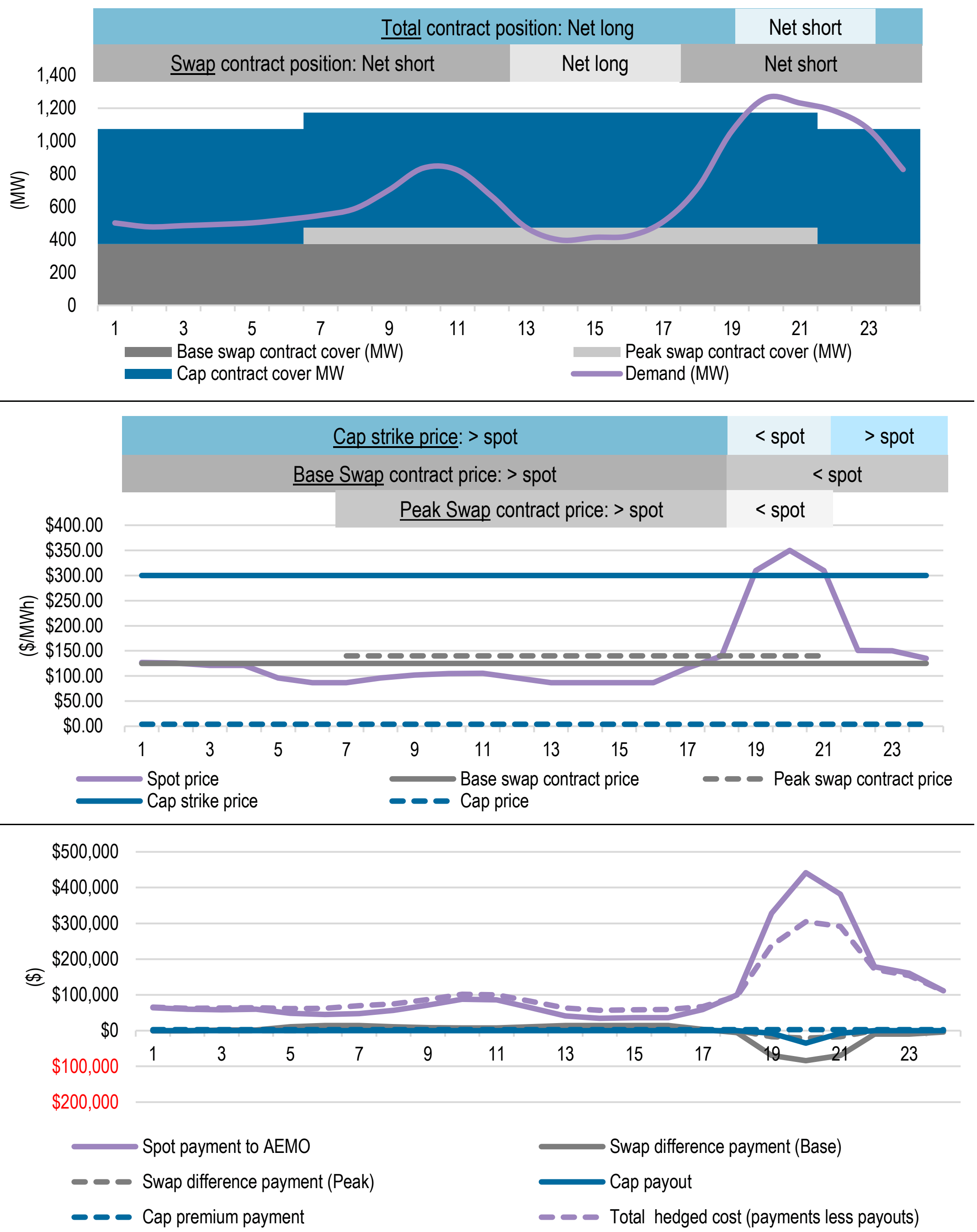
- Pays AEMO the spot price multiplied by the demand.
- Pays the contract counterparty the difference between the swap contract strike price and the spot price, multiplied by the swap contract quantity. This is the case for the base swap contract regardless of time of day, and for the peak swap contract 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 80 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 51 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 561 (i.e. 51 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 561 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 51 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 51 years of weather data and uses a matching algorithm to produce 51 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 561 simulations as this is time prohibitive. However, we run the full set of 561 simulations once the strategy has been chosen.

- The set of 51 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 51 simulations equals the energy forecast, and the distribution of annual seasonal peak loads across the 51 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 51 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 51 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 2022-23 we use our March 2022 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.

We note that coal and gas prices have increased since the Draft Determination. ACIL Allen uses its proprietary coal netback model to calculate the delivered coal prices into the New South Wales coal fired power stations, and those coal fired power stations in Queensland exposed to export coal prices. A key driver of the delivered coal price is the export coal price, which we take from the forward curve. Similarly, we use our proprietary east coast gas market model, GasMark, to model the price of gas into gas fired power stations in the NEM, which also takes into account export LNG prices.

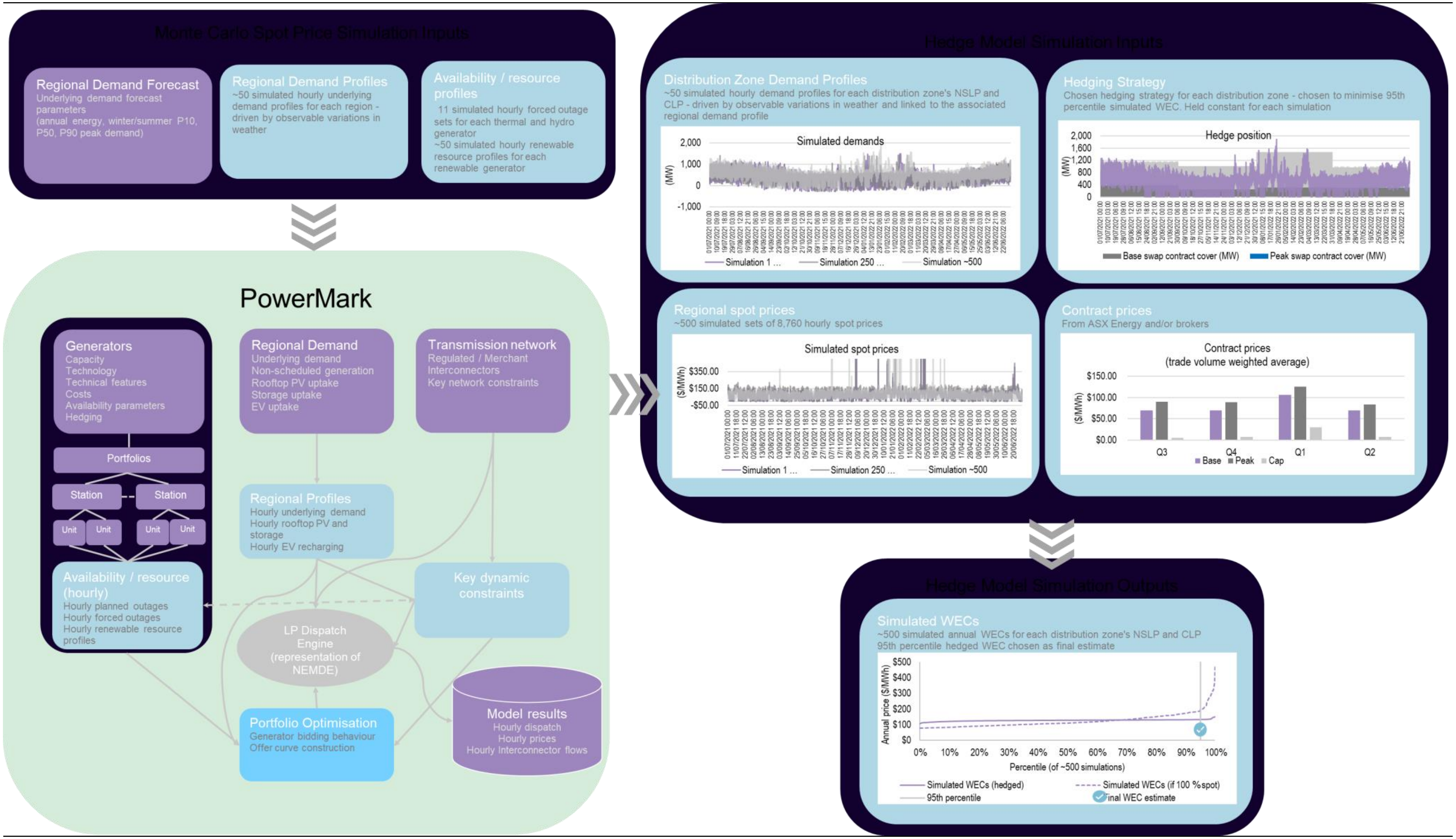
For the Final Determination we have assumed a Newcastle export coal price of USD$246/t for 2022-23 based on the recent ICE forward curve, compared with $100/t assumed in the Draft Determination. We note the forward curve for coal for 2022-23 has declined from the extraordinary high price spike of around USD$400/t apparent in late February and early March with the commencement of the conflict in Ukraine – which no doubt influenced ASX Energy contract prices.

Based on our latest GasMark projection, taking into account recent domestic and global developments, for the Final Determination we have assumed delivered gas prices of around $10.50/GJ into CCGTs, and about $11-12/GJ into peaking plant (there are variations around these values dependent on each power station's location and the associated different transportation costs). This represents an increase of about $0.75/GJ, compared with the assumed gas prices used in the Draft Determination.

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



WEC estimation accuracy

The estimated WEC for any determination will invariably be different to the actual WEC incurred. This will be a function of several factors, including the actual hedging strategy adopted by a retailer (noting different retailers may have different strategies) compared with the simplified hedging strategy adopted in the methodology, the actual load profiles, spot price and contract price outcomes.

Although we attempt to minimise the error of the estimate by undertaking a large number of simulations to account for variations in weather related demand, thermal plant availability, renewable energy resource, and spot price outcomes, the methodology does not attempt to predict the final trade weighted average contract price for each of the assumed contract products adopted in the hedging strategy. Instead, the methodology relies on contract data available at the time the Determination is made.

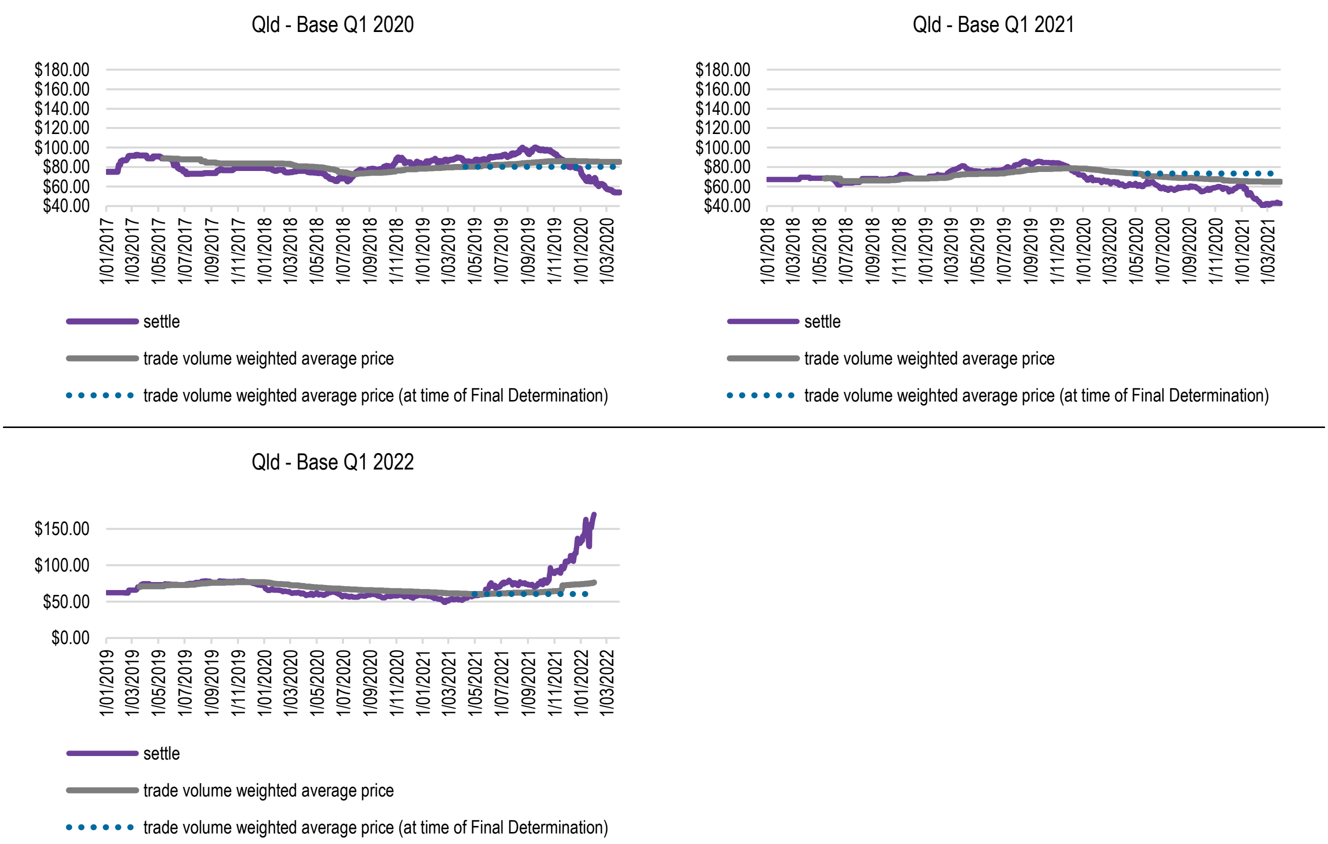
Contract prices are a key driver of the WEC estimate. In some years, contract prices may increase after the Final Determination is made, in other years they may decrease, and in some cases, they may remain relatively stable. Figure 2.4 provides three examples of this phenomenon for quarter one base contracts in Queensland over the past three years. The graphs show the daily contract prices, the moving trade weighted average price, as well as the trade weighted average price at the time of the respective Final Determination.

After the date the 2019-20 Final Determination was made, Q1 2020 traded prices increased slightly and then decreased slightly resulting in an actual trade weighted average price very similar to that used in the Final Determination. This is an example of a stable market price environment (at least in terms of the trade weighted average price) – resulting in a reasonably close estimate.

After the date the 2020-21 Final Determination was made, Q1 2021 traded prices decreased consistently resulting in an actual trade weighted average price about $8.50 lower than that used in the Final Determination. This is an example of a decreasing market price environment – resulting in an overestimate of the WEC (all other things equal).

After the date the 2021-22 Final Determination was made, Q1 2022 traded prices increased consistently resulting in an actual trade weighted average price about $17.00 higher than that used in the Final Determination. This is an example of an increasing market price environment – resulting in an underestimate of the WEC (all other things equal).

Figure 2.4 Daily settlement prices and trade volume weighted prices ($/MWh) for Q1 base contracts in Queensland



Source: ACIL Allen analysis of ASX Energy data

The graphs in Figure 2.4 demonstrate a number of important points about the WEC estimation methodology:

— It is much easier to estimate the WEC during periods of market and contract price stability.

— It is much more challenging to estimate the WEC during periods of increasing or decreasing contract prices.

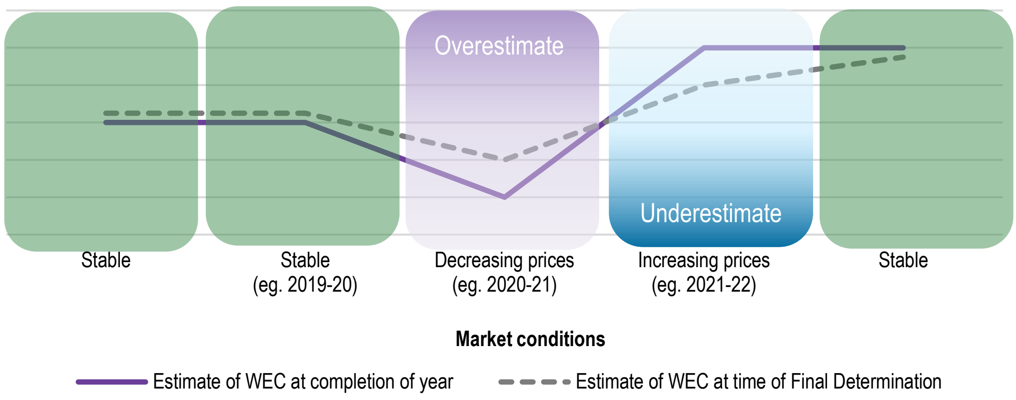
— The error in the WEC estimate, due to contract price variation, is likely to be greater in an environment of increasing prices, than it is in an environment of decreasing prices. This is because of the skewed nature of wholesale electricity prices in the NEM – prices can increase a lot more than they can decrease – and demonstrates the risk faced by retailers. This is another reason to adopt a higher percentile of the simulated WECs.

— Adopting a bookbuild period from the date of the first trade, rather than artificially constraining it to a shorter time frame, means that the trade weighted average contract price has a greater chance of smoothing out temporary fluctuations in contract prices.

In some years contract prices will increase, and in others they will decrease after the Final Determination is made. It is unlikely that the market will enter into an extended period of seemingly ever-increasing or -decreasing prices – at some point, the market will respond accordingly with investment and/or retirement of capacity.

Hence, it is likely that over the long run, the market will follow some form of pattern of increasing, decreasing and stable price outcomes. With this in mind, the methodology may well result in a comparatively smooth WEC estimate trajectory – underestimating outcomes in an increasing price environment, and overestimating outcomes in a decreasing price environment – as illustrated in Figure 2.5.

Figure 2.5 Illustrative comparison of WEC estimation accuracy given market environment



Source: ACIL Allen

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), the Energy Consumers Australia (ECA), DER, and IT upgrade costs associated with 5MS.

The approach uses for estimating market fees is to make use of AEMO's budget report.

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 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 2022-23, just as it was 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 used 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. This is done 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 spot 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 money market rate used in this analysis is 0.10 per cent[3]. 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.

[3] The cash rate at the time of finalisation of the 2022-23 estimates.

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 is currently not triggered for 2022-23, and hence we are not required to account for the RRO in the wholesale costs for 2022-23. 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 2022-23, ACIL Allen uses the following elements:

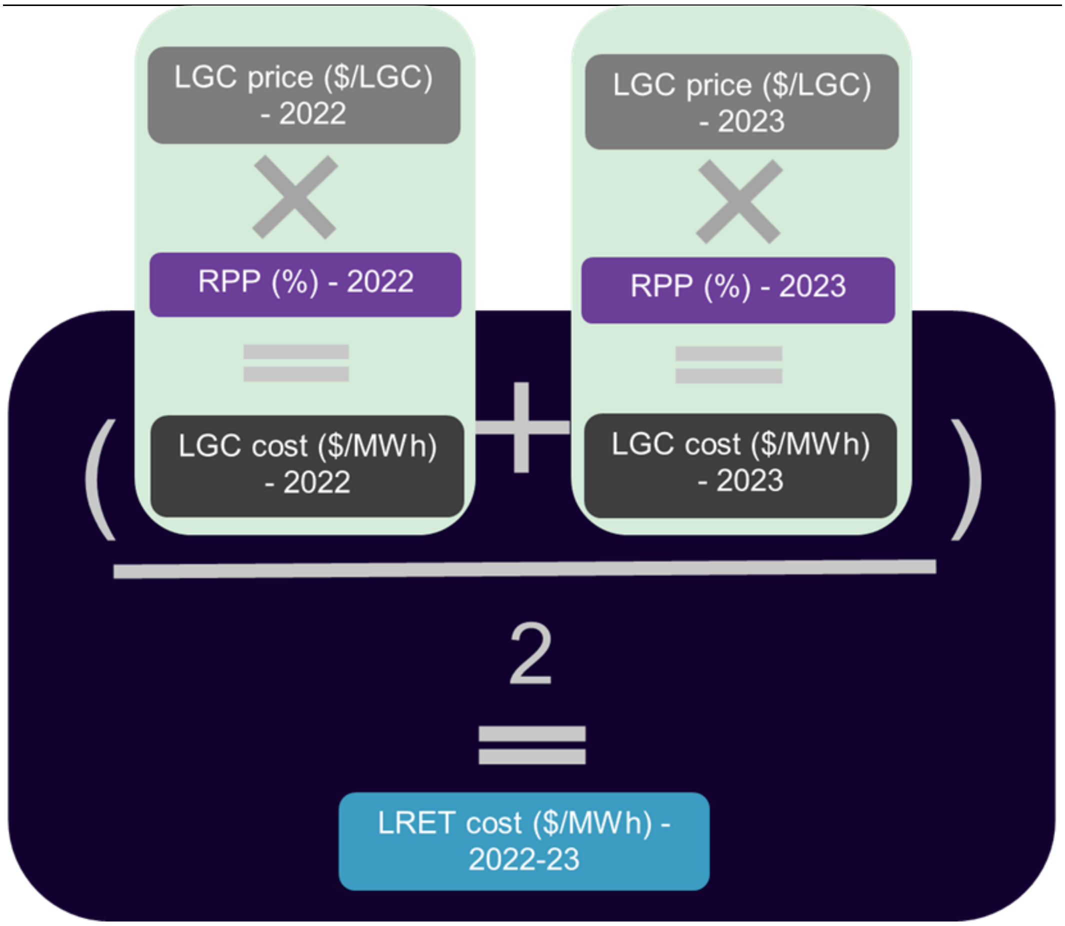
— The average of the trade-weighted average of LGC forward prices for 2022 and 2023 from brokers TFS

— the Renewable Power Percentage (RPP) for 2022, published by the CER

— estimated RPP value for 2023[4].

[4] The estimated RPP value for 2023 is estimated using ACIL Allen's estimate of liable acquisitions and the CER-published mandated LRET target for 2023.

Figure 2.6 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.

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 2022 as published by the CER

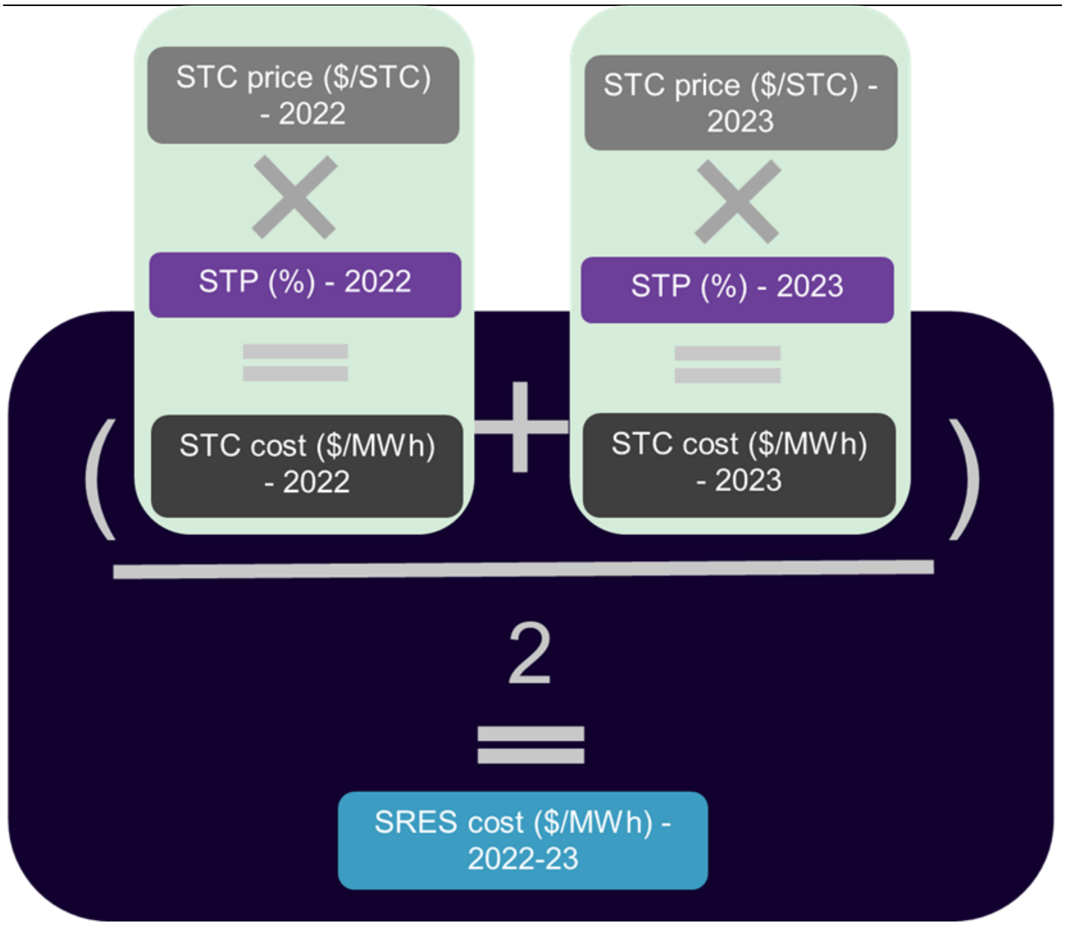
— an estimate of the STP value for 2023[5]

— CER clearing house price[6] for 2022 and 2023 for Small-scale Technology Certificates (STCs) of $40/MWh.

[5] The STP value for 2023 is estimated using estimates of STC creations and liable acquisitions in 2023, 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.

Figure 2.7 Steps to estimate the cost of SRES



Source: ACIL Allen

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 and DLFs used to estimate losses for the Final Determination for 2022-23 are based on the final 2022-23 MLFs and DLFs published by AEMO on 1 April 2022.

[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 eight public submissions and one confidential submission 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 2022-23 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:

— movement in the WEC
— Callide C outage
— WEC estimation methodology
— meter type
— availability of cap contracts
— estimating NEM fees
— RERT
— ACIL Allen's scope of work.

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 and other costs	Prudential costs	Energy losses
1	CANEGROWERS	Yes	Nil	Nil	Nil	Nil	Nil
2	Cotton Australia	Yes	Nil	Nil	Nil	Nil	Nil
3	Ergon Energy Retail	Yes	Yes	Nil	Yes	Nil	Nil
4	Etrog Consulting	Yes	Yes	Nil	Yes	Nil	Nil
5	National Irrigators' Council	Nil	Nil	Nil	Nil	Nil	Nil
6	Northern Iron and Brass Foundry	Nil	Nil	Nil	Nil	Nil	Nil
7	Queensland Electricity Users Network	Nil	Nil	Nil	Nil	Nil	Nil
8	Queensland Farmers' Federation	Nil	Nil	Nil	Nil	Nil	Nil

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

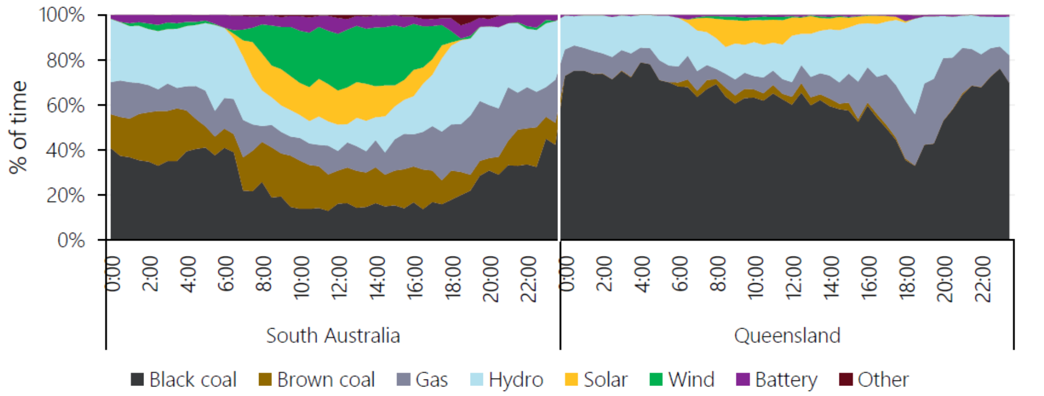
3.1 Movement in WEC

A number of submissions expressed concern or surprise at the extent of the increase in the WEC between the 2021-22 Final Determination and the 2022-23 Draft Determination. Some submissions, including Etrog Consulting's submission, noted the increase is at odds with the expectation that an increase in renewable generation displacing coal in Queensland's generation mix should result in a lower WEC.

Spot prices in the NEM are based on the concept of marginal pricing – the price offered by the marginal generator sets the spot price for all dispatched generation within a region for the given five minute period (regardless of what prices the other generators offered).

Although there has been an increase in renewable output in the generation mix in Queensland and across the NEM in recent times, coal and gas fired generators continue to set the spot price for about 70 per cent of the time in Queensland as shown in the graph below. This means that aside from daylight hours, when the extent of rooftop PV output and utility scale solar generation is sufficient to be at the margin forcing down prices, coal and gas fired generation tend to set the price outside of daylight hours. The increase in renewable generation may well result in a change in which coal plant set the price – moving towards the more efficient / lower cost coal plant being at the margin which would normally result in a decline in price outcomes, but this is being offset of an increase in gas and coal costs for those gas and coal plant when they are setting the spot price. Given this spot price setting dynamic, it is then not surprising that futures contract prices have increased in response to the increase in coal and gas prices. That is, the market is still expecting gas and coal plant to play an important role in the setting of spot prices in 2022-23

Figure 3.1 Proportion of time wholesale spot price is set by given fuel types by time of day – January to March 2022



Note: Although there is no brown coal generation in Queensland, the interconnected nature of the NEM means that the offer of a brown coal generator may set the price in Queensland.

Source: Quarterly Energy Dynamics Q 1 2022, AEMO, April 2022

3.2 Callide C outage

Cotton Australia on page two of its submission is concerned the cost of the outage at Callide C is recovered by consumers via the calculation of the WEC:

… it is unacceptable that electricity users must shoulder the cost of the loss of generation at the Callide power plant. Electricity users already fund the running, maintenance, and replacement of power plants through pricing, and therefore should not have to fund the costs that arise out of failure.

Where is the incentive for power companies to properly maintain their equipment, if they can simply recover the cost of their failures through higher prices?

The business interruption costs, and replacement costs incurred by the owners of Callide C due to the outage are not separately included in the WEC calculation. The extent to which the market expects spot prices will increase due to the outage tightening the demand-supply balance in 2022-23 is reflected in the increase in futures contract prices. The increase in contract prices in response to the outage is not a case of the market reaching a position on what the price needs to increase to for the owners of Callide C to recover their business interruption costs, and replacement costs. The intended design of the NEM is that when there is a reduction in supply prices may increase – which in turn provides a signal for future investment. This increase in contract prices due to the outage is incurred by retailers and therefore the WEC methodology should not be altered in an attempt to reverse out the impact of the outage from contract prices.

3.3 WEC estimation methodology

Etrog Consulting on page 11 of its submission questions whether the current WEC estimation methodology remains valid given the changes that have occurred in the market over the past decade:

We hear that the system is now awash with renewables, with negative prices, and renewables are supposed to be bringing down the cost of energy. Why then is the QCA's energy cost analysis showing higher costs? The QCA's energy cost analysis methodology is probably now about 20 years old. Is it still fit for purpose? Should it be reviewed?

QEUN also request the QCA engage another consultant to estimate the WEC. Presumably because QEUN have formed the view that the WEC estimates ACIL Allen has derived are too high.

We have addressed the reasons for the increase in WEC in the context of increased renewable energy in section 3.1.

It can be inferred from Etrog's and QEUN's submissions that they have formed the view that the methodology is in some way responsible for the increase in WEC. This is further illustrated on page 12 of Etrog's submission in which Etrog compares the WEC estimated for the Draft Determination with the WEC estimated by the AEMC in its residential price trends report:

Clearly the differences between the modelling undertaken by the AEMC and the modelling undertaken by ACIL Allen lead to diametrically different outcomes for consumers. The useful documentation of difference provided by ACIL Allen can be used to form that basis of a fundamental review of methodology that we are calling for, so that consumers can benefit from the energy transition, and not simply see higher prices than necessary due perhaps in part to use of an outdated methodology.

Although we agree with Etrog that the market is in transition, the framework and fundamentals remain unchanged:

— There remains an energy only wholesale spot market based on system marginal pricing in which generators and retailers participate.

— There remain portfolios of generators operating and selling their energy in the spot market.

— There remain retailers buying their consumer's energy needs from the spot market, and retailing electricity to consumers.

— There remain market rules which allow portfolios of generators to attempt to profit maximise by altering their offer curves.

— There remains variability in demand and generator availability (whether it be variability in thermal generator availability or variability in renewable energy resource).

— There remains, due to a combination of the above dot points, spot price volatility which continues to represent a risk to retailers when retailing electricity at fixed prices.

— Hence there remains a need for retailers to manage this spot price risk.

— And not surprisingly, retailers wanting to manage this risk continue to create a demand for, and use, hedge products.

It is for this reason that the methodology has not fundamentally changed.

That said, adjustments have been made to the methodology in recent determinations to reflect the energy transition. For example, the mix of base/peak/cap contracts adopted in the hedge portfolio has changed over time in response to the changing shape of the NSLP due to the uptake of rooftop PV. We have also included other costs which were not relevant in 2013-14 (such as the 5MS IT NEM fee component) and have excluded costs which hare no longer relevant (such as NTP fees).

Most importantly, the methodology attempts to deliver an unbiased estimate using the latest available information from the actual market – reflecting the observable and transparent sentiment of those actors participating in the market.

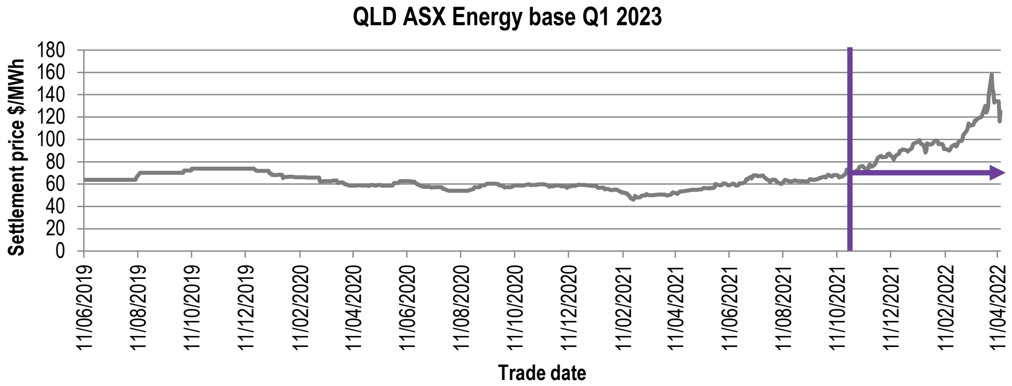
Etrog refer to the projected decrease in the WEC between 2021-22 and 2022-23 presented by the AEMC, as well as our comparison of the AEMC methodology in our report for the Draft Determination. The methodology used by AEMC is virtually identical to that of ACIL Allen. The only major difference is that because the AEMC produces its report much earlier than the QCA's determinations, it needs to project the trend in the ASX contract prices – whereas we do not.

ACIL Allen supports the use of, and continues to use, the latest available contract data subject to the time constraints of producing the final estimates for the QCA. However, we are not in favour of attempting to estimate how contract prices beyond the cut-off date might evolve. Developing a large and appropriately varying set of *spot* price simulations and adopting a percentile is one matter, as we are not suggesting at all that the chosen percentile is guaranteed to occur - simply there is a chance it will occur. But to produce a *single* view of where *contract* prices finally settle, which is what the AEMC methodology does, is likely to cause endless debate, and the result of which will be invariably wrong, and therefore not contribute to a more accurate WEC estimate over the longer term.

When the AEMC undertook its analysis back in October 2021, 2022-23 contract prices were much lower than where they are today (as illustrated in Figure 3.2 for Q1 2023 base contracts). Market sentiment at the time of the AEMC analysis was that prices would be around $65/MWh, and no doubt the AEMC adopted that sentiment when projecting future trades in contracts beyond October 2021 as part of its methodology. This is not a criticism of the AEMC – it is unlikely that anyone would have been able to predict a doubling in market prices at that time from about $65/MWh to above $120/MWh today (if they did then it would have been reflected in the contract prices at that time). This is the main reason why the WEC estimated by the AEMC is less than the WEC estimated by ACIL Allen.

Market conditions have changed dramatically since October 2021 – none of which are in the control of retailers, regulators or market consultants. To suggest that retailers are not able to cover the increase in costs they have faced since October 2021 would increase the likelihood of retailers becoming insolvent.

Figure 3.2 Settled price of trades in ASX Energy Q1 2023 base contracts - Queensland



Source: ACIL Allen analysis of ASX Energy data

ACIL Allen suggests that what might be of more value to Etrog's and QEUN's clients, and indeed the QCA and ACIL Allen, is if Etrog and QEUN could describe which elements of the current methodology are of concern and demonstrate what the shortfalls in the methodology are and make suggestions on how those methodological elements might be improved. If this approach was taken, that would allow ACIL Allen to give due consideration to the concerns raised by Etrog and QEUN..

3.4 Meter type

CANEGROWERS on page two of its submission suggests that the type of meter a consumer is on has no impact on actual energy costs:

Wholesale energy costs should reflect how retailers incur costs when purchasing electricity from the NEM. That irrigators may be on accumulation meters has no impact on retailers' purchasing decisions. Those decisions are based on retailers' assessments of their bulk energy needs at zone substation level at different time of the day, not on the type of meters customers hold.

We agree that energy costs are not impacted by the type of meter, assuming no change in consumption patterns as a result of a change in meter type. We also acknowledge that different consumers have different consumption patterns.

However, we have been asked to estimate the WEC for a given set of demand profiles based on the NSLPs and control loads, as these are what are used by AEMO when billing retailer load for consumers on accumulation meters.

Whilst it is theoretically possible to estimate a WEC for different load profiles, such as those from each zone substation (providing the data is made available), it is unlikely that retailers consider their mass market load requirements at this finer level of detail when developing their hedging strategy.

Finally, 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.

3.5 Availability of cap contracts

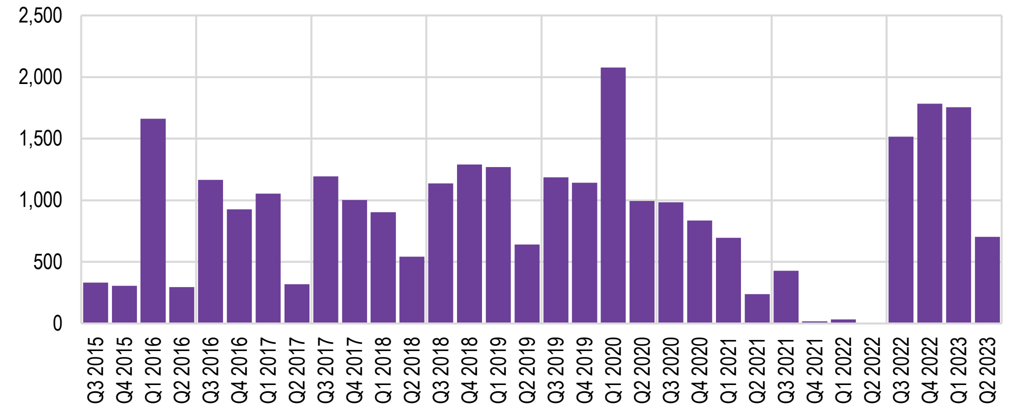
Similar to its submission to the Consultation Paper, Ergon Energy Retail on page one of its submission suggests a lower degree of availability of cap contracts on ASX Energy should be a consideration in the methodology. Ergon note that the volume of caps we have used in the hedging strategy is greater than the volume of open interest for caps available on ASX.

As noted in the methodology section 2.3, we are using the ASX contract data together with an assumed hedge book strategy based on ASX products only, as a proxy for the hedging strategy used by retailers. Each retailer will adopt its own strategy using a combination of ASX products, OTC hedges, direct hedges, and longer terms contracts. This means that the volume of hedges traded on ASX will unsurprisingly be less than the actual volumes of the combination of the various hedge products retailers use.

Figure 3.3 shows the actual cumulative trade volumes of quarterly cap products at the time of previous final determinations, compared with the volumes for this current Final Determination. Setting aside 2021-22, when cap volumes were much lower due to the transition to 5MS, cumulative trade volumes for 2022-23 are higher for most quarters or on par to trade volumes of previous years. On this basis, we see no reason to alter the methodology.

As noted in many of our reports for previous determinations, by using ASX Energy contract data, the methodology is not explicitly assuming that retailers only hedge with using ASX Energy products. Rather, the methodology develops a simplified hedging strategy using transparent ASX Energy data to represent the costs of hedging. We are in effect pricing other contracts at the ASX trade weighted price.

Figure 3.3 Cumulative trade volumes of ASX Energy quarterly caps in Queensland



Note: Volumes are cumulative at the time of the respective final determination.
Source: ACIL Allen analysis of ASX Energy data

3.6 NEM fees

Ergon on page two of its submission notes the step change in AEMO's latest proposed fees for 2022-23 should be included.

ACIL Allen's approach is to estimate the NEM fees using AEMO's latest available budget document.

Prior to the previous two determinations, AEMO included forecasts of NEM fees in its budget document beyond its current budget year, and we adopted the corresponding year's forecast in the determination. However, given AEMO stopped publishing NEM fee forecasts beyond the current budget year for the past two determinations, we adopted the current NEM fees from the latest available budget document, which results in a 12-month lag.

Since the Draft Determination, AEMO has published its *Draft FY23 Budget & Fees: Presentation to Finance Consultation Committee* (4 March 2022). Although this document is in draft form and does not contain explicit costs in $/MWh terms, it provides the following table which shows the budgeted changes in the various components of the NEM fees.

For the Final Determination we have applied the percentage changes, as shown in the column 'Budget 2022/23', to the fee components contained in AEMO 2021-22 budget (or put another way, we have applied these percentage changes to the NEM fee components used in the Draft Determination).

Figure 3.4 Percentage change in NEM fees by component

NEM Entities - Revenue ($ Million)	Actual 2020/21	Forecast 2021/22	Budget 2022/23	Estimate 2023/24	Estimate 2024/25
NEM Core					
Tariff & Fees Revenue	98.8	106.1	203.5	203.2	201.7
Growth	*8%*	*7%*	*92%*	*0%*	*-1%*
Other Revenue	21.3	25.5	25.9	26.6	27.2
Growth	*49%*	*20%*	*2%*	*3%*	*2%*
FRC					
Tariff & Fees Revenue	13.8	14.2	13.5	12.8	12.2
Growth	*1%*	*3%*	*-5%*	*-5%*	*-5%*
5MS & GS					
Tariff & Fees Revenue	-	24.8	44.2	43.8	43.4
Growth			*78%*	*-1%*	*-1%*
DER					
Tariff & Fees Revenue	-	5.7	5.5	5.4	5.3
Growth			*-4%*	*-3%*	*-2%*
NTP					
Tariff & Fees Revenue	12.2	23.0	19.0	19.0	19.8
Growth	*124%*	*88%*	*-17%*	*0%*	*4%*
NEM 2025					
Tariff & Fees Revenue	-	-	-	16.6	53.1
Growth					*220%*
Other					
Tariff & Fees Revenue	1.5	1.6	3.6	3.3	3.3
Growth	*-10%*	*5%*	*126%*	*-7%*	*0%*

Source: AEMO Draft FY23 Budget & Fees: Presentation to Finance Consultation Committee (4 March 2022)

3.7 Reliability and Emergency Reserve Trader (RERT)

Ergon on page two of its submission refers to the activation of the RERT mechanism in Queensland on 1 February 2022. ACIL Allen agrees that this should be included in the Final Determination.

Etrog suggest that the RERT be excluded from the energy cost stack:

The costs of administering the RERT scheme are incurred by AEMO because retailers leave gaps in their contracting. Therefore it is not appropriate for retailers to be allowed to pass these costs through to consumers in regulated prices, as it does not encourage retailers to do their part to minimise RERT costs.

We urge the QCA to consider that these costs should not be passed on to customers in regulated prices. Instead the QCA should signal to retailers that expects them to play their part to avoid RERT costs being incurred by AEMO, otherwise they will have to bear these costs themselves.

ACIL Allen does not agree with Etrog's assertion that the triggering of the RERT is due to retailers leaving gaps in their contracting. The RERT relates to the matter of a physical shortfall in capacity not a shortfall in hedging. The RERT allows AEMO to contract for emergency reserves such as physical generation or physical demand response that are not otherwise available in the market when there is a critical shortfall in reserves and the supply demand balance is tight. AEMO triggers the RERT to meet the reliability standard.

If Etrog's assertion is that retailers could avoid the RERT being triggered by entering into more contracts, and hence influencing more investment in generation capacity or demand response, then the cost of those additional contracts ought to be included as it would quite rightly need to be recovered from consumers since they benefit from the avoidance of breaching the reliability standard. Suggesting retailers absorb this cost makes no commercial sense.

Further, Etrog suggest that retailers can hedge against the RERT. ACIL Allen is not aware of a transparent and verifiable source of RERT hedges. If there was, then we would consider including the hedges as a cost component instead of the actual RERT cost – which would mean that the hedged RERT cost would be included for each determination regardless of whether AEMO actually triggers the RERT.

3.8 ACIL Allen's scope of work

QUEN and QFF make various comments about ACIL Allen's role in the QCA's determination process. Both appear to be of the view that our role is providing advice on retail prices.

To be clear, our scope is to provide advice on the wholesale energy and environmental costs incurred by retailers. We have not been engaged to provide advice on retail prices, retail tariff structures, application of the CSO, or the economic impact of increasing electricity prices. Given these items are outside our scope, it would be inappropriate of us to provide comments on them, regardless of whether they are raised by QUEN or QFF, or other stakeholders.

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 2022-23.

4.1.1 Historic demand and energy price levels

Figure 4.1 shows the average time of day spot price for the Queensland region of the NEM, and the associated average time of day load profiles for the past 10 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 was 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 was 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 was 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 New South Wales and some Queensland coal fired power stations), rather than an increase in price volatility.

Compared with 2018-19, wholesale spot prices in 2019-20 decreased by about $25/MWh in Queensland. This was 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 2020-21, prices were generally lower than in 2019-20 up until the last six weeks of the financial year when Callide C unit 4 suffered a critical outage in May 2021 which resulted in multiple coal fired power station units tripping in Queensland. A consequence of this incident was an increase in price volatility due to lower levels of plant availability, which resulted in the annual wholesale spot price being by about $10/MWh higher than that of 2019-20.

Prices in Queensland for 2021-22 to date have doubled, increasing by about $60/MWh when compared with 2020-21. This is despite the continued uptake of rooftop PV putting downward pressure on price outcomes during daylight hours. The main reasons for the increase in prices overall are the:

— large increase in coal costs for New South Wales and some Queensland coal fired power stations which is increasing price outcomes overnight and during the day when coal is at the margin
— increase in gas costs which is increasing prices during the evening peak when gas is at the margin
— continued outage of Callide C Unit 4 (which is not expected to return until the end of the first quarter in 2023 at the earliest) as well as other plant outages (such as Kogan Creek in the first quarter of 2022) which are contributing to an increase in price volatility across the evening peak periods.

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 was also a morning peak.
— In 2021-22 to date, prices during daylight hours have decreased (due to further rooftop PV uptake), but these are more than offset by strong increases in prices during the evening peak and overnight (due to reduced plant availability, and increasing gas and coal prices). 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 varies 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 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. That said, with a continued decrease in prices during daylight hours (due to continued rooftop PV uptake), costs of tariff 33 may well converge with those of tariff 31 over time.
— Over the past seven or so years, the Energex NSLP and the Ergon NSLP load profiles, have experienced a carving out of load during daylight hours with the increased penetration of rooftop solar PV. This results in the load profile becoming peakier over time and

consequently, the demand weighted spot prices[8] (DWP) for the NSLP load profiles have increased relative to the corresponding regional time weighted average spot price (TWP). The carving out of the NSLPs during daylight hours increases the relative weighting of the load profile during the higher priced evening peak and reduces the relative weighting during the lower priced daylight hours.

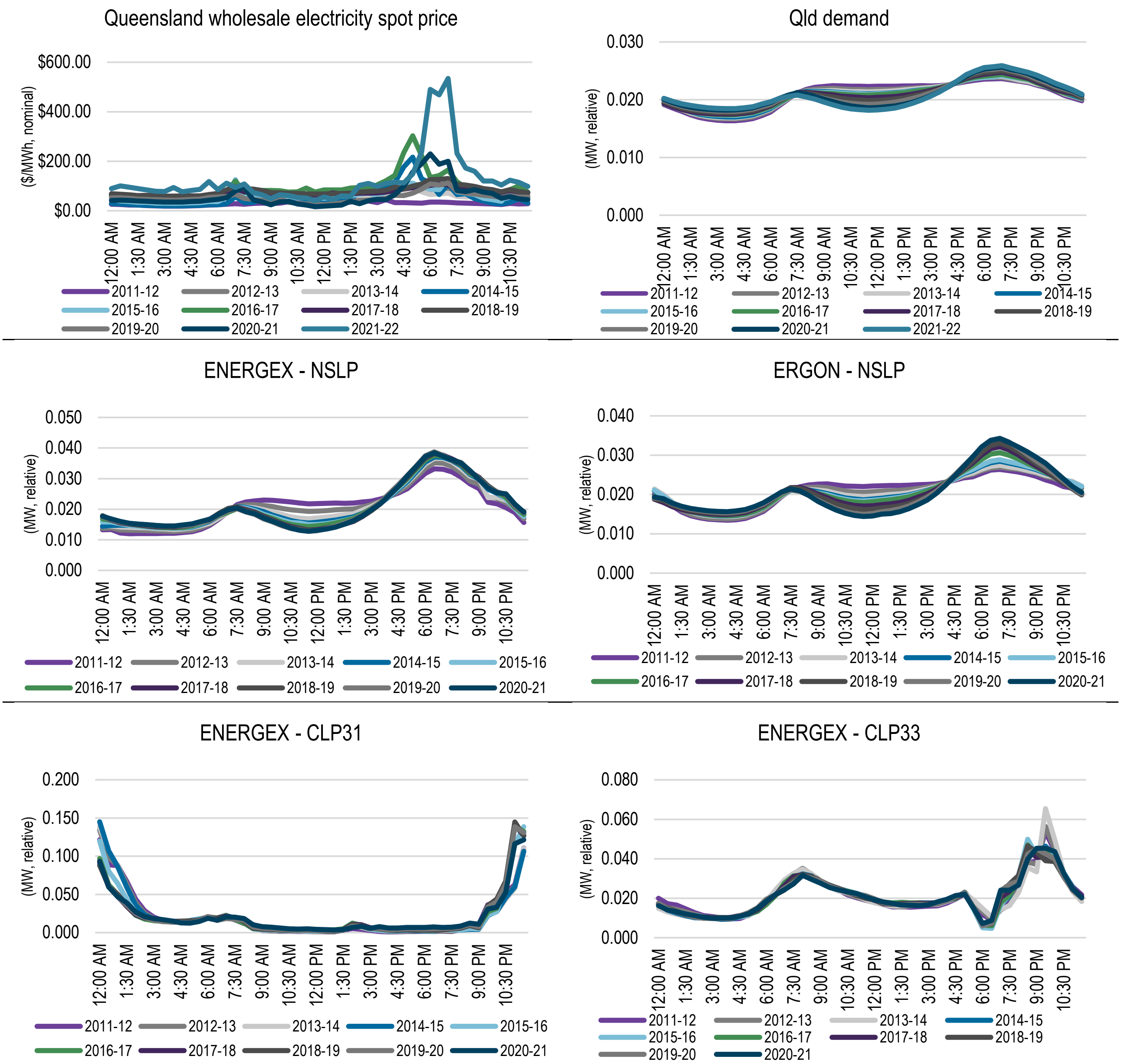
— However, over the past few years the rate of carve out has slowed and this is most likely due to new rooftop solar PV installations being paired with the installation of interval meters – removing those consumers from the NSLP.

— 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.

— Although the increased penetration of rooftop PV is placing downward pressure wholesale spot prices during daylight hours, price volatility during the evening peak has persisted. Indeed, it has increased in 2021-22 to date due to increased gas prices and the prolonged outage at Callide C, as well as shorter outages of other plant.

[8] The demand weighted price is in effect the unhedged wholesale energy cost that the retailers pay AEMO for the NSLP.

Figure 4.1 Actual average time of day wholesale electricity spot price ($/MWh, nominal) and load profiles (MW, relative) – Queensland – 2011-12 to 2021-22



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. 2021-22 price and demand series includes data up to May 2022. Insufficient NSLP/CLP data available for 2021-22

Source: ACIL Allen analysis of AEMO data

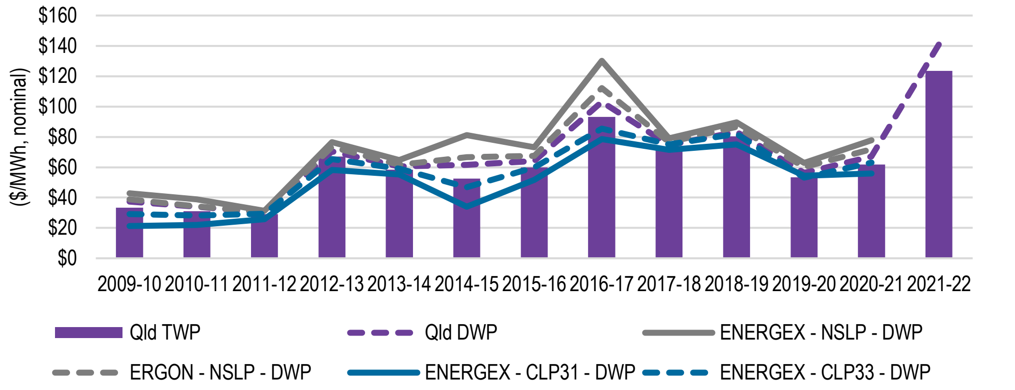
Figure 4.2 shows the actual annual demand weighted spot price (DWP) for each of the tariff loads compared with the time weighted average spot price in Queensland (TWP) over the past 12 years. The DWP for the Energex NSLP is at a 20 per cent premium to the TWP on average over the past five years, compared with an average premium of about 15 per cent for the Ergon NSLP over the same period.

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 12 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 they are used to manage network congestion – hence their shape is not purely a result of consumer behaviour.

Although AEMO is yet to publish sufficient load data for the NSLPs for 2021-22, based on the observed premiums of the DWP to TWP over the past five years, it is likely the DWPs for the NSLPs in 2021-22 will be between $140 and $150/MWh, compared with $70-$80/MWh in 2020-21.

Figure 4.2 Actual annual average demand weighted price ($/MWh, nominal) by profile and Queensland time weighted average price ($/MWh, nominal) – 2009-10 to 2021-22



Note: Values reported are spot (or uncontracted) prices. 2021-22 price series includes data up to May 2022. Insufficient NSLP/CLP data available for 2021-22.

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, although the mix does. The movement in contract price is a key contributor to movement in the estimated wholesale energy costs of the different profiles year on year.

Figure 4.3 shows that compared with 2021-22, futures base and peak contract prices for 2022-23, on an annualised and trade weighted basis to date, have increased by about $16.60/MWh and $43.10/MWh respectively for Queensland. Cap contract prices have increased by about $10.20/MWh.

Unlike the previous four determinations in which there was a clear decline in contract prices, the market is now clearly expecting an increase in price outcomes due to the strong increase in coal and gas costs, coupled with the continued unavailability of Callide C Unit 4, and the closure of Liddell in New South Wales, more than offsetting the amount of utility scale renewable investment coming on-line between 2021-22 and 2022-23 (which is slowing compared with recent years).

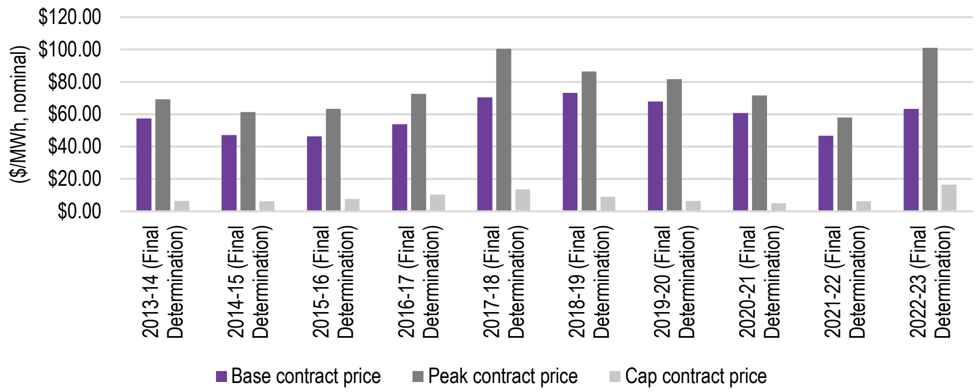
Further, cap contract prices have increased substantially for 2022-23 compared with 2021-22. This may reflect a degree of uncertainty faced by providers of caps around the ability of their peaking plant to cover price spikes in the spot market under five-minute settlement (5MS), as well as an expectation of an increase in underlying price volatility due to the continued outage of Callide C

Unit 4 and possibly an expectation of further plant outages. Our analysis shows that a $1/MWh increase in cap price can increase the WEC for the NSLP by about $3/MWh, all other things equal, due to the peaky shape of the NSLP.

The cost of hedging the NSLP is further exacerbated by the expected continued strong uptake of rooftop PV which carves out the demand during daylight hours, resulting in very low spot price outcomes during daylight hours, certainly less than the base contact price, making the already peaky NSLP demand profile more expensive to hedge.

The increase in contract prices means that the trade weighted average price levels to date for 2022-23 are quite similar to those of 2017-18 (which was the previous high in price outcomes) for peak and cap contracts. The 2022-23 base contract price is not quite as high as that of 2017-18. The decline in prices experienced since 2017-18 appears to have come to an end at this point in time.

Figure 4.3 Queensland Base, Peak, and Cap trade weighted average contract prices ($/MWh, nominal) – 2013-14 to 2022-23



Source: ACIL Allen analysis of ASX Energy Data

4.2 Estimation of the Wholesale Energy Cost

4.2.1 Estimating contract prices

Contract prices for the 2022-23 year were estimated using the trade-weighted average of ASX Energy daily settlement prices since the contract was listed up until 15 April 2022 inclusive.

Table 4.1 shows the estimated quarterly swap and cap contract prices for 2021-22 and 2022-23. Base contract prices have increased from 2021-22 to 2022-23 by about 36 per cent. And there are very strong increases in cap prices across all quarters – averaging over 200 per cent.

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

	Q3	Q4	Q1	Q2
		2021-22		
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
		2022-23		
Base	$58.31	$59.76	$78.22	$57.43
Peak	$62.00	$65.40	$172.34	$106.35

	Q3	Q4	Q1	Q2
Cap	$13.32	$15.04	$29.53	$8.31
Percentage change from 2021-22 to 2022-23				
Base	39%	36%	29%	41%
Peak	12%	18%	125%	136%
Cap	511%	163%	111%	152%

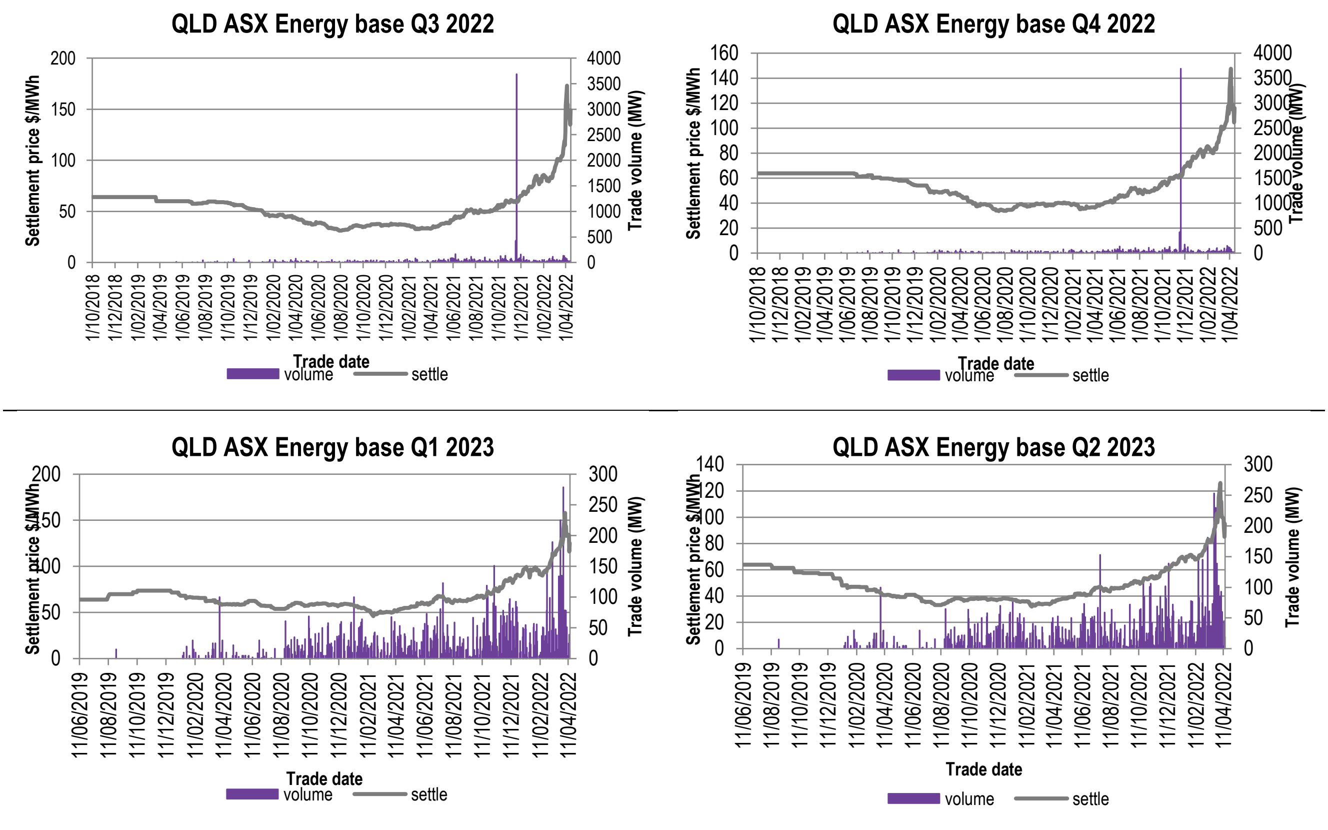
Source: ACIL Allen analysis using ASX Energy and TFS data up to 15 April 2022 for 2022-23

In addition to the increase in rooftop PV and the outage at Callide C, another driver of change in the relativity of base and cap contract prices in 2022-23 is an increase in gas prices for gas fired generation. Spot prices across the east coast gas market have increased from their lower levels observed of around $6-$8/GJ over the previous few years to about $10/GJ - a reflection of higher international LNG prices which affects domestic gas prices via a higher LNG netback price.

The following charts show daily settlement prices and trade volumes for 2022-23 ASX Energy quarterly base futures, peak futures and cap contracts up to 15 April 2022. It can be seen that the trading of these contracts tends to commence from mid to late 2019.

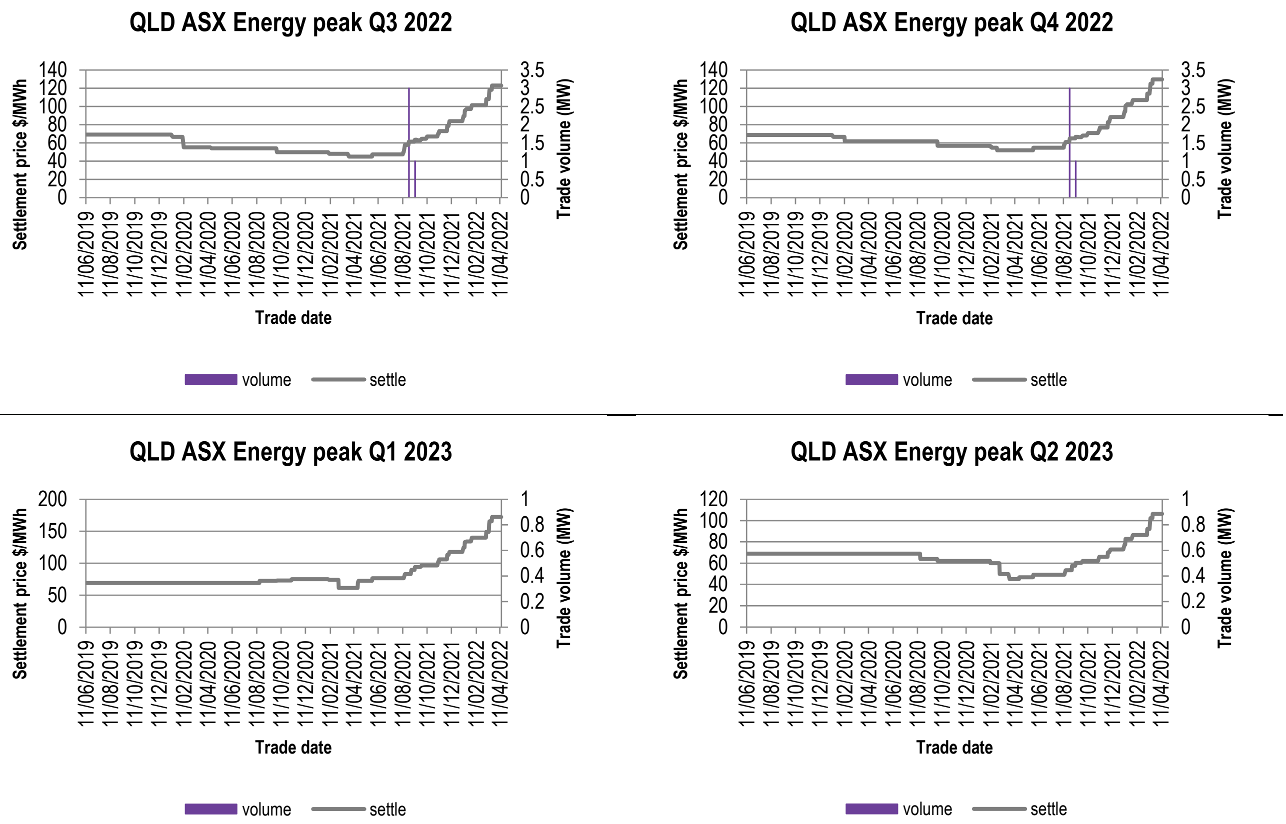
There is little or no trade in peak contracts which is not surprising given the carve out of demand during daylight hours. The traditional definition of the peak period (7am to 10pm weekdays) appears to be no longer relevant to market participants when considering managing spot price risk.

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



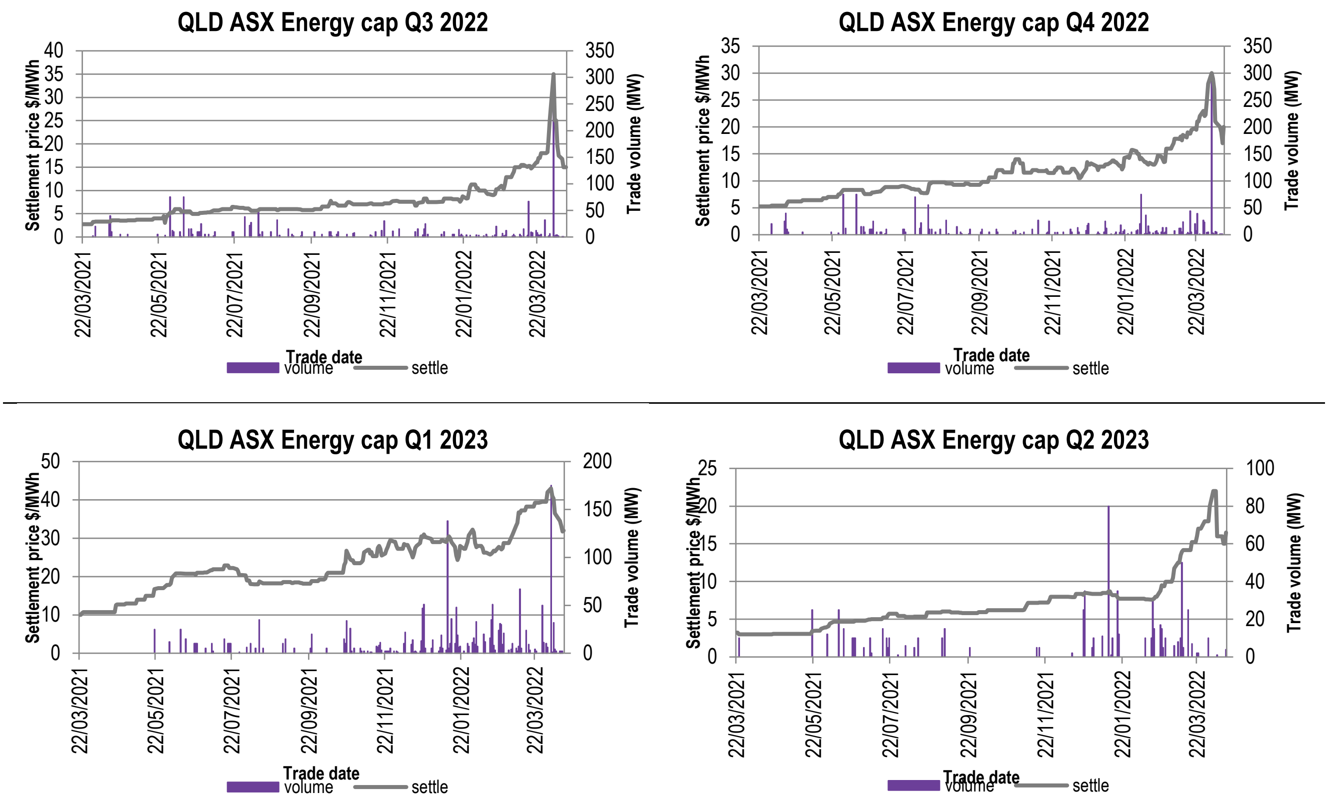
Source: ASX Energy data up to 15 April 2022

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



Source: ASX Energy data up to 15 April 2022

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



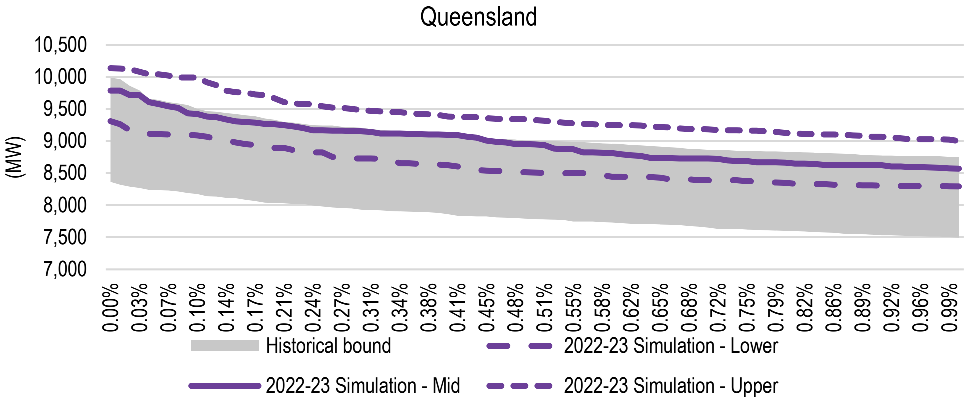
Source: ASX Energy data up to 15 April 2022

4.2.2 Estimating wholesale spot prices

ACIL Allen's proprietary electricity model, *PowerMark* was run to estimate the hourly spot prices for the 561 simulations (51 demand and 11 outage sets).

Figure 4.7 shows the range of the upper one percent segment of the demand duration curves for the 51 simulated Queensland system demand sets resulting from the methodology for 2022-23, 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 51 simulated sets. It can be seen that the demand duration curves of the simulated demand sets for 2022-23 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 spot price outcomes as discussed further in this section.

Figure 4.7 Comparison of upper one per cent of hourly loads of 2022-23 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 2022-23 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.

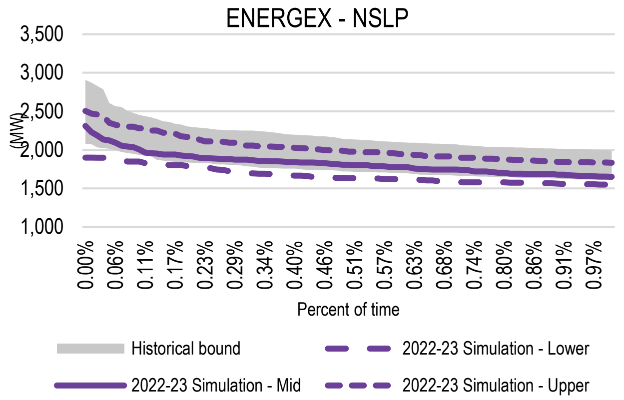
The left panel of Figure 4.8 shows the range of the simulated NSLP peak demands envelope recent actual outcomes. This variation results in the annual load factor[9] of the 2022-23 simulated demand sets ranging between 28 percent and 36 percent compared with a range of 29 percent to 43 percent for the 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. However, it is fair to say this reduction has slowed in the past couple of years – which may well be related to recent rooftop PV installations being associated with meter upgrades (from accumulation to interval meters) or changes in demand patterns due to COVID-19 restrictions.

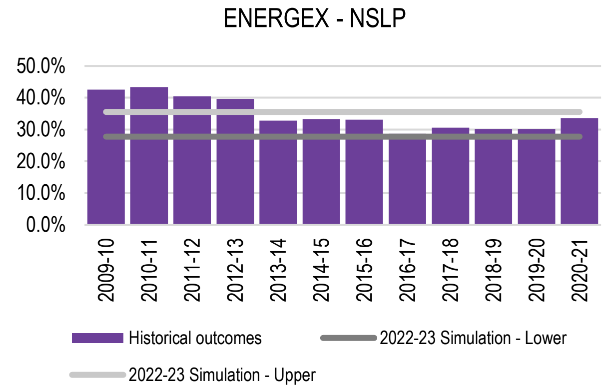
All other things being equal, the increased peakiness of the load, which is hedged under the methodology, is likely to result in a larger degree of over hedging across the general day-time peak periods, resulting in a larger degree of over hedging overall on an annual basis, which means estimated hedging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

[9] 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 2022-23 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 561 simulations for 2022-23 with the regional TWPs from the past 21 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 spot price outcomes for 2022-23 when compared with the past 21 years of history.

Comparing the upper one percent of hourly prices from 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 561 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 561 simulations is consistent with those recorded in history. For some of the 2022-23 simulations the contribution of price spikes is greater than historical levels, reflecting the continued outage of Callide C Unit 4, and the general tightening of the demand-supply balance in the market.

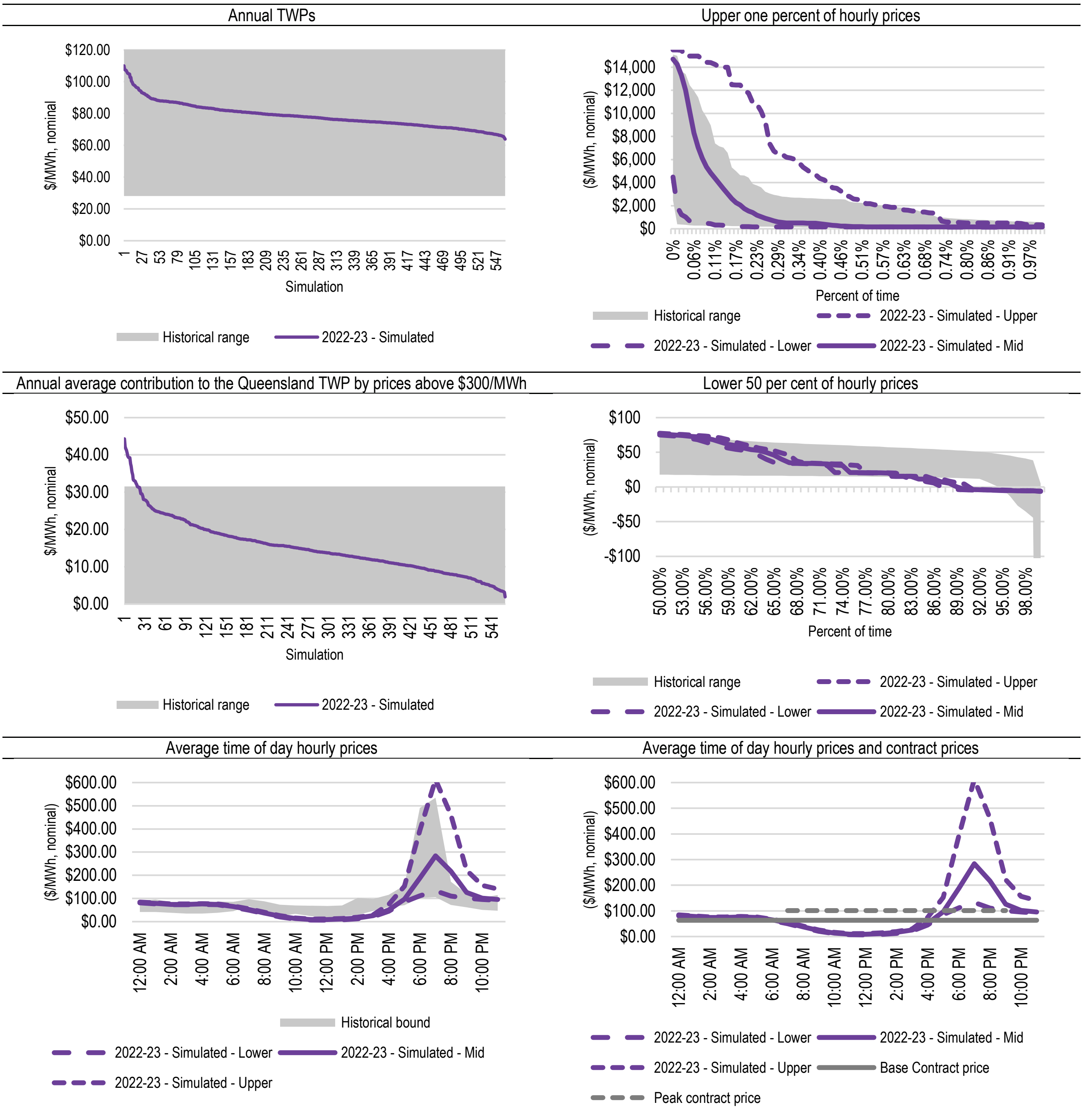
The mid right panel of Figure 4.9 compares the lower 50 per cent of hourly prices in the simulations with historical spot prices. The projected increase in uptake of rooftop PV coupled with the commissioning of the committed utility scale solar projects in Queensland by 2022-23 results in an increase 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 2022-23 during daylight hours.

Simulated spot prices during daylight hours for 2022-23 are on average around $20/MWh – well below the annualised base contract price of about $63/MWh (as shown in the lower right panel of Figure 4.9). Indeed, simulated prices during daylight hours are well below 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.

Based on these metrics, ACIL Allen is satisfied that in an aggregate sense the distribution of the 561 simulations for 2022-23 cover an adequately wide range of possible annual spot price outcomes.

Figure 4.9 Comparison of various metrics of hourly prices from the 2022-23 simulations with historical outcomes – Queensland



Source: ACIL Allen analysis and AEMO data

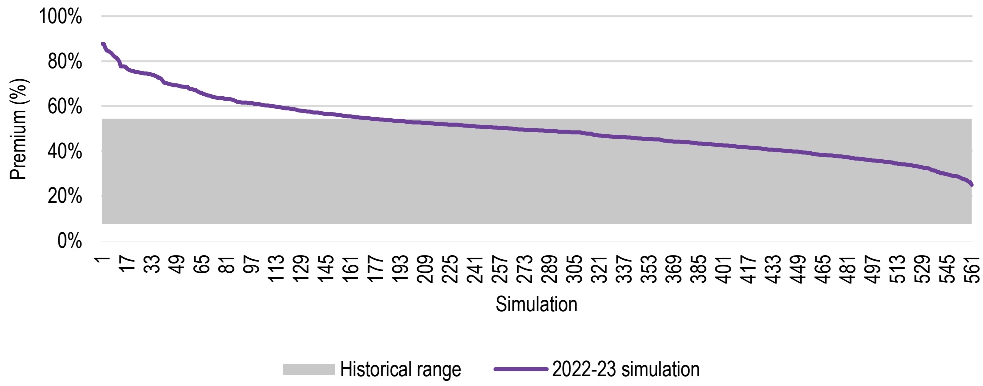
The maximum demand of the NSLP is not in isolation a critical feature in determining the cost of supply. The shape and volatility of the NSLP demand trace and its relationship to the shape and volatility of the regional demand/price traces is a critical factor in the cost of supplying the NSLP demand.

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 11 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 561 simulations for 2022-23 for the NSLP, this percentage varies from 25 percent to 88 percent. The modelling suggests a greater range in the premium for 2022-23 as a result of greater variability in thermal power station availability and the increasing influence of variability in renewable energy resource availability coupled a decline in price outcomes during daylight hours when the NSLP demand is at its lowest.

The comparison with actual outcomes over the past 11 years in Figure 4.10 demonstrates that the relationship between the NSLP demand and corresponding regional spot prices in the 561 simulations is sound.

Figure 4.10 Simulated annual DWP for Energex NSLP as percentage premium of annual TWP for 2022-23 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 561 simulations cover the range of expected price outcomes for 2022-23 across all three regions in terms of annual averages and distributions. These comparisons clearly show that the 51 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 2022-23.

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 adopted for the hedging strategy for 2022-23 are calculated for each settlement class for each quarter as follows, and are largely similar (in percentage terms) from the 2021-22 determination:

The NSLP contract volumes are calculated for the tariff classes for each quarter as follows:

— The base contract volume is set to equal the 90th percentile of the off-peak period hourly demands across all 51 demand sets for the quarter. This is an increase compared with 2021-22 reflecting the changing differential between base and cap contract prices.

— The optimal hedging strategy no longer requires peak contracts due to the increasing carved out shape of prices during daylight hours and the increasing high price of the contracts making peak contracts unattractive.

— The cap contract volume is set at 90 per cent of the median of the annual peak demands across the 51 demand sets minus the base and peak contract volumes. This is a slight decrease from 100 per cent used in the Draft Determination and is due to the strong increase in cap contract prices. The optimal hedging strategy now allows for a small amount of exposure to the spot market.

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 50th percentile of the off-peak period hourly demands across all 51 demand sets for the quarter.

— The optimal hedging strategy does not require peak contracts.

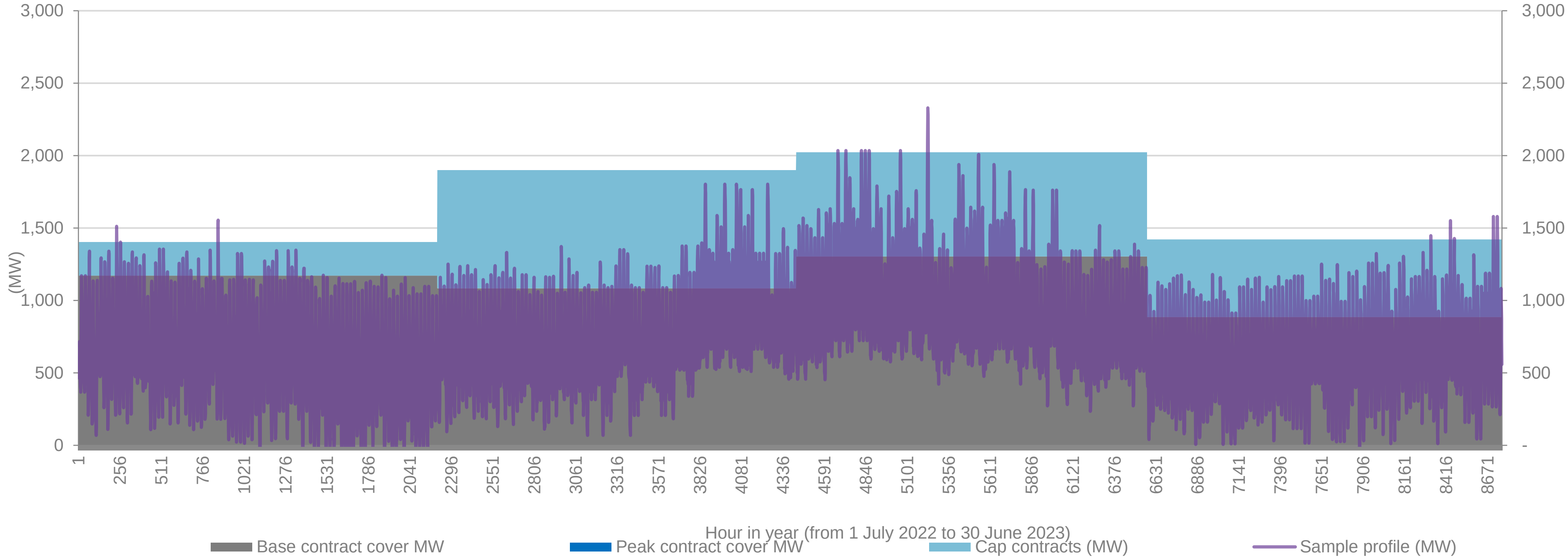
— The cap contract volume is set at 70 per cent of the median of the annual peak demands across the 51 demand sets minus the base and peak contract volumes.

The same hourly hedge volumes (in MW terms) apply to each of the 51 demand sets for a given tariff class and year, and hence to each of the 561 simulations. To be clear, we are not altering the hedge volume (in MW terms) on an ex-post basis for each of the 51 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 561 simulations when calculating the wholesale energy cost. The contract volumes for the Energex NSLP used are shown in Figure 4.11. It can be seen there is a higher weighting (or reliance) on base contracts compared with cap contracts.

Generally, the contracting strategy places no reliance on peak contracts. This is not surprising – 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 non-reliance on peak contracts matches well with the very small or nil volume of peak contracts traded relative to base contracts in the actual futures market.

Figure 4.11 Contract volumes used in hedge modelling of 561 simulations for 2022-23 for Energex NSLP

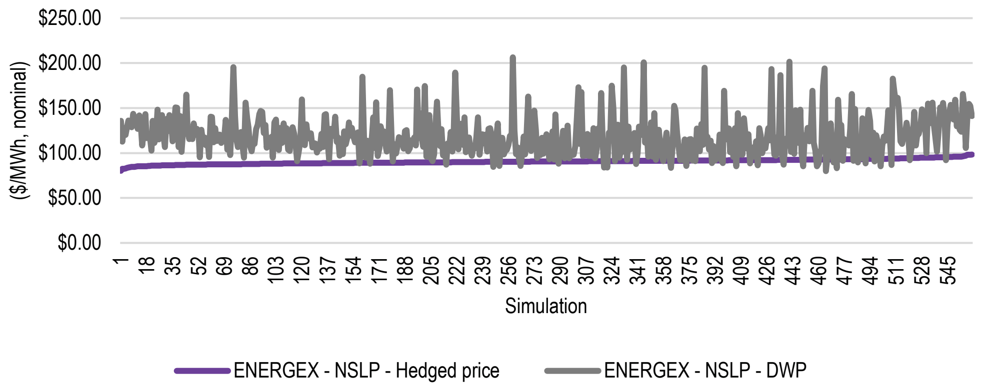


Source: ACIL Allen analysis

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.

It is worth noting the hedged price outcomes for the NSLPs are lower than the spot price outcomes in many of the simulations. This is a function of the methodology assuming a book build period from the date of the first trade. In this instance, the book build takes into account previously lower priced trades in the contracts relative to the higher price levels they are trading at today

Figure 4.12 Annual hedged price and DWP ($/MWh, nominal) for Energex NSLP for the 561 simulations – 2022-23



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 561 WECs (the annual hedged prices). ACIL Allen's estimate of the WEC for each tariff class for 2022-23 are shown in Table 4.2.

Table 4.2 Estimated WEC ($/MWh, nominal) for 2022-23 at the regional reference node

Settlement class	2021-22 – Final Determination	2022-23 – Final Determination	Change from 2021-22 to 2022-23 (%)
Energex - NSLP - residential and small business	$67.76	$94.93	40%
Energex - Controlled load tariff 9000 (31)	$53.34	$78.80	48%
Energex - Controlled load tariff 9100 (33)	$54.83	$83.78	53%
Energex - NSLP - unmetered supply	$67.76	$94.93	40%
Ergon Energy - NSLP - CAC and ICC	$61.09	$84.61	39%
Ergon Energy - NSLP - SAC demand and street lighting	$61.09	$84.61	39%
Energex – Small business primary load control tariff	$58.75	$82.20	40%
Ergon – Large business primary and secondary load control tariffs	$54.83	$83.78	53%

Source: ACIL Allen analysis

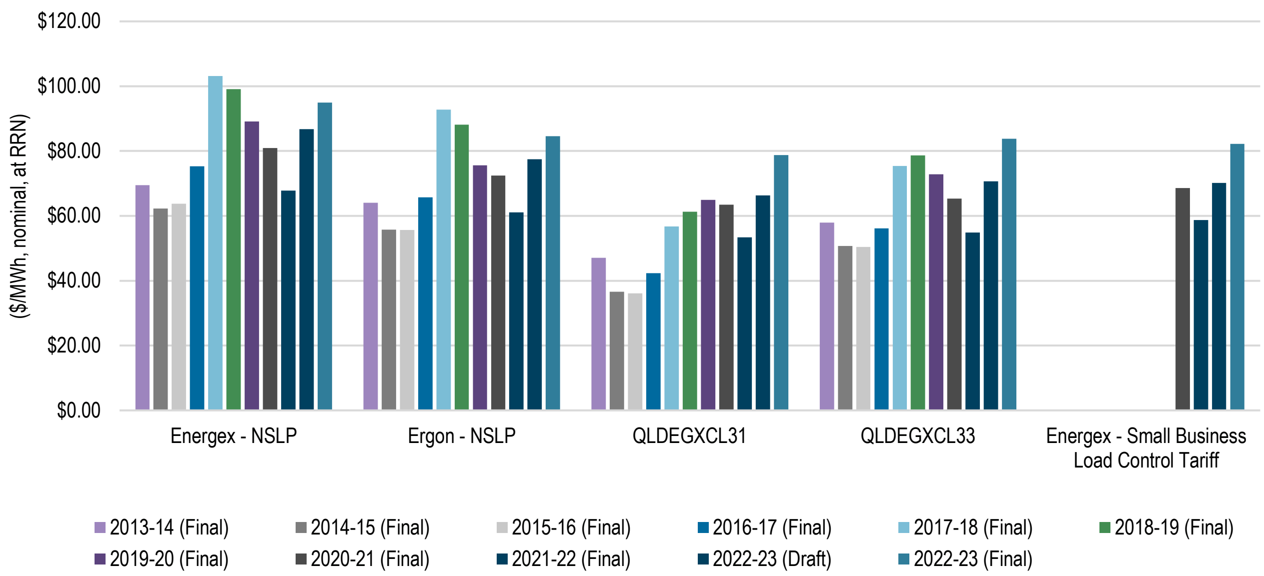
The 2022-23 WECs for the NSLPs and CLPs increase by between 39 and 53 per cent compared with 2021-22 – reflecting the increase in trade weighted base contract prices, the more than doubling of the trade weighted cap contract prices and the decline in spot prices during daylight hours when demand is at its lowest point and hence over contracted.

As discussed earlier, the WEC for each of the tariff classes is unlikely to change by the same amount between two determinations – whether in dollar or percentage terms – due to their different load shapes, differences in how the load shapes are changing over time, and different hedging strategy.

Figure 4.13 shows the trend in WEC over the past determinations. The increase in the NSLP WECs between 2021-22 and 2022-23 represents the first increase since 2017-18, after four consecutive years of decreasing WECs. Despite the magnitude of the increase in the NSLP WECs in 2022-23, they are similar to the WEC levels of 2018-19, and are less than the WECs estimated for 2017-18.

The CLP WECs for 2022-23 are higher than the WEC levels of all previous years. The tariff 31 WEC in particular continues to increase – reflecting the increase in price outcomes during the overnight period due to stronger coal costs.

Figure 4.13 Estimated WEC ($/MWh, nominal) for 2022-23 at the regional reference node in comparison with WECs from previous determinations



Source: ACIL Allen analysis

4.2.5 Do the changes in WEC make intuitive sense?

An increase in WEC of 40 to 50 per cent is very large and will impact the cost of living for residential consumers, as well as the input costs for businesses for which electricity represents a high proportion of production input.

Hence the estimated WECs warrant further investigation to ensure the estimated changes align with what is observed in the market. The charts below plot the changes in WECs and trade weighted contract prices from this Final Determination together with previous final determinations.

The top chart plots the annual change, and the lower chart plots the cumulative change since 2013-14 (using 2013-14 as the base observation). Key features of the charts are:

— Overall, the year-on-year trend in estimated WECs follows the trend in contract prices.

— The trend in cap price movements displays the largest degree of variability of the contract products, with very large increase occurring in 2017-18 and 2022-23.

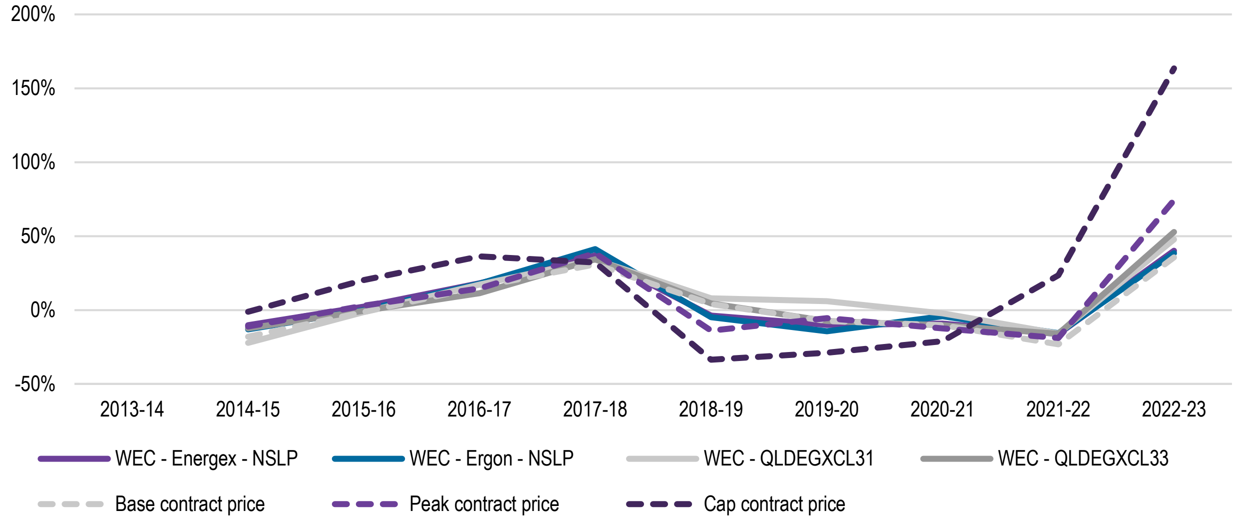
— The trend in WECs aligns very closely to the trend in base contract prices. This is not surprising given the stronger reliance on base contracts in the hedging strategy.

- Over the past few determinations, the growth in the WEC for tariff 31 has been slightly higher than that of the other WECs. This is a result of the load profile of tariff 31 continuing to occur during the overnight period, despite prices in the overnight period now tending to be higher than prices during daylight hours.
- The large percentage increase in WEC in 2022-23 is almost as high as the increase in WEC in 2017-18, and this aligns with the corresponding strong increases in contract prices.
- There has been no occasion in which the movement in the WEC is at odds with the movement in observable trade weighted average contract prices.

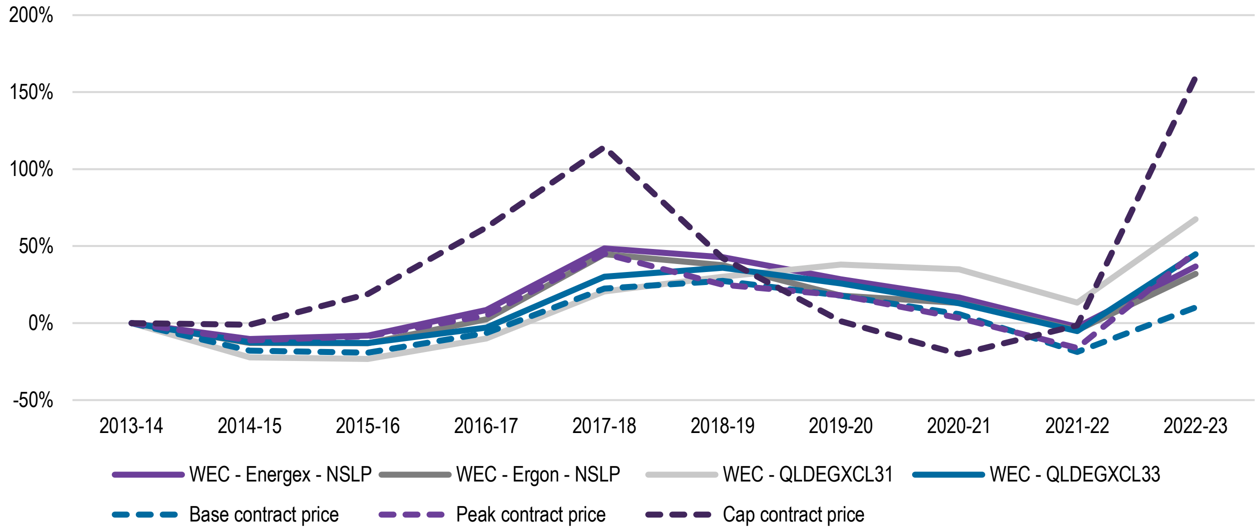
On this basis, ACIL Allen is satisfied that the methodology is appropriately estimating the WECs for 2022-23, and that the estimated WECs reflect the consensus view of market conditions for the given determination year at the time the determination was made.

Figure 4.14 Change in WEC and trade weighted contract prices (%) – 2013-14 to 2022-23

Annual change (%)



Cumulative change (%) since 2013-14



Note: Cumulative change uses 2013-14 as the base observation.
Source: ACIL Allen analysis

4.2.6 Comparison of WECs from previous determinations with actual spot market outcomes

Given the same WEC methodology has been adopted for the past 10 determinations, there is now a reasonable time series of consistent data points to be able to make meaningful comparisons between actual outcomes in the market and the estimated WECs.

The main graph in Figure 4.15 compares actual spot market outcomes from the past nine years with the corresponding final determination trade volume weighted base contract prices and Energex NSLP WECs. The smaller graphs in Figure 4.15 provide pairwise comparisons of the different variables from the main graph. We have also included the WEC and contract price for this Final Determination for completeness.

The key observations are:

1. In terms of the spot market, the Energex DWP (which is what retailers are charged by AEMO for the NSLP load) follows the movements in the Queensland TWP, albeit at a premium. This premium changes from year to year depending on the dynamics in the market at the time and is influenced by the changing shape of the NSLP and spot price outcomes.

2. Trade weighted base contract prices tend to lag the trend in the TWP. This is because the trades for a given year that occur ahead of that year are partly influenced by what is happening in the market at the time the trade is made. For example, trades for 2019-20 that occurred prior to 2019-20 would have been partly influenced by the higher spot market outcomes in 2017-18 and 2018-19, resulting in a trade weighted average higher than the actual spot market outcome for 2019-20.

2. Further, the trend in contract prices is not as volatile as that of the spot market prices. This is because the contract price represents the average of market participants' views on the risk weighted outcome for the given year.

3. The WEC follows the trend in base contract prices. This is not surprising given the hedging strategy adopted to estimate the WEC makes use of those contract prices. The WEC also follows the trend in cap contract prices but these are not included given the difference in scale.

3. Although the WEC follows the trend in base contract prices, it does so at a reasonable premium. This is not surprising given the shape of the NSLP.

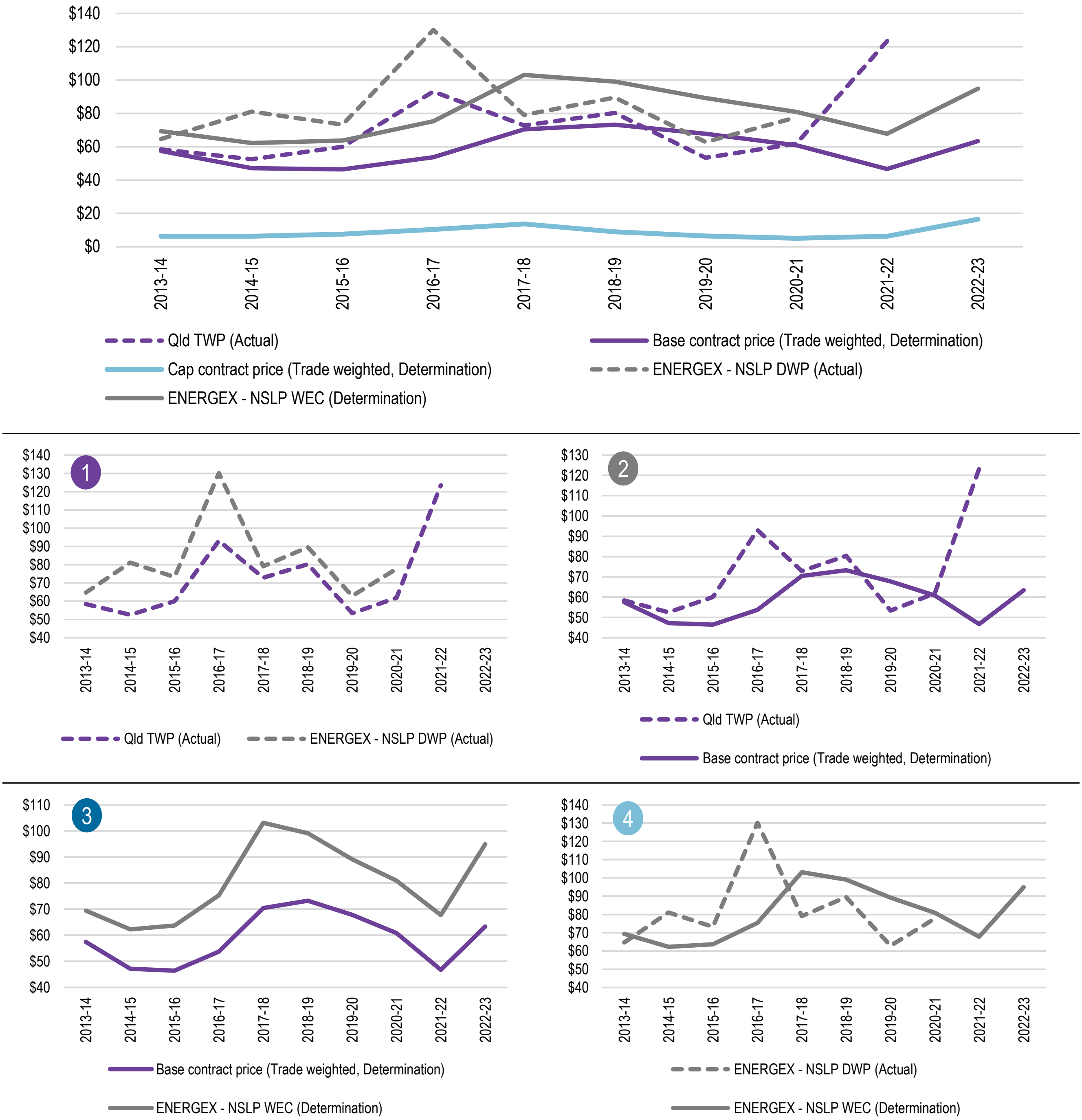
4. The lag in contract prices, relative to spot market outcomes, means that the WEC also lags actual spot market DWP for the NSLP. Given the trend in contract prices is not as volatile as that of the spot market prices, the trend in WEC is also not as volatile as the trend in the actual spot market DWP.

4. Across the entire time series, the average of the WECs is within $2/MWh of the average of the actual spot market DWPs. This reflects the fact that on average, market participants, when entering into contracts, have an expectation that is not dissimilar to actual outcomes over the medium term.

4. The lag in WEC relative to the actual spot market DWP means that if one was to look at a snapshot or portion of the time series, then erroneous conclusions will be made. This is particularly the case for periods of consistently increasing or consistently decreasing price outcomes. For example, if the graph was truncated to include 2013-14 to 2016-17 only, then one might conclude that the WEC methodology results in estimates that are consistently lower than actual outcomes. Conversely, if the graph was truncated to include 2017-18 to 2020-21 only, then one might conclude that the WEC methodology results in estimates that are consistently higher than actual outcomes.

Although the WEC estimation methodology is a simplification of how retailers manage their retail load and exposure to the spot market, based on the above comparative analysis, ACIL Allen is satisfied that the methodology provides an unbiased estimate of the WEC.

Figure 4.15 Comparison of time weighted spot prices, base contract prices, demand weighted spot prices, WECs ($/MWh, nominal) – Energex NSLP



Note: WEC and contract values for 2013-14 to 2021-22 are from the corresponding final determinations; WEC and contract values for 2022-23 are from this current Final Determination. TWP for 2021-22 is up to end of April 2022. Energex NSLP data for 2021-22 is yet to be published by AEMO.

Source: ACIL Allen

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[10]) are required to comply and surrender certificates for both LRET and SRES.

Energy costs associated with the LRET and the SRES have been estimated using price information from brokers TFS, information published by the Clean Energy Regulator (CER) and modelling by ACIL Allen.

Retailer compliance with these schemes operates on a calendar year basis and hence estimates are required for 2022 and 2023 calendar years, with the costs averaged to estimate the 2022-23 financial year costs.

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

— historical Large-scale Generation Certificate (LGC) market forward prices for 2022 and 2023 from brokers TFS

— estimated Renewable Power Percentages (RPP) values for 2022 and 2023 of 18.64 per cent[11]

— binding Small-scale Technology Percentage (STP) values for 2022 of 27.26 per cent, as published by CER

— estimated STP value for 2023 of 27.26 per cent[12]

— CER clearing house price[13] for 2022 and 2023 for Small-scale Technology Certificates (STCs) of $40/MWh.

The STP for 2023 used in the Final Determination is equal to the binding 2022 STP, rather than the 2023 non-binding value published by the CER. Based on our interpretation of the three consultant reports published by the CER estimating the rooftop PV uptake[14] (an input in calculating the STPs), it appears the projected uptake rates for 2022 and 2023 are similar to recently observed uptake rates. Given the projected uptake rates from the consultant reports for 2022 ended up being less than the actual uptake rate, we think it is appropriate to use the 2022 STP as the estimate of the 2023 STP on the assumption the estimation error is the same for 2023 and 2022.

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.

[10] 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.

[11] The RPP values for 2022 and 2023 are based on the CER's published RPP for 2022 and assumes no change in liable acquisitions and the CER-published mandated LRET targets for 2022 and 2023.

[12] The STP value for 2023 assumes a similar level of STC creations, oversupply from the previous year and liable acquisitions in 2023 as in 2022.

[13] 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.

[14] http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/the-small-scale-technology-percentage/small-scale-technology-percentage-modelling-reports

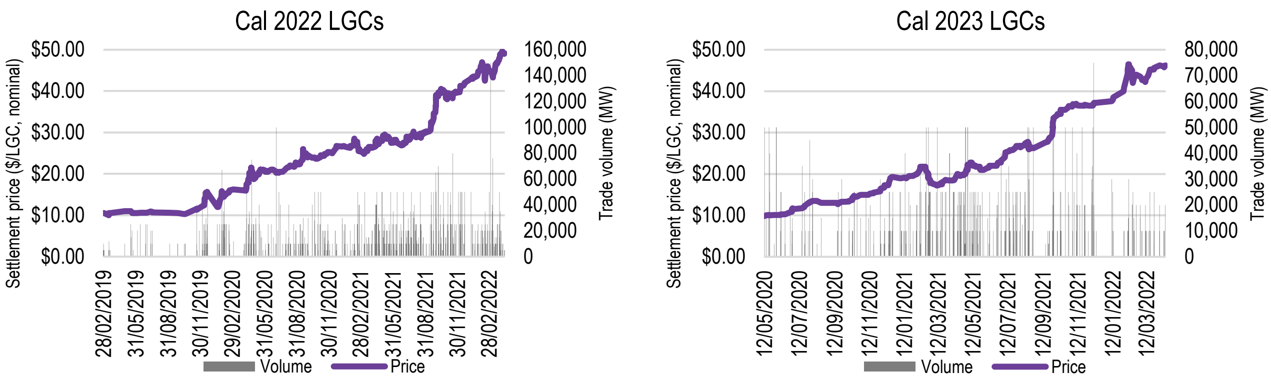
The RPP is determined ex-ante by the CER and represents the relevant year's LRET target (in fixed GWh terms) as a percentage of the estimated volume of liable electricity consumption throughout Australia in that year.

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 up to 15 April 2022.

The LGC price used in assessing the cost of the scheme for 2022-23 is found by taking the trade-weighted average of the forward prices for the 2022 and 2023 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 4.16). The average LGC prices calculated from the TFS data are $28.94/MWh for 2022 and $24.72/MWh for 2023.

Figure 4.16 LGC prices for 2022 and 2023 for 2022-23 ($/LGC, nominal)



Source: ACIL Allen analysis of TFS data

The RPP value for 2022 was set by the CER on 8 February 2022 at 18.64 per cent. The RPP value for 2023 is estimated by using the mandated target for 2023 of 33 TWh and the CER's published cumulative adjustment and estimate of electricity acquisitions in 2022 of 175.01 TWh. In other words, ACIL Allen has assumed electricity acquisitions remain constant in 2022 and 2023, and hence the RPP values for 2022 and 2023 are both 18.64 per cent.

Key elements of the 2022 and 2023 RPP estimation are shown in Table 4.3.

Table 4.3 Estimating the 2023 RPP value

	2022 (published by CER)	2023 (estimate based on 2022 RPP)
LRET target, MWh (CER)	32,618,891	32,618,891
Relevant acquisitions minus exemptions, MWh (CER)	175,010,000	175,010,000
Estimated RPP	18.64%	18.64%

Source: ACIL Allen analysis of CER and AEMO data

ACIL Allen calculates the cost of complying with the LRET in 2022 and 2023 by multiplying the RPP values for 2022 and 2023 by the trade volume weighted average LGC prices for 2022 and 2023, respectively. The cost of complying with the LRET in 2022-23 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be $5.00/MWh in 2022-23 as shown in Table 4.4.

Table 4.4 Estimated cost of LRET – 2022-23

	2022	2023	Cost of LRET 2022-23
RPP %	18.64%	18.64%	
Trade weighted average LGC price ($/LGC, nominal)	$28.94	$24.72	
Cost of LRET ($/MWh, nominal)	**$5.39**	**$4.61**	**$5.00**

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 2022-23.

ACIL Allen estimates the cost of complying with SRES to be $10.90/MWh in 2022-23 as set out in Table 4.5.

Table 4.5 Estimated cost of SRES – 2022-23

	2022	2023	Cost of SRES 2022-23
STP %	27.26%	27.26%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of SRES ($/MWh, nominal)	**$10.90**	**$10.90**	**$10.90**

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 2022-23 as set out in Table 4.6.

Since the 2021-22 estimate, the cost of LRET has increased by around 19 per cent, driven by higher LGC prices in 2022-23, and the cost of SRES has decreased by five per cent, driven by the shortening of the SRES deeming period.

Table 4.6 Total renewable energy policy costs ($/MWh, nominal) – 2022-23

	2021-22	2022-23
LRET	$4.29	$5.00
SRES	$11.52	$10.90
Total	**$15.81**	**$15.90**

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

- spot and hedging prudential costs
- the Reliability and Emergency Reserve Trader (RERT).

4.4.1 NEM management fees

NEM management fees are payable by retailers to AEMO to cover operational expenditure, costs associated with full retail contestability (FRC), the Energy Consumers Australia (ECA)[15], DER and IT system upgrades for 5MS.

Based on the draft projected percentage change in fees presented in AEMO's Financial Consultation Committee *Draft FY23 Budget & Fees* published in March 2022, our estimate of the fees for 2022-23 are $1.13/MWh (up from $0.49/MWh for 2021-22). The breakdown of total fees is shown in Table 4.7. The majority of the increase in fees relates to the increase in NEM core fees, and the inclusion of IT upgrade costs for 5MS.

Table 4.7 NEM management fees ($/MWh, nominal) – 2022-23

Cost category	2021-22	2022-23
NEM fees (admin, registration, etc.)	$0.37	$0.77
FRC - electricity	$0.078	$0.077
ECA - electricity	$0.040	$0.037
DER fee	$0.000	$0.025
IT upgrade and 5MS/GS compliance	$0.00	$0.219
Total NEM management fees	**$0.49**	**$1.13**

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 2022-23, the estimates cost of ancillary services is shown in Table 4.8.

There has been a noticeable increase in weekly ancillary service costs in Queensland over the past two quarters as a result of upgrade works associated with the QNI giving rise to price separation between the two regions.

Table 4.8 Ancillary services ($/MWh, nominal) – 2022-23

Region	2021-22	2022-23
Queensland	$0.41	$1.42

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.

[15] ECA requirements are measured in terms of connection points for small customers. It is not clear in AEMO's *Electricity Final Budget and Fees 2021-22* 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.

AEMO prudential costs

AEMO calculates a maximum credit limit for each counterparty in order to determine the requirement for any or a combination of:

- bank guarantees
- reallocation certificates
- prepayment of cash.

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

MCL = OSL + PML

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

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

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

Taking a 1 MWh average daily load and assuming the inputs in Table 4.9 for each season for the Energex NSLP gives an estimated MCL of $10,861.

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 $10,861/42 = $258.59/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 $258.59 gives $0.74/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 – 2022-23

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$135.01	$69.78	$75.09
Participant Risk Adjustment Factor	1.5447	1.2616	1.3526
OS Volatility factor	1.50	1.53	1.41
PM Volatility factor	2.71	2.12	1.88
OSL	$14,969	$5,824	$6,412
PML	$2,994	$1,165	$1,282
MCL	$17,963	$6,989	$7,695
Average MCL		$10,861	
AEMO prudential cost ($/MWh, nominal)		**$0.74**	

Source: ACIL Allen analysis of AEMO data

Table 4.10 AEMO prudential costs for Ergon NSLP – 2022-23

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$135.01	$69.78	$75.09
Participant Risk Adjustment Factor	1.2694	1.1428	1.1980
OS Volatility factor	1.50	1.53	1.41
PM Volatility factor	2.71	2.12	1.88
OSL	$11,151	$5,021	$5,345
PML	$2,230	$1,004	$1,069
MCL	$13,382	$6,026	$6,414
Average MCL		$8,593	
AEMO prudential cost ($/MWh, nominal)		**$0.59**	

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 assumed 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 9 percent on average for a base contract, 16 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 7.22 per cent but adjusted for an assumed 0.10 per cent return on cash lodged with the clearing (giving a net funding cost of 7.12 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 2022-23

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$63.37	$27,000	$0.88
Peak	$101.12	$30,000	$2.27
Cap	$16.50	$14,000	$0.46

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 – 2022-23

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.88	1.6253	$1.43
Peak	$2.27	0.0000	$0.00
Cap	$0.46	0.8422	$0.38
Total cost		**$1.81**	

Source: ACIL Allen analysis

Table 4.13 Hedge Prudential funding costs for ERGON NSLP – 2022-23

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.88	1.5150	$1.33
Peak	$2.27	0.0000	$0.00
Cap	$0.46	0.4032	$0.18
Total cost		**$1.51**	

Source: ACIL Allen analysis

Total prudential costs

Adding the AEMO and hedge prudential costs gives a total prudential requirement for 2022-23 as set out in Table 4.14. Prudential costs for 2022-23 are higher than 2021-22 due to higher hedge prices and higher expected price volatility across 2022-23.

Table 4.14 Total prudential costs ($/MWh, nominal) – 2022-23

Jurisdiction	2021-22	2022-23
Energex NSLP	$1.67	$2.55
Ergon NSLP	$1.36	$2.10

Source: ACIL Allen analysis

4.4.4 Reliability and Emergency Reserve Trader (RERT)

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 activated the RERT twice for the 12-month period prior to the Final Determination – in Queensland on both occasions.

AEMO activated the RERT for 15 MW in Queensland on 25 May 2021, in response to a forecast Lack of Reserve (LOR) 2 condition which developed into an actual LOR 2 and a forecast LOR 3 condition. This was the result of the loss of several generating units due to the fire at unit 4 of Callide. AEMO reported the costs of this activation to be $452,881. When dividing this value by the total energy requirements in Queensland, the cost of the RERT is about one cent per MWh.

AEMO activated the RERT for 331 MW in Queensland on 1 February 2022 due to a forecast LOR 2 which developed into an actual LOR 2 condition, due to high temperatures increasing demand levels, coupled with plant unavailability. AEMO reported the costs of this activation to be $50,960,399. When dividing this value by the total energy requirements in Queensland, the cost of the RERT is $1.00/MWh.

AEMO forecast LOR 2 conditions in Queensland on 2 February 2022, but it appears the forecast LOR 2 did not develop into an actual LOR 2 condition. Hence, there are no associated RERT activation costs.

In total, the RERT costs for Queensland for the Final Determination are set at $1.01/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 2022-23 Final Determination and is compared with the costs for 2021-22.

Table 4.15 Total of other costs ($/MWh, nominal) – Energex NSLP – 2022-23

Cost category	2021-22	2022-23
NEM management fees	$0.49	$1.13
Ancillary services	$0.41	$1.42
Hedge and spot prudential costs	$1.67	$2.55
Reserve and Emergency Reserve Trader	$0.00	$1.01
Total	**$2.57**	**$6.11**

Source: ACIL Allen analysis

Table 4.16 total of other costs ($/MWh, nominal) – Ergon NSLP – 2022-23

Cost category	2021-22	2022-23
NEM management fees	$0.49	$1.13
Ancillary services	$0.41	$1.42
Hedge and spot prudential costs	$1.36	$2.10
Reserve and Emergency Reserve Trader	$0.00	$1.01
Total	**$2.26**	**$5.66**

Source: ACIL Allen analysis

4.5 Estimation of energy losses

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

The MLFs and DLFs used to estimate losses for the Final Determination for 2022-23 are based on the final 2022-23 MLFs and DLFs published by AEMO on 1 April 2022.

The estimation of transmission and distribution loss factors for the settlement classes to be used in calculating energy costs for 2022-23 is shown in Table 4.17.

Table 4.17 Estimated transmission and distribution losses

	2021-22			2022-23		
	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	1.059	1.006	1.066	1.061	1.007	1.069
Energex – Controlled load tariff 9000 (31)	1.059	1.006	1.066	1.061	1.007	1.069
Energex – Controlled load tariff 9100 (33)	1.059	1.006	1.066	1.061	1.007	1.069
Energex – NSLP - unmetered supply	1.059	1.006	1.066	1.061	1.007	1.069
Ergon Energy – NSLP - CAC and ICC	1.036	0.986	1.022	1.036	0.985	1.020
Ergon Energy - NSLP - SAC demand and street lighting	1.077	0.986	1.062	1.083	0.985	1.067
Energex – Small business primary load control tariff	1.059	1.006	1.066	1.061	1.007	1.069
Ergon – Large business primary and secondary load control tariffs	1.077	0.986	1.062	1.083	0.985	1.067

Source: ACIL Allen analysis of AEMO data

As described by AEMO[16], to arrive at prices at the customer terminal (price at load connection point) the MLF and DLF are applied to the prices at the regional reference node (RRN) as follows:

*Price at load connection point = RRN Spot Price * (MLF * DLF)*

[16] 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 2022-23 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 2022-23 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 ($/MWh)	Change from 2021-22 Final Determination ($/MWh)	Change from 2021-22 Final Determination (%)
Energex – NSLP - residential and small business	$94.93	$15.90	$6.11	1.069	$8.07	**$125.01**	$33.18	36.13%
Energex – Controlled load tariff 9000 (31)	$78.80	$15.90	$6.11	1.069	$6.96	**$107.77**	$31.32	40.97%
Energex – Controlled load tariff 9100 (33)	$83.78	$15.90	$6.11	1.069	$7.30	**$113.09**	$35.05	44.91%
Energex – NSLP - unmetered supply	$94.93	$15.90	$6.11	1.069	$8.07	**$125.01**	$33.18	36.13%
Ergon Energy – NSLP - CAC and ICC	$84.61	$15.90	$5.66	1.020	$2.12	**$108.29**	$27.39	33.86%
Ergon Energy - NSLP - SAC demand and street lighting	$84.61	$15.90	$5.66	1.067	$7.11	**$113.28**	$29.21	34.75%
Energex – Small business primary load control tariff	$82.20	$15.90	$6.11	1.069	$7.19	**$111.40**	$29.18	35.49%
Ergon – Large business primary and secondary load control tariffs	$83.78	$15.90	$5.66	1.067	$7.06	**$112.40**	$34.98	45.19%

Source: ACIL Allen analysis

AEMC 2021 Residential electricity price trends report

A

The AEMC's report, *2021 Residential Electricity Price Trends,* was released in November 2021 (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.

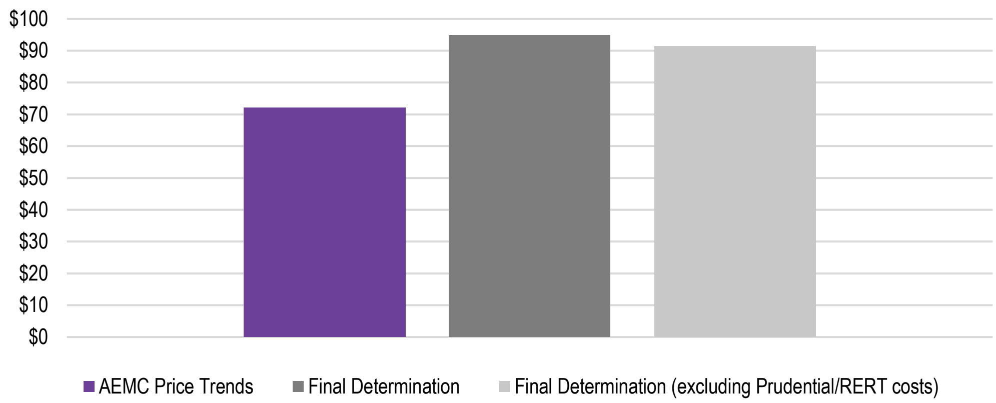
A.1 Wholesale energy costs

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 NSLPs within the New South Wales region to produce a state-based NSLP, and in the case of Queensland aggregate the NSLP and control load produce an aggregate WEC.
- 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 renewable capacity between now and 2022-23, as well as changes in underlying costs). AEMC acknowledges that bidding behaviour may change in the future and therefore affect their results.
- 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 October 2021.
  - It appears AEMC's portfolio build-up is assumed to be completed by April 2022, 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 2022-23 (with the six-month period being October 2021 to end of March 2022).
  - 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 2022-23, AEMC is missing at least, an assumed, 60 per cent of ASX Energy trade volumes and corresponding prices, and is using their modelled spot prices to represent the missing 60 per cent of trade volumes and contract 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.
  - 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 in April 2022 for the Final Determination, whereas AEMC had to make their final estimates at the beginning of October 2021 (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 did not explicitly predict the volume or price level of trades in contracts between January 2022 and April 2022 – instead, we simply close the contract data as of 21 January 2022.
- Wholesale costs:
  - Given the continued upward trend in 2022-23 contract prices since the beginning of October 2021, the projected wholesale costs presented in the AEMC report for 2022-23 are about $22/MWh lower than those of this Final Determination for Queensland. Contract prices for Queensland for 2022-23 have almost doubled since AEMC undertook its analysis.

Figure A.1 Total wholesale costs ($/MWh, nominal)



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 will be available for the Final Determination. In general, 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.

— It is also worth noting that the AEMC revised upwards its wholesale cost estimates for 2021-22 in its latest report (compared with its December 2020 report). For example, for south-east Queensland, the wholesale cost estimates for 2021-22 have increased from about $61/MWh to $85/MWh. This is important to note because one of the headlines from the latest AEMC report is that prices in Queensland will decline between 2021-22 and 2022-23 due to reducing wholesale costs – which is in contrast to our analysis.

Melbourne
Level 9, 60 Collins Street
Melbourne VIC 3000 Australia
+61 3 8650 6000

Sydney
Level 9, 50 Pitt Street
Sydney NSW 2000 Australia
+61 2 8272 5100

Brisbane
Level 15, 127 Creek Street
Brisbane QLD 4000 Australia
+61 7 3009 8700

Canberra
Level 6, 54 Marcus Clarke Street
Canberra ACT 2601 Australia
+61 2 6103 8200

Perth
Level 12, 28 The Esplanade
Perth WA 6000 Australia
+61 8 9449 9600

Adelaide
167 Flinders Street
Adelaide SA 5000 Australia
+61 8 8122 4965

ACIL Allen Pty Ltd
ABN 68 102 652 148

acilallen.com.au