ACIL ALLEN CONSULTING

REPORT TO
AUSTRALIAN ENERGY REGULATOR
23 SEPTEMBER 2020

DEFAULT MARKET OFFER 2021-22

WHOLESALE ENERGY AND ENVIRONMENTAL COSTS

METHODOLOGY PAPER FOR DMO 3

ACIL ALLEN CONSULTING PTY LTD
ABN 68 102 652 148

LEVEL NINE
60 COLLINS STREET
MELBOURNE VIC 3000
AUSTRALIA
T+61 3 8650 6000

LEVEL NINE
50 PITT STREET
SYDNEY NSW 2000
AUSTRALIA
T+61 2 8272 5100

LEVEL FIFTEEN
127 CREEK STREET
BRISBANE QLD 4000
AUSTRALIA
T+61 7 3009 8700

LEVEL SIX
54 MARCUS CLARKE STREET
CANBERRA ACT 2601
AUSTRALIA
T+61 2 6103 8200

LEVEL TWELVE
28 THE ESPLANADE
PERTH WA 6000
AUSTRALIA
T+61 8 9449 9600

167 FLINDERS STREET
ADELAIDE SA 5000
AUSTRALIA
T +61 8 8122 4965

ACILALLEN.COM.AU

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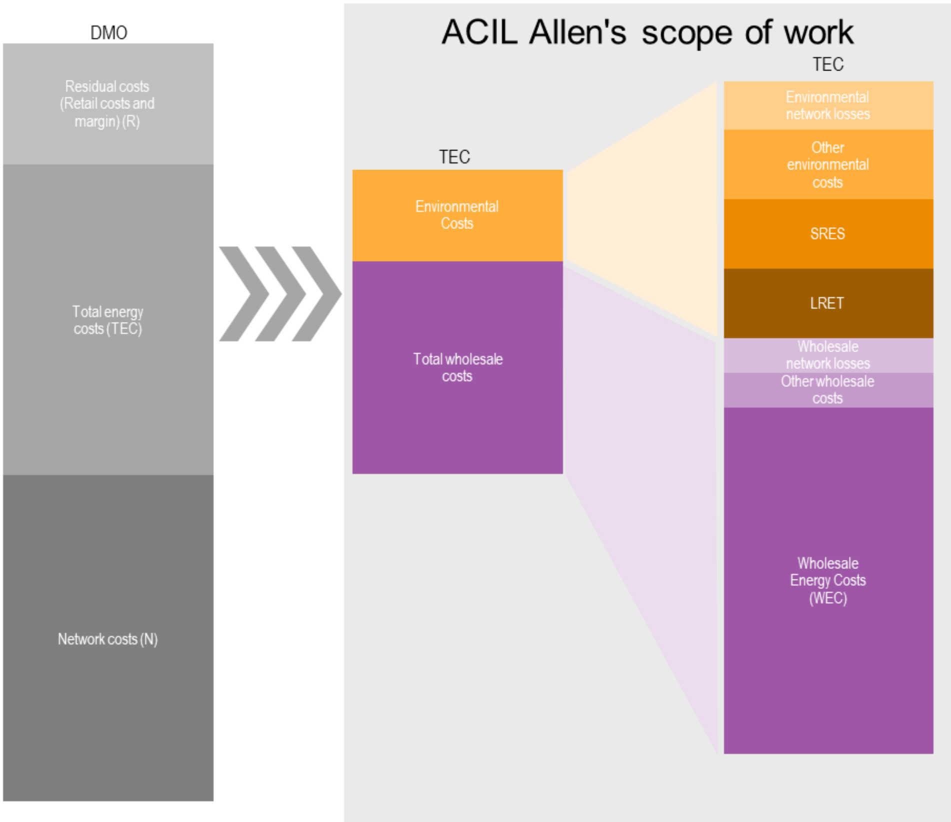
DEFAULT MARKET OFFER 2021-22: WHOLESALE ENERGY AND ENVIRONMENTAL COSTS – METHODOLOGY PAPER, ACIL ALLEN, SEPTEMBER 2020

EXECUTIVE SUMMARY

ACIL Allen Consulting (ACIL Allen) has been engaged by the Australian Energy Regulator (AER) to support the AER in estimating specific cost inputs required for the determination of the 2021-22 Default Market Offer (DMO or DMO 3) prices. Specifically, ACIL Allen is to estimate the underlying wholesale and environmental cost inputs, also referred to in aggregate as the Total Energy Costs (TEC) component of the DMO.

Figure ES 1 summarises the cost components covered by ACIL Allen's scope of work in relation to the overall DMO.

FIGURE ES 1 COMPONENTS OF DMO AND COMPONENTS OF TEC



SOURCE: ACIL ALLEN

The first phase of our engagement, the subject of this report, is to review the current methodology used to estimate the underlying wholesale and environmental cost inputs for the 2020-21 DMO (DMO 2), and to clearly set out any recommended changes, refinements, or considerations to the existing methodology for DMO 3.

Current methodology

The current methodology, adopted for DMO 2, 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 is market based and includes undertaking a large number of wholesale energy market simulations to estimate expected spot market costs and volatility, and the cost of hedging 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.

The three largest cost inputs to the TEC are the WEC, LRET and SRES costs.

Estimating the WEC - market-based approach

At the core of the market-based approach is an assumed hedging strategy that an efficient retailer would use to manage its electricity spot market risks. The methodology simulates the cost of hedging by building up a portfolio of hedges consisting of exchange traded base and peak swap contracts, and cap contracts. This is not to say we are of the view that retailers only use financial derivatives to manage risk (they use other approaches such as owning or underwriting a portfolio of generators (the gen-tailer model), entering into bilateral contracts directly with generators, and purchasing over the counter (OTC) contracts via a broker) – it simply reflects the availability and transparency of data.

The key steps to estimating the WEC are:

— Run a stochastic demand model to develop about 50 weather influenced simulations of hourly demand traces for each region of the NEM, and for residential and small-business customers. The retail and small-business loads are represented by the distribution zone Net System Load Profiles (NSLPs) and the Control Load Profiles (CLPs) published by AEMO.

— Run a stochastic outage model to develop 11 hourly power station availability simulations

— Run an energy market simulation model, such as PowerMark, to produce about 500 simulations of hourly spot prices of the NEM using the stochastic demand traces and power station availabilities as inputs.

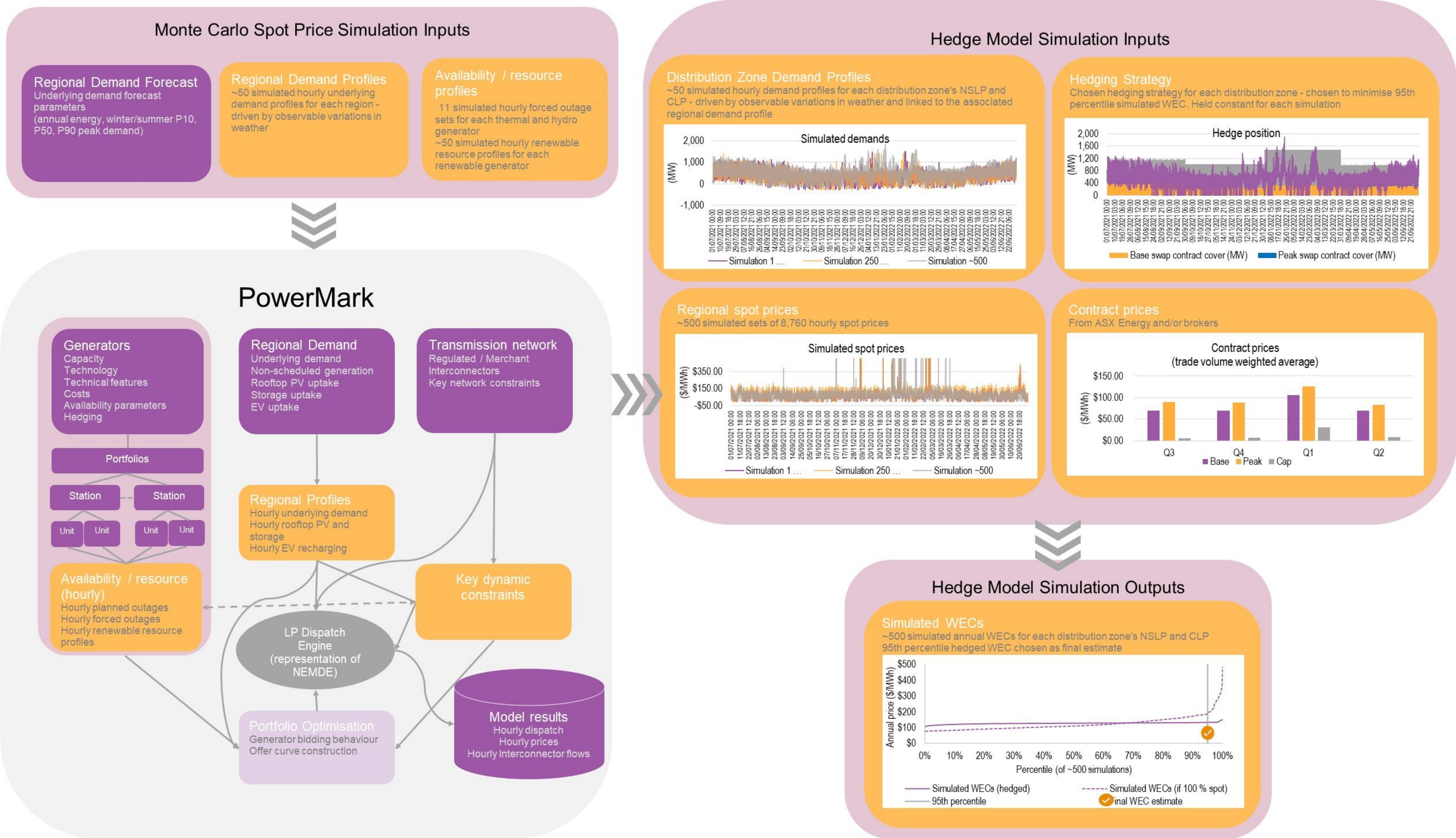
— Analyse exchange traded contract data to estimate contract prices.

— Run a hedge model taking the above analyses as inputs to estimate a distribution of WECs for each tariff class.

The distribution of WEC outcomes produced by the above approach is analysed, and the 95th percentile of the distribution is chosen to provide a risk adjusted estimate of the WEC.

Figure ES 2 visually summarises the key inputs and steps of the market-based approach used to estimate the WEC.

FIGURE ES 2 ESTIMATING THE WEC - MARKET-BASED APPROACH



Estimating 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.

Prudential costs

Prudential costs, for AEMO, as well as representing the capital used to meet prudential requirements to support hedging are taken into account and are calculated for each jurisdiction. The approach adopted is a simplification of the method AEMO and brokers/ASX Energy use.

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

Environmental costs

Large-scale Renewable Energy Target (LRET) and Small-scale Renewable Energy Scheme (SRES)

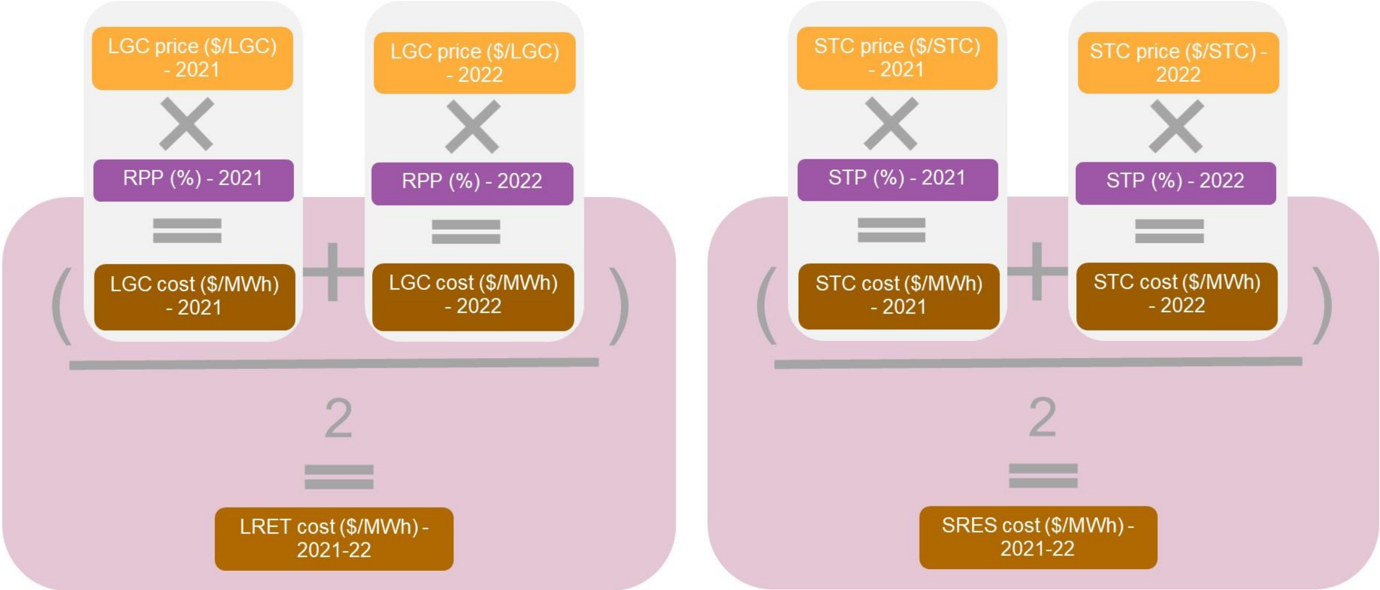
The estimated cost of compliance with the LRET scheme is derived by multiplying the Renewable Power Percentage (RPP), which translates the aggregate LRET target into the number of Large-scale Generation Certificates (LGCs) that liable entities must purchase and acquit under the scheme, and the determined LGC price.

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

The cost of compliance with the SRES is based on the clearing price for Small-technology Certificates (STCs) and the Small-scale Technology Percentage (STP).

Figure ES 3 visually summarises the key inputs and steps of the market-based approach used to estimate the cost of the LRET and SRES.

FIGURE ES 3 STEPS TO ESTIMATE THE COST OF LRET AND SRES



SOURCE: ACIL ALLEN

Other environmental costs

New South Wales Energy Savings Scheme (ESS)

The ESS is a certificate based New South Wales Government program to assist households and businesses reduce their energy consumption.

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

— Energy Savings Scheme Target for 2021 and 2022 of 8.5 per cent, as published by IPART
— Historical Energy Savings Certificate (ESC) market forward prices for 2021 and 2022 from brokers TFS

South Australia Retailer Energy Efficiency Scheme (REES)

The Retailer Energy Efficiency Scheme (REES) is a South Australian Government energy efficiency scheme that provides incentives for South Australian households and businesses to save energy.

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

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.

Distribution Loss Factors (DLF) for each distribution zone and average Marginal Loss Factors (MLF) as published by AEMO 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.

Review of sub-components of wholesale and environmental costs

We have attempted to identify if there are any new cost elements to be included in DMO 3, or cost elements in existence in DMO 2 that are no longer relevant.

From our review we have identified the following additional cost component for consideration:

— Retailer Reliability Obligation.

Retailer Reliability Obligation

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

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

The RRO has not been triggered for 2021-22, and hence we are not required to account for the RRO in the wholesale costs of DMO 3. 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 DMO.

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.

ACIL Allen's recommendation

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.

Review of current methodology

Based on the various submissions to the DMO 2 determination, feedback from the AER, our review of other retail electricity price determinations made in the past 12 months, as well as various reports from the AEMC, the key areas for consideration for DMO 3 are:

- Five-minute settlement
- Ancillary Services
- Separate WEC estimates for residential and small business customers
- Whether the estimate of LGC costs considers data other than broker supplied exchange data.
- The manner the impact of COVID-19 is taken into account when estimating the wholesale and environmental costs.

Five-minute settlement

Five-minute settlement commences on 1 October 2021. According to the AEMC, the intention of five-minute settlement is to provide better price signals for investment in fast response technologies, such as batteries, new generation gas peaker plants and demand response. The AEMC in its determination expressed the view that five-minute settlement should lead to lower wholesale costs. However, it also noted concerns from some stakeholders that the rule change could have the potential to reduce the volume of cap contracts offered to the market due to uncertainty as to whether gas peaking generators are able to defend cap contracts at the same volumes currently on offer.

Impact on price outcomes

Whether the market views five-minute settlement as having the potential to lower or raise wholesale electricity spot prices will be reflected in the forward contract market. Hence, this will be taken into account through the use of contemporary contract prices within the hedge model.

Hedge product availability

A key change at present of moving to five-minute settlement is the reduced availability in cap contracts. In August 2020, ASX Energy announced that market participants can trade quarterly caps until 30 September 2021. This means that for the three remaining quarters of the 2021-22 determination period, there is currently no cap contract price and volume data available from ASX Energy.

ACIL Allen has consulted with ASX Energy, and the broker, TFS, which provided trade volume and price data on OTC traded contracts for DMO 2. At this stage ASX Energy and TFS intend on developing a new cap product accounting for five-minute settlement which will be made available in the near future for the December 2021 quarter onwards. ACIL Allen proposes to make use of the trade volume and price data of this new cap product in the hedge model.

Any noticeable change in cap volumes offered in the market will be reflected in the hedging strategy adopted in the hedge model by including a limit within the algorithm that searches for the efficient hedging strategy. Equally, any changes in the volume of base and peak contracts made available to the market will also be reflected in the hedge model.

It is possible that other exchange and OTC traded contract products are developed. One example is the so-called *super-peak* contract which covers the morning and/or evening portion of the traditional peak period (and thereby excludes the period in between during which solar output is at its highest).

A consequence of the change in availability of quarterly contract products and the potential inclusion of new contract products is that the optimal hedging strategy will likely need to be expressed with different percentiles of base and peak load for each quarter – rather than adopting the same percentiles across all four quarters.

ACIL Allen's recommendation

Despite these changes in the contract market due to five-minute settlement, on balance, ACIL Allen is of the opinion that moving to five-minute settlement does not require a change in the methodology used to estimate the WEC. However, limits on caps and inclusion of other contract products, where appropriate, will be taken into account, and it is likely to be the case that the final hedging strategy will need to expressed on a quarter by quarter basis (rather than assuming the same percentiles of base and peak loads for all four quarters).

Ancillary services costs

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

ACIL Allen's recommendation

ACIL Allen proposes to continue to use the same data set, but will provide separate estimates of ancillary services costs for each region.

Whether separate WEC estimates be developed for residential and small business customers

The current methodology estimates the WEC based on the NSLP for the given distribution zone. This implies that the same WEC estimate is used for residential and small business customers. The NSLP is used as the representative load profile for residential and small business customers because the majority of residential and small business customers in New South Wales, Queensland, and South Australia, are on accumulation (or basic) meters. And those customers with digital (or interval) meters are in the minority. In some ways it is the technology of the meters that influences the WEC estimation methodology.

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

The DMO sets a maximum price a retailer can charge electricity customers on standing offers, and as such, retailers are able to set their retail offers below this maximum price, and in theory offer differentiating retail products to different customers. Thus, if different retailers have different customer mixes, they can structure their offers accordingly.

Although it is possible to estimate a separate WEC for residential and small-business customers using interval meter data, the following challenges remain:

- It is entirely possible that the aggregate load profile for customers on basic meters (the NSLP) is different to the load profile of customers on interval meters.
- It is not possible to estimate a separate WEC for residential and small business customers on basic meters (which could well be the vast majority of customers subject to the DMO).

  Do the separate WECs estimated for residential and small-business customers, based on interval meter data, also apply to customers on basic meters?
  - This runs the real risk of misrepresenting the true WEC in aggregate since the proportion of customers on interval meters may be quite low in some distribution zones and not representative of the vast majority of customers on basic meters. This would actually result is a less accurate estimate of the WEC in aggregate than continuing with the current approach of having a single WEC per NSLP.
- Do customers on a basic meter have a WEC based on the NSLP?

  - This would mean that all residential and small business customers on a basic meter have the same WEC – which defeats the purpose of having separate WECs.
- Do only customers on an interval meter have a separate WEC based on their classification?
  - This would mean differentiating between customers based on their meter type.
  -
- What about data transparency?
  - Although the AER could use its information gathering powers to readily gather the interval meter load data, making use of the aggregated interval meter load data will represent a departure from the usual approach of relying on data readily accessible in the public domain.

ACIL Allen's recommendation

ACIL Allen maintains the view that splitting the load into residential and non-residential customers does not improve accuracy and is largely arbitrary. It ignores, and does not account for, the large variety of non-residential load profile shapes that exist and the different mixes of these profiles that each retailer may have, and for some non-residential customers their profile may well be closer related to a residential profile given the nature of their business and hours of operation. Nor does it account for the difference in residential customers with and without rooftop solar PV – which are more likely to have very different load profiles.

ACIL Allen recommends not changing the current approach of using the NSLPs and CLPs to estimate the WEC for residential and small-business customers.

Whether the estimate of LGC costs considers data other than broker supplied exchange data.

Throughout the DMO 2 process, ACIL Allen made clear its view that a market-based approach using contemporary forward LGC prices represents most appropriate indicator of the current market consensus view of the price of LGCs in the near-term.

Although some stakeholders supported the market-based approach during the DMO 2 consultation process, others put forward as an alternative the use of renewable energy Power Purchase Agreements (PPAs) to ascertain the value of an LGC at the time the PPA was struck.

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

A PPA is not a regulated investment, and as such does not provide a guaranteed return, nor does it represent a guaranteed value. Hence, the value of an LGC within a PPA is determined by market conditions that actually eventuate at a given point in time – rather than at the time the investment decision was made.

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

We note that a market-based approach for estimating the LGC costs is adopted by all regulators in the NEM:

- AER for the DMO for the regulated price cap for residential and small business customers in south east Queensland, New South Wales and South Australia
- ESC for the VDO in Victoria,
- Queensland Competition Authority (QCA) for regulated retail electricity prices in regional Queensland,
- Independent Competition and Regulatory Commission (ICRC) for regulated retail electricity prices in the ACT
- Office of the Tasmanian Economic Regulator for regulated retail electricity prices in Tasmania.

ACIL Allen's recommendation

ACIL Allen sees no valid reason to change the current approach for estimating the cost of the LRET.

Accounting for the impacts of COVID-19

The extent to which COVID-19 is impacting the market is inherently taken into account in the current methodology. ACIL Allen considers the following key inputs to the methodology likely to be impacted by COVID-19:

- The demand forecast parameters
  - The WEC estimation methodology will use the demand forecast from the AEMO August 2020 Electricity Statement of Opportunities (ESOO). According to the ESOO report, the demand forecasts include the projected impacts of COVID-19.
- The demand profiles
  - The WEC estimation methodology will use the hourly demand profiles for the regional system demand satisfied by the spot market, and the corresponding hourly demand profiles for the NSLP and CLP. Although measures and restrictions associated with COVID-19 are likely to have resulted in shifts in electricity consumption from usual places of work to the home – despite the loss of employment, the overall level of consumption and its shape has not changed for the regional loads and NSLPs by an extent that is greater than what has been observed in previous years.
- Contract prices
  - The forward contract market will already be reflecting the market's view of the impact of COVID-19 on wholesale electricity prices in 2021-22 and will continue to evolve its view over time
- Spot prices.
  - The basis of the 500 or so spot price simulations is ACIL Allen's latest Reference case projection of the NEM. The Reference case is updated each quarter to reflect changes in the market that ought to be included in the modelling. These include updated demand forecasts, supply side settings and network assumptions. The Reference case adopted for the Final Determination of DMO 3 will include the latest input assumptions that drive spot price outcomes.

ACIL Allen's recommendation

On this basis, ACIL Allen is satisfied that the current methodology appropriately captures the impacts of COVID-19 on the wholesale electricity market, and its associated costs.

ACIL Allen's overall recommendation

ACIL Allen's overall conclusion based on our review is that current methodology remains valid for estimating the wholesale and environmental costs for the DMO 3 determination and continues to satisfy the objectives of the DMO.

ACIL Allen recommends the following minor modifications to the current methodology for DMO 3:

- Account for the costs associated with the RRO if it is triggered by increasing the optimal contract cover in the hedge model to 100 per cent of the P50 peak load.
- Although moving to five-minute settlement does not require a change in the methodology used to estimate the WEC, limits on caps and inclusion of other contract products, where appropriate, should be taken into account.
- Ancillary services costs should be estimated separately for each region of the NEM.

CONTENTS

FIGURES

TABLES

1 INTRODUCTION

ACIL Allen Consulting (ACIL Allen) has been engaged by the Australian Energy Regulator (AER) to support the AER in estimating specific cost inputs required for the determination of the 2021-22 Default Market Offer (DMO or DMO 3) prices. Specifically, ACIL Allen is required to provide consultancy services to the AER to estimate the underlying wholesale and environmental cost inputs to inform the determination for 2021-22.

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

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

- **Phase 1**: Review and assessment of methodology
  - The services in this phase include reviewing the methodology used to estimate the underlying wholesale and environmental cost inputs for the 2020-21 DMO (DMO 2), and clearly set out any changes, refinements, or considerations to the existing methodology for DMO 3. The deliverables in this phase will form part of the Position paper for DMO 3 (the Position Paper) to be published by the AER.
- **Phase 2**: Estimating the underlying costs to inform the DMO 2021-22 determination
  - If required, the services in this phase include estimating the underlying cost inputs for the DMO 3 determination based on the methodology refined in Phase 1. The deliverables in this phase will form part of the draft DMO 3 prices (Draft Determination) and the final DMO prices (Final Determination).

This report summarises our Phase 1 analysis and findings, and is set out as follows:

- In Chapter 3 we provide a summary of the current approach to estimating the wholesale and environmental costs (that is, the approach used in DMO 2).
- We identify any new components of the wholesale and environmental costs that ought to be included in DMO 3 in the first part of Chapter 4.
- In the second part of Chapter 4 we review the estimation methodology, and consider any refinements that ought to be considered.

More details of the scope of work for Phase 1

The wholesale and environmental cost estimation methodology applies to the following distribution zones:

- New South Wales: Ausgrid, Endeavour, Essential
- Queensland: Energex

- South Australia: SA Power Networks (SAPN).

The cost estimates for each of the above distribution zones are to be provided to enable the AER to calculate the forecast changes in retail electricity bill costs for the following customer types:

- Residential without controlled load
- Residential with controlled load
- Flat rate small business customers.

Our report is to transparently set out the forecasting methodology to enable stakeholders to make an informed assessment as to how the forecasts are, or are proposed to be, derived. The report is to discuss all relevant inputs, such as load profiles, and material information to assist stakeholders in assessing the methodology.

In 2019, ACIL Allen was engaged by the AER to develop and implement the wholesale and environmental cost estimation methodology for DMO 2. As such, for DMO 3, we are not required to devise and propose a methodology from first principles (or 'from scratch'), but rather to consider the methodology used in DMO 2 and how it may be refined. The refinement could be in response to changes in circumstance (for example, the triggering of the Retailer Reliability Obligation), or changes in availability of data (for example, the increase in penetration of interval meters).

Therefore, this paper provides a summary of the existing methodology and then explores options for refinement to the methodology. These refinement considerations are open to feedback from stakeholders through submissions to the AER's Position Paper.

2 OVERVIEW OF METHODOLOGY USED FOR DMO 2

3.1 Introduction

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

— an electricity retailer should be able to make a reasonable profit in relation to supplying electricity in the region

— to reduce the unjustifiably high level of standing offer prices for consumers who are not engaged in the market

— to set DMO prices at a level that provides consumers and retailers with incentives to participate in the market

— to allow retailers to recover their efficient costs in servicing customers.

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

With the objectives of the DMO in mind, presented in this chapter is a summary of the methodology used for DMO 2. Refinements to the methodology are considered in the next chapter.

3.2 Components of the total energy cost estimates

ACIL Allen is required to estimate the Total Energy Costs (TEC) component of the DMO. Total Energy Costs comprise of the following components:

— Wholesale energy costs (WEC) for various demand profiles

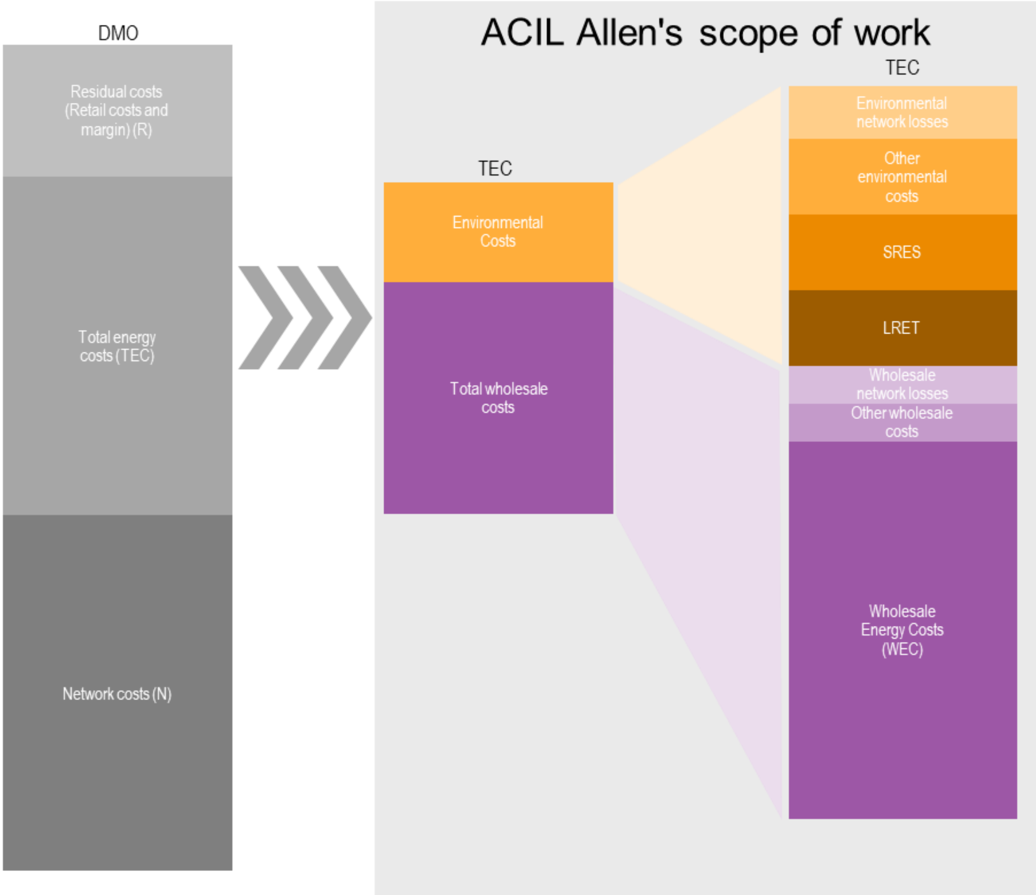
— Environmental Costs: costs of complying with state and federal government policies, including the Renewable Energy Target (RET)

— 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.

For the purpose of the DMO, the AER has requested ACIL Allen to present the estimates of the TEC components in two broad groupings – Wholesale and Environmental – in the manner shown in Figure 3.1.

FIGURE 3.1 COMPONENTS OF DMO AND COMPONENTS OF TEC



SOURCE: ACIL ALLEN

3.3 Methodology

The ACIL Allen methodology adopted for DMO 2 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.

3.3.1 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:

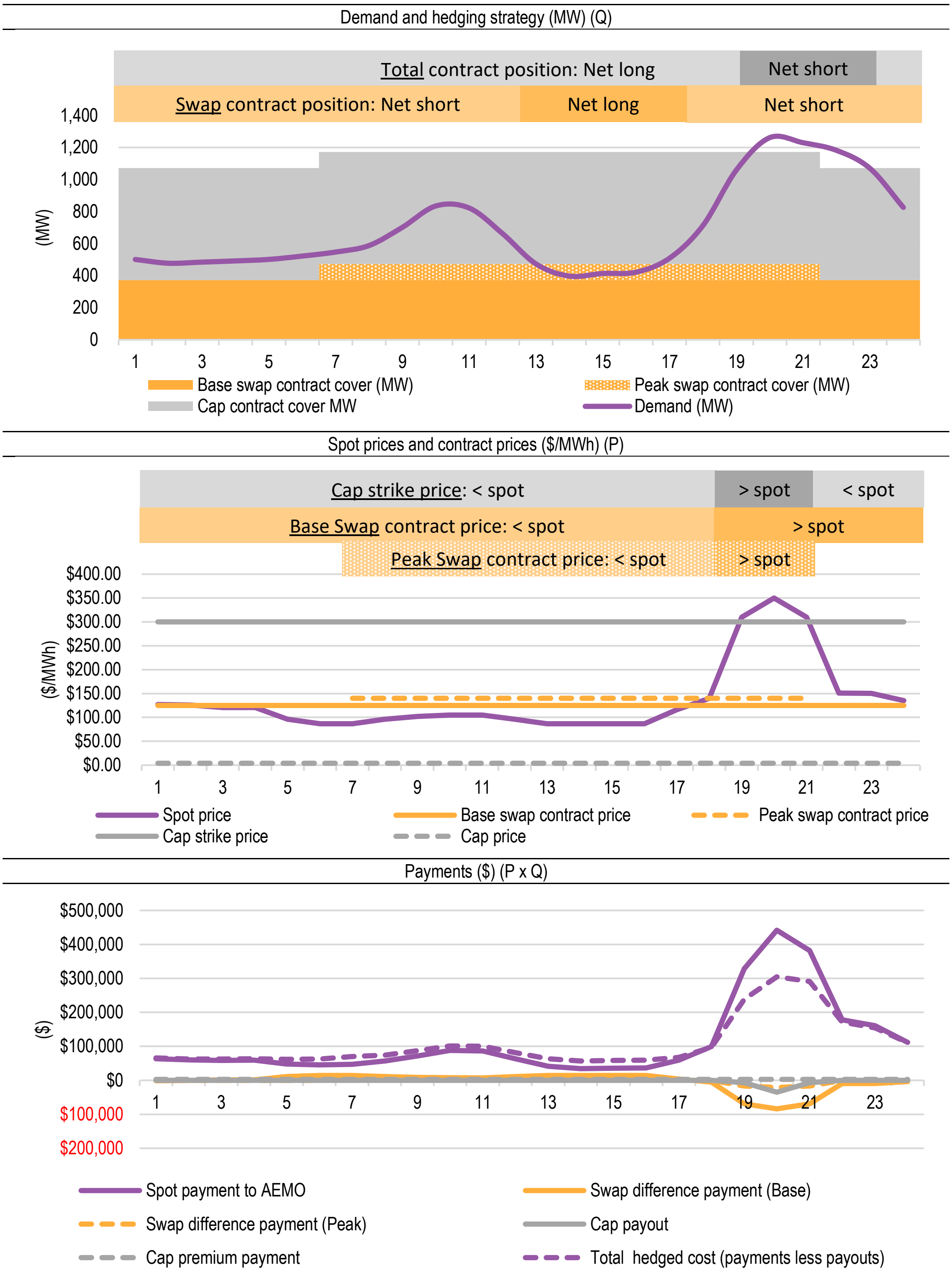
— Pays AEMO the spot price multiplied by the demand
— Pays the contract counterparty the difference between the swap contract strike price and the spot price, multiplied by the swap contract quantity. This is the case for the base swap contract regardless of time of day, and for the peak swap contract 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 3.2 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 3.2 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 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

Our scope of work requires the estimation of the WEC for residential and small business load in each distribution zone.

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) and controlled load profiles (CLPs) - used to model the cost of procuring energy for residential and small business customers for the following:

New South Wales: Ausgrid, Endeavour, Essential
Queensland: Energex
South Australia: SAPN.

Historical load data is available from AEMO – as shown in Table 3.1.

In the current methodology, the NSLP is used as the representative load profile for residential and small business customers because the majority of residential and small business customers in New South Wales, Queensland, and South Australia, are on accumulation (or basic) meters. And those customers with digital (or interval) meters are in the minority.

TABLE 3.1 SOURCES OF LOAD DATA

Region	Distribution Network	Load Type	Load Name	Source
New South Wales	NA	System Load	NSW1	MMS
	Ausgrid	NSLP	NSLP,ENERGYAUST	MSATS
	Ausgrid	CLP	CLOADNSWCE,ENERGYAUST	MSATS
	Ausgrid	CLP	CLOADNSWEA,ENERGYAUST	MSATS
	Endeavour	NSLP	NSLP,INTEGRAL	MSATS
	Endeavour	CLP	CLOADNSWIE,INTEGRAL	MSATS
	Essential	NSLP	NSLP,COUNTRYENERGY	MSATS
	Essential	CLP	CLOADNSWCE,COUNTRYENERGY	MSATS
Queensland	NA	System Load	QLD1	MMS
	Energex	NSLP	NSLP,ENERGEX	MSATS
	Energex	CLP	QLDEGXCL31,ENERGEX	MSATS
	Energex	CLP	QLDEGXCL33,ENERGEX	MSATS

Region	Distribution Network	Load Type	Load Name	Source
South Australia	NA	System Load	SA1	MMS
	SAPN	NSLP	NSLP,UMPLP	MSATS
	SAPN	CLP	SACLOAD,UMPLP	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 49[1] 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 539 (i.e. 49 by 11) simulations of hourly spot prices of the NEM using the stochastic demand and renewable energy resource traces and power station availabilities as inputs.
4. Estimate the forward contract price using ASX Energy contract price data, verified with broker data. 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 539 simulations – for a given simulation, for each hour calculate the spot purchase cost, contract purchase costs, and different payments, and then aggregate to get an annual cost which is divided by the annual load to get a price in $/MWh terms.

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

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

[1] 49 weather influenced simulations were used for DMO 2, whereas 50 simulations will be used for DMO 3 (given the additional year of weather data).

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. We select a strategy that is robust and plausible for each load profile, noting that:

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

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

Demand-side settings

The 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 four years are obtained. The profiles are adjusted by ‘adding’ back the estimated rooftop PV generation for the system demand and each NSLP (based on the amount of rooftop PV in each distribution network).
— A stochastic demand model is used to develop about 50 weather influenced simulations of hourly demand traces for the NSLPs, each regional demand, and each renewable resource – importantly maintaining the correlation between each of these variables. The approach takes the past three years of actual demand data, as well as the past 50 years of weather data and uses a matching algorithm to produce 49 sets of weather-related demand profiles of 8,760 half-hourly loads. This approach does not rely on attempting to develop a statistical relationship between weather outcomes and demand – instead it accepts there is a relationship and uses a matching algorithm to find the closest matching weather outcomes for a given day across the entire NEM from the past four years to represent a given day in the past.
— The set of 50 simulations of regional system demands is then grown to the AEMO demand forecast using a non-linear transformation so that the average annual energy across the 50 simulations equals the energy forecast, and the distribution of annual seasonal peak loads across the 50 simulations generally matches the distribution of peak loads inferred by the P10, P50 and P90 seasonal peaks from the AEMO demand forecast.
— A relationship between the variation in the NSLPs and the corresponding regional demand from the past four years is developed to measure the change in NSLP as a function of the change in regional demand. This relationship is then applied to produce 50 simulations of weather related NSLP profiles of 17,520 half-hourly loads which are appropriately correlated with system demand, but also exhibit an appropriate level of variation in the NSLP across the 50 simulations.
— The projected uptake of rooftop PV for the determination year is obtained (using our internal rooftop PV uptake model).

— The half-hourly rooftop PV output profile is then grown to the forecast uptake and deducted from the system demand and NSLPs.

Supply side settings

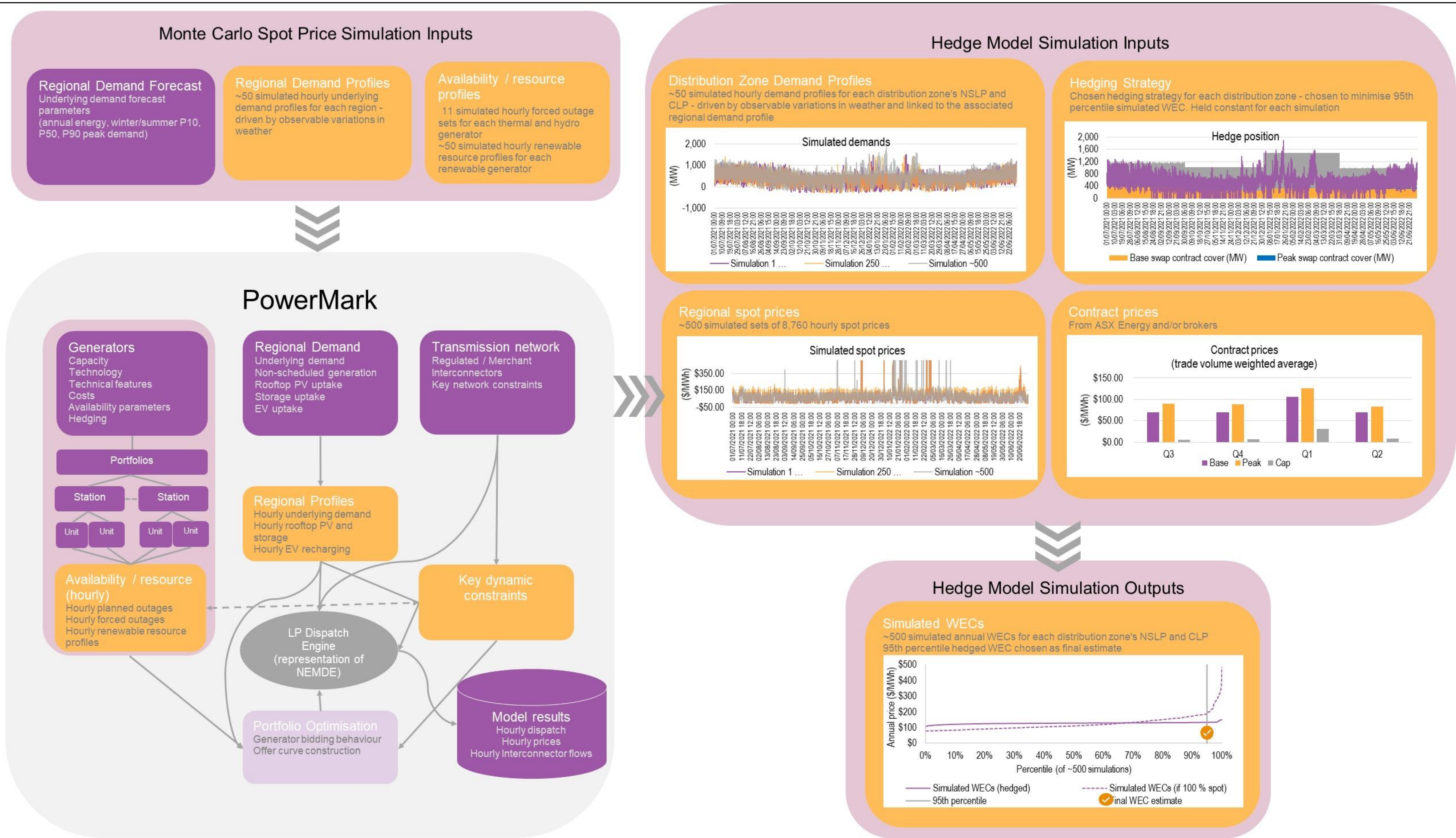
ACIL Allen maintains a Reference case projection of the NEM, which it updates each quarter in response to supply changes announced in the market in terms of new investment, retirements, fuel costs, and plant availability. In this analysis, for 2021-22 we will use our September 2020 Reference case projection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

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

Summary infographic of the approach to estimate the WEC

Figure 3.3 provides a infographic type summary of the data, inputs, and flow of the market based approach to estimating the WEC.

FIGURE 3.3 ESTIMATING THE WEC - MARKET-BASED APPROACH



3.3.2 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 National Transmission Planner (NTP) and the Energy Consumers Australia (ECA).

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

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 current 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.

Prudential costs

Prudential costs, for AEMO, as well as representing the capital used to meet prudential requirements to support hedging take into account:

— the AEMO assessed maximum credit limit (MCL)
— the future risk-weighted pool price
— participant specific risk adjustment factors
— AEMO published volatility factors
— futures market prudential obligation factors, including:
— the price scanning range (PSR)
— the intra month spread charge
— the spot isolation rate.

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

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

AEMO prudential costs

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

— bank guarantees
— reallocation certificates
— prepayment of cash.

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

MCL = OSL + PML

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

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

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

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

Hedge prudential costs

ACIL Allen relies on the futures market to determine hedging costs. The futures market includes prudential obligations by requiring entities to lodge initial margins (we assume cash) when contracts are purchased or sold. We understand that the cash that is lodged as an initial margin receives a money market related return which offsets some of the funding costs. The current money market rate is 0.50 per cent. Additional margin calls may apply where contracts move unfavourably for the purchaser or seller. However, as these may be favourable or unfavourable, we have assumed that they average out over time.

We understand that the initial margin is set based on three parameters being:

— the price scanning range (PSR) expressed as a percentage of the contract face value and is set for each of the base, peak and cap contract types.
— the intra monthly spread charge and is set for each of the base, peak and cap contract types
— the spot isolation rate and is set for each of the base, peak and cap contract types.

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

Reliability and Emergency Reserve Trader (RERT)

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

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

3.3.3 Environmental costs

Large-scale Renewable Energy Target (LRET)

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

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

The estimated cost of compliance with the LRET scheme is derived by multiplying the RPP and the determined LGC price to establish the cost per MWh of liable energy supplied to customers. Since the cost is expressed as a cost per MWh, it is applicable across all retail electricity tariffs.

Market-based approach

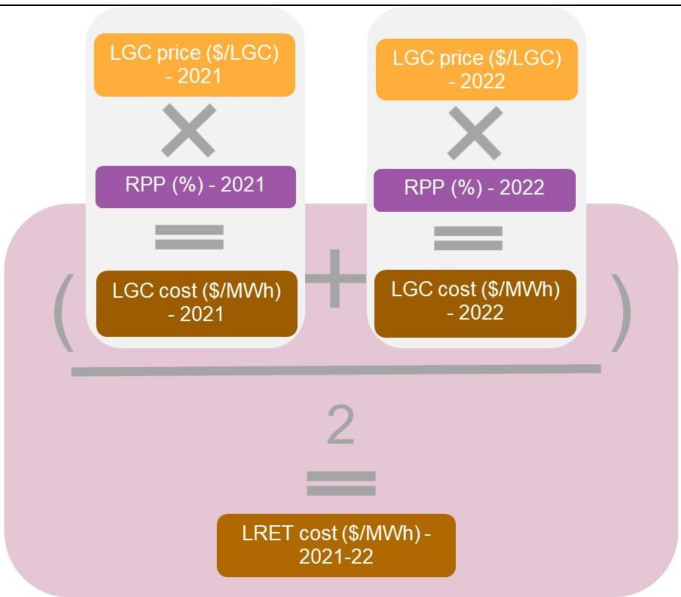
A market-based approach is used to determine the price of a LGC, which assumes that an efficient and prudent electricity retailer builds up LGC coverage prior to each compliance year.

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

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

— The average of the trade-weighted average of LGC forward prices for 2021 and 2022 from brokers TFS
— the Renewable Power Percentages (RPPs) for 2021, to be published by the CER
— estimated RPP values for 2022[2].

FIGURE 3.4 STEPS TO ESTIMATE THE COST OF LRET



SOURCE: ACIL ALLEN

Small-scale Renewable Energy Scheme (SRES)

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

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

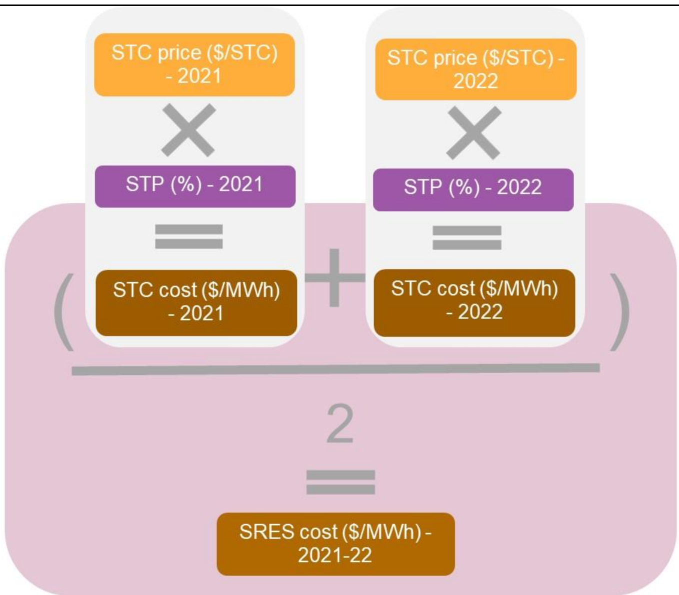
The estimated cost of compliance with the SRES is derived by multiplying the estimated STP value.

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

— the binding Small-scale Technology Percentages (STPs) for 2021 to be published by the CER
— estimated STP value for 2022[3]
— CER clearing house price[4] for 2021 and 2022 for Small-scale Technology Certificates (STCs) of $40/MWh.

[2] The estimated RPP values for 2021 and 2022 will be estimated using ACIL Allen's estimate of liable acquisitions and the CER-published mandated LRET targets for 2021 and 2022, respectively.
[3] The STP value for 2022 will be estimated using ACIL Allen's estimates of STC creations and liable acquisitions in 2022.
[4] 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 3.5 STEPS TO ESTIMATE THE COST OF SRES



SOURCE: ACIL ALLEN

3.3.4 Other environmental costs

New South Wales Energy Savings Scheme (ESS)

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

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

— Energy Savings Scheme Target for 2021 and 2022 of 8.5 per cent, as published by IPART

— Historical Energy Savings Certificate (ESC) market forward prices for 2021 and 2022 from brokers TFS

South Australia Retailer Energy Efficiency Scheme (REES)

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

The targets are set by the Essential Services Commission of South Australia (ESCOSA). REES commenced in 2009 and was set to operate until 31 December 2020.[5] However, in late 2019, a review into the scheme recommended it be extended to 31 December 2030[6], and hence it was included in DMO 2, and will be included in DMO 3 for 2021-22

The cost of the REES is recovered directly through retail electricity tariffs, and therefore should be considered as part of the environment cost component – but care needs to be taken that these costs are not double counted in the retail cost component.

[5] https://www.escosa.sa.gov.au/ArticleDocuments/214/20190627-REES-RegulatoryFrameworkInformationSheet.pdf.aspx?Embed=Y
[6] https://www.energymining.sa.gov.au/__data/assets/pdf_file/0008/356228/2019_REES_Review_Report.pdf

In the AEMC's 2018 price trends methodology report, the cost of the REES was sourced using data from the relevant jurisdiction, although there is no link to the exact location of this data.[7] The estimated cost was $2.50/MWh. The same cost was also report in the 2019 price trends report[8].

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

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

3.3.5 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[9], 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)*

[7] Table 8.5, page 49 at https://www.aemc.gov.au/sites/default/files/2018-12/AEMC%202018%20Residential%20Electricity%20Price%20Trends%20Methodology%20Report%20-%20CLEAN.pdf
[8] https://www.aemc.gov.au/sites/default/files/2019-12/2019%20Residential%20Electricity%20Price%20Trends%20final%20report%20FINAL.pdf
[9] See Page 23 of the AEMO publication *Treatment of loss factors in the national electricity market- July 2012*

AREAS OF CONSIDERATION FOR REFINEMENT OF THE METHODOLOGY FOR DMO 3

3

4.1 Introduction

In this chapter we consider whether there are any new cost components that ought to be included in our estimate of wholesale and environmental costs, as well as whether any aspects of the methodology used in DMO 2 ought to be refined for DMO 3.

4.2 Review of sub-components of wholesale and environmental costs.

4.2.1 Approach to undertaking the review

In this review we have attempted to identify if there are any new cost elements to be included in DMO 3, or cost elements in existence in DMO 2 that are no longer relevant.

It is important to note that the cost elements need to relate to wholesale and environmental costs, and care needs to be taken to ensure the cost elements are not already covered by other aspects of the DMO. This is particularly the case for elements related to the cost of retailing electricity. For example, there may very well be an increase in cost faced by retailers in relation to COVID-19 in terms of customer engagement and electricity bill collection activities - but these items do not form part of the TEC portion of the DMO.

We have made use of recent, and currently underway, state regulatory determinations, as well as the various Australian Energy Market Commission (AEMC) reports to identify whether any sub-components that ought to be considered.

From our review we have identified the following additional cost component for consideration:

— Retailer Reliability Obligation.

4.2.2 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.

On 9 January 2020, the South Australia Minister for Energy and Mining triggered the RRO in South Australia for the first quarters of 2022 and 2023. However, this was the first step in the triggering process. The second step requires AEMO to confirm that a reliability gap exists and issue a reliability instrument. AEMO released its 2020 Electricity Statement of Opportunities (ESOO) in late August 2020. In the ESOO, AEMO undertook a reliability forecast identifying any potential reliability gaps in the coming five years, and concluded that in the summer of 2021-22 (the T-1 year for the RRO), the reliability forecasts remain below both the reliability standard and the Interim Reliability Measure (IRM).

On this basis, the RRO has not been triggered, and hence we are not required to account for the RRO in the wholesale costs of DMO 3.

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, and as such we present our proposed approach for accounting for the RRO (if it were to be triggered in the future).

We think that entering into a mix of firm base, peak, and cap contracts satisfies the qualifying contract definition. It will be recalled that 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 DMO. The optimiser defines the contract volume in percentile or percentage terms of the load profile for the quarter.

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.

For example, for the 2020-21 determination, the total optimal hedge cover was 90 per cent of the median annual peak quarterly load for SAPN, and 100 per cent for Energex/Essential/Endeavour, and 110 per cent for Ausgrid. In this example, if the RRO had been triggered for South Australia for say January to March 2021, then we would propose adjusting the optimal cover upwards from 90 per cent to 100 per cent (which would result in a change in the estimated value of the WEC). However, in this example, had the RRO been triggered in one of the other states, then no change would be required since the optimal level of contract cover in the other states was already equal to or greater than 100 per cent of the P50 peak demand.

Hence, 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.
— 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.

4.3 Review of estimation methodology and consider other options

4.3.1 Approach to undertaking the review

Unlike DMO 2, the objective of this step of our engagement for DMO 3 is not to ‘start from scratch’ since there already exists a methodology which was successfully adopted for DMO 2. Rather, we have explored if the existing methodology can be improved to provide more accurate cost estimates, or needs to be modified due to changes in the market.

Based on the various submissions to the DMO 2 determination, feedback from the AER, our review of other retail electricity price determinations made in the past 12 months, as well as various reports from the AEMC, it is our view that the key areas for consideration for DMO 3 should focus on:

— Five-minute settlement
— Ancillary Services
— Separate WEC estimates for residential and small business customers
— Whether the estimate of LGC costs considers data other than broker supplied exchange data.
— The manner the impact of COVID-19 is taken into account when estimating the wholesale and environmental costs.

4.3.2 Five-minute settlement

In late 2017 the AEMC made a final rule to change the settlement period for the wholesale electricity spot price from 30 minutes to five minutes from 1 July 2021. According to the AEMC, the intention of five-minute settlement is to provide better price signals for investment in fast response technologies, such as batteries, new generation gas peaker plants and demand response. The rule aligns operational dispatch (already at five minutes) and financial settlement (currently at 30 minutes).

The AEMC in its determination expressed the view that five-minute settlement should lead to lower wholesale costs. However, it also noted concerns from some stakeholders that the rule change could have the potential to reduce the volume of cap contracts offered to the market due to uncertainty as to whether gas peaking generators are able to defend cap contracts at the same volumes currently on offer.

On 9 July 2020, the AEMC delayed the commencement of the five-minute settlement rule to 1 October 2021.

The rule change may have two impacts:

— The manner in which plant change their bidding strategy with the implementation of five-minute settlement

— The availability of cap contracts offered to the forward contract market, and the evolution of other contract products.

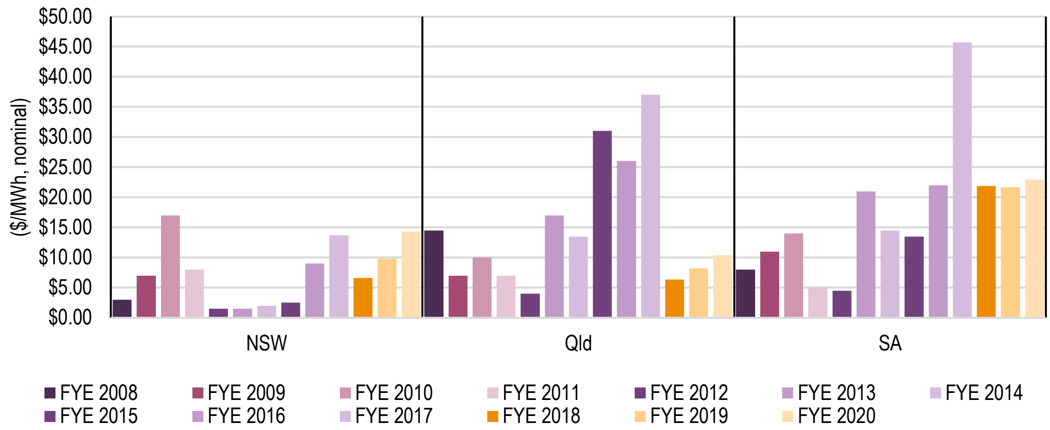
Bidding behaviour

PowerMark simulates the spot market at the hourly level. Although this is a simplification of the real market, it represents a sensible trade-off between a potential improvement in the representation of future market outcomes and avoiding unmanageable model run times. The key issue for consideration for PowerMark when modelling the spot market is replicating the behaviour of plant in the spot market affected by the rule change.

Part of the reasoning for the five-minute settlement review was the observed increase in propensity in early and late five-minute price spikes within the 30-minute settlement period, which was driven by bidding behaviour of generators. Since the AEMC's determination in late 2017, there has been either a reduction in, or stabilising of, the absolute deviation between the half-hourly settlement price and the individual five minute dispatch interval price as shown in Figure 4.1. This suggests that over the past three financial years, the distortion of certain bidding practices on 30-minute settlement prices has either stabilised (in the case of New South Wales and South Australia), or declined (in the case of Queensland). This could be due to a number of factors, including directions from generator shareholders and the reduced opportunity to undertake to sorts of bidding practices that give rise to price spikes in the first and 6th five-minute intervals of a 30 minute settlement period due to the substantial increase in renewable energy capacity entering the market over the past 12 to 18 months. This suggests that any estimation error resulting from PowerMark modelling the spot market at the hourly resolution level is unlikely to increase as a result of five-minute settlement.

Whether the market views five-minute settlement as having the potential to lower or raise wholesale electricity spot prices will be reflected in the forward contract market. Hence, this will be taken into account through the use of contract prices within the hedge model.

FIGURE 4.1 ANNUAL AVERAGE IN ABSOLUTE DIFFERENCE BETWEEN 5 MINUTE AND HALF HOURLY PRICE ($/MWH) – VOLUME WEIGHTED



SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

Hedge product availability

The current methodology relies on contract price and trade volume data from ASX Energy, which is supplemented and verified with broker data.

A key change as a result of moving to five-minute settlement is the reduced availability in cap contracts. In August 2020, ASX Energy announced that market participants can trade quarterly caps until 30 September 2021. This means that for the three remaining quarters of the 2021-22 determination period, there is currently no cap contract price and volume data available from ASX Energy.

This raises three immediate questions:

1. From which source should reliable cap price and volume data be sourced?
2. Whether any changes need to be made to the methodology to reflect the lower availability of cap contracts?
3. Are there other traded contract products that have recently been developed or taken up in response to five-minute settlement that should be included in the hedge strategy within the hedge model?

ACIL Allen will continue to use ASX Energy trade volumes and prices for base and peak swap contracts for all four quarters of DMO 3, and for the first quarter of DMO 3 for cap contracts.

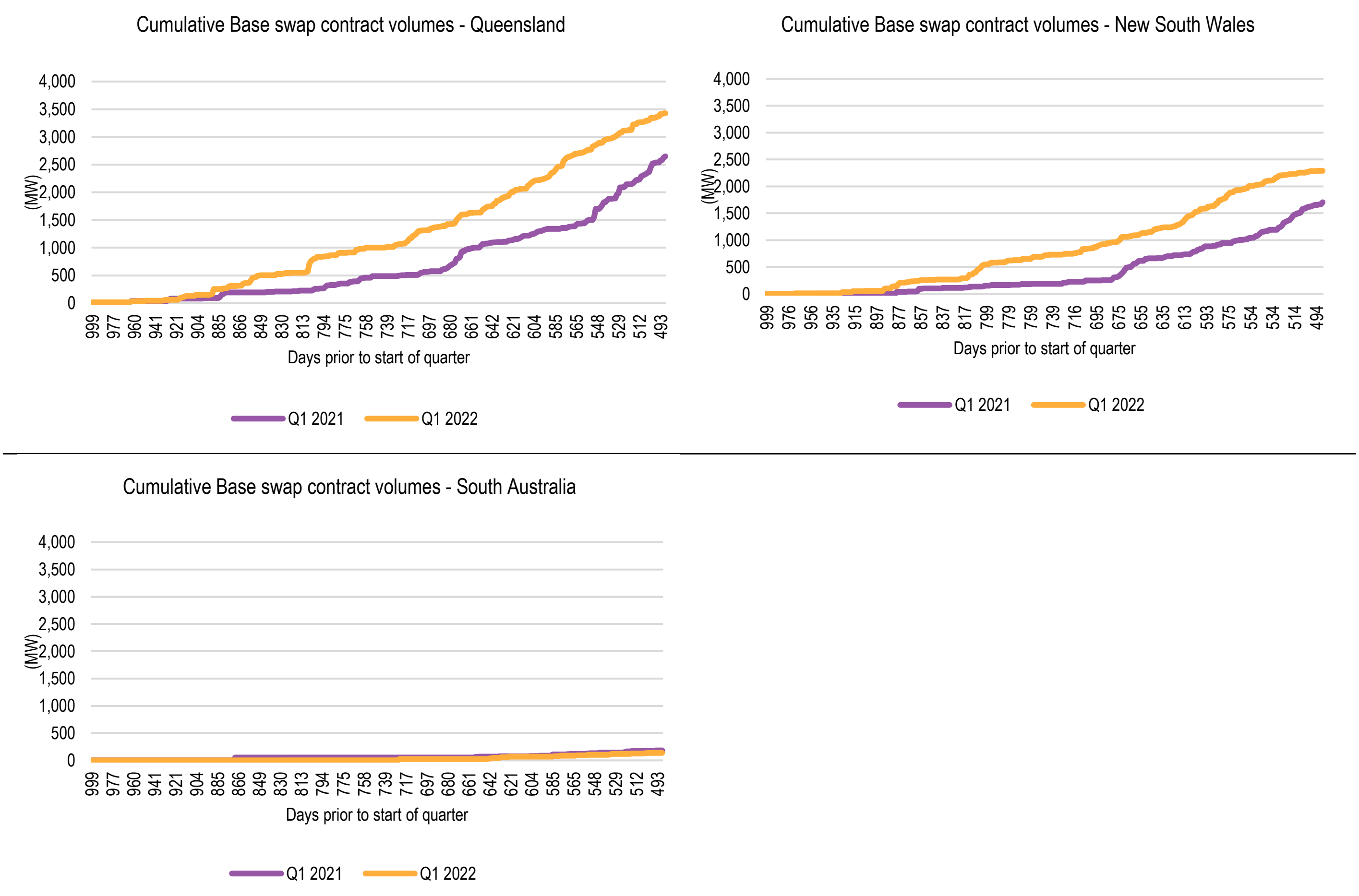
ACIL Allen has consulted on this matter with ASX Energy, and at this stage ASX Energy intends on developing a new cap product accounting for five-minute settlement which will be made available in the near future for the December 2021 quarter onwards. ACIL Allen proposes to make use of the trade volume and price data of this new cap product in the hedge model.

Similarly, ACIL Allen has consulted with the broker, TFS, which provided trade volume and price data on OTC traded contracts for DMO 2. TFS indicated that it will also be facilitating the trade in cap products for the December 2021 quarter and onwards in the near future. ACIL Allen proposes to continue to use the services of a broker to supplement the estimate the trade volume weighted price of contracts from ASX Energy.

ACIL Allen understands, that up to this point ASX Energy and brokers have not facilitated the trade in these new cap products due to uncertainty in the timing of the implementation of five-minute settlement and the associated lack of demand in the products as a result of this uncertainty (noting the AEMC's decision to delay the commencement of five minute settlement was only delivered in July this year).

Any noticeable change in cap volumes offered in the market will be reflected in the hedging strategy adopted in the hedge model by including a limit within the algorithm that searches for the efficient hedging strategy. Equally, any changes in the volume of base and peak contracts made available to the market will also be reflected in the hedge model. For example, Figure 4.2 compares the cumulative volume of trades in quarter one base contracts on ASX Energy for 2021 and 2022, and shows that the volume of trades in 2022 is about 30 per cent higher than those of 2021 for Queensland and New South Wales. This suggests the market, up to this point in time, is placing a higher reliance on base contacts in the absence of cap contracts in quarter one of 2022. This has been corroborated by ACIL Allen with various market participants.

FIGURE 4.2 COMPARISON OF CUMULATIVE TRADE VOLUMES (MW) FOR QUARTER 1 2021 AND QUARTER 1 2022 BASE CONTRACTS



SOURCE: ACIL ALLEN ANALYSIS OF ASX ENERGY DATA

It is possible that other exchange and OTC traded contract products are developed. One example is the so-called *super-peak* contract which covers the morning and/or evening portion of the traditional peak period (and thereby excludes the period in between during which solar output is at its highest).

ACIL Allen understands that brokers are already facilitating trades in super-peak contracts – although the volumes are small at this stage. We also understand that ASX Energy may well be looking at developing a similar exchange traded product.

ACIL Allen will continue to liaise with brokers to ascertain the extent that other contract products have experienced an increased uptake in response to five-minute settlement and/or the recent strong increase in solar PV (both rooftop and utility scale). New products that represent a reasonable portion of all trade volume and are readily implementable in the hedge model, will be included in the analysis since they represent a change in strategy that retailers have needed to adopt in response to the reduced availability in cap contracts and uptake of solar PV.

A consequence of the change in availability of quarterly contract products and the potential inclusion of new contract products is that the optimal hedging strategy will likely need to be expressed with different percentiles of base and peak load for each quarter – rather than adopting the same percentiles across all four quarters.

ACIL Allen's recommendation

Despite these changes in the market, on balance, ACIL Allen is of the opinion that moving to five-minute settlement and the continued increase in solar PV does not require a change in the methodology used to estimate the WEC. However, limits on caps and inclusion of other contract products, where appropriate, will be taken into account, and it is likely to be the case that the final hedging strategy will need to expressed on a quarter by quarter basis (rather than assuming the same percentiles of base and peak loads for all four quarters).

4.3.3 Ancillary services costs

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

Some ancillary services are recovered from customers across the NEM (referred to as the global requirement) and others are recovered within a NEM region (referred to as the local requirement). However, the data files that AEMO publish do not explicitly categorise recovery into local and global. Instead, the data files present the weekly costs by region, and we assume that the variable in the data file relating to customer recovery costs has accounted for the appropriate prorating of local and global requirements.

ACIL Allen's recommendation

On this basis, ACIL Allen proposes to continue to use the same data set, but will provide separate estimates of ancillary services costs for each region (noting that within a region, each distribution zone will have the same ancillary services cost).

4.3.4 Whether separate WEC estimates be developed for residential and small business customers

The current methodology estimates the WEC based on the NSLP for the given distribution zone. This implies that the same WEC estimate is used for residential and small business customers. A small number of submissions in the DMO 2 consultation process suggested that a separate WEC be estimated for the two customer classifications given different retailers have different mixes of these customers.

In the current methodology, the NSLP is used as the representative load profile for residential and small business customers because the majority of residential and small business customers in New South Wales, Queensland, and South Australia, are on accumulation (or basic) meters. And those customers with digital (or interval) meters are in the minority. In some ways it is the technology of the meters that influences the WEC estimation methodology.

By its very definition, the NSLP is the half-hourly profile of the load that remains after deducting the half-hourly load that is associated (and hence measured) with interval meters (which largely relates to large commercial and industrial customers).

ACIL Allen acknowledges that it is inevitable that different retailers will have different mixes of customers and that different customer types will have different profiles. However, the approach needs to be pragmatic, transparent, consistent, and manageable. As stated by the AER, the DMO protects consumers by setting a maximum price a retailer can charge electricity customers on standing offers. Retailers are able to set their retail offers below this maximum price, and if different retailers have different customer mixes, they can structure their offers accordingly.

It is possible to estimate a separate WEC for residential and small customers

ACIL Allen has investigated the availability of load data that distinguishes between residential and small business customers. Based on our understanding of the AEMO's MSATS Guide, the following data is available for each National Metering Identifier (NMI):

— customer classification (including residential or business)
— customer class (small, large)
— meter type (basic or interval)
— meter status (active, de-energised)
— distribution zone.

ACIL Allen recommends that the AER obtain this data from AEMO, for the period 1 July 2017 to 30 June 2020, so that it is possible to understand the split of customers on basic and interval meters by distribution zone over time. ACIL Allen has observed this data in the past for a separate engagement and is aware that about 90 per cent of customers in Queensland are on basic meters (and hence are represented by the NSLP), and 10 percent are on interval meters.

The MSATS data can also provide the aggregate half-hourly load for customers on interval meters, by customer classification, class, and distribution zone. Therefore, it is possible for the AER to obtain the necessary data from AEMO to allow the estimation of a separate WEC for residential and small-business customers.

Challenges in estimating a separate WEC for residential and small customers

Although it is possible to estimate a separate WEC for residential and small-business customers using interval meter data, the following challenges remain:

— It is entirely possible that the aggregate load profile for customers on basic meters (the NSLP) is different to the load profile of customers on interval meters.
— It is not possible to estimate a separate WEC for residential and small business customers on basic meters (which could well be the vast majority of customers subject to the DMO).

These two matters will need to be considered if a separate WEC is to be estimated for residential and small business customers:

Do the separate WECs estimated for residential and small-business customers, based on interval meter data, also apply to customers on basic meters?

  – This runs the real risk of misrepresenting the true WEC in aggregate since the proportion of customers on interval meters may be quite low in some distribution zones and not representative of the vast majority of customers on basic meters. This would actually result is a less accurate estimate of the WEC in aggregate than continuing with the current approach of having a single WEC per NSLP.

— Do customers on a basic meter have a WEC based on the NSLP?
  – This would mean that all residential and small business customers on a basic meter have the same WEC – which defeats the purpose of having separate WECs.
— Do only customers on an interval meter have a separate WEC based on their classification?
  – This would mean differentiating between customers based on their meter type.

ACIL Allen maintains the view that splitting the load into residential and non-residential customers does not improve accuracy and is largely arbitrary. It ignores, and does not account for, the large variety of non-residential load profile shapes that exist and the different mixes of these profiles that each retailer may have, and for some non-residential customers their profile may well be closer related to a residential profile given the nature of their business and hours of operation. Nor does it account for the difference in residential customers with and without rooftop solar PV – which are more likely to have very different load profiles.

What about data transparency?

Although the AER could use its information gathering powers to readily gather the interval meter load data, making use of the aggregated interval meter load data will represent a departure from the usual approach of relying on data readily accessible in the public domain. Currently, AEMO publishes the NSLP data, but not the aggregate interval meter load data. The AER will need to consider if the aggregate interval meter load data is to be used in estimate the WECs, whether this data be made available to stakeholders.

ACIL Allen's recommendation

On this basis, ACIL Allen recommends not changing the current approach of using the NSLPs and CLPs to estimate the WEC for residential and small-business customers.

The Victorian Essential Services Commission VDO

ACIL Allen notes that the load profiles used in the Essential Services Commission's (ESC) Victorian Default Offer (VDO) are based on the Victorian Manually Read Interval Meter (MRIM) data, which AEMO filtered and split into residential and small business customers with consumption less than 40 MWh per annum.

An important distinction between the VDO and DMO is that in Victoria there has been the mandatory roll out of interval meters in all five distribution regions in Victoria between 2013 and 2016. This means that the vast majority of customers are represented by the MRIM data – the opposite of the current situation in New South Wales, Queensland, and South Australia. Thus, the VDO WEC estimates for residential and small-business do not have the issue of relying on NSLP load data which does not distinguish and hence mutes the differential between residential and small-business customers.

It is also worth noting that evidence from the VDO suggests that the difference between residential and business WECs estimated by the ESC for the 2020 VDO is varied and typically about six per cent.

4.3.5 Whether the estimate of LGC costs considers data other than broker supplied exchange data.

Throughout the DMO 2 process, ACIL Allen made clear its view that a market-based approach using contemporary forward LGC prices represents most appropriate indicator of the current market consensus view of the price of LGCs in the near-term.

Although some stakeholders supported the market-based approach during the DMO 2 consultation process, others put forward as an alternative the use of renewable energy Power Purchase Agreements (PPAs) to ascertain the value of an LGC at the time the PPA was struck.

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

A PPA is not a regulated investment, and as such does not provide a guaranteed return, nor does it represent a guaranteed value. Hence, the value of an LGC within a PPA is determined by market conditions that actually eventuate at a given point in time – rather than at the time the investment decision was made.

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

Finally, we note that a market-based approach for estimating the LGC costs is adopted by all regulators in the NEM:

— AER for the DMO for the regulated price cap for residential and small business customers in south east Queensland, New South Wales, and South Australia
— ESC for the VDO in Victoria,
— Queensland Competition Authority (QCA) for regulated retail electricity prices in regional Queensland,

— Independent Competition and Regulatory Commission (ICRC) for regulated retail electricity prices in the ACT
— Office of the Tasmanian Economic Regulator for regulated retail electricity prices in Tasmania.

ACIL Allen's recommendation

ACIL Allen sees no valid reason to change the current approach for estimating the cost of the LRET.

4.3.6 Accounting for the impacts of COVID-19

The extent to which COVID-19 is impacting the market is inherently taken into account in the current methodology. ACIL Allen considers the following key inputs to the methodology likely to be impacted by COVID-19:

— The demand forecast parameters
— The demand profiles
— Contract prices
— Spot prices.

Demand forecast parameters

In August 2020, AEMO released its ESOO which includes the annual energy and winter/summer peak load forecasts. As noted earlier, these load forecast parameters will be used in developing the regional load profiles used in the simulation modelling of the spot market, as well as developing the simulated customer load profiles used in the hedge model.

According to the ESOO report, the demand forecasts include the projected impacts of COVID-19. The impacts are largely included within the economic forecast (in terms of interstate and international population migration, exchange rates, and GDP and GSP) and appear to extend to about 2024 (thus covering the DMO 3 determination period).

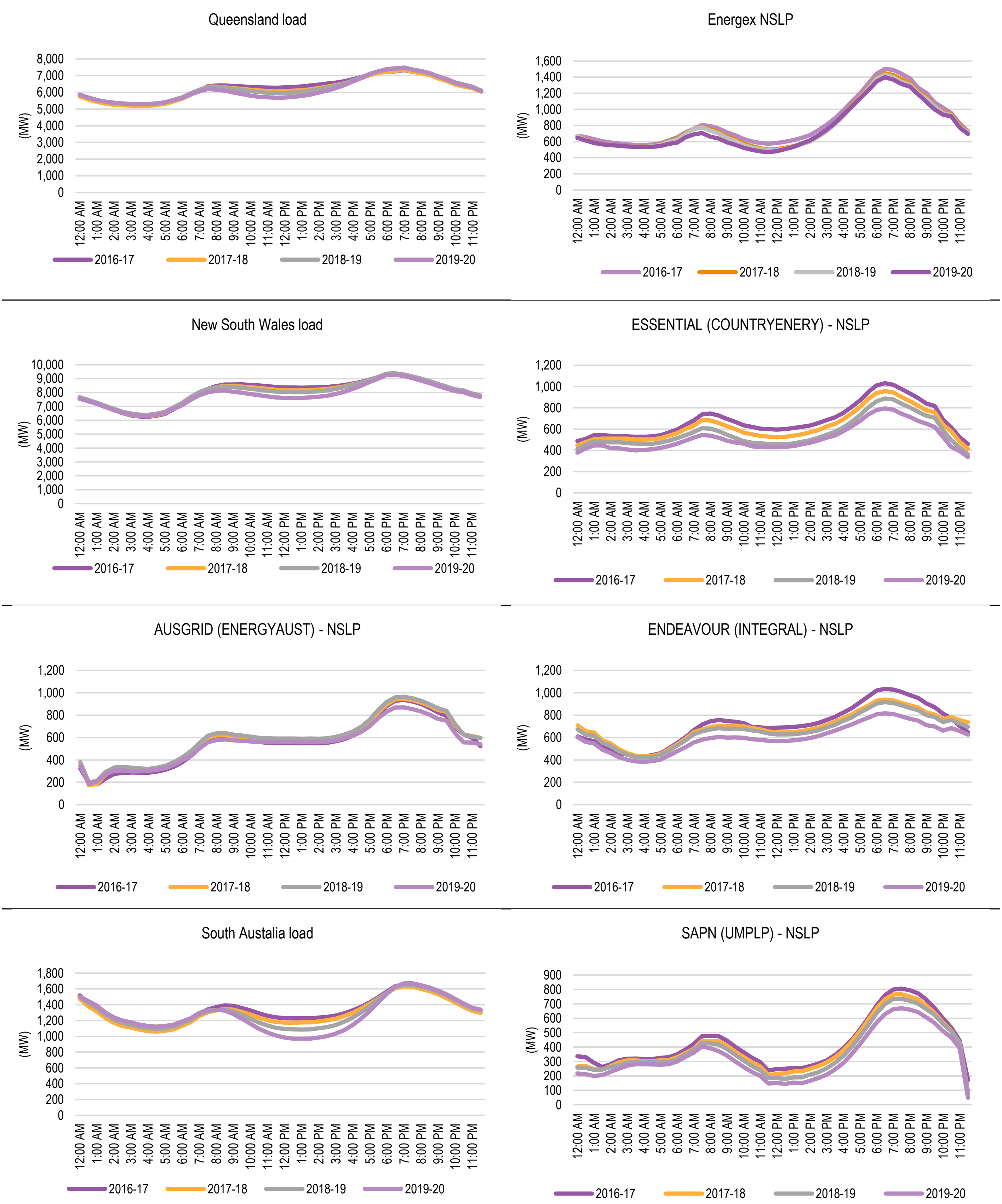
Demand profiles

A key input into the market-based approach in estimating the WEC are the hourly demand profiles for the regional system demand satisfied by the spot market, and the corresponding hourly demand profiles for the NSLP and CLP.

Figure 4.3 summarises the demand profiles by time of day for the past four financial years – for the regional demand as well as the corresponding NSLPs. As noted in our report to the Final Determination for DMO 2, although measures and restrictions associated with COVID-19 are likely to have resulted in shifts in electricity consumption from usual places of work to the home – despite the loss of employment, the overall level of consumption and its shape has not changed by an extent that is greater than what has been observed in previous years. And this is the case for the regional demand and NSLPs/CLPs.

Figure 4.4 to Figure 4.6 show the half-hourly demand traces for 2019-20 to date. Similar to the average time of day traces, there is no observable step change in level of demand or pattern of demand from the time restrictions were introduced in mid-March 2020. Of course, the DMO relates to Queensland, New South Wales, and South Australia – regions which have not experienced the same degree of COVID-19 cases and restrictions to date as Victoria.

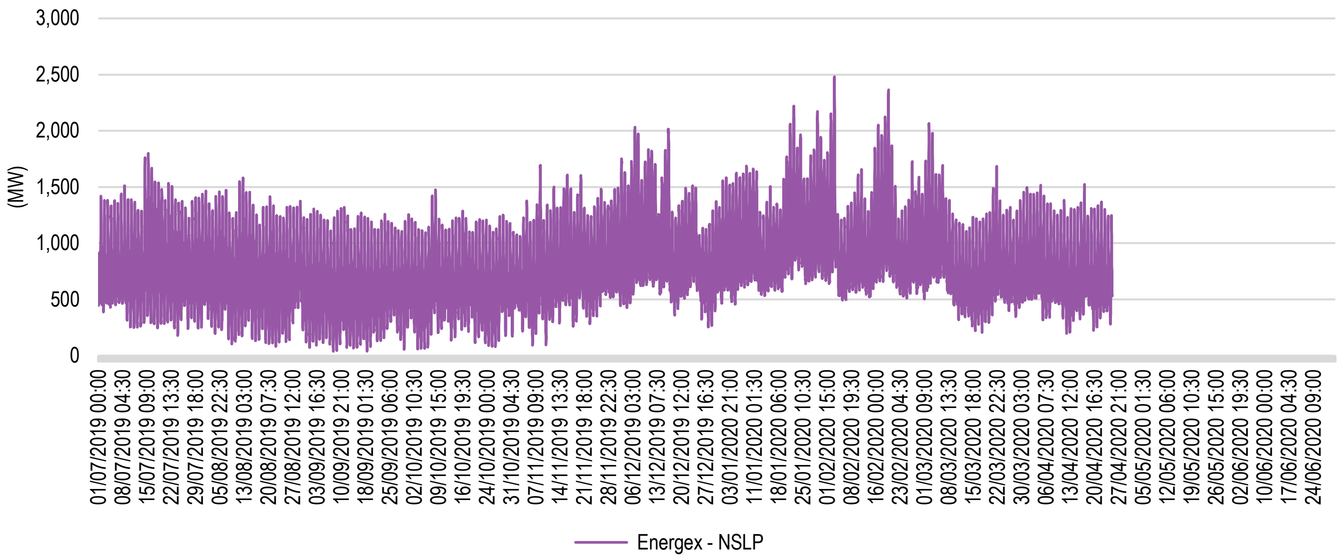
FIGURE 4.3 AVERAGE TIME OF DAY DEMAND (MW) – 2016-17 TO 2019-20



Note: Includes data to 26 April 2020 due to lag in AEMO publishing NSLP data

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

FIGURE 4.4 HALF-HOURLY LOAD PROFILE (MW) – ENERGEX NSLP – 2019-20



Note: Includes data to 26 April 2020 due to lag in AEMO publishing NSLP data

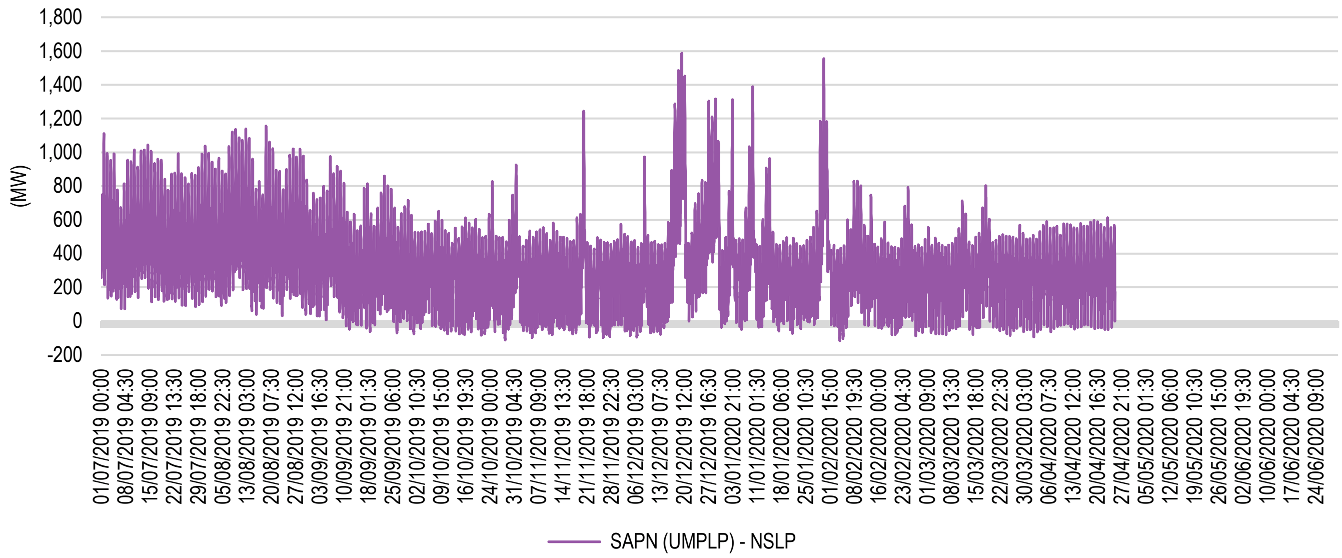
SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

FIGURE 4.5 HALF-HOURLY LOAD PROFILE (MW) – ESSENTIAL, AUSGRID, ENDEAVOUR NSLPS – 2019-20

Note: Includes data to 26 April 2020 due to lag in AEMO publishing NSLP data

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

FIGURE 4.6 HALF-HOURLY LOAD PROFILE (MW) – SAPN NSLP – 2019-20



Note: Includes data to 26 April 2020 due to lag in AEMO publishing NSLP data

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

Contract prices

The forward contract market will already be reflecting the market's view of the impact of COVID-19 on wholesale electricity prices in 2021-22 and will continue to evolve its view over time. The current methodology uses the trade volume weighted average price for each quarterly contract product and hence will reflect any changes in view of the impact of COVID-19. The Final Determination of DMO 3 will make use of the latest available contract price data in order to capture the latest available information.

Spot prices

The basis of the 500 or so spot price simulations is ACIL Allen's latest Reference case projection of the NEM. The Reference case is updated each quarter to reflect changes in the market that ought to be included in the modelling. These include updated demand forecasts, supply side settings and network assumptions. The Reference case adopted for the Final Determination of DMO 3 will include the latest input assumptions that drive spot price outcomes.

ACIL Allen's recommendation

On this basis, ACIL Allen is satisfied that the current methodology appropriately captures the impacts of COVID-19 on the wholesale electricity market, and its associated costs.