WATERNSW'S ENERGY PURCHASE COSTS - BROKEN HILL PIPELINE

FINAL REPORT FOR IPART

8 FEBRUARY 2019

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1 INTRODUCTION

Frontier Economics is advising IPART on its review of WaterNSW's energy purchase costs for the Broken Hill Pipeline.

1.1 Background

IPART is currently undertaking the inaugural review of the maximum prices WaterNSW can charge for the water transportation services provided by the Murray River to Broken Hill Pipeline (the pipeline). The pipeline will carry water from the Murray River to Broken Hill, supplying water to Broken Hill, surrounding communities and a small number of offtake customers along the pipeline. The primary customer of the pipeline will be Essential Water. WaterNSW has entered into a contract (the O&M contract) with a joint venture led by John Holland (the pipeline contractor) to design, construct, operate and maintain the pipeline. The pipeline is currently under construction and is scheduled for completion in April 2019.

1.2 Scope

Our review of energy costs for WaterNSW's Murray River to Broken Hill Pipeline includes the following tasks:

- Reviewing WaterNSW's energy cost proposal, including the procurement process undertaken by the pipeline contractor, who is responsible for purchasing electricity for the pipeline.
- Assessing and providing recommendations on the efficient energy cost for WaterNSW's pipeline load over each year over the period 1 July 2019 to 30 June 2024. However, we have been unable to estimate the efficient energy cost for the last year – the period 1 July 2023 to 30 June 2024 – as WaterNSW provided no demand data beyond 30 June 2023.

IPART has appointed other advisors to review WaterNSW's non-energy cost proposals, including establishing an efficient load profile for the pipeline, which is required to calculate an efficient benchmark energy price.

1.3 About this report

This report presents our analysis and findings. It is structured as follows:

- Section 2 describes our methodology.
- Section 3 reviews WaterNSW's energy cost proposal.
- Section 4 presents our estimates of efficient energy purchase costs for WaterNSW for the pipeline.
- Section 5 presents a simplified approach to estimating efficient energy purchase costs that does not depend on a forecast of WaterNSW's electricity load for the pipeline.

2 METHODOLOGY

Frontier Economics has two related tasks in the review of WaterNSW's energy purchase costs for the pipeline over the determination period:

- Review and comment on the appropriateness of WaterNSW's proposal.
- Provide independent forecasts of efficient electricity prices for WaterNSW.

We describe our approach to each task in more detail below.

2.1 Review and comment on the appropriateness of WaterNSW's proposal

To review and comment on the appropriateness of WaterNSW's proposal we undertook the following steps:

- we reviewed WaterNSW's proposal and the accompanying ACIL Allen Consulting report to consider the robustness of the methodologies adopted and information presented
- we interviewed WaterNSW and the pipeline contractor staff member responsible for procurement to inform our assessment of the robustness of the procurement process.

To assist in our analysis WaterNSW and IPART provided the following information:

- WaterNSW's Pricing Proposal for regulated prices for the Wentworth to Broken Hill Pipeline[1]
- ACIL Allen's report on projecting retail electricity prices for the pipeline[2] (including the spreadsheet used to forecast retail electricity prices)
- a workbook estimating electricity consumption provided by Trility
- the O&M contract between WaterNSW and the pipeline contractor (John Holland Pty Ltd and Trility Pty Ltd), and
- the electricity retail agreement between the pipeline contractor and the energy provider.

Our analysis and findings on the appropriateness of WaterNSW's proposal are presented in Section 3.

2.2 Provide independent forecasts of efficient electricity costs for WaterNSW

To develop independent forecasts of efficient electricity costs for the pipeline we consider the costs that an electricity retailer would face in supplying electricity to WaterNSW for the pipeline. These costs are:

- Wholesale electricity costs
- Renewable energy policy costs
- Costs of complying with environmental policies (including the NSW Energy Savings Scheme (ESS) and the Climate Change Fund)

1 WaterNSW (2018), Pricing Proposal to the Independent Pricing and Regulatory Tribunal – Regulated prices for the Wentworth to Broken Hill Pipeline.

2 ACIL Allen (2018), Wentworth to Broken Hill Pipeline Methodology and electricity retail price projection for 2018-19 to 2022-23.

- Market fees and ancillary services costs
- Network costs
- Energy losses
- Retail operating cost and margin.

We used our standard approach to forecasting efficient electricity costs for each year of the determination period. This standard approach is set out in Section 4. This approach has been previously adopted by regulators for the purposes of regulating retail electricity prices.

To apply our standard approach to forecasting efficient electricity costs we require a half hourly load profile for the pipeline. Given the time constraints associated with the publication of this report we generated a half-hourly load profile to use in our analysis based on information provided to us by IPART on minimum and maximum pumping loads and weekly pumping requirements. Changes to this load profile, for example due to changes in assumptions about the demand for water provided by the pipeline, will in turn change the demand profile and the efficient benchmark energy cost for the pipeline. In particular, our estimation of wholesale electricity costs takes the demand profile as a fixed input. It is impossible to accurately predict what impact a change in the water demand forecast for the pipeline would have on our estimation of wholesale electricity costs, as it depends on the change in volume and change in the load shape, and the way it interacts with half-hourly spot prices.

In Section 5 we also present a simplified approach to estimating efficient energy purchase costs that does not depend on a forecast of WaterNSW’s electricity load for the pipeline. This simplified approach relies only forecast spot prices.

3 WATERNSW'S ENERGY COST PROPOSAL

This Section reviews WaterNSW's energy cost proposal. We begin by summarising the energy cost proposal presented by WaterNSW in its submission. We then describe and comment on the procurement process used by the pipeline contractor to secure the contract to purchase energy to supply the pipeline, and provide an overview of the resulting contract. Finally, we comment on the approach adopted by WaterNSW's advisors in estimating electricity retail prices for the pipeline.

3.1 WaterNSW's energy cost proposal

Electricity costs are incurred due to the energy needs of the four pump stations which operate to transmit water up the pipeline. The operating schedule of the pipeline will prioritise off-peak and shoulder pumping times, to minimise on-peak operation.

Electricity prices have been sourced by the pipeline contractor from a competitive tender process (discussed in Section 3.2) required under the O&M contract for the financial years 2019-20 and 2020-21. Electricity prices for the remaining years of the determination period (2021-2022 and 2022-23) will be sourced under a subsequent tender process, expected to be held within the determination period. Illustrative forecast electricity costs prepared by WaterNSW for the 2019-23 regulatory period are shown in **Table 1** (assuming an average demand of 5,746 MLs per annum).

Table 1: Forecast electricity costs for the 2019-23 regulatory period ($'000, $2018-19)

	2019-20	2020-21	2021-22	2022-23	TOTAL	AVERAGE
Electricity payment	2,706.2	2,587.6	2,331.0	2,514.7	10,139.6	2,534.9

Source: WaterNSW (2018), WaterNSW Pricing Proposal for the Wentworth to Broken Hill Pipeline, p.76.

WaterNSW proposes to offset the cost of electricity using revenue derived from offtakers, with the proposed charges including:

- A fixed electricity charge
- An electricity demand charge, a single rate on water usage which applies at all times, and
- A variable electricity charge, which varies depending on the amount of water ordered or delivered.

3.2 The procurement process

The pipeline contractor (John Holland) is responsible for arranging and entering into a Power Supply Agreement (PSA) throughout the term of the O&M contract. The O&M contract contains several provisions intended to drive efficient electricity purchase costs:

- To ensure competitive market rates, the pipeline contractor was required to source three quotes for electricity and select the most competitive from these, to produce the same competitive pricing outcomes that would be achieved if WaterNSW were to procure the PSA itself.
- The O&M contract is designed to provide incentives for the pipeline contractor to minimise energy costs, by allowing the pipeline contractor to share in the savings.[3]

This section provides an overview of the procurement process used by the pipeline contractor to secure the PSA and a discussion of whether the process was consistent with the efficient purchase of energy.

3.2.1 Overview of the procurement process

The pipeline contractor formed the view that the efficient approach to meeting its electricity requirements was to purchase electricity from a retailer. The pipeline contractor indicated that it did consider investing in solar PV to supply electricity to the pipeline, but previous experience across a range of assets has shown that it is consistently cheaper to enter into an electricity supply contract for the provision of energy (rather than developing alternative sources of supply).

In addition, a contract aligned better with the O&M contract with WaterNSW (which allows them to pass through the electricity costs).[4]

The pipeline contractor undertook a tender process for retail supply of electricity with the help of a broker. The broker contacted seven retailers directly, but also published the tender.

The tender specified the time period and the energy volume required per year (notwithstanding that the first year was not a full year),[5] which ramped up over time. The load was specified in terms of off-peak, shoulder and peak periods, and the pipeline contractor expected that the quote would follow a similar pattern (based on previous experience engaging energy suppliers). Quotes were requested from October 2018 to June 2019 (the initial nine-month period) and for three, twelve-month terms thereafter. This term structure was adopted to align with the determination period and avoid the requirement to renew the PSA in the summer period when prices tend to be highest.

Three offers were received – from **[commercial-in-confidence]**. The offers were expressed over periods of 9 months, 17 months or 33 months (commencing 1/10/2018) for periods of peak, off-peak and shoulder. All proponents offered lower average prices over a longer contractual period of 33 months. No offers were received to supply the third twelve-month term requested.

The pipeline contractor engaged in some negotiation with the preferred tendered – **[commercial-in-confidence]** – as part of which the preferred tendered reduced its tendered price: the preferred tendered dropped the differential between peak and off-peak, and reduced the shoulder price, which resulted in an overall lower price.

3.2.2 Overview of selection process

The pipeline contractor concluded that the preferred tendered offered the lowest total cost for each year of the offer period – with the differential increasing in future years. To some extent, this assessment required assumptions about future costs of renewable certificates (since only the preferred tendered

[3] To incorporate this principle, the O&M contract included a mechanism to measure any cost savings realised by the pipeline contractor (calculated as energy payments less actual energy costs incurred) on an annual basis and share these savings 50/50 between the contractor and WaterNSW.

[4] The pipeline contractor indicated that they did look into the cost of solar, however, it was not financially viable.

[5] The reason the pipeline contractor specified the load in annual blocks was because it aligned with the regulatory period, and because in their experience, it is best to avoid going to market in peak times (December/January), when prices are likely to be higher.

offered fixed costs for these renewable certificates). Where this was necessary, the pipeline contractor relied on market rates for this certificates and the views of its broker.

Although the sole selection criteria was the lowest price for electricity, as required by the O&M contract, the preferred tendered's proposal also had a number of other advantages over the alternatives, including:

- Fixed green costs,[6] rather than a pass through of green costs (as per the other proposals). This increased the certainty associated with the electricity supply contract price.
- The widest 'flex', or scope for consumption under or over contracted levels without penalties. The pipeline contractor considered this flexibility to be important given the demand uncertainty associated with the greenfield nature of the pipeline.
- A price below spot trends. The pipeline contractor's broker provided some analysis on spot trends, and while the other tenderer's proposals were in line with trends, the preferred tenderer's proposal was lower than the benchmark provided.

In addition, the 33-month pricing from the preferred tenderer was considered appropriate as:

- The 33 months better aligned with the determination pricing cycle (for the regulatory year ending FY 21) and the determination pricing framework (where prices are generally fixed for a 4 to 5 year period in the interest of price stability).
- A longer term was considered appropriate to mitigate the current price volatility observed in the electricity market.
- A longer term of 33 months would provide the operator with more time to understand the best and most efficient operating ranges for the pipeline. A shorter term may give a distorted (short term) view of power requirements which may then force the energy provider to further increase their charges in a subsequent tender process.

Although the pipeline contractor had not written a contract with the preferred tenderer before, the terms and conditions included in the electricity supply contract were standard.

3.2.3 The electricity supply contract

The PSA with the preferred tenderer sets out the terms and conditions on which the preferred tenderer has agreed to sell, and the pipeline contractor has agreed to buy, electricity between 1 October 2018 and 30 June 2021.[7] **Table 2** sets out the energy price, between 1 October 2018 and 30 June 2021, as per the agreement with the preferred tenderer. These energy prices assume forecast consumption of 32,055 MWh over the period.

[6] These include the costs of meeting the liability under the Large Scale Renewable Target (LRET) (i.e. the cost of Large-scale Generation Certificates), Small Scale Renewable Scheme (SRES) (i.e. the cost of Small-scale Technology Certificates) and the Energy Security Scheme (ESS) (i.e. the cost of Energy Savings Certificates).

[7] We understand the 'ready for water' milestone is in December 2018. However, it is possible that when the pipeline contractor entered into the PSA they anticipated an earlier 'ready for water' milestone.

Table 2: Agreed energy prices (c/kWh)

CONTRACT YEAR	PEAK8	SHOULDER9	OFF-PEAK10
1 October 2018 to 30 June 2021	8.213	8.213	6.398

Source: [commercial-in-confidence]

Electricity network tariffs and other ancillary charges (including metering charges) will be treated as a pass-through cost under the PSA. These will be determined under the AER annual pricing approach process for network electricity charges. WaterNSW proposes to pass through the actual cost of network and other ancillary charges through an annual update mechanism.

As shown in **Table 3**, under the PSA, green costs are fixed between 2018 and 2020. Given uncertainty around what type of environmental scheme will be in place in 2021, the preferred tenderer has not provided Environmental Scheme Costs for the calendar year 2021, but notes that they will provide costs (based on prevailing market rates) by no later than 30 November of the preceding contract year.

Table 3: Environmental certificate pricing ($/MWh)

CERTIFICATE TYPE	2018	2019	2020	2021
Large-scale Generation Certificates	$13.89	$14.13	$7.53	TBC
Small-scale Technology Certificates	$6.75	$4.80	$4.60	TBC
Energy Savings Certificates	$2.06	$2.25	$2.32	TBC

Source: John Holland Trility (2018), executed LOA – John Holland Pty Ltd and Trility Pty Ltd (Joint Venture)

3.2.4 Assessment

In reviewing the pipeline contract we considered a series of questions, including:

- What was the objective of the energy procurement process?
- What other alternatives, if any, did the pipeline operator consider before proceeding with its energy purchase strategy?
- What was the pipeline contractor's process for requesting tenders? Did the pipeline contractor engage in a competitive tender?
- What criteria did the pipeline contractor use to assess the offers?
- How did the pipeline contractor compare the offers?
- Did the pipeline contractor benchmark the offers?

In our view, the procurement process adopted supported the execution of an efficiently priced PSA. The O&M contract contains provisions to incentivise the pipeline contractor to efficiently purchase electricity.

8 Between 7am to 9am and 5pm to 8pm (AEST/AEDT), business days.

9 Between 9am to 5pm and 8pm to 10pm (AEST/AEDT), business days.

10 All times outside Shoulder Periods and Peak Periods.

The pipeline contractor adopted a standard procurement process, informed by their experience securing similar contracts in the past. This procurement process involved clearly specifying its requirements and soliciting a number of competing offers with the support of a broker. A number of directly comparable offers were received, and compared to a standard benchmark. The pipeline contractor had a clear and structured process (including clear objectives), selected the most competitive offer and sought and received an additional discount. In our assessment the procurement process was appropriate and likely to support the procurement of efficiently priced electricity.

3.3 ACIL Allen’s methodology and electricity retail price projection

As retail market electricity prices are not generally available over the longer term, WaterNSW engaged ACIL Allen to provide them with forecast electricity prices for the proposed 4-year period of the determination. These forecast prices have been used to determine the electricity price for the expected average demand profile and used in generating the illustrative revenue requirement over the term of the proposed determination.

This section provides a high-level discussion on whether ACIL Allen’s approach to forecasting retail electricity prices is appropriate.

3.3.1 Overview of approach

To estimate the likely cost of electricity the pipeline will incur between 2018-19 and 2022-23, ACIL Allen:

- Used historical and projected water consumption data provided by WaterNSW to estimate demand for electricity required to operate the pipeline. As this review focuses on electricity prices, we have not reviewed ACIL Allen’s demand forecasts.
- Utilised a range of in-house models and in-house assumptions to estimate wholesale electricity costs, including running a range of scenarios of alternative hedging positions to select the most appropriate strategy.
- Drew on publicly available data to estimate other components of the electricity cost, including the costs associated with the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES).

3.3.2 Assessment

In our view, ACIL Allen’s approach is reasonable. In particular, the estimation of electricity purchasing costs by estimating wholesale purchase costs and adding other components of retail charges is an appropriate methodology. We adopt this broad approach to estimate a benchmark energy price in the next section.

However, we do make a number of observations about aspects of ACIL Allen’s approach and assumptions:

- ACIL Allen uses input assumptions developed around the start of the year, when they commenced their modelling. As a result, a number of the input assumptions that they use may no longer be the most recent data available. For example, the wholesale price forecasting analysis adopts demand forecasts from the Australian Energy Market Operator (AEMO) that have since been updated, and will not have the most recent information on newly committed generation plant.
- Many of the input assumptions adopted in ACIL Allen’s wholesale price forecasting are in-house input assumptions. In many cases there is little information provided on how these inputs are developed, and thus it is difficult to assess the appropriateness of the assumptions. To the extent

that there is an industry-standard set of input assumptions it is those that are provided by AEMO as part of its modelling work. We also note that these input assumptions from AEMO – developed as part of its Integrated System Plan – have been released more recently than ACIL Allen's input assumptions were developed.

- ACIL Allen's analysis does not determine the efficient hedging position, but rather, it tests a large number of alternative hedging positions to identify one potentially efficient strategy. It is possible that ACIL Allen's approach overlooks preferable combinations of hedging contracts.
- ACIL Allen's analysis takes a two-year rolling average of ASX Energy prices to estimate contract prices. In our view, estimating contract prices based on their mark-to-market value provides a better measure of the current value of contracts.

We consider that each of these matters has the potential to affect ACIL Allen's estimate of electricity costs.

4 ESTIMATING A BENCHMARK ENERGY PRICE

This Section presents our estimate of efficient electricity costs for WaterNSW for the pipeline. Our approach is to consider the costs that an electricity retailer would face in supplying electricity to WaterNSW for the pipeline. These costs are:

- Wholesale electricity costs
- Renewable energy policy costs
- Costs of complying with environmental policies (including the NSW ESS and the Climate Change Fund)
- Market fees and ancillary services costs
- Network costs
- Energy losses
- Retail operating cost and margin.

Unless otherwise specified, our results are reported in real dollars ($2018-19).

4.1 Pipeline load

A key driver of the electricity purchase costs will be the electricity load of the pipeline. To determine the electricity purchase costs for WaterNSW's pipeline pumping load, a half-hourly load profile must be derived and combined with the appropriate half-hourly prices.

IPART provided us with weekly load profiles for the pipeline, as well as information on minimum and maximum pumping loads. IPART provided us with three sets of weekly load profiles, corresponding to different climatic conditions: median rainfall, high rainfall and low rainfall. For each of these three sets of weekly load profiles we derived a half-hourly load profile that is consistent with this information. The key assumptions that we used to disaggregate the load profile to a half-hourly profile include the following:

- The minimum load for any half-hour is 0.2663 MW.
- A maximum load for any half-hour is 2.60 MW.
- Pumping to meet total annual requirements is scheduled to first occur during off-peak times.
- If this is not sufficient to meet total annual requirements, then pumping is next scheduled to occur during shoulder times.
- Lastly, pumping is scheduled to occur in peak times if necessary.

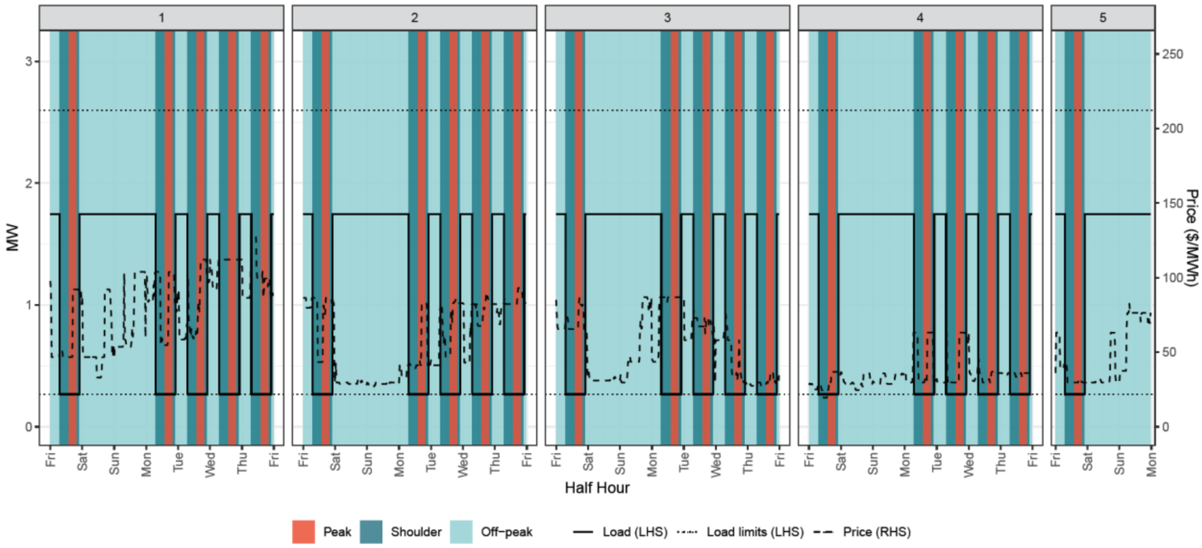
In **Figure 1** a typical load profile is given for July for the median rainfall scenario. The numbers at the top of each panel indicate the week of the year. Load is given by the black solid line and electricity spot prices by the dashed line. The minimum and maximum loads are given by the horizontal dotted lines. The shaded areas represent off-peak, shoulder and peak times.

It is apparent from **Figure 1** that in the median rainfall scenario all the required weekly pumping can take place in off-peak periods, and that to do so does not even require load to approach the maximum load of 2.6 MW. The only load during shoulder and peak periods is the minimum load of 0.2663 MW.

Figure 2 and **Figure 3** show the same data for the high rainfall and low rainfall scenarios, respectively. In the high rainfall case all required pumping can take place during off-peak periods, the only real difference to the median case is that the off-peak load that is required to meet the required total weekly pumping is lower (because less pumping occurs with high rainfall). In the low rainfall case pumping occurs in both the off-peak periods and shoulder periods (because more pumping occurs with low rainfall). The reason that pumping occurs in should periods is not that the amount of off-peak pumping exceeds the maximum half-hourly load of 2.6 MW; rather, the off-peak pumping exceeds a total weekly off-peak pumping limit that equates to 1.949 MW on average, which IPART has informed us also binds pumping in off-peak periods. This means that some electricity load above minimum load occurs in shoulder periods in the low rainfall scenario.

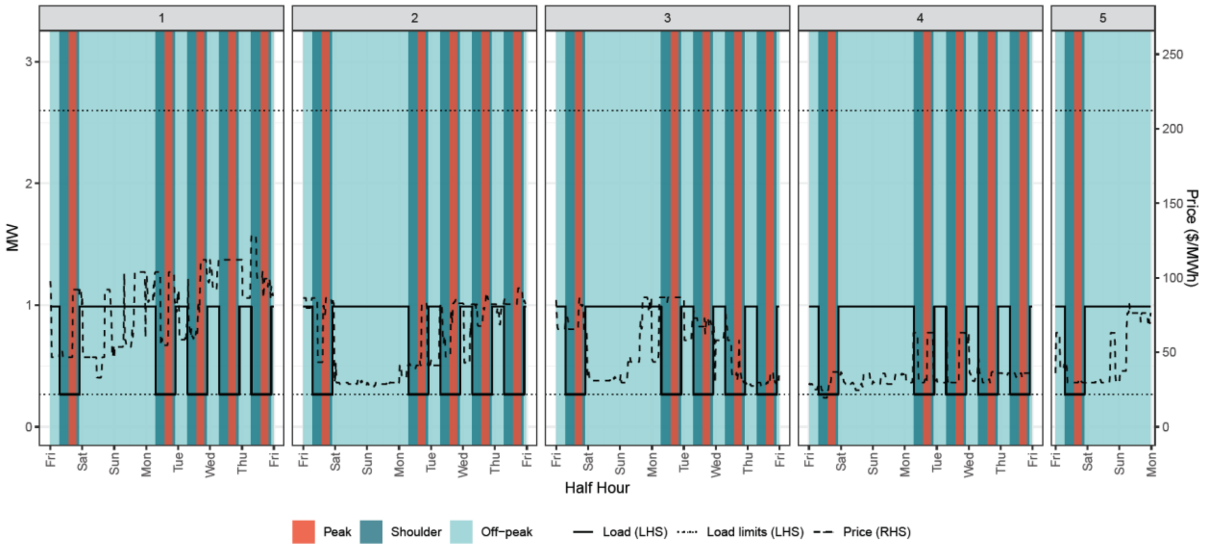
Given that the weekly pumping data provided by IPART does not change from week to week, or over the years of the determination, these weekly patterns shown in **Figure 1** through **Figure 3** are representative of all weeks during the determination period.

Figure 1: Typical load profile given for July 2019 – median rainfall



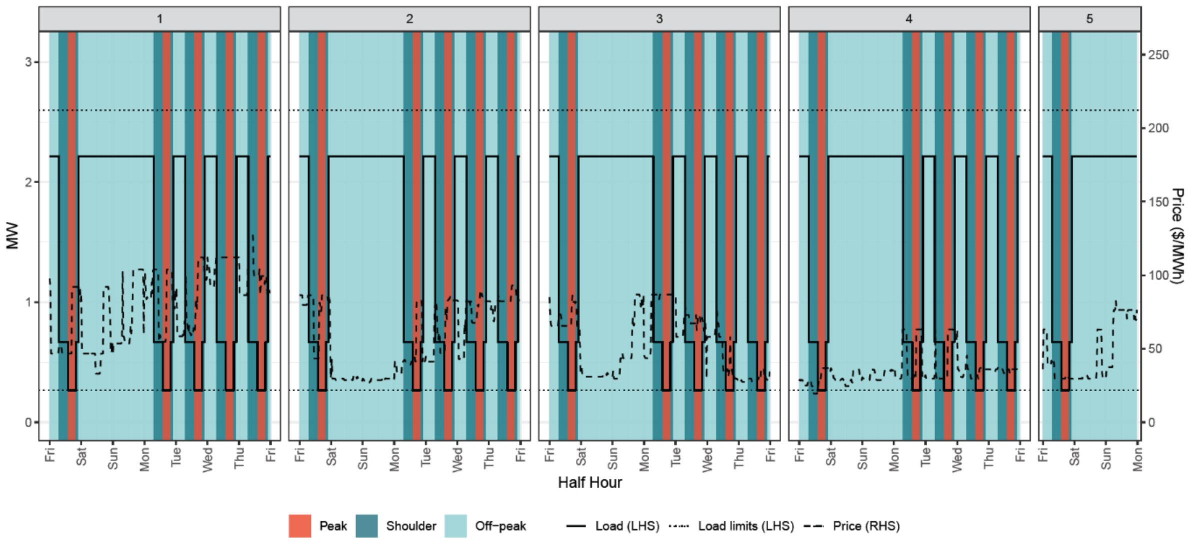
Source: Frontier Economics

Figure 2: Typical load profile given for July 2019 – high rainfall



Source: Frontier Economics

Figure 3: Typical load profile given for July 2019 – low rainfall



Source: Frontier Economics

4.2 Wholesale electricity costs

We apply a market modelling approach to estimating wholesale electricity costs in the NEM (which includes Queensland, South Australia, New South Wales, the ACT, Tasmania and Victoria). This section discusses our approach to estimating wholesale electricity costs.

4.2.1 Market-based approach

The market-based approach to determining the wholesale electricity cost to meet a load involves two steps:

- First, a forecast of wholesale market prices is required. In a market-based approach, this forecast of wholesale market prices should have regard to bidding behaviour of market participants and actual supply and demand conditions in the market.
- Second, a forecast of the cost of purchasing electricity to meet the pipeline load is required. In a market-based approach this forecast of the cost of purchasing electricity should include the cost of purchasing hedging contracts for the purposes of risk management. The forecast cost of purchasing electricity can be based on a forecast of contract prices (typically tied to forecast spot prices) or publicly available contract prices (such as the published prices of ASX Energy contracts).

In order to properly estimate the wholesale electricity cost faced by WaterNSW, it is important to ensure that the risk of meeting their load is accurately captured in the modelling approach. Key to this is ensuring that the assumed load shape is correctly correlated to pool price outcomes. Given these inputs – accurately correlated spot prices and pumping load – a framework for quantifying the trade-off between risk and reward, and ultimately determining an optimal hedging position and associated wholesale supply costs is required.

In order to achieve forecast prices for WaterNSW’s pumping load, we model long-term investment outcomes in NSW and the rest of the NEM using our long-term optimisation model, *WHIRLYGIG*. This long-term investment is then used to forecast prices on a half-hourly level, using *SYNC*. These half-hourly prices are then fed into our portfolio optimisation model – *STRIKE* – to determine the cost of wholesale electricity.

4.2.2 Modelling expected investment outcomes

WHIRLYGIG is a long-term investment model for electricity markets, which relies on a detailed representation of the electricity system and, based on this, optimises total generation cost in the electricity market, calculating the least cost mix of existing generation plant and new generation plant options to meet demand. The model incorporates policy or regulatory obligations facing the generation sector, such as a renewable energy target, and calculates the cost of meeting these obligations. *WHIRLYGIG* provides a forecast of the least cost investment path as well as least cost dispatch. *WHIRLYGIG* provides an estimate of the long run marginal cost (LRMC) of electricity and the marginal cost of meeting any policy obligations. An overview of *WHIRLYGIG* is provided in **Figure 4**.

WHIRLYGIG includes a representation of demand and supply conditions in each of the regions of the NEM, including the capacity of interconnectors between the regions. *WHIRLYGIG* does not include existing intra-regional network constraints, largely because there is no robust way to forecast these network constraints in the long-term without detailed network modelling undertaken by the transmission network service providers. *WHIRLYGIG* models outcomes in the electricity market, but does not jointly model outcomes in markets for ancillary services.

Figure 4: *WHIRLYGIG* Schematic

Source: Frontier Economics

In order to model long-term investment and retirement decisions over the long-term, *WHIRLYGIG* models 54 representative demand points for each year, rather than the full 17,520 half hours of the year. *WHIRLYGIG* also models additional demand points that represent peak demand outcomes for a 1-in-10 year (POE10). These representative demand points are defined to capture a diverse range of outcomes for demand (ensuring we account for periods of high demand), solar PV generation and wind generation (ensuring we account for periods of low generation) across seasons. *WHIRLYGIG* includes dispatch of the power system for each one of these 54 representative demand points for each year, to ensure demand can be met at each point, having regard to the level of intermittent generation for that point.

Nevertheless, it is clear that modelling sequential half-hourly outcomes is important for a robust assessment of dispatch and prices in the context of a generation mix that increasingly consists of variable wind and solar generation and storage. For this reason, we model dispatch and pricing making use of our half-hourly dispatch model – *SYNC*.

To undertake our *WHIRLYGIG* modelling we populate the model with a set of input assumptions from AEMO's Integrated System Plan[11] and from AEMO's Electricity Statement of Opportunities.[12]

The key exception to this is coal price forecasts. The current coal prices forecasts for NSW generators from AEMO's ISP have coal prices of around $1.50/GJ for Bayswater and Liddell and between $2.00/GJ and $2.50/GJ for Mt Piper, Vales Point and Eraring. However, based on current international coal prices, the net-back price of coal to these power stations is estimated to be between $3.00/GJ and $3.50/GJ.

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[11] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

[12] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

An analysis of recent bidding by these power stations into the NEM suggests that their marginal cost is indeed much more consistent with a net-back price between $3.00/GJ and $3.50/GJ than it is with a coal price between $1.50/GJ and $2.50/GJ.

4.2.3 Modelling expected dispatch and price outcomes

We model dispatch and wholesale price outcomes in NSW and the rest of the NEM using our electricity market dispatch model, *SYNC*. *SYNC* is an electricity market dispatch model that focuses on detailed short-term (half-hourly or less) fluctuations in demand, supply and system constraints. *SYNC* relies on a detailed representation of the electricity system and, based on this, determines market-clearing dispatch and pricing outcomes. *SYNC* makes use of investment outcomes modelled in *WHIRLYGIG* and uses a long-term forecast of bidding patterns. The model focuses on factors that affect short term price fluctuations and volatility in the wholesale market. These include half-hourly fluctuations in demand and intermittent wind and solar generation, ramping constraints as well as start-up costs of different technologies. *SYNC* provides a dispatch and wholesale price forecast at a half-hourly level. In this way we are able to provide a forecast of the prices WaterNSW will incur over the modelling period. An overview of *SYNC* is provided in **Figure 5**.

Figure 5: *SYNC* schematic

Source: Frontier Economics

SYNC includes a representation of demand and supply conditions in each of the regions of the NEM, including interconnectors between the regions. Like *WHIRLYGIG*, *SYNC* does not include existing intra-regional network constraints, largely because there is no robust way to forecast these network constraints in the long-term without detailed network modelling undertaken by the transmission network service providers. *SYNC* models outcomes in the electricity market, but does not jointly model outcomes in markets for ancillary services.

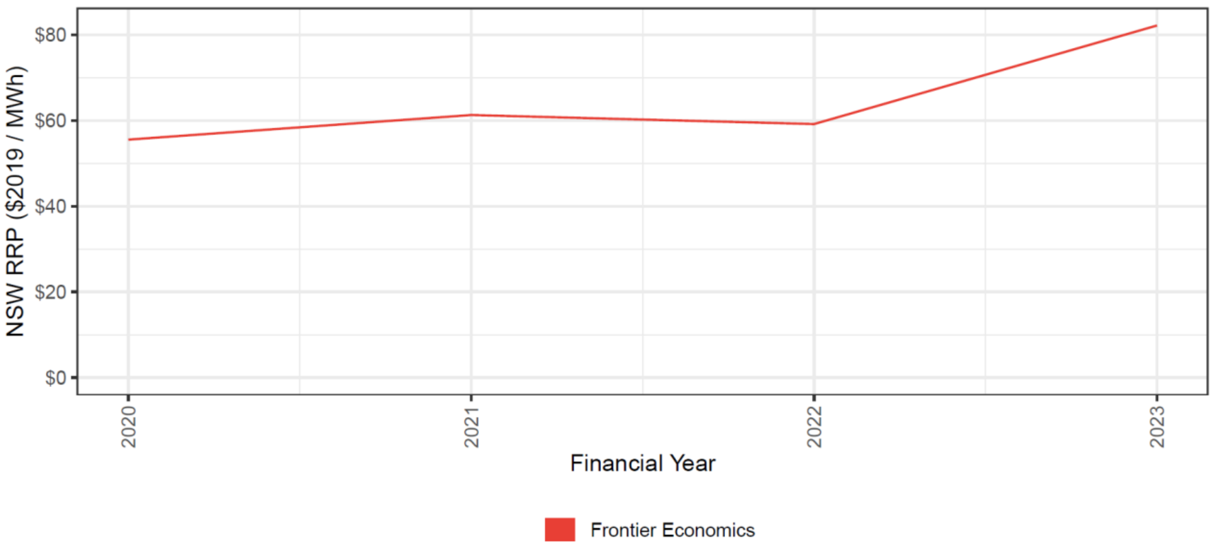
Once we have modelled *SYNC*, we test whether the results are consistent with the investment outcomes in *WHIRLYGIG* and, if not, adjust our *WHIRLYGIG* modelling accordingly and repeat our modelling process.

We note that this sequential modelling approach – with investment decisions modelled in a long-term model with a simplified demand duration curve and dispatch and wholesale prices modelled in a half-hourly dispatch model – is consistent with the modelling framework adopted by AEMO for its Integrated System Plan.

To undertake our *SYNC* modelling we populate the model with the same set of input assumptions used in *WHIRLYGIG* – which are sourced from AEMO's Integrated System Plan and from AEMO's Electricity Statement of Opportunities, but with adjusted coal price forecasts as discussed above.

The wholesale spot price outcomes in NSW that are forecast in *SYNC* are shown in **Figure 6**. These wholesale spot prices are referred to as the Regional Reference Price (RRP). These forecast wholesale price outcomes are materially lower than current prices in NSW. The reason for this is that our modelling incorporates significant investment in new generation plant – primarily renewable generation plant – over coming years, driven by the LRET and jurisdictional renewable energy targets. This increase in generation capacity (most of which has a short run marginal cost that is effectively zero) outstrips forecast growth in demand, resulting in lower prices. The increase in forecast wholesale prices in 2022/23 is a result of the planned retirement of Liddell power station in NSW.

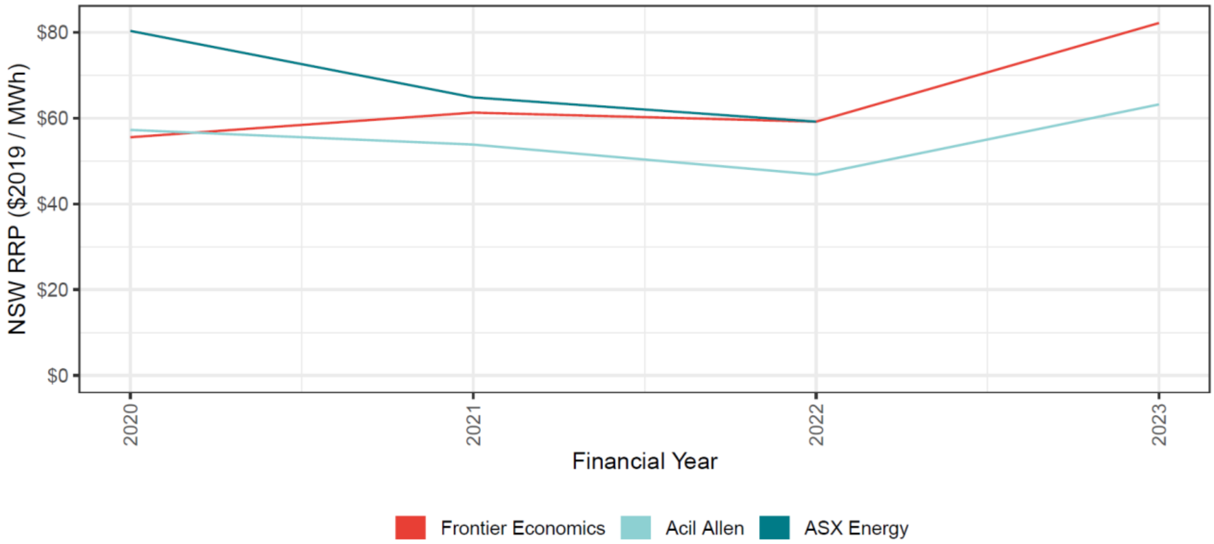
Figure 6: Forecast wholesale prices in NSW



Source: Frontier Economics

Our forecast wholesale price outcomes are compared with forecast wholesale prices from ACIL Allen's report for WaterNSW and with ASXEnergy swap prices (on 22 January 2019) in **Figure 7**. Compared with the price forecasts from ACIL Allen, our forecasts for 2019/20 are about the same, but our forecasts for subsequent years are increasingly higher than ACIL Allen's. Compared to ASXEnergy, our forecasts are materially lower in 2019/20, but are quite comparable for 2020/21 and 2021/22.

Figure 7: Forecast wholesale prices in NSW, compared with ACIL Allen and ASXEnergy



Source: Frontier Economics, ACIL Allen and ASXEnergy

4.2.4 Modelling energy purchase costs

To meet its pumping load for the pipeline, WaterNSW has taken the decision to enter into an electricity supply agreement with an electricity retailer. In a competitive market an electricity retailer supplying WaterNSW would be expected to set a retail price to WaterNSW that reflects the cost to the retailer of purchasing wholesale energy to meet WaterNSW's pumping load. This retailer would likely enter into hedging contracts to minimise its exposure to large fluctuations in wholesale electricity prices. The cost to the retailer of purchasing wholesale energy to meet WaterNSW's pumping load will then reflect the costs associated with this hedging position.

In order to determine the energy purchase costs associated with WaterNSW's pumps, we calculate an efficient hedging position and the cost of that hedging position. This hedging position is determined by using Frontier Economics' portfolio optimisation model, *STRIKE.*

STRIKE is a model that uses portfolio theory to find the best mix (portfolio) of available electricity purchasing options. This model can be used to determine the additional cost of meeting a load. In this case, we use this model to estimate the costs of supplying the pipeline load. We assume that, to hedge their position in the electricity market, a retailer to WaterNSW is able to buy quarterly baseload swaps, peak swaps or baseload caps (which are the principal contracts traded on ASXEnergy).

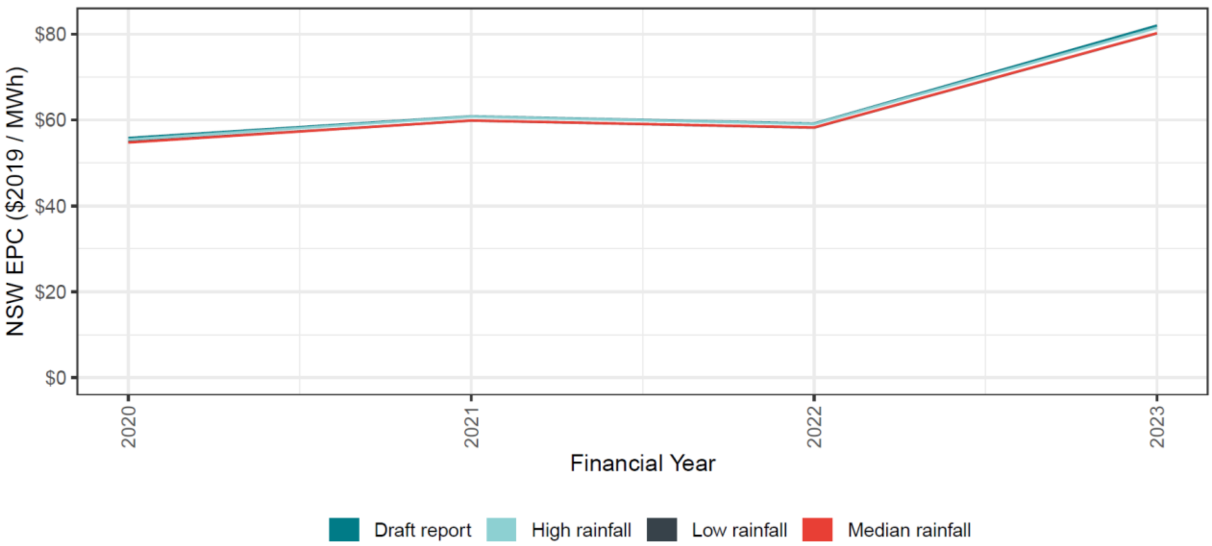
STRIKE determines an efficient hedging position, and the cost of that hedging position, by making use of the following inputs:

- The forecast half-hourly load for the pipeline that we developed (as discussed in Section 4.1).
- The forecast half-hourly wholesale electricity prices from *SYNC* (as discussed in Section 4.2.3).

- Estimates of prices for swap and cap contracts that are based on forecast half-hourly wholesale electricity prices from *SYNC*, and include an assumed contract premium of 5% relative to forecasts spot prices.

The results estimates of the energy purchase cost for WaterNSW – for each of the three scenarios used for this final report, and for the single scenario from the draft report, for the purposes of comparison – are shown in **Figure 8**. These energy purchase costs follow a very similar pattern to the wholesale spot prices that we forecast – this is based the forecast load profile is not changing over time so it is only changes in wholesale spot prices (and, by extension, contract prices) that change from year to year. The energy purchase costs for each of the scenarios are also very similar – this is because in all cases the majority of electricity load is modelled to occur during off-peak half-hours, so the average price is very similar. In the median and high rainfall cases the only electricity load that occurs in shoulder or peak periods is the minimum load; the prices for these cases differ only because the greater off-peak pumping requirement in the median case brings down the average cost of electricity. In the low rainfall case, the average cost is almost identical to the average cost in the median case: while greater off-peak pumping in the low rainfall case does bring down the average cost, the need also to undertake shoulder period pumping brings the average cost back up.

Figure 8: Energy purchase cost for WaterNSW – three final report scenarios and draft report

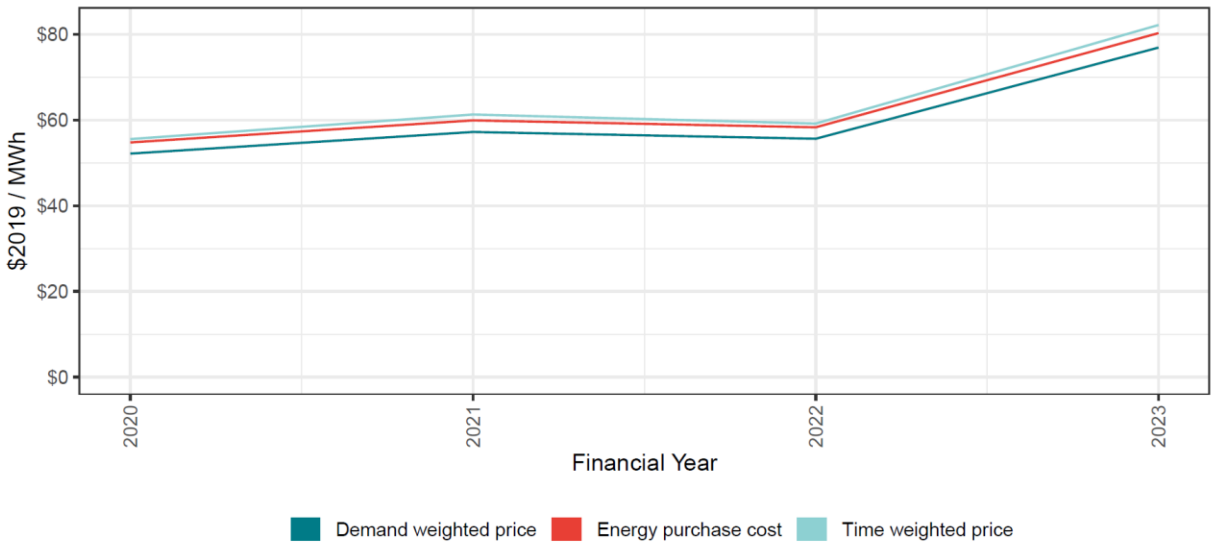


Source: Frontier Economics

Figure 9 through **Figure 11** show the same energy purchase costs derived from *STRIKE* for the three scenarios we have modelled. These figures also compares the energy purchase cost to the wholesale electricity price for NSW (the time-weighted average price) and the load-weighted price for the load.

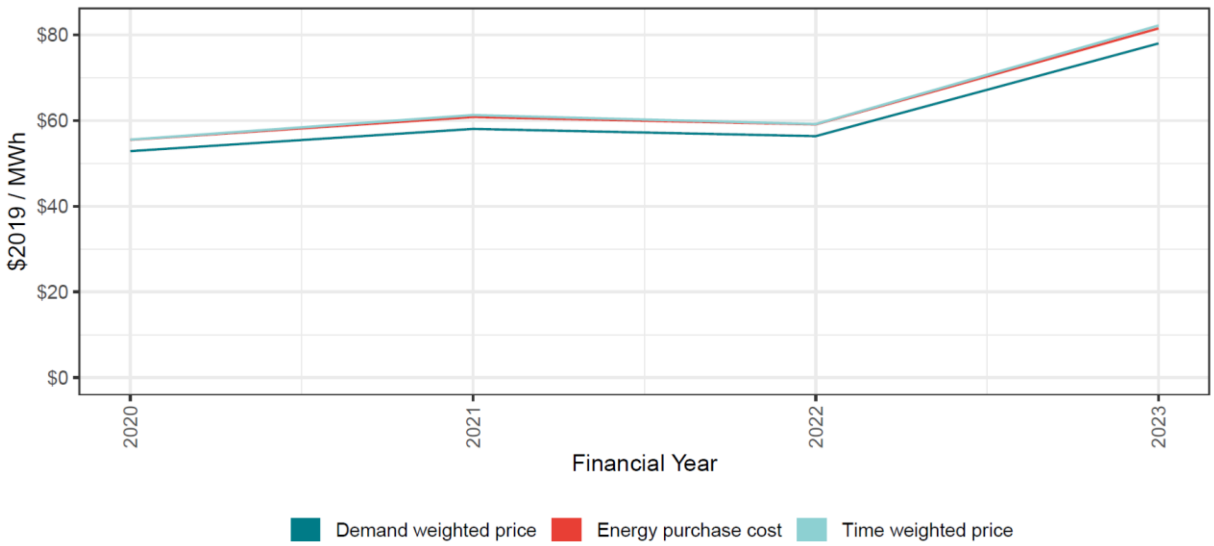
The load-weighted price is lower than the time-weighted average price because pumping can occur during off-peak periods, when the average price tends to be lower. The energy purchase cost is very close to the time-weighted average price, but noticeably higher than the load-weighted average price; this higher cost of hedging, compared with the load being exposed to the spot market, provides for lower price risk for the retailer to WaterNSW. The difference between the annual average cost of hedging and the demand-weighted price is only relatively small because the load is not particularly volatile, making it cheaper to effectively hedge.

Figure 9: Electricity purchase costs for WaterNSW median rainfall case, compared with NSW regional reference price



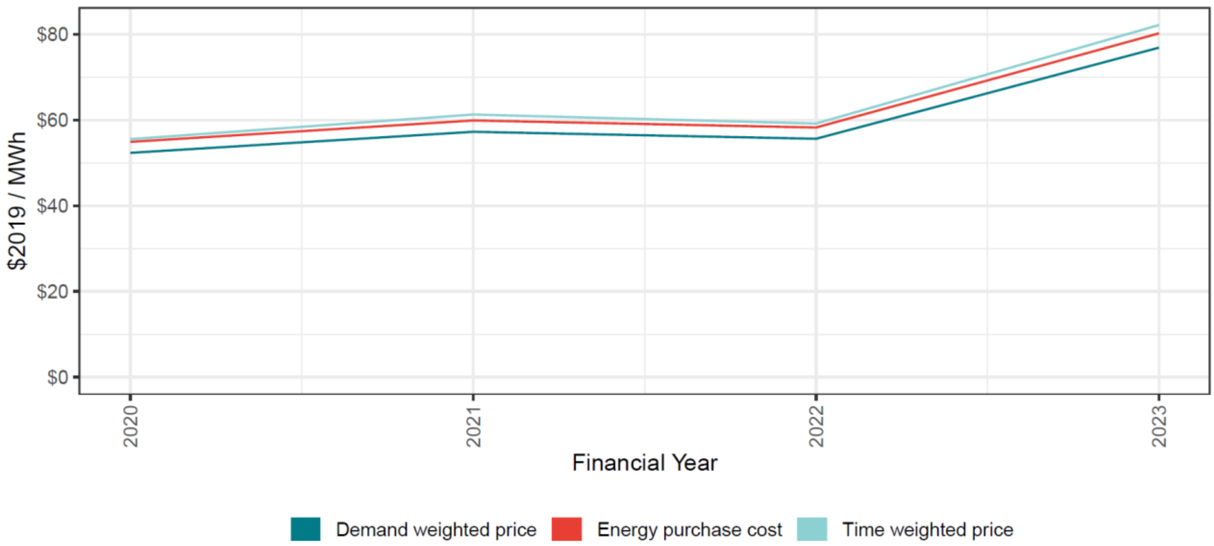
Source: Frontier Economics

Figure 10: Electricity purchase costs for WaterNSW high rainfall case, compared with NSW regional reference price



Source: Frontier Economics

Figure 11: Electricity purchase costs for WaterNSW low rainfall case, compared with NSW regional reference price



Source: Frontier Economics

More detail about the contract position that underlies these estimates of energy purchase cost is provided in Appendix A.

4.3 Renewable energy policy costs (LRET and SRES)

An electricity retailer supplying WaterNSW to meet its pumping load for the pipeline must incur costs associated with complying with green schemes, including the costs of complying with the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). This section presents our approach to estimating costs of complying with the LRET and SRES.

Since these costs are driven by annual obligations based on annual consumption, rather than by half-hourly load, the average cost (in $/MWh) of complying with these schemes does not differ across the scenarios.

4.3.1 Cost of complying with the LRET

The LRET places a legal liability on wholesale purchasers of electricity to proportionately contribute towards the generation of additional renewable electricity from large-scale generators. Liable entities support additional renewable generation through the purchase of Large-scale Generation Certificates (LGCs). The number of LGCs to be purchased by liable entities each year is determined by the Renewable Power Percentage (RPP), which is set each year by the Clean Energy Regulator. LGCs are created by eligible generation from renewable energy power stations.

In order to calculate the cost to a retailer to WaterNSW of complying with the LRET, it is necessary to determine the RPP for the retailer (which determines the number of LGCs that must be purchased) and the cost of obtaining each LGC. **Table 4** outlines the cost of complying with the LRET, with the following sections providing additional detail around our approach.

Table 4: Cost of complying with the LRET – based on market price of LGC ($/MWh, $2018-19)

	2019-20	2020-21	2021-22	2022-23
Cost of complying with the LRET	$6.18	$3.75	$2.38	$0.41

Source: Frontier Economics

Renewable Power Percentage

The RRP establishes the rate of liability under the LRET and is used by liable entities to determine how many LGCs they need to surrender to discharge their liability each year. The RPP is set to achieve the renewable energy targets specified in the legislation. The Clean Energy Regulator is responsible for setting the RPP for each year, with the RPP for 2018 set at 16.06 per cent.

The *Renewable Energy (Electricity) Act* 2000 states that where the RPP for a year has not been determined it should be calculated as the RPP for the previous year multiplied by the required GWh's of renewable energy for the current year divided by the required GWh's of renewable energy for the previous year. This calculation increases the RPP in line with increases in the renewable energy target but does not decrease the RPP to account for any growth in demand. As a result, this calculation is likely to overestimate the RPP for a given year when energy demand is growing.

We have used the published RRP for 2018 (16.06%) to perform the default calculations for the RPP for 2019 to 2023. These values are set out in **Table 5**.

Table 5: Renewable Power Percentages

	2019	2020	2021	2022	2023
RPP (% of liable acquisitions)	17.52%	18.98%	18.51%	18.51%	18.51%

Source: Clean Energy Regulator; Frontier Economics

As shown in **Table 6**, to convert the values to financial year we have taken the arithmetic average.

Table 6: Renewable Power Percentages (FY)

	2019-20	2020-21	2021-22	2022-23
RPP (% of liable acquisitions)	18.25%	18.75%	18.51%	18.51%

Source: Clean Energy Regulator; Frontier Economics

Cost of obtaining LGCs

The cost to a retailer of obtaining LGCs can be determined either on the basis of the resource costs associated with creating LGCs, or on the basis of the market price at which LGCs are traded.

For this report, we have used a market price for LGCs to determine the cost of complying with the LRET. Our current modelling indicates that the marginal resource cost associated with creating additional LGCs is zero. The reason for this is that our modelling indicates that there is sufficient existing and committed renewable generation to more than meet the current LRET, so that a marginal increase in that target will not require any additional investment in renewable generation or any additional cost. If the estimate of the cost of complying with the LRET were based on estimated resource costs, therefore, that cost of complying would also be zero.

The market price for LGCs is determined by the current price of LGCs reported by Mercari.[13] **Table 7** outlines the 40-day average LGC futures price.

There are a number of reasons potential reasons that these market prices are higher than are estimates of resource costs, including different views on the number of LGCs that are likely to be generated by existing of committed renewable generation, the number of LGCs that are likely to be voluntarily surrendered or the willingness of holders of excess LGCs to transact those LGCs.

Table 7: 40-day average LGC futures price from Mercari Rates ($/certificate, $2018/19)

	2019-20	2020-21	2021-22	2022-23
40-day average LGC futures price	$33.84	$19.99	$12.85	$2.24

Source: Mercari Rates

4.3.2 Cost of complying with the SRES

The SRES places a legal liability on wholesale purchasers of electricity to proportionately contribute towards the costs of creating small-scale technology certificates (STCs). The number of STCs to be purchased by liable entities each year is determined by the Small-scale Technology Percentage (STP), which is set each year by the Clean Energy Regulator. STCs are created by eligible small-scale installations based on the amount of renewable electricity produced or non-renewable energy displaced by the installation.

Liable entities can purchase STCs on the open market or through the STC Clearing House. There is a guaranteed price of $40/STC through the Clearing House, but certificates may take some time to clear, delaying payment to sellers of STCs.

In order to calculate the cost to a retailer to WaterNSW of complying with the SRES, it is necessary to determine the STP for the retailer (which determines the number of STCs that must be purchased) and the cost of obtaining each STC. In broad terms, the cost to a retailer of complying with the SRES is the STP multiplied by the cost of STCs. **Table 8** outlines the cost of complying with the SRES, with the following sections providing additional detail around our approach.

13 Mercari (2018), http://lgc.mercari.com.au/, accessed 30th January 2019.

Table 8: Cost of complying with the SRES ($/MWh, $2018-19)

	2019-20	2020-21	2021-22	2022-23
Cost of complying with the SRES	$4.62	$4.40	$4.29	$4.19

Source: Frontier Economics

Small-scale Technology Percentage

The STP establishes the rate of liability under the SRES and is used by liable entities to determine how many STCs they need to surrender to discharge their liability each year.

The STP is determined by the Clean Energy Regulator and is calculated as the percentage required in order to remove STCs from the STC Market for the current year liability. The STP is calculated in advance based on:

- the estimated number of STCs that will be created for the year
- the estimated amount of electricity that will be acquired for the year
- the estimated number of all partial exemptions expected to be claimed for the year

The STP is to be published for each compliance year by March 31 of that year. The Clean Energy Regulator must also publish a non-binding estimate of the STP for the two subsequent compliance years by March 31. The non-binding STPs for 2019 and 2020 published by the Clean Energy Regulator are set out in **Table 9**. After 2020, we have assumed that the STP remains constant at the 2020 level.

Table 9: Small-scale Technology Percentages

	2019*	2020*	2021*	2022*	2023*
STP (% of liable acquisitions)	12.13%	11.55%	11.55%	11.55%	11.55%

Source: Clean Energy Regulator

**Non-binding*

As shown in **Table 6**, to convert the values to financial year we have taken the arithmetic average.

Table 10: Small-scale Technology Percentages (FY)

	2019-20	2020-21	2021-22	2022-23
RPP (% of liable acquisitions)	11.84%	11.55%	11.55%	11.55%

Source: Clean Energy Regulator; Frontier Economics

Cost of STCs

For this report, we assume that the cost of STCs is equal to this STC Clearing House price of $40 ($nominal) as set out in **Table 11**.

Historically, the reported spot price of STCs has typically been at, or close to, this price of $40.

Table 11: STC costs ($/certificate, $2018-19)

	2019-20	2020-21	2021-22	2022-23
Cost of STCs	$39.02	$38.07	$37.14	$36.24

Source: Frontier Economics

4.4 Costs of complying with jurisdictional environmental policies

Legislation requires electricity businesses to comply with the NSW Energy Savings Scheme (ESS) and the Climate Change Fund (CCF). In particular:

- The ESS places an obligation on electricity retailers to obtain and surrender Energy Savings Certificates (ESC). Liability under the scheme is set as a fixed percentage of electricity sales for which ESCs need to be surrendered in each calendar year, as legislated under the *Electricity Supply Act* 1995 No. 94.
- The CCF was established by the NSW Government to support energy and water savings initiatives. It is mostly funded from the NSW electricity distribution network service providers, which pass on the costs to consumers through distribution network prices. The network tariffs discussed in Section 4.6 include the amount for the CCF.

The Australian Energy Market Commission's (AEMC) annual Residential Electricity Price Trends forecasts the expected cost of complying with environmental policies. We have used these estimates from the AEMC and assumed that the cost of complying with the ESS remains constant in real terms from 2020. The AEMC does not discuss its approach to estimating the costs of the ESS in its 2017 Price Trends Report. In its 2016 Price Trends Report the AEMC state that the estimates were provided by the NSW Government.

Table 12: Cost of complying with environmental policies ($/MWh, $2018-19)

	2019-20	2020-21	2021-22	2022-23
Cost of complying with the ESS	$4.10	$4.10	$4.10	$4.10

Source: Australian Energy Market Commission, 2017 Residential Electricity Price Trends

Since these costs are driven by annual obligations based on annual consumption, rather than by half-hourly load, the average cost (in $/MWh) of complying with these schemes does not differ across the scenarios.

4.5 Market fees and ancillary services costs

An electricity retailer supplying WaterNSW to meet its pumping load for the pipeline will also face the cost of market fees and ancillary services costs. This section presents our approach to estimating market fees and ancillary services costs.

Since these costs are driven by annual obligations based on annual consumption, rather than by half-hourly load, the average cost (in $/MWh) of complying with these schemes does not differ across the scenarios.

4.5.1 Market fees

Market fees are charged to participants in the National Energy Market (NEM) in order to recover the cost of operating the market, based on the budgeted revenue requirements of AEMO, and include fees for the following functions:

- NEM;
- FRC electricity;
- National Transmission Planner (NTP); and
- the recovery of costs for the Consumer Advocacy Panel (ECA).

Market fees for the coming financial year are set out in budget documents on AEMO's website.[14] These documents state that fees are expected to remain relatively constant in real terms over the period of the Determination. For that reason, we propose to use fees for 2018/19 as the basis for fees for each year of the Determination. These estimates are outlined in **Table 13**.

Table 13: Forecasted market fees ($/MWh, $2018-19)

	2018-19	2019-20	2020-21	2021-22	2022-23
NEM	$0.44	$0.44	$0.44	$0.44	$0.44
FRC-Electricity	$0.08	$0.08	$0.08	$0.08	$0.08
NTP	$0.02	$0.02	$0.02	$0.02	$0.02
ECA-Electricity	$0.01	$0.01	$0.01	$0.01	$0.01
Total market fees	**$0.55**	**$0.55**	**$0.55**	**$0.55**	**$0.55**

Source: AEMO (2018), Electricity Functions 2018-19 Final Budget and Fees; Frontier Economics.

4.5.2 Ancillary services costs

Ancillary services are those services used by AEMO to manage the power system safely, securely and reliably. Ancillary services can be grouped under the following categories:

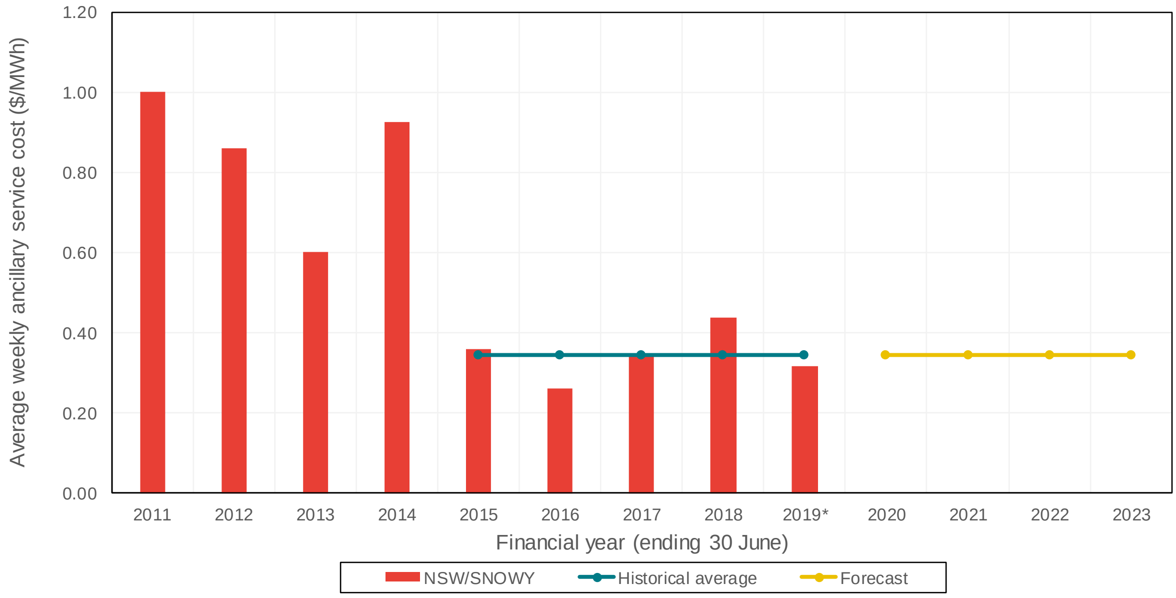
- Frequency Control Ancillary Services (FCAS) are used to maintain the frequency of the electrical system.
- Network Control Ancillary Services (NCAS) are used to control the voltage of the electrical network and control the power flow on the electricity network.
- System Restart Ancillary Services (SRAS) are used when there has been a whole or partial system blackout and the electrical system needs to be restarted.

[14] AEMO (2018), *Electricity functions 2018-19 AEMO Final Budget and Fees.*

AEMO operates a number of separate markets for the delivery of FCAS and purchases NCAS and SRAS under agreements with service providers and publishes historic data on ancillary services costs on its web site. To estimate the future cost of ancillary services, we have examined the past 9 years of ancillary service cost data published by AEMO for the New South Wales region of the NEM.

Typically, weekly ancillary services costs have been in the range of $0.25/MWh to $0.96/MWh. Outlined in **Figure 12** are average annual ancillary service costs by financial from 2011 to 2019.[15] Due to volatility in the historical ancillary service cost data for New South Wales over the past 9 years , we have used the arithmetic average over the past 5 years of data as the best estimate for ancillary service costs for the period of the Determination (as it appears that, recently, ancillary costs have fallen). These estimates are outlined in **Table 14**.

Figure 12: Historical ancillary service costs in New South Wales ($/MWh, $2018-19)



Source: AEMO, Frontier Economics Analysis

** Partially complete year of data*

Table 14: Ancillary service costs ($/MWh, $2018-19)

	2018-19	2019-20	2020-21	2021-22	2022-23
Ancillary service costs ($/MWh)	$0.34	$0.34	$0.34	$0.34	$0.34

Source: Frontier Economics

4.6 Network costs

Australian electricity networks, whether transmission or distribution, are considered to be natural monopolies. As such the network tariffs that retailers pay the network businesses for use of the networks

15 2019 is an incomplete year of data

are subject to economic regulation by the Australian Energy Regulator. The pipeline is located within Essential Energy's distribution network and information provided by the pipeline contractor indicates that the relevant Essential Energy network tariffs classes are BLND3AO and BHND3AO (see **Table 15**).

Table 15: Tariff classes

SUPPLY TYPE	SITE(S)	TARIFF	ESSENTIAL ENERGY DESCRIPTION
Low voltage	River Murray Pump Station	BLND3AO	LV ToU Demand 3 Rate
High voltage	Wentworth Pump Station Silver City Pump Station Bulk Water Storage	BHND3AO	HV ToU mthly Demand

Source: WaterNSW

Through using publicly available data on network tariffs we can estimate network costs that would be incurred by a retailer supplying WaterNSW. **Table 16** sets out the network use of service (NUOS) tariffs for tariff BLND3AO and tariff BHND3AO for Essential Energy's network area for 2018/19.

Table 16: NUOS Network tariffs in 2018-19 ($2018-19)

	NETWORK ACCESS ($/DAY)	ENERGY PEAK ($/KWH)	ENERGY SHOULDER ($/KWH)	ENERGY OFF PEAK ($/KWH)	DEMAND PEAK ($/KVA/M)	DEMAND SHOULDER ($/KVA/M)	DEMAND OFF PEAK ($/KVA/M)
BLND3AO	14.72	0.04	0.04	0.02	9.87	8.93	2.15
BHND3AO	18.23	0.03	0.03	0.02	8.66	7.83	2.34

Source: Essential Energy – Network Price List

Note NUOS tariffs include jurisdictional scheme charges

We have calculated network costs by applying these network tariffs to the forecasts of pumping load with which we have been provided. Since these tariffs have peak, shoulder and off-peak components, and demand components, the total cost to a retailer to WaterNSW of NUOS charges will depend on half-hourly load and will, therefore, differ across the three scenarios.

Recognising that there are two relevant network tariffs, using information provided by Trility[16] we have calculated the demand-weighted average network costs for 2018-19. In particular, we have assumed that demand associated with the River Murray Pumping Station is on the low-voltage tariff (BLND3AO) and demand at the Wentworth and Silver City Pumping Station and the Bulk Water Storage is on the high-voltage tariff (BHND3AO).

Given the uncertainty around future tariffs,[17] we have assumed they increase with inflation (assumed to be equal to 2.5%) (see **Table 17**).

[16] See Trility (2018), *20180415 W2BH BWS outflow Energy kVA Demand Calculator V2_150418*.

[17] Including uncertainty around the appeal of exiting revenue determinations.

Table 17: Network costs ($2018-19)

	2018-19	2019-20	2020-21	2021-22	2022-23
Network access charge ($/day)	17.92	17.92	17.92	17.92	17.92
Energy Peak (cents/kWh)	3.13	3.13	3.13	3.13	3.13
Energy shoulder (cents/kWh)	2.84	2.84	2.84	2.84	2.84
Energy off peak (cents/kWh)	2.27	2.27	2.27	2.27	2.27
Demand peak (cents/kVA/M)	873.94	873.94	873.94	873.94	873.94
Demand shoulder (cents/kVA/M)	790.71	790.71	790.71	790.71	790.71
Demand off peak (cents/kVA/M)	233.08	233.08	233.08	233.08	233.08

Source: Frontier Economics

4.7 Energy losses

The estimated energy purchase costs are referenced to the New South Wales Regional Reference Node (RRN) and, therefore, must be adjusted to account for transmission and distribution losses associated with transmitting electricity from the RRN to the end-user using Distribution Loss Factors (DLF) and Transmission Loss Factors (TLF). DLFs for the Essential Energy zone and marginal loss factors (MLF) for Broken Hill (NSW) and Red Cliffs (VIC) (to derive TLFs) for 2018-19 are available on AEMO's website.[18]

As there are two relevant connection points we have used information provided by Trility[19] to calculate the demand-weighted average TLF.

As shown in **Table 18**, we have assumed that the DLF and TLF remain constant throughout the Determination period.

Table 18: Distribution and transmission losses

	2018-19	2019-20	2020-21	2021-22	2022-23
Distribution loss factor	1.07	1.07	1.07	1.07	1.07
Transmission loss factor	1.02	1.02	1.02	1.02	1.02

Source: AEMO

[18] See AEMO (2018), *Distribution Loss Factors for the 2018/2019 Financial Year*; AEMO (2018), *2018-19 MLF Applicable from 01 July 2018 to 30 June 2019 – updated 11 July 2018*.

[19] See Trility (2018), *20180415 W2BH BWS outflow Energy kVA Demand Calculator V2_150418*.

4.8 Retail operating cost and margin

An electricity retailer supplying WaterNSW to meet its pumping load for the pipeline will incur retail operating costs (ROC) and must cover its retail margin.

ROC are the costs associated with services provided by a retailer to its customers, which typically include billing and revenue collection costs, call centre costs, customer information costs, corporate overheads, energy trading costs, regulatory compliance costs and marketing costs.

The retail margin represents the return to investors for retailers' exposure to systematic risks associated with providing retail electricity services. The margin can also include other costs incurred by retailers, such as depreciation, amortisation, interest payments and tax expense.

There is limited publicly available information to determine appropriate ROC and retail margin allowances for large customers because regulators in most jurisdictions only determine retail electricity prices for small customers. As shown in **Table 19**, in the last Determination Period the Queensland Competition Authority (QCA) (which regulates retail electricity prices for large customers consuming more than 4 GWh per year) set an allowance for ROC and the retail margin that is fixed for large customers, equal to $2,159 ($2015-16) (adjusted for inflation) and a variable allowance of 5.7% of all variable costs. In its 2013 Review of Regulated Retail Prices for Electricity, IPART determined a regulated ROC and retail margin for customers consuming less than 100 MWh per year, equal to $110 ($2012-13) per customer and 5.7% of total cost, respectively.

In addition, Frontier Economics analysis conducted for the Western Australian Office of Energy in 2009 and the Economic Regulation Authority (ERA) in 2012 suggests that the cost of servicing larger customers was significantly higher than the cost of servicing smaller customers. This cost difference was based on the higher costs of marketing, account management and pricing of large customer loads.[20]

As such, in line with the QCA's most recent decision, we have adopted a fixed ROC and retail margin allowance of $2,279.60 ($2018-19) and a variable ROC and retail margin allowance of 6.04% of total variable costs, across the Determination Period.[21]

[20] Frontier Economics (2012), *Retail Operating Costs*, report prepared for the Economic Regulation Authority of Western Australia, February 2012.

[21] An allowance of 6.04% applied to all charges, produces a ROM of 5.70%, consistent with the approach adopted by QCA in its most recent decision.

Table 19: Overview of recent decisions around ROC and retail margin

DECISION	REGULATORY PERIOD	ROC ALLOWANCE ($/CUSTOMER)	RETAIL MARGIN	ROC AND RETAIL MARGIN (FIXED)*	ROC AND RETAIL MARGIN (VARIABLE)	COMMENTS
QCA (QLD) (2015)	2015-16	$2,159	5.7%			Set a separate allowance for ROC and ROM. ROM was applied as a percentage of total costs.
QCA (QLD) (2016)	2016-17			$2,148	5.7% of total variable costs, via a variable cost allocator of 6.0445%.	Maintain base retail costs for large and very large customers established in the 2015-16 determinations, with the fixed retail component escalated by forecast inflation (equal to 2%). Set a fixed and variable allowance for ROC and ROM together, where the fixed component is equal to the ROC component and the variable component is equal to the ROM.
QCA (QLD) (2017)	2017-18			$2,191	5.7% of total variable costs, via a variable cost allocator of 6.0445%.	Maintain base retail costs for large and very large customers established in the 2015-16 determinations, with the fixed retail component escalated by forecast inflation (equal to 2%). Set a fixed and variable allowance for ROC and ROM together, where the fixed component is equal to the ROC component and the variable component is equal to the ROM.
QCA (QLD) (2018)	2018-19			$2,234	5.7% of total variable costs via a variable cost allocator of 6.0445%.	Set a fixed and variable allowance for ROC and ROM together. Maintained fixed cost allowances and variable cost percentage allocators established in the 2016-17 and 2017-18 price determinations. To allocate the variable component across total variable costs, the QCA adopted a variable retail cost allocator of 6.0445 per cent of total variable costs (excluding variable retail costs)
IPART (NSW) (2013)	2013-2016	$110	5.7% of total costs			Set a separate allowance for ROC and ROM for residential and small customers. Set the ROC allowance in line with the mid-point of the range for a Standard Retailer's efficient ROC.

Source: QCA (2018), Regulated retail electricity prices for 2018-19, February 2018, IPART, Review of Regulated Retail Prices for Electricity
** adjusted using an inflation rate of 2.00% in line with QCA specifications*.

4.9 Summary

Table 20 summarises our estimated electricity demand for the three scenarios. The weekly load provided by IPART was highest for the low rainfall scenario and lowest for the high rainfall scenario. In the median case and the high rainfall case, the only load during peak and shoulder periods was the minimum load, with the different total pumping requirement in these cases simply resulting in different load during off-peak periods (as reflected in both the MWh demand and the MW peak demand). In the low rainfall case there is also some pumping that occurs in shoulder periods (as reflected in both the MWh demand and the MW peak demand).

The estimated electricity demand set out in **Table 20** is materially lower than the electricity demand that was proposed by WaterNSW. For the purposes of comparison, **Table 21** sets out the electricity demand that was previously provided to us by IPART, and which was based on a weekly load profile prepared by the pipeline contractor. This electricity demand (and the corresponding peak demand) was used in our draft report.

Table 20: Estimated electricity demand

	HIGH RAINFALL	MEDIAN RAINFALL	LOW RAINFALL
	Demand		
Peak (MWh)	404	404	404
Shoulder (MWh)	606	606	1450
Off-peak (MWh)	4,824	8,505	10,874
Total (MWh)	**5,834**	**9,515**	**12,727**
	Peak demand		
Peak (MW)	0.2663	0.2663	0.2663
Shoulder (MW)	0.2663	0.2663	0.8039
Off-peak (MW)	1.0187	1.8097	2.2153

Source: Frontier Economics

Table 21: Estimated electricity demand – from pipeline contractor, used for Draft Report

	2019-20	2020-2021	2021-22	2022-23
		Demand		
Peak (MWh)	558	573	583	606
Shoulder (MWh)	2,668	2,754	2,830	2,885
Off-peak (MWh)	12,780	12,774	12,799	12,787
Total (MWh)	**16,006**	**16,101**	**16,212**	**16,278**
		Peak demand		
Peak (MW)	0.58	0.68	0.66	0.77
Shoulder (MW)	2.60	2.60	2.60	2.60
Off-peak (MW)	2.60	2.60	2.60	2.60

Source: Frontier Economics

Table 22 summarises our estimated total electricity cost for the three scenarios, and compares this with WaterNSW's estimate of total electricity cost. Clearly, our total cost estimates in each scenario are materially lower than WaterNSW's estimates. To a large extent this is driven by lower total energy consumption under the three scenarios we investigate (as seen in the comparison of **Table 20** and **Table 21** above). This lower total energy consumption means that less electricity needs to be purchased, fewer LGCs and STCs need to be surrender, ancillary services costs and market fees are lower and network energy charges are lower. Also as a result of this lower total energy consumption, our half-hourly load profile suggests that there is no need for pumping in shoulder or peak periods, and even during off-peak periods pumping load does not need to reach the maximum load of 2.6 MW – this means that network demand charges are much lower than they would be if maximum load were to occur in each of the off-peak, shoulder and peak periods.

Table 22 Comparison of estimated electricity costs ($2018-19)

	2019-20	2020-2021	2021-22	2022-23
WaterNSW estimate	$2,706,200	$2,587,600	$2,331,000	$2,514,700
Frontier Economics estimate – median rainfall	$1,140,806	$1,168,214	$1,134,222	$1,353,489
Frontier Economics estimate – high rainfall	$732,054	$750,074	$728,422	$865,834
Frontier Economics estimate – low rainfall	$1,559,748	$1,594,054	$1,548,142	$1,841,303

Source: WaterNSW (2018), Pricing Proposal for the Wentworth to Broken Hill Pipeline, p.76; Frontier Economics

Table 23 through **Table 25** provide a summary of each of the cost components that we have estimated, for each of the three scenarios that we have investigated. The costs reported in **Table 23** through **Table 25** are unit costs.

Table 26 through **Table 28** provide the summary of each of the cost components that we have estimated, but reports these costs as a total annual cost, based on the estimated demand set out in **Table 20**. **Table 26** through **Table 28** also aggregate the cost components into the following three categories:

- **Total volumetric charges** – consists of all costs that are driven by total energy consumption, which includes all wholesale energy costs, all renewable energy policy costs, all costs associated with market fees and ancillary services and all energy-related network charges. The retail margin of 5.7% is also applied to these total volumetric charges.
- **Total demand charges** – consists of all costs that are driven by peak demand, which includes all the demand-related network charges. The retail margin of 5.7% is also applied to these total demand-based charges.
- **Total fixed charges** – consists of all costs that are neither volumetric or demand-based, which includes the network access charges and the allowance for retail operating costs. The retail margin of 5.7% is also applied to these total fixed charges.

Table 23: Estimated electricity cost components – median rainfall ($2018-19)

	2019-20	2020-21	2021-22	2022-23
Wholesale energy costs				
EPC ($/MWh)	54.76	59.90	58.29	80.27
Losses ($/MWh)	5.01	5.47	5.33	7.34
Renewable energy policy costs				
Costs of complying with the LRET ($/MWh)	6.18	3.75	2.38	0.41
Costs of complying with the SRES ($/MWh)	4.62	4.40	4.29	4.19
Cost of complying with jurisdictional environmental policies ($/MWh)	4.10	4.10	4.10	4.10
Market fees and ancillary services				
Market fees ($/MWh)	0.55	0.55	0.55	0.55
Ancillary services costs ($/MWh)	0.34	0.34	0.34	0.34
Network charges				
Network access charge ($/day)	17.92	17.92	17.92	17.92
Energy Peak (cents/kWh)	3.13	3.13	3.13	3.13
Energy shoulder (cents/kWh)	2.84	2.84	2.84	2.84
Energy off peak (cents/kWh)	2.27	2.27	2.27	2.27
Demand peak (cents/kVA/M)	873.94	873.94	873.94	873.94
Demand shoulder (cents/kVA/M)	790.71	790.71	790.71	790.71
Demand off peak (cents/kVA/M)	233.08	233.08	233.08	233.08
Retail operating cost and margin				
Allowance for ROC ($/annum)	2,280	2,280	2,280	2,280
Allowance for ROM22 (%)	6.04%	6.04%	6.04%	6.04%

Source: Frontier Economics

Assumed to apply to all charges, to produce a ROM of 5.7%, consistent with the approach adopted by QCA in its most recent decision.

Table 24: Estimated electricity cost components – high rainfall ($2018-19)

	2019-20	2020-21	2021-22	2022-23
Wholesale energy costs				
EPC ($/MWh)	55.48	60.80	59.07	81.49
Losses ($/MWh)	5.07	5.56	5.40	7.45
Renewable energy policy costs				
Costs of complying with the LRET ($/MWh)	6.18	3.75	2.38	0.41
Costs of complying with the SRES ($/MWh)	4.62	4.40	4.29	4.19
Cost of complying with jurisdictional environmental policies ($/MWh)	4.10	4.10	4.10	4.10
Market fees and ancillary services				
Market fees ($/MWh)	0.55	0.55	0.55	0.55
Ancillary services ($/MWh)	0.34	0.34	0.34	0.34
Network charges				
Network access charge ($/day)	17.92	17.92	17.92	17.92
Energy Peak (cents/kWh)	3.13	3.13	3.13	3.13
Energy shoulder (cents/kWh)	2.84	2.84	2.84	2.84
Energy off peak (cents/kWh)	2.27	2.27	2.27	2.27
Demand peak (cents/kVA/M)	873.94	873.94	873.94	873.94
Demand shoulder (cents/kVA/M)	790.71	790.71	790.71	790.71
Demand off peak (cents/kVA/M)	233.08	233.08	233.08	233.08
Retail operating cost and margin				
Allowance for ROC ($/annum)	2,280	2,280	2,280	2,280
Allowance for ROM23 (%)	6.04%	6.04%	6.04%	6.04%

Source: Frontier Economics

Assumed to apply to all charges, to produce a ROM of 5.7%, consistent with the approach adopted by QCA in its most recent decision.

Table 25: Estimated electricity cost components – low rainfall ($2018-19)

	2019-20	2020-21	2021-22	2022-23
Wholesale energy costs				
EPC ($/MWh)	54.90	59.88	58.24	80.21
Losses ($/MWh)	5.02	5.47	5.32	7.33
Renewable energy policy costs				
Costs of complying with the LRET ($/MWh)	6.18	3.75	2.38	0.41
Costs of complying with the SRES ($/MWh)	4.62	4.40	4.29	4.19
Cost of complying with jurisdictional environmental policies ($/MWh)	4.10	4.10	4.10	4.10
Market fees and ancillary services				
Market fees ($/MWh)	0.55	0.55	0.55	0.55
Ancillary services ($/MWh)	0.34	0.34	0.34	0.34
Network charges				
Network access charge ($/day)	17.92	17.92	17.92	17.92
Energy Peak (cents/kWh)	3.13	3.13	3.13	3.13
Energy shoulder (cents/kWh)	2.84	2.84	2.84	2.84
Energy off peak (cents/kWh)	2.27	2.27	2.27	2.27
Demand peak (cents/kVA/M)	873.94	873.94	873.94	873.94
Demand shoulder (cents/kVA/M)	790.71	790.71	790.71	790.71
Demand off peak (cents/kVA/M)	233.08	233.08	233.08	233.08
Retail operating cost and margin				
Allowance for ROC ($/annum)	2,280	2,280	2,280	2,280
Allowance for ROM24 (%)	6.04%	6.04%	6.04%	6.04%

Source: Frontier Economics

[24] Assumed to apply to all charges, to produce a ROM of 5.7% of total charges including margin, consistent with the approach adopted by QCA in its most recent decision.

Table 26: Estimated electricity cost components – median rainfall ($/annum, $2018-19)

	2019-20	2020-21	2021-22	2022-23
Wholesale energy costs				
EPC	$521,041	$569,949	$554,629	$763,769
Losses	$47,623	$52,093	$50,693	$69,808
Renewable energy policy costs				
Costs of complying with the LRET	$64,140	$38,924	$24,703	$4,306
Costs of complying with the SRES	$47,977	$45,662	$44,547	$43,467
Cost of complying with the environmental policies	$39,012	$39,012	$39,012	$39,012
Market fees and ancillary services				
Market fees	$5,712	$5,712	$5,712	$5,712
Ancillary services costs	$3,531	$3,531	$3,531	$3,531
Network charges				
Network access charge	$6,542	$6,542	$6,542	$6,542
Energy Peak	$12,629	$12,629	$12,629	$12,629
Energy shoulder	$17,215	$17,215	$17,215	$17,215
Energy off peak	$192,780	$192,780	$192,780	$192,780
Demand peak	$31,031	$31,031	$31,031	$31,031
Demand shoulder	$28,075	$28,075	$28,075	$28,075
Demand off peak	$56,240	$56,240	$56,240	$56,240
Retail operating cost and margin				
Allowance for ROC	$2,280	$2,280	$2,280	$2,280
Allowance for ROM	$64,980	$66,541	$64,605	$77,094
Total volumetric charges	**$1,009,139**	**$1,036,547**	**$1,002,554**	**$1,221,822**
Total demand charges	**$122,313**	**$122,313**	**$122,313**	**$122,313**
Total fixed charges	**$9,355**	**$9,355**	**$9,355**	**$9,355**

Source: Frontier Economics

Note: network losses are applied to renewable energy policy costs and market fees and ancillary services.

Table 27: Estimated electricity cost components – high rainfall ($/annum, $2018-19)

	2019-20	2020-21	2021-22	2022-23
Wholesale energy costs				
EPC	$323,670	$354,707	$344,614	$475,413
Losses	$29,583	$32,420	$31,498	$43,453
Renewable energy policy costs				
Costs of complying with the LRET	$39,327	$23,866	$15,147	$2,640
Costs of complying with the SRES	$29,416	$27,997	$27,313	$26,651
Cost of complying with the environmental policies	$23,919	$23,919	$23,919	$23,919
Market fees and ancillary services				
Market fees	$3,502	$3,502	$3,502	$3,502
Ancillary services costs	$2,165	$2,165	$2,165	$2,165
Network charges				
Network access charge	$6,542	$6,542	$6,542	$6,542
Energy Peak	$12,629	$12,629	$12,629	$12,629
Energy shoulder	$17,215	$17,215	$17,215	$17,215
Energy off peak	$109,344	$109,344	$109,344	$109,344
Demand peak	$31,031	$31,031	$31,031	$31,031
Demand shoulder	$28,075	$28,075	$28,075	$28,075
Demand off peak	$31,658	$31,658	$31,658	$31,658
Retail operating cost and margin				
Allowance for ROC	$2,280	$2,280	$2,280	$2,280
Allowance for ROM	$41,321	$42,433	$41,247	$49,141
Total volumetric charges	**$626,453**	**$644,473**	**$622,821**	**$760,233**
Total demand charges	**$96,246**	**$96,246**	**$96,246**	**$96,246**
Total fixed charges	**$9,355**	**$9,355**	**$9,355**	**$9,355**

Source: Frontier Economics

Note: network losses are applied to renewable energy policy costs and market fees and ancillary services.

Table 28: Estimated electricity cost components – low rainfall ($/annum, $2018-19)

	2019-20	2020-21	2021-22	2022-23
Wholesale energy costs				
EPC	$698,767	$762,153	$741,279	$1,020,913
Losses	$63,867	$69,661	$67,753	$93,311
Renewable energy policy costs				
Costs of complying with the LRET	$85,799	$52,068	$33,045	$5,760
Costs of complying with the SRES	$64,178	$61,081	$59,589	$58,145
Cost of complying with the environmental policies	$52,185	$52,185	$52,185	$52,185
Market fees and ancillary services				
Market fees	$7,640	$7,640	$7,640	$7,640
Ancillary services costs	$4,723	$4,723	$4,723	$4,723
Network charges				
Network access charge	$6,542	$6,542	$6,542	$6,542
Energy Peak	$12,629	$12,629	$12,629	$12,629
Energy shoulder	$41,190	$41,190	$41,190	$41,190
Energy off peak	$246,477	$246,477	$246,477	$246,477
Demand peak	$31,031	$31,031	$31,031	$31,031
Demand shoulder	$84,753	$84,753	$84,753	$84,753
Demand off peak	$68,845	$68,845	$68,845	$68,845
Retail operating cost and margin				
Allowance for ROC	$2,280	$2,280	$2,280	$2,280
Allowance for ROM	$88,022	$90,162	$87,650	$104,494
Total volumetric charges	**$1,354,613**	**$1,388,919**	**$1,343,007**	**$1,636,168**
Total demand charges	**$195,780**	**$195,780**	**$195,780**	**$195,780**
Total fixed charges	**$9,355**	**$9,355**	**$9,355**	**$9,355**

Source: Frontier Economics

Note: network losses are applied to renewable energy policy costs and market fees and ancillary services.

5 A SIMPLIFIED APPROACH TO ESTIMATING A BENCHMARK ENERGY PRICE

As discussed, the approach to estimating a benchmark energy price for supplying the pipeline that is set out in Section 4 relies on a forecast of pumping load.

IPART has also asked for estimated energy prices for peak, off-peak and shoulder periods in each quarter, so that these estimated energy prices could be applied to a different forecast of the electricity load for the pipeline. Our understanding is that the intention behind having these estimated energy prices for peak, off-peak and shoulder periods is for IPART to have the flexibility in future to estimate a benchmark energy price for a different forecast of demand for electricity.

Given that the purpose of these prices is to calculate a total energy purchase cost for an alternate load forecast, our view is that the most sensible approach is to base these on forecasts of the NSW RRP, which will not be affected by the pipeline load. Accordingly, we have calculated the average NSW RRP for peak, off-peak and shoulder periods in each quarter, based on the half-hourly spot price forecasts from *SYNC* discussed in Section 4.2.3. This gives rise to the prices set out in **Table 29**.

To partially account for the additional cost to a retailer of hedging the pipeline load, a contract premium of 5% could be added to these spot prices in order to closer reflect the costs that a retailer is likely to face in supplying load. As noted in Section 4.2.4, we assume that hedging contracts trade at a 5% price premium to the expected spot price,[25] which reflects an additional cost of managing price risk. Including this contract premium of 5% will only partially account for the additional cost of hedging the pipeline load because it may be that within each of these time periods the pipeline tends to operate at times with higher than average spot prices, which would increase the average cost to the retailer.

[25] While it is impossible to directly observe the level of the contract premium, our analysis of historical spot and contract prices indicates that on average over the long-term it is reasonable to assume that hedging contracts trade at a 5% price premium to out-turn spot prices.

Table 29: NSW RRP for peak, off-peak and shoulder periods ($2018-19)

FINANCIAL YEAR	QUARTER	OFF-PEAK	SHOULDER	PEAK
2020	3	$51.95	$60.26	$64.03
2020	4	$43.77	$43.70	$48.84
2020	1	$60.48	$70.84	$85.68
2020	2	$47.95	$58.85	$66.44
2021	3	$57.34	$66.21	$72.62
2021	4	$45.51	$45.21	$52.30
2021	1	$69.58	$75.54	$115.80
2021	2	$50.98	$61.52	$71.96
2022	3	$55.99	$63.01	$69.02
2022	4	$46.03	$44.46	$52.53
2022	1	$66.60	$72.10	$112.24
2022	2	$49.19	$56.74	$66.51
2023	3	$75.39	$85.68	$96.16
2023	4	$61.09	$57.66	$70.58
2023	1	$99.76	$103.77	$157.00
2023	2	$64.65	$79.54	$101.82

Source: Frontier Economics

Accounting for the 5% contract premium, the prices in **Table 29**, when multiplied by the demand that we have estimated (as summarised in **Table 20**) results in an average energy cost as set out in **Table 30**. This results in total electricity costs as set out in **Table 31**. As with the results presented in Section 4.9, the material differences in the WaterNSW's estimated total electricity costs and the estimates for the three scenarios we have investigated is the lower assumed load in each of the three scenarios we have investigated.

Table 30: Results for simplified approach to wholesale energy cost ($2018-19)

	2019-20	2020-21	2021-22	2022-23
Median rainfall	$54.69	$59.96	$58.32	$80.64
High rainfall	$55.43	$60.86	$59.10	$81.79
Low rainfall	$54.90	$60.04	$58.33	$80.63

Source: Frontier Economics

Table 31 Comparison of estimated electricity costs ($2018-19)

	2019-20	2020-2021	2021-22	2022-23
WaterNSW estimate	$2,706,200	$2,587,600	$2,331,000	$2,514,700
Frontier Economics simplified estimate – median rainfall	$1,140,035	$1,168,875	$1,134,552	$1,357,564
Frontier Economics simplified estimate – high rainfall	$731,716	$750,479	$728,624	$867,859
Frontier Economics simplified estimate – low rainfall	$1,559,748	$1,596,411	$1,549,467	$1,847,490

Source: WaterNSW (2018), Pricing Proposal for the Wentworth to Broken Hill Pipeline, p.76; Frontier Economics

A APPENDIX A

To estimate the energy purchase costs a retailer would face supplying electricity to WaterNSW's pipeline, the cost of both buying the electricity and the cost of hedging must be taken into account. Frontier Economics does this through the use of our *STRIKE* model, which is a portfolio optimisation model. This model uses the load profile of WaterNSW's Broken Hill pipeline, along with the corresponding prices from *SYNC* and electricity derivatives to determine a hedging position.

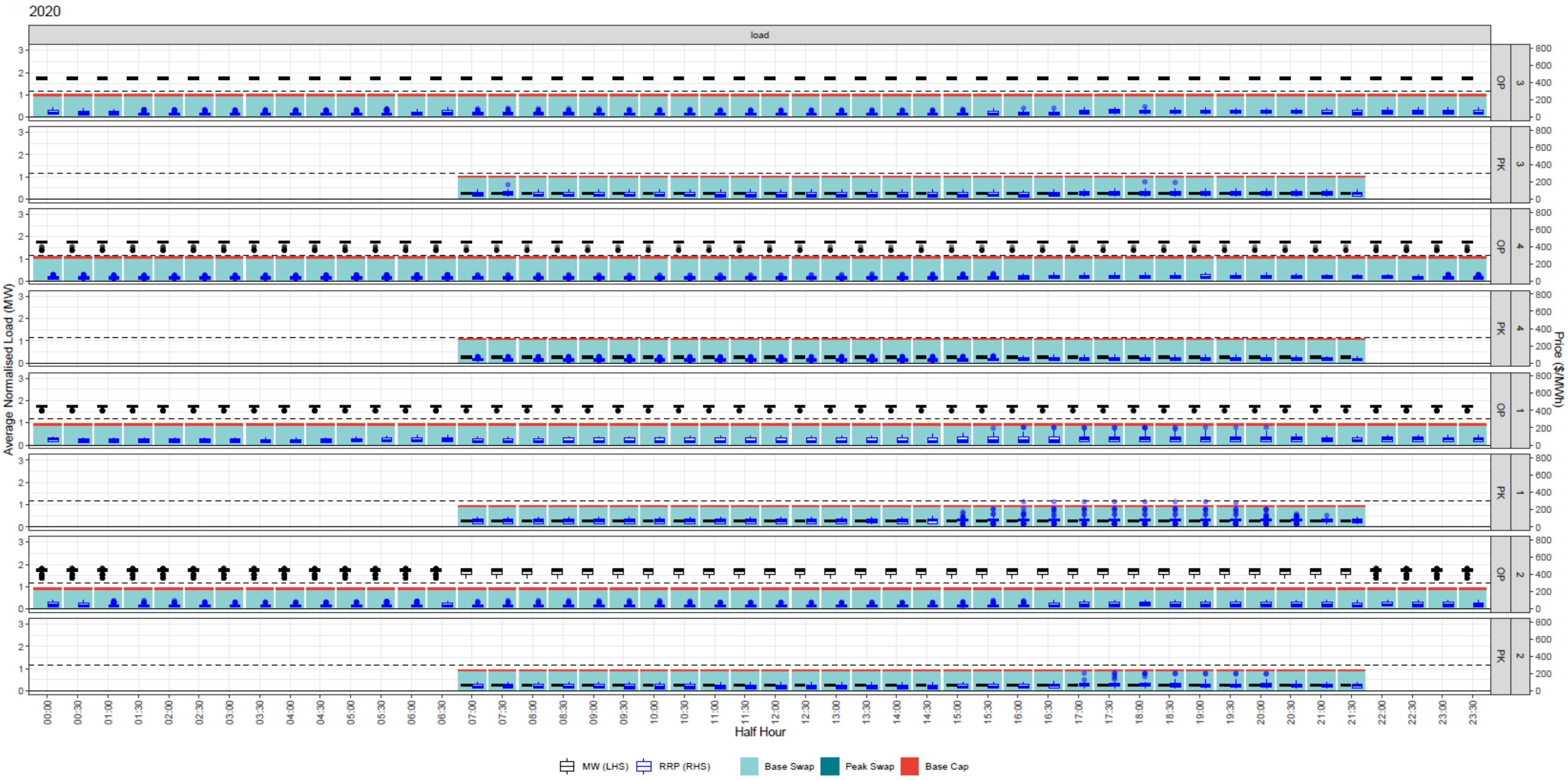
In each quarter of the modelling period the model can invest in three different electricity derivatives:

- Base swaps: A swap contract which covers all half-hour intervals in a given quarter.
- Peak swaps: A swap contract which only covers intervals which belong to peak time in a given quarter.
- Base caps: A cap contract (with $300 strike price) which covers all half hour intervals for a given quarter.

Figure 13 shows the efficient contract position determined by *STRIKE* for the year 2020 for the median scenario. **Figure 13** shows results for each quarter and period (peak and off-peak) on the vertical panels and for each half-hour of the day on the horizontal axis. The half-hourly load of the pipeline in each of the resulting time blocks is given by the black box-and-whisker plot for each half-hour interval (scale on the LHS), while the corresponding half-hourly prices are given by the blue box-and-whisker plot with the $300 price given by the dotted line (scale on the RHS). As expected, for this median case, most of the load occurs in off-peak periods. The load during peak and shoulder periods sits on the minimum load. The equivalent pictures for the low rainfall and high rainfall cases would look much the same although, as we have seen, the level of pumping during off-peak periods will vary between the cases and there will be some pumping in shoulder periods in the low rainfall case.

The coloured bars indicate how much of each hedging contract is purchased to hedge the load according to the efficient contract position determined by *STRIKE*. Base swap contracts are bought for all quarters, to a volume roughly mid-way between the minimum load and the off-peak pumping load. This is enough to cover the load during times of high prices, while during off-peak times the difference between the base swap and the load is exposed to the spot price. The model does this because this price is usually low during off-peak, so the risk of being 'under-hedged' is not significant. Enough base cap contracts are usually bought to hedge shoulder times against the possibility of high spot prices. No peak swap contracts are bought since most of the pumping load occurs in off-peak times.

Figure 13: Contract positions from *STRIKE* model



Source: Frontier Economics

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