WATERNSW'S ENERGY PURCHASE COSTS - BROKEN HILL PIPELINE

FINAL REPORT FOR IPART – MAY 2019

Introduction

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.

Frontier Economics is advising IPART on its review of WaterNSW's energy purchase costs for the Broken Hill Pipeline. We have previously completed the following tasks for IPART in relation to this review:

- 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 2 years – the period 1 July 2022 to 30 June 2024 – as WaterNSW provided no updated demand data beyond 30 June 2022.

In February 2019 we provided our final report to IPART setting out the results of our review and assessment.[1]

We have now been engaged by IPART to update our estimates for the energy purchase cost of WaterNSW's pipeline load for IPART's final report. This note provides the results of our updated assessment.

Methodology

The methodology that we adopt for assessing the efficient energy cost for WaterNSW's pipeline load over is set out in our February 2019 Final Report. We apply the same methodology for this update, but make use of certain updated input assumptions.

[1] Frontier Economics, *WaterNSW's Energy Purchase Costs – Broken Hill Pipeline*, Final Report for IPART, 8 February 2019. Available at: https://www.ipart.nsw.gov.au/files/sharedassets/website/shared-files/pricing-reviews-water-services-rural-water-prices-for-waternsw-murray-river-to-broken-hill-pipeline-services-from-1-july-2019/legislative-requirements-prices-for-waternsw-murray-river-to-broken-hill-pipeline-services-from-1-july-2019/consultant-report-by-frontier-waternsw-energy-purchase-costs-broken-hill-pipeline-8-february-2019.pdf

Updated input assumptions

This section describes the input assumptions that we have updated in order to update our estimate of efficient electricity costs for WaterNSW for the pipeline.

There are two key sets of inputs for which we have new information that could have a material impact on our estimate of efficient electricity costs:

- We have been provided with updated estimates of pipeline load by IPART.
- More recent information is available about the cost of complying with the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES).

For the other drivers or components of efficient electricity costs – including wholesale electricity prices, market fees and ancillary services, network costs, energy losses and retail operating costs and margin – our view is that no new information has become available since we developed the estimate of efficient electricity costs set out in our February 2019 Final Report that would cause us to materially change our view.

We discuss the new information on pipeline load and costs of complying with the LRET and SRES in the sections below.

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.

For the purposes of our February 2019 Final Report, 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 three different scenarios.

For this update, IPART has provided us with updated weekly load profiles for the pipeline. IPART has again provides us with weekly load profiles for three scenarios: a median demand scenario, a low demand scenario and a high demand scenario.

As we did in our analysis for our February 2019 Final Report, 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.

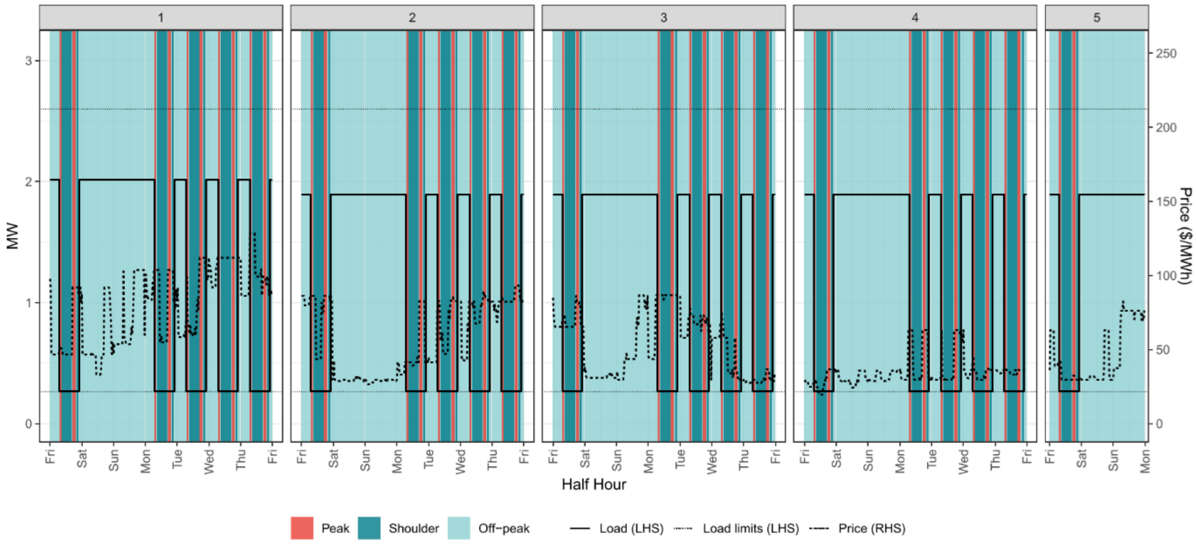
Since our February 2019 Final Report we have found that there was a minor error in the way that our calculations defined peak and shoulder periods. We have corrected this error so that the definition of peak and shoulder periods correctly matches the definition of these periods. This error did not materially affect results.

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

It is apparent from **Figure 1** that in the median demand scenario all the required weekly pumping in July 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.

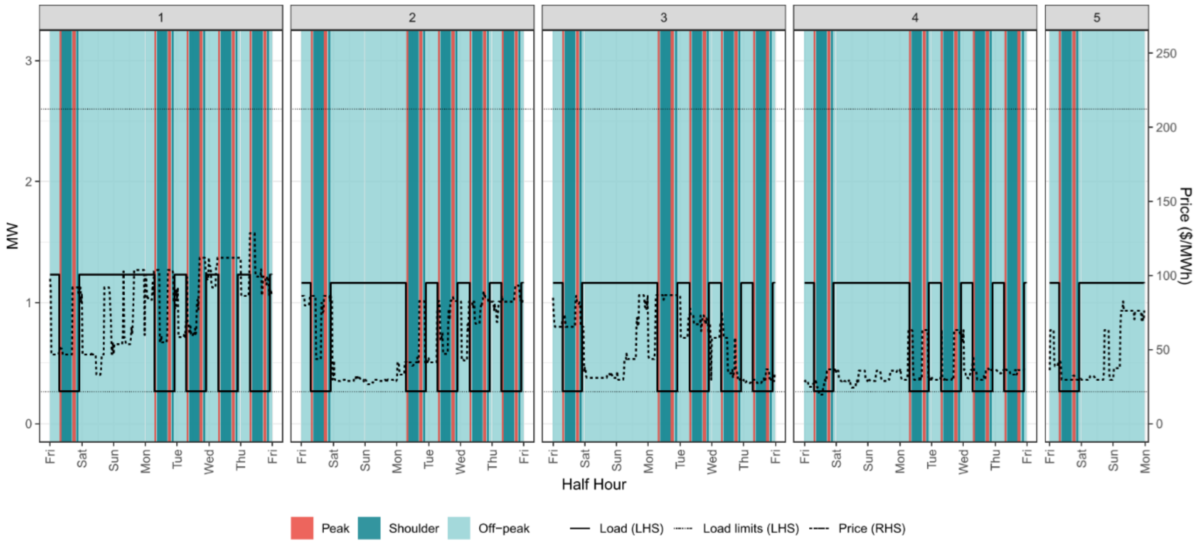
Figure 2 and **Figure 3** show the same data for the low demand scenario and the high demand scenario, respectively. With the updated forecasts from IPART, in July in the low demand scenario all required pumping can take place during off-peak periods, the only real difference to the median demand scenario is the amount of off-peak load that is required to meet the required total weekly pumping; however, in the high demand scenario pumping also occurs during shoulder periods.

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



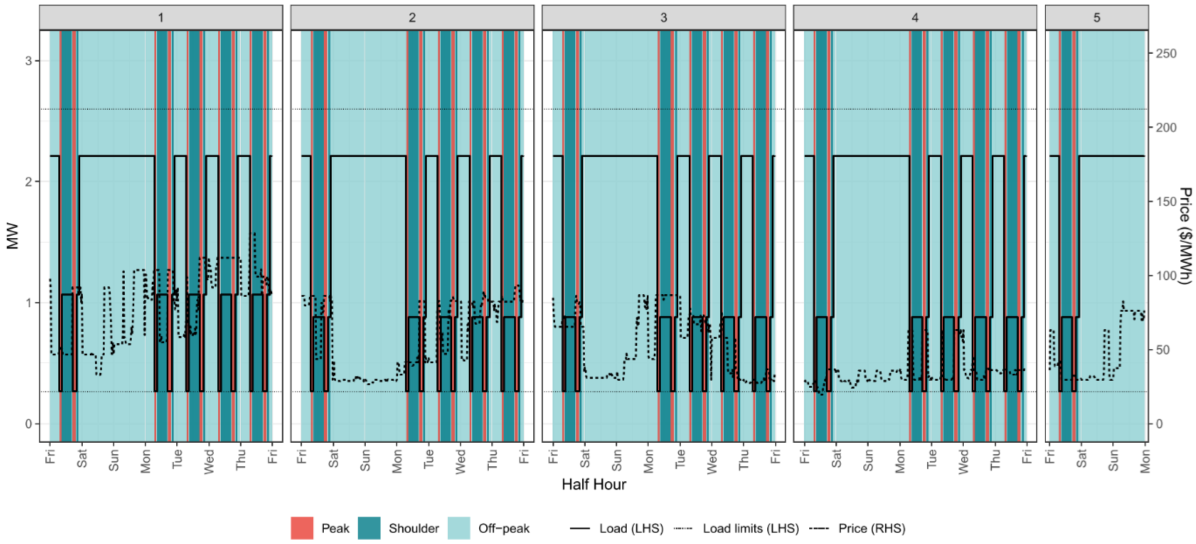
Source: Frontier Economics

Figure 2: Typical load profile given for July 2019 – low demand scenario



Source: Frontier Economics

Figure 3: Typical load profile given for July 2019 – high demand scenario



Source: Frontier Economics

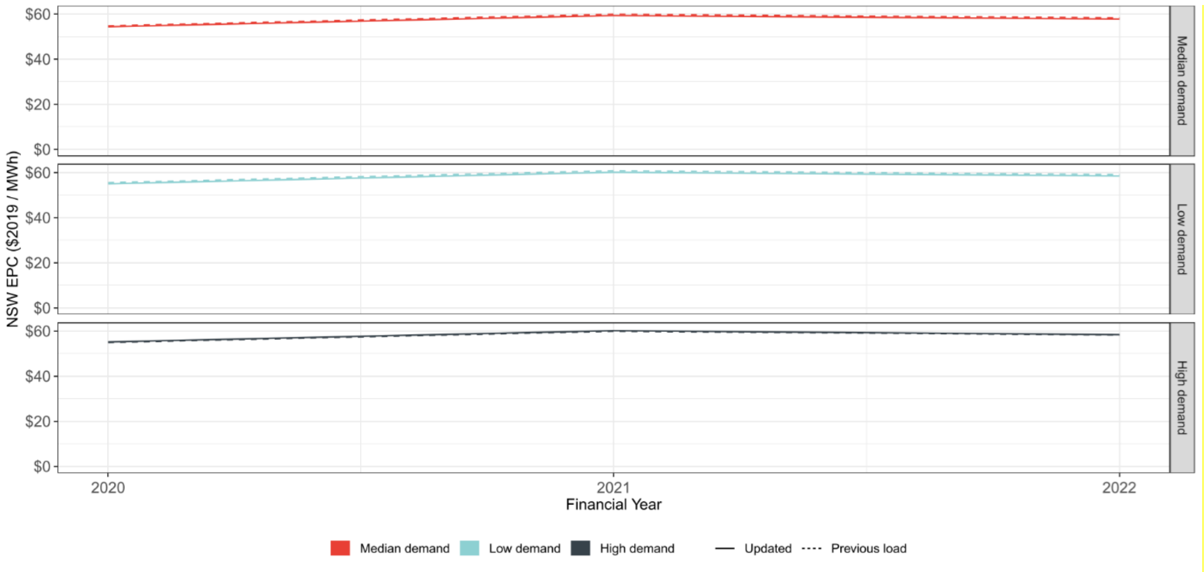
Based on the updated estimates of half-hourly pumping load, and the same wholesale electricity prices we used in our February 2019 Final Report, we calculate the energy purchase cost for WaterNSW.

Figure 4 shows our updated estimates of energy purchase costs for each scenario, compared to the estimates from our February 2019 Final Report.

For both the median demand and low demand scenarios the energy purchase costs decreases very slightly. The reason is that for both these scenarios the updated forecasts from IPART are for higher demand; in these scenarios as pumping is increased, it results in an increase in off-peak pumping, which decreases the average energy purchase cost since there is no equivalent increase in load during shoulder and peak times (which remains at the minimum load of 0.2663 MW).

For the high demand scenario the energy purchase cost increases very slightly. The reason is that in this scenario the higher demand in the updated forecasts from IPART results in more pumping having to occur in shoulder and peak times (particularly in summer), which increases the average energy purchase cost.

Figure 4: Comparison of energy purchase costs between scenarios and reports

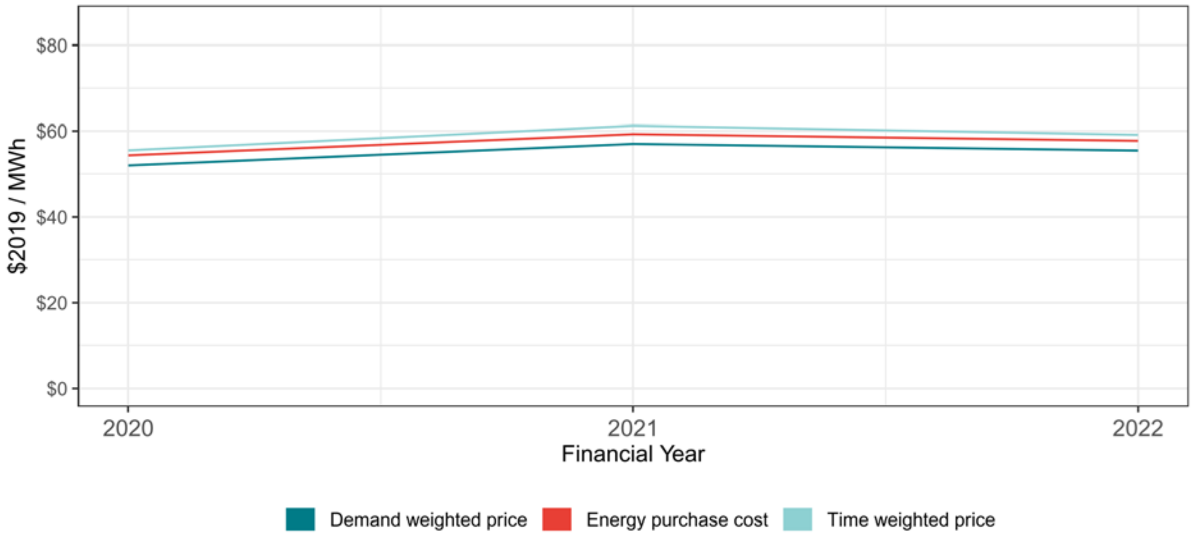


Source: Frontier Economics

Figure 5 through **Figure 7** show these same updated energy purchase costs for the three scenarios we have modelled. These figures also compare the energy purchase cost to the wholesale electricity price for NSW (the time-weighted average price) and the load-weighted average price for the pumping load.

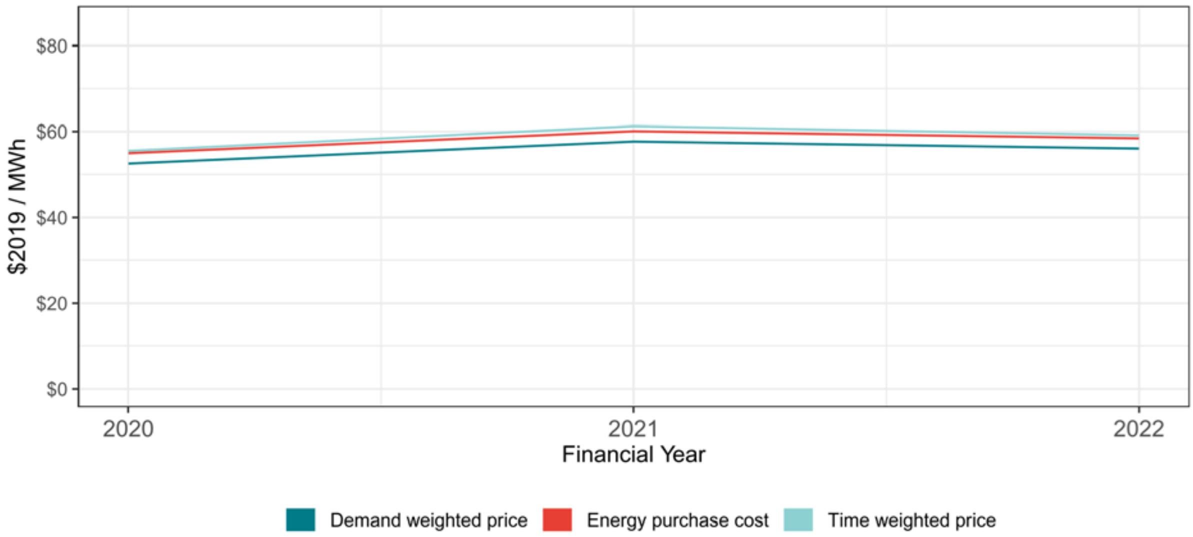
The load-weighted average price is lower than the time-weighted average price because pumping can occur during off-peak periods, when the average price tends to be lower. The energy purchase cost is higher than the load-weighted average price; this higher cost of hedging, compared with the load being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

Figure 5: Electricity purchase costs for median demand scenario, compared with NSW regional reference price



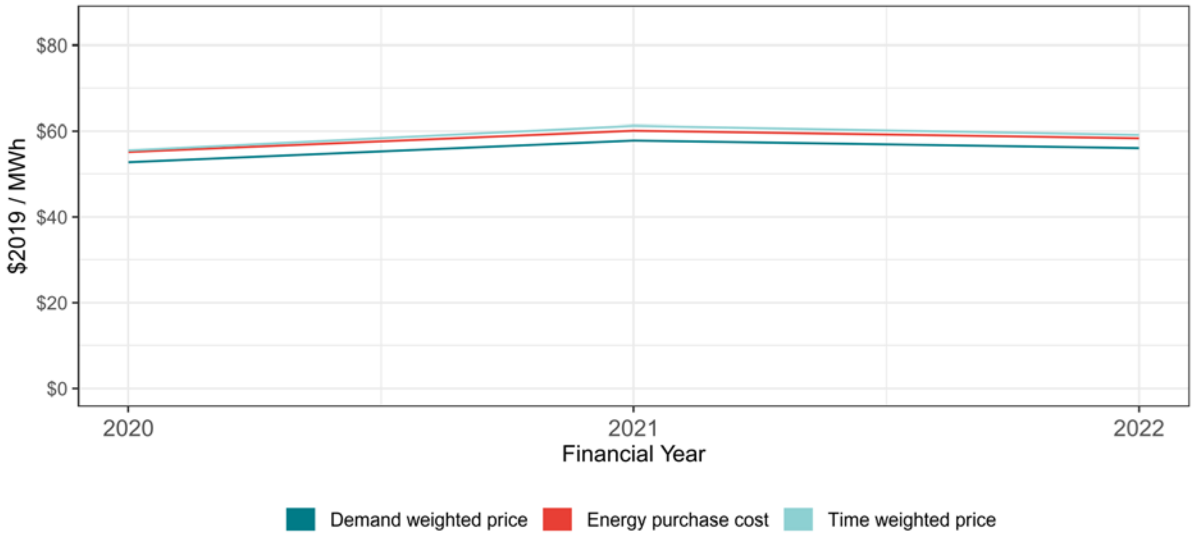
Source: Frontier Economics

Figure 6: Electricity purchase costs for low demand scenario, compared with NSW regional reference price



Source: Frontier Economics

Figure 7: Electricity purchase costs for high demand scenario, compared with NSW regional reference price



Source: Frontier Economics

Costs of complying with the LRET

In order to calculate the cost of complying with the LRET, it is necessary to determine the Renewable Power Percentage (RPP) (which determines the number of Large-scale Generation Certificates (LGCs) that must be purchased) and the cost of obtaining each LGC.

Since our February 2019 Final Report, the RPP for 2019 has been published. The Clean Energy Regulator is responsible for setting the RPP for each year, with the RPP for 2019 set at 18.60 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 relevant 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. We have used the published RRP for 2019 (18.60%) to perform the default calculations for the RPP for 2020 to 2022, and then averaged these calendar year results to derive financial year RPPs. These values are set out in **Table 1**.

Table 1: Renewable Power Percentages (FY)

	2019-20	2020-2021	2021-22
RPP (% of liable acquisitions)	19.38%	19.90%	19.65%

Source: Clean Energy Regulator, Frontier Economics

For our February 2019 Final Report we used a market price for LGCs to determine the cost of complying with the LRET. Since our February 2019 Final Report this market price has changed. **Table 2** outlines the most recent 40-day average LGC futures price, based on data reported by Mercari.[2]

Table 2: 40-day average LGC futures price from Mercari Rates ($/certificate, $2018/19)

	2019-20	2020-2021	2021-22
40-day average LGC futures price	$28.15	$17.72	$12.00

Source: Mercari Rates

Based on these updated estimates of the RPP and the cost of LGCs, **Table 3** outlines the cost of complying with the LRET.

Table 3: Cost of complying with the LRET – based on market price of LGC ($/MWh, $2018-19)

	2019-20	2020-2021	2021-22
Cost of complying with the LRET	$5.45	$3.53	$2.36

Source: Frontier Economics

Cost of complying with the SRES

In order to calculate the cost of complying with the SRES, it is necessary to determine the Small-scale Technology Percentage (STP) (which determines the number of Small-scale Technology Certificates (STCs) that must be purchased) and the cost of obtaining each STC.

Since our February 2019 Final Report, the STP for 2019 has been published. The Clean Energy Regulator has also published a non-binding estimate of the STP for the two subsequent compliance years. After 2021, we have assumed that the STP remains constant at the 2021 level. These binding, non-binding and estimated values have been averaged to create the financial year STPs set out in **Table 4**.

Table 4: Small-scale Technology Percentages (FY)

	2019-20	2020-2021	2021-22
STP (% of liable acquisitions)	18.15%	13.72%	13.72%

Source: Clean Energy Regulator, Frontier Economics

Since liable entities can purchase STCs through the STC Clearing House for a guaranteed price of $40/STC, the estimated cost of STCs has not changed since our February 2019 Final Report.

2 Mercari (2018), http://lgc.mercari.com.au/, accessed 8th April 2019.

Based on these updated estimates of the STP, and the cost of STCs, **Table 5** outlines the cost of complying with the SRES.

Table 5: Cost of complying with the SRES ($/MWh, $2018-19)

	2019-20	2020-2021	2021-22
Cost of complying with the SRES	$7.08	$5.22	$5.10

Source: Frontier Economics

Results

Table 6 through **Table 8** summarise estimated electricity demand for the median demand scenario, low demand scenario and high demand scenario respectively. In the median demand scenario and the low demand scenario the only load during peak periods and shoulder periods is the minimum load. In high demand scenario the only load during peak periods is also the minimum load.

Table 6: Estimated electricity demand – median demand scenario

	2019-20	2020-21	2021-22
Demand			
Peak (MWh)	343	343	343
Shoulder (MWh)	695	695	695
Off-peak (MWh)	9,175	9,153	9,125
Peak demand			
Peak (MW)	0.27	0.27	0.27
Shoulder (MW)	0.27	0.27	0.27
Off-peak (MW)	2.02	1.96	1.95

Source: Frontier Economics

Table 7: Estimated electricity demand – low demand scenario

	2019-20	2020-21	2021-22
Demand			
Peak (MWh)	343	343	343
Shoulder (MWh)	695	695	695
Off-peak (MWh)	5,637	5,615	5,586
Peak demand			
Peak (MW)	0.27	0.27	0.27
Shoulder (MW)	0.27	0.27	0.27
Off-peak (MW)	1.23	1.19	1.19

Source: Frontier Economics

Table 8: Estimated electricity demand – high demand scenario

	2019-20	2020-21	2021-22
Demand			
Peak (MWh)	343	343	343
Shoulder (MWh)	2,384	2,283	2,219
Off-peak (MWh)	10,768	10,766	10,763
Peak demand			
Peak (MW)	0.27	0.27	0.27
Shoulder (MW)	1.46	1.45	1.44
Off-peak (MW)	2.22	2.22	2.22

Source: Frontier Economics

Table 9 summarises our estimated total electricity cost for the three scenarios, and compares this with WaterNSW's estimate of total electricity cost. From our February 2018 Final Report, our estimates have increased slightly, however are still materially lower than WaterNSW's estimates. The reasons for this are stated in the February 2018 Final Report.

Table 9 Comparison of estimated electricity costs ($2018-19)

	2019-20	2020-2021	2021-22
WaterNSW estimate	$2,706,200	$2,587,600	$2,331,000
Frontier Economics estimate – median demand	$1,236,969	$1,246,416	$1,209,643
Frontier Economics estimate – low demand	$818,856	$838,239	$812,511
Frontier Economics estimate – high demand	1,750,774	1,756,699	1,700,316

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

Table 10 through **Table 12** provide a summary of each of the cost components that we have estimated, for each of the three scenarios that we have investigated. These tables are updates of **Table 23** through **Table 25** in our February 2019 Final Report. The cost components that have been updated are EPC (and, as a result of this, losses), the cost of complying with the LRET and the cost of complying with the SRES. All other cost components in these tables are the same as in our February 2019 Final Report.

Table 13 and **Table 15** provide the summary of each of the cost components that we have estimated, but reports these costs as a total annual cost rather than unit costs, based on the estimated demand set out above. These tables are updates of **Table 26** through **Table 28** in our February 2019 Final Report.

Table 10: Estimated electricity cost components – median demand scenario ($2018-19)

	2019-20	2020-21	2021-22
Wholesale energy costs			
EPC ($/MWh)	54.37	59.32	57.77
Losses ($/MWh)	4.97	5.42	5.28
Renewable energy policy costs			
Costs of complying with the LRET ($/MWh)	5.45	3.53	2.36
Costs of complying with the SRES ($/MWh)	7.08	5.22	5.10
Cost of complying with the environmental policies ($/MWh)	4.10	4.10	4.10
Market fees and ancillary services			
Market fees ($/MWh)	0.55	0.55	0.55
Ancillary services costs ($/MWh)	0.34	0.34	0.34
Network charges			
Network access charge ($/day)	17.92	17.92	17.92
Energy Peak (cents/kWh)	3.13	3.13	3.13
Energy shoulder (cents/kWh)	2.84	2.84	2.84
Energy off peak (cents/kWh)	2.27	2.27	2.27
Demand peak (cents/kVA/M)	873.94	873.94	873.94
Demand shoulder (cents/kVA/M)	790.71	790.71	790.71
Demand off peak (cents/kVA/M)	233.08	233.08	233.08
Retail operating cost and margin			
Allowance for ROC ($)	2,280	2,280	2,280
Allowance for ROM[3] (%)	6.04%	6.04%	6.04%

Source: Frontier Economics

3 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 11: Estimated electricity cost components – low demand scenario ($2018-19)

	2019-20	2020-21	2021-22
Wholesale energy costs			
EPC ($/MWh)	54.98	60.11	58.46
Losses ($/MWh)	5.03	5.49	5.34
Renewable energy policy costs			
Costs of complying with the LRET ($/MWh)	5.45	3.53	2.36
Costs of complying with the SRES ($/MWh)	4.62	4.40	4.29
Cost of complying with the environmental policies ($/MWh)	4.10	4.10	4.10
Market fees and ancillary services			
Market fees ($/MWh)	0.55	0.55	0.55
Ancillary services ($/MWh)	0.34	0.34	0.34
Network charges			
Network access charge ($/day)	17.92	17.92	17.92
Energy Peak (cents/kWh)	3.13	3.13	3.13
Energy shoulder (cents/kWh)	2.84	2.84	2.84
Energy off peak (cents/kWh)	2.27	2.27	2.27
Demand peak (cents/kVA/M)	873.94	873.94	873.94
Demand shoulder (cents/kVA/M)	790.71	790.71	790.71
Demand off peak (cents/kVA/M)	233.08	233.08	233.08
Retail operating cost and margin			
Allowance for ROC ($)	2,280	2,280	2,280
Allowance for ROM[4] (%)	6.04%	6.04%	6.04%

Source: Frontier Economics

[4] 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 12: Estimated electricity cost components – high demand scenario ($2018-19)

	2019-20	2020-21	2021-22
Wholesale energy costs			
EPC ($/MWh)	55.16	60.16	58.38
Losses ($/MWh)	5.04	5.50	5.34
Renewable energy policy costs			
Costs of complying with the LRET ($/MWh)	5.45	3.53	2.36
Costs of complying with the SRES ($/MWh)	7.08	5.22	5.10
Cost of complying with the environmental policies ($/MWh)	4.10	4.10	4.10
Market fees and ancillary services			
Market fees ($/MWh)	0.55	0.55	0.55
Ancillary services ($/MWh)	0.34	0.34	0.34
Network charges			
Network access charge ($/day)	17.92	17.92	17.92
Energy Peak (cents/kWh)	3.13	3.13	3.13
Energy shoulder (cents/kWh)	2.84	2.84	2.84
Energy off peak (cents/kWh)	2.27	2.27	2.27
Demand peak (cents/kVA/M)	873.94	873.94	873.94
Demand shoulder (cents/kVA/M)	790.71	790.71	790.71
Demand off peak (cents/kVA/M)	233.08	233.08	233.08
Retail operating cost and margin			
Allowance for ROC ($)	2,280	2,280	2,280
Allowance for ROM (%)	6.04%	6.04%	6.04%

Source: Frontier Economics

Table 13: Estimated electricity cost components ($/annum, $2018/19) – median demand scenario

	2019-20	2020-21	2021-22
Wholesale energy costs			
EPC	555,236	604,551	587,094
Losses	50,749	55,256	53,660
Renewable energy policy costs			
Costs of complying with the LRET	60,788	39,223	26,162
Costs of complying with the SRES	78,917	58,097	56,519
Cost of complying with the environmental policies	41,872	41,785	41,667
Market fees and ancillary services			
Market fees	6,130	6,118	6,100
Ancillary services costs	3,790	3,782	3,771
Network charges			
Network access charge	6,542	6,542	6,542
Energy Peak	10,726	10,726	10,726
Energy shoulder	19,737	19,737	19,737
Energy off peak	207,961	207,478	206,829
Demand peak	31,020	31,020	31,020
Demand shoulder	28,066	28,066	28,066
Demand off peak	62,698	60,760	60,568
Retail operating cost and margin			
Allowance for ROC	2,280	2,280	2,280
Allowance for ROM	70,457	70,995	68,901
Total volumetric charges	1,098,475	1,109,976	1,073,407
Total demand charges	129,139	127,085	126,881
Total fixed charges	9,355	9,355	9,355

Source: Frontier Economics

Table 14: Estimated electricity cost components ($/annum, $2018/19) – low demand scenario

	2019-20	2020-21	2021-22
Wholesale energy costs			
EPC	367,018	399,903	387,250
Losses	33,545	36,551	35,395
Renewable energy policy costs			
Costs of complying with the LRET	39,731	25,604	17,053
Costs of complying with the SRES	33,657	31,927	31,012
Cost of complying with the environmental policies	27,368	27,276	27,159
Market fees and ancillary services			
Market fees	4,007	3,993	3,976
Ancillary services costs	2,477	2,469	2,458
Network charges			
Network access charge	6,542	6,542	6,542
Energy Peak	10,726	10,726	10,726
Energy shoulder	19,737	19,737	19,737
Energy off peak	127,774	127,270	126,620
Demand peak	31,020	31,020	31,020
Demand shoulder	28,066	28,066	28,066
Demand off peak	38,266	37,129	36,937
Retail operating cost and margin			
Allowance for ROC	2,280	2,280	2,280
Allowance for ROM	46,642	47,746	46,280
Total volumetric charges	706,269	726,858	701,334
Total demand charges	103,232	102,025	101,822
Total fixed charges	9,355	9,355	9,355

Source: Frontier Economics

Table 15: Estimated electricity cost components ($/annum, $2018/19) – high demand scenario

	2019-20	2020-21	2021-22
Wholesale energy costs			
EPC	744,384	805,640	778,010
Losses	68,037	73,636	71,110
Renewable energy policy costs			
Costs of complying with the LRET	80,325	51,542	34,304
Costs of complying with the SRES	104,282	76,344	74,108
Cost of complying with the environmental policies	55,330	54,908	54,635
Market fees and ancillary services			
Market fees	8,101	8,039	7,999
Ancillary services costs	5,008	4,970	4,945
Network charges			
Network access charge	6,542	6,542	6,542
Energy Peak	10,726	10,726	10,726
Energy shoulder	67,713	64,859	63,034
Energy off peak	244,084	244,026	243,972
Demand peak	31,020	31,020	31,020
Demand shoulder	154,374	153,263	151,939
Demand off peak	68,844	68,844	68,844
Retail operating cost and margin			
Allowance for ROC	2,280	2,280	2,280
Allowance for ROM	99,723	100,061	96,849
Total volumetric charges	1,471,825	1,478,929	1,423,950
Total demand charges	269,594	268,415	267,012
Total fixed charges	9,355	9,355	9,355

Source: Frontier Economics

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