Revised Final Plan

Attachment 11.3

Response to Draft Decision on Capacity and Throughput

October 2020

Dampier Bunbury Pipeline

1. Response to Draft Decision on Capacity and Throughput

We have not amended our Final Plan to incorporate the ERA's Draft Decision on contracted capacity or throughput. We consider that our forecasts in Table 1 (with detail in the appendices) have been arrived at on a reasonable basis and represent the best forecast of contracted capacity and throughput possible in the circumstances. This submission provides the relevant background to support this position.[1]

Table 1: Summary of capacity and throughput forecasts in this revised Final Plan

	2021	2022	2023	2024	2025
Full Haul					
Capacity	592.25	582.25	574.15	507.45	499.35
Throughput	536.28	526.80	520.22	464.45	458.15
FH Equivalent of Part Haul					
Capacity	25.97	25.39	26.87	41.07	43.08
Throughput	17.74	17.86	19.57	34.00	36.33
FH Equivalent of Back Haul					
Capacity	18.09	17.29	17.29	17.89	17.89
Throughput	13.89	13.27	13.27	13.27	13.27
Total System					
Capacity	**636.31**	**624.93**	**618.31**	**566.41**	**560.33**
Throughput	**567.91**	**557.93**	**553.06**	**511.72**	**507.75**

1.1. Overview

This attachment sets out our response to the ERA's Draft Decision on our contracted capacity (also referred to as "pipeline capacity" or "capacity") and throughput over the next (2021 to 2025) Access Arrangement period (AA5). In particular we are responding to the following Required Amendment in the Draft Decision:

Required Amendment 7
DBP must amend its demand forecast for full haul reference services to maintain throughput and contracted capacity at 2020 forecast amounts as shown in Table 14 of this Draft Decision.

As part of our Final Plan we provided capacity and throughput forecasts for each of the reference services proposed for AA5, being the:

- Full Haul Service – forward full haul service with outlet point south of Compressor Station 9;
- Part Haul Service – forward part haul service with outlet point up stream of Compressor Station 9; and
- Back Haul Service – where the inlet point is downstream of the outlet point.

Our forecasts of capacity for all three services were based on actual information we received from shippers as to how they will utilise the DBNGP over AA5, as per our contracts with them. The full

[1] These forecasts are substantively the same as those sent to the ERA on May 29th, [redacted].

haul service forecasts showed a significant decline in contracted capacity from 2020 to 2021 reflecting our shippers' response to changes that have been occurring, and will continue to occur, in the electricity market in Perth where the fuel used to generate electricity is switching away from gas to renewable sources.

This shift in fuel used for electricity generation has meant two of our key shippers were significantly over-contracted in relation to full haul capacity in AA4 and therefore have elected to recontract at significantly reduced volumes in AA5. Under their previous agreements, these shippers could have simply relinquished that excess capacity. However, in anticipation of that occurring, DBP proactively engaged in a re-contracting process with these shippers to shore up their usage of the pipeline. [redacted].

In May 2020 we submitted updated capacity and throughput forecasts reflecting the outcome of the re-contracting process. The ERA in its Draft Decision accepted our May 2020 forecasts of contracted capacity and throughput for part haul and back haul services, but indicated that significant amendments would be required to our forecasts for the full haul service in order to make the proposal acceptable to the ERA.

The ERA set aside our actual full haul contracted capacity as they did not consider the reduction in capacity and throughput was supported by publicly available information, being the AEMO Gas Statement of Opportunities (GSOO) of December 2019.[2] The ERA was also concerned that the majority, if not all, of the reduced full haul capacity was not a true reduction of capacity, but a transfer of capacity to the peaker service which would deliver DBP unregulated revenue .[3] The ERA therefore required we substitute our full haul capacity and throughput forecasts for AA5 with 2020 values held flat over AA5.[4]

This reasoning by the ERA is concerning as:

- The AEMO GSOO relates to throughput, which is completely different from contracted capacity and is an 'apples and pears' comparison. Throughput will not drop suddenly on 1 January 2021, but contracted capacity will, because some of our largest shippers are over-contracted today and are taking the opportunity to reduce contracted capacity. This is an unarguable and straight forward fact that the ERA must consider in its decision.
- The ERA has also accepted our proposal in our Final Plan to make the peaker service revenues rebateable. If the ERA's reasoning for maintaining forecast contracted capacity at 2020 levels is to allow for peaker capacity then this represents a clear double count.
- The effect of these two proposals is to make it impossible for us to recover the ERA's proposed allowed revenues.

We have therefore not amended our Final Plan to incorporate the ERA's Draft Decision amendment. In this response to the Draft Decision we:

- Provide our market and operational understanding of the causes of the significant decreases in full haul capacity, being the changes to the electricity market with the advent of significant and new renewable electricity sources, and why we understand such reductions to reflect the actions of rational participants in the electricity market.
- Provide the ERA with our actual contracted capacity by shipper for full haul reference services and all non-reference services that utilise the DBNGP for AA5, including the peaker service.

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[2] ERA Draft Decision, [187].
[3] ERA Draft Decision, [200].
[4] ERA Draft Decision, [202].

- Demonstrate that the reduction of full haul capacity is a true reduction of that capacity and not a transfer to non-reference services.
- Reconciled the AEMO December 2019 GSOO with our forecasts, demonstrating that our forecasts of full haul throughput are not at significant variance to the GSOO.

1.2. ERA Draft Decision

Table 2: Summary of ERA's Draft Decision on Demand

	ERA Draft Decision	ERA Comment
Demand	**Reject**	DBP must amend its demand forecast for full haul reference services to maintain throughput and contracted capacity at 2020 forecast amounts - 626.22 throughput and 766.34 contracted capacity

1.3. Our Response to the Draft Decision

1.3.1. National Gas Rule requirements

NGR 72(1)(d) requires DBP to provide, to the extent it is practicable, a forecast of pipeline capacity and utilisation of pipeline capacity over the forthcoming access arrangement period, and the basis on which the forecast has been derived.

Under NGR 74, forecasts must be arrived at on a reasonable basis and must represent the best forecast or estimate possible in the circumstances.

As the ERA noted in its Draft Decision (see [159]), there are two relevant forecasts required for each reference service:

1. contracted capacity over the AA5 period; and
2. throughput over the AA5 period.

The first reflects the actual capacity our customers have contracted for over the AA5 period. AGIG does not have any expectation that any existing full haul shipper will increase or decrease their pipeline capacity over and above what they have presently contracted for in respect of the AA5 period or that a new full haul shipper will take up pipeline capacity or an existing shipper relinquish capacity at some point during the AA5. For this reason the forecast of capacity based on actual contracted capacity is the most reasonable basis upon which to forecast pipeline capacity and represents the best forecast possible in the circumstances. Our fixed costs are covered by the charged associated with contracted capacity.

The second forecast (throughput) is a forecast of the physical volume of gas that will flow through the DBNGP during the AA5 period. Our variable costs are covered by the commodity or throughput charge, and the forecast of throughput also drives our system use gas costs.

1.3.2. The Draft Decision forecasts

The ERA's Draft Decision forecasts of contracted capacity and throughput are set out in the following tables. The forecasts represent an increase from DBP's proposed forecasts of roughly 150TJ/d in respect of contracted capacity, and 70TJ/d of throughput on average over AA5.

Figure 1: ERA and AGIG capacity and throughput forecasts

Table 14: ERA's demand forecasts for reference services for AA5 (full haul equivalent TJ/d)

	2021	2022	2023	2024	2025
Full haul					
Throughput	589.35	589.35	589.35	589.35	589.35
Contracted capacity	718.08	718.08	718.08	718.08	718.08
Part haul					
Throughput	17.74	17.86	19.57	21.27	23.60
Contracted capacity	25.97	25.39	26.87	28.34	30.36
Back haul					
Throughput	13.89	13.27	13.27	13.27	13.27
Contracted capacity	18.09	17.29	17.29	17.89	17.89
Total system					
Throughput	620.98	620.48	622.18	623.89	626.22
Contracted capacity	762.14	760.76	762.24	764.32	766.34

Table 12: DBP's revised May 2020 demand forecasts for AA5 (full haul equivalent TJ/d)

	2021	2022	2023	2024	2025
Full haul					
Revised forecast throughput	536.28	526.80	520.22	514.45	508.15
Revised forecast contracted capacity	592.25	582.25	574.15	557.45	549.35
Part haul					
Revised forecast throughput	17.74	17.86	19.57	21.27	23.60
Revised forecast contracted capacity	25.97	25.39	26.87	28.34	30.36
Back haul					
Revised forecast throughput	13.89	13.27	13.27	13.27	13.27
Revised forecast contracted capacity	18.09	17.29	17.29	17.89	17.89
Total system					
Revised forecast throughput	567.91	557.93	553.06	548.99	545.03
Revised forecast contracted capacity	636.31	624.93	618.31	603.69	597.60

The ERA accepted as reasonable our part haul and back haul forecasts (contacted capacity and throughput). [redacted] This information was not available for either our Final Plan or the Draft Decision. All other part and back haul forecasts are as per our Final Plan and as accepted by the ERA in the Draft Decision.

The ERA's Draft Decision required amendments to our full-haul forecasts and these are the focus of this response. The ERA's Draft Decision was that it is reasonable to forecast full haul contracted capacity and throughput as being constant through the AA5 period from the level that DBP had forecast for 2020. There appear to be two primary reasons for the ERA's Draft Decision (discussed at [185] to [201]):

- AGIG forecasts a large drop in contracted capacity and throughput in 2021, which does not match the slight increase in gas "demand" in Western Australia forecast by AEMO in the 2019 GSOO, made with particular reference to the closure of Muja C.[5]
- Demand for services on the DBNGP includes reference and non-reference services. The ERA's Draft Decision was that the peaker service offered by DBP could act as a substitute for reference services.[6] Given the uncertainties of peaker demand, the ERA determined that a flat demand for reference services from 2020 levels is reasonable to account for some substitution to the peaking service.[7]

However:

- The ERA's comparison of contracted capacity with the GSOO gas demand forecasts is 'apples and pears' – it compares and confuses contracted capacity with throughput (which is the subject of the GSOO). Throughput will not change significantly on 1 January 2021 compared to 31 December 2020, but contracted capacity will, because key shippers have taken actions to reduce their contracted capacity because they are over-contracted at present. This is a relevant fact. GSOO forecasts of throughput are not directly relevant to contracted capacity.
- A forecast which holds full haul contracted capacity constant takes no account of changes in the market, which have driven a change in contracting behaviour by our shippers. It also takes no account of our customers resulting reductions in actual contracted capacity from 2021 onwards. Our actual contracted capacity is the best evidence available of forecast contracted capacity over AA5. Given the change to the electricity market, particularly the substantial increases in renewable electricity, there is no reasonable basis to forecast any significant new demand for full haul contracted capacity to offset reductions in the capacity contracted for by major electricity generators in the SWIS. Such new demand has not eventuated in AA4 nor is it reasonable to expect it will occur in AA5. We are certainly not aware of any new full haul capacity over and above the actual contracted capacity on the DBNGP.
- There have been significant changes in the Western Australian electricity market over the AA4 period which will intensify over AA5 and beyond. The evolution of the WA electricity market, driven by substantial increases in renewable electricity generation (wind and solar, and now battery storage), will impact on how shippers that use gas to generate electricity use the DBNGP, with consequential impacts on demand for full haul contracted capacity on the DBNGP.

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[5] ERA Draft Decision, [186]-[188] and [197].
[6] ERA Draft Decision, [191] to [194] and [200].
[7] ERA Draft Decision, [200].

- Similarly, holding forecast throughput constant at 2020 levels does not represent the best estimate because it does not take account of the significant changes in the electricity market [redacted]
- [redacted]
- Further, the effect of the ERA's reasoning summarised above is to account in its forecast of reference service capacity, capacity for a non-reference service, being the peaker service. This results in non-reference service capacity being accounted for twice; first in determining reference service full haul capacity and second in rebateable non-reference service capacity. This approach cannot give rise to the best estimate of full haul contracted capacity.
- The AEMO forecasts in the GSOO equate to throughput and not to contracted capacity. While the GSOO forecasts may be relevant to the forecast of throughput, when properly analysed the differences from DBP's throughput forecasts are small.

We discuss these issues further below.

1.4. Incorrect contracted capacity in the Draft Decision

By far the most important issue in the ERA's Draft Decision is its decision to base contracted full haul capacity forecasts on a view formed from consideration of throughput found in the 2019 GSOO. The issue of whether the GSOO is an adequate forecast of throughput given that it is now a year out of date, and the question of which part of the GSOO forecast is relevant are questions we detail further below. In this section we address the topic of what has actually been contracted by our shippers, how this differs from the ERA's forecast, and the consequences of that to our ability to earn our efficient cost of service.

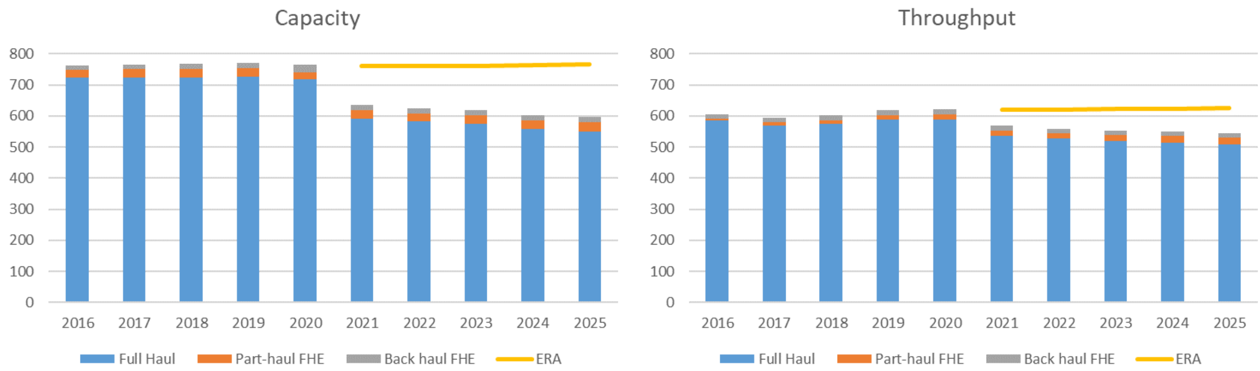
In making its Draft Decision, the ERA set aside the re-contracting decisions made by our customers who are reducing full haul contracted capacity to 592TJ/d in 2021, and set a tariff based on current levels of contracted capacity of 718TJ/d. Because of this, it is impossible for us to recover anything close to the ERA's view of our efficient cost of service in its Draft Decision. Based on the ERA's Draft Decision, we would recover revenue of around $1,230m only (see below). This includes revenues on all our other services, including the new peaker service.

The ERA's decision to set aside our customers' recontracting decisions is the aspect of the Draft Decision which is of greatest concern to us, and is not consistent with the ERA's approach for previous access arrangement decisions. Estimating contracted capacity should be straightforward and uncontroversial, as actual contracting decisions by customers are known and represent the best estimate of this.

The ERA makes reference to evidence including AEMO's GSOO that gas 'demand' is not falling. This reference is very concerning to us as it relates to throughput, which is different from contracted capacity and is an 'apples and pears' comparison. Throughput has a relatively small decline on 1 January 2021, but contracted capacity drops much more sharply, because some of our largest shippers are over-contracted today and are taking the opportunity to relinquish capacity. This is an unarguable fact that the ERA needs to consider in its decision. The ERA may feel we are making up the revenue shortfall from reductions in capacity through other unregulated revenues, such as the peaking services. However this is not the case, as is discussed below.

The significant reduction in contracted capacity, and the much smaller reduction in throughput is shown in Figure 2 below.

Figure 2: Capacity and throughput from AA4 to AA5 (including ERA forecasts)



Further detail underpinning both the actual contracted capacity position and the throughput forecasts is provided in subsequent sections. However, the practical consequence of ignoring the significant drop in contracted capacity can be seen in Table 3 below. In this table, we apply the ERA's Draft Decision reference service tariff (of roughly $1.05 full haul equivalent) to the contracted capacity information and throughput forecast we have provided to the ERA (summarised in Table 12 of the ERA's Draft Decision) to derive reference service revenue, and then add to this the forecasts revenues, post-rebate, from non-reference services.

Table 3: Reference and non-reference service revenues post rebate - $ mil real (2020 ERA tariffs with AGIG demand forecasts)

	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The ERA's assessment of what our efficient costs are is $1.5 billion (in dollars of December 2020), and it asserts that we should recover $1.46 billion of this from reference tariffs. As shown in Table 3 above, if our capacity and throughput forecasts are correct, which forecasts reflect actual contracted capacity, we would recover only $1.155 billion from reference services and only around $45 million from non-reference services, to give a total of $1.20 billion, or a shortfall of:

- around $300 million compared to what the ERA considers to be our efficient costs in its Draft Decision; and
- Around $377 million compared to this revised Final Plan.

There appears to be a view in the Draft Decision (see, for example [200]) that there has been some substitution from reference to non-reference service demand, and therefore that forecasting flat throughput and capacity from 2020 is reasonable. Table 3 shows this to be incorrect. We are unable to earn our efficient costs from a combination of references and non-reference service revenues.

These fundamental facts underscore our view in this response that the ERA's forecast of capacity and throughput cannot be the best available forecast, and the impacts summarised above highlight the importance of this issue in making the final decision. We now turn to the detailed background which underpins our views noted above.

1.5. Changes in the WA electricity market

The DBP was originally developed to deliver gas to domestic markets from the North West Shelf Consortium. Since that time, the capacity of the pipeline has been expanded and additional inlet points have been added to service growth. As set out in the October 2020 report from ACIL Allen titled "Gas Demand Review; Dampier to Bunbury Natural Gas Pipeline" (Attachment 11.4), when the wholesale electricity market for the South West Interconnected System (SWIS) commenced in 2006, there was a strong outlook for gas demand in the SWIS.[8]

[8] ACIL Allen:"Gas Demand Review, Dampier to Bunbury Natural Gas Pipeline, October 2020, section 3 p8.

Over the past 10 years, gas for power generation in the SWIS has been a major consumer of domestic gas supply in Western Australia, consuming between 70PJ and 80PJ over that time.[9] During AA4, gas for power generation represented roughly 50% of our full-haul capacity, and around 25% of our full-haul throughput. In AA5, this has fallen to represent 25% and 15% respectively.

By 2014, the environment had changed significantly from that which existed in 2006[10]:

- Gas prices rose as oil and LNG prices rose making gas less competitive with other fuels for electricity generation.
- Several significant wind farms had either entered or were in the process of entering the market.
- The falling cost of wind and solar technologies drove projections of additional wind and solar farms to enter.

From 2014 to 2020, there have been further developments[11]:

- Renewable technology costs have improved faster than projected in 2014 with several large-scale wind and solar projects being developed.
- The reintegration of Synergy (retailer) and Verve (generator) – into a new entity called Synergy – increased incentives for Synergy, which provides around 50% of the electricity sold to household and business customers in the SWIS, to develop self-owned renewable electricity in the SWIS.
- Shortages in renewable electricity certificates (RECs) led to a large rise in REC spot prices and the forward curve (during the latter part of the last decade), increasing general interest in the development of renewable projects.
- Grid based demand in the SWIS fell as rooftop solar PV increased.
- Synergy owned and operated Muja A&B was closed with Muja C to be closed progressively from 2022 to 2024.
- The Kwinana gas fired generators owned by Synergy were retired.

The result of these significant changes in the WA electricity market has been a substantial drop in projected SWIS gas consumption (capacity and throughput) compared with earlier years[12]. This is shown in Figure 3 prepared by ACIL Allen, using historical consumption and ACIL's own Wholesale Electricity Market (WEM) simulation model.

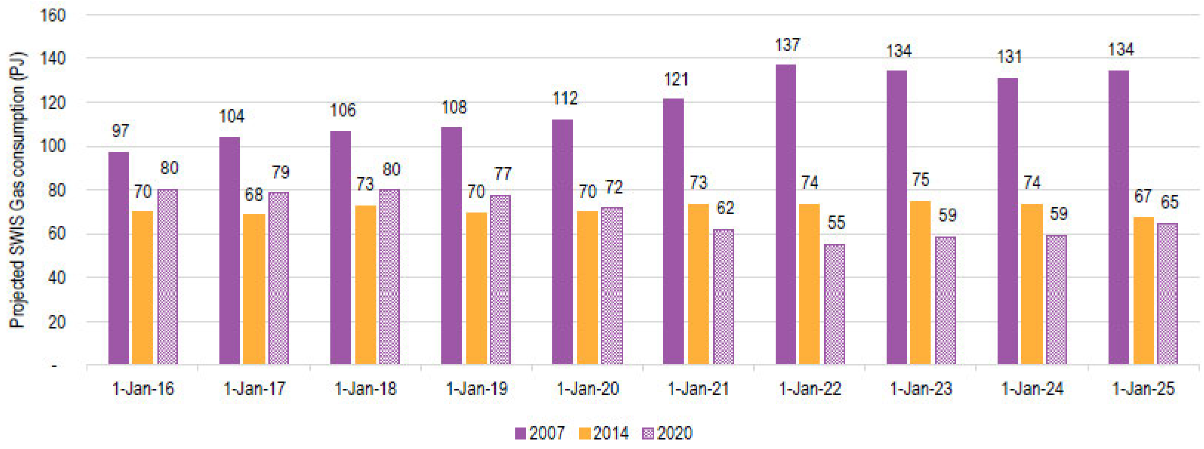
[9] Ibid.

[10] Ibid.

[11] ACIL Allen:"Gas Demand Review, Dampier to Bunbury Natural Gas Pipeline, October 2020, section 3 pp8-9

[12] ACIL Allen:"Gas Demand Review, Dampier to Bunbury Natural Gas Pipeline, October 2020, section 3 p9

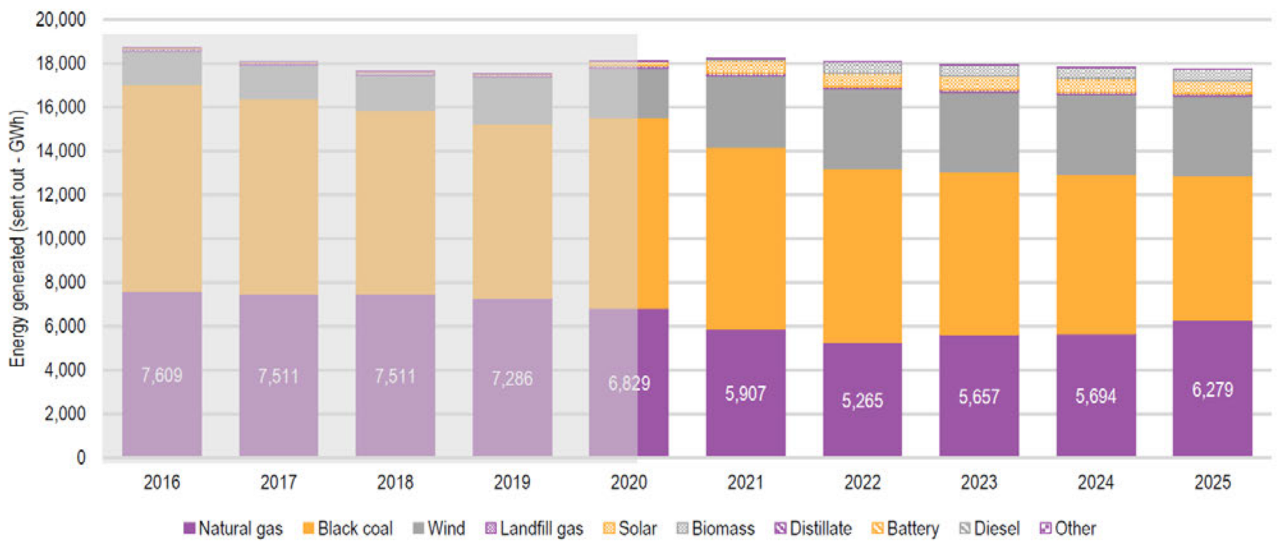
Figure 3: ACIL Allen historical projections of SWIS demand



Source: ACIL Allen, 2020, p9

ACIL Allen's simulation of the WEM predicts gas fired power generation in AA5 to fall to be around 78% of the annual average gas-fired power generation in AA4. The projected fall is driven by additional rooftop solar PV installations and grid-based renewable electricity entering the market.[13] The ACIL Allen WEM modelling projects an increase in renewable electricity generation of around 2,500 GWh of renewable electricity in the WEM over 2020-2022.

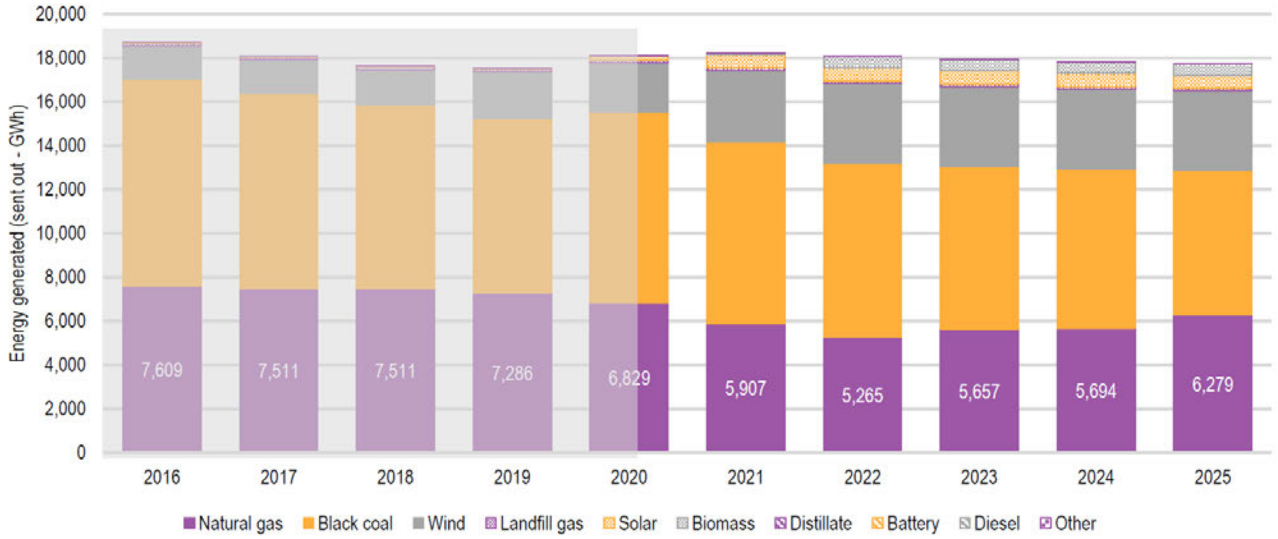
ACIL Allen explain that gas is now the most expensive fossil fuel used to fire electricity generation in the WEM, and has therefore become the swing fuel in the market.[14] With the retirement of the Muja C power station in late 2022 to 2024, gas fired power generation is projected to increase by around 1000 GWh by 2025, from the low point in 2022. The relative increase in gas-fired generation is consistent with the expected loss of coal-fired generation over the latter part of AA5. This is shown in Figure 4: Historical and projected sources of electricity generation in the SWIS



Source: ACIL Allen, 2020, p11.

Figure 4: Historical and projected sources of electricity generation in the SWIS

[13] ACIL Allen:"Gas Demand Review, Dampier to Bunbury Natural Gas Pipeline, October 2020, section 3 p11
[14] Ibid



Source: ACIL Allen, 2020, p11

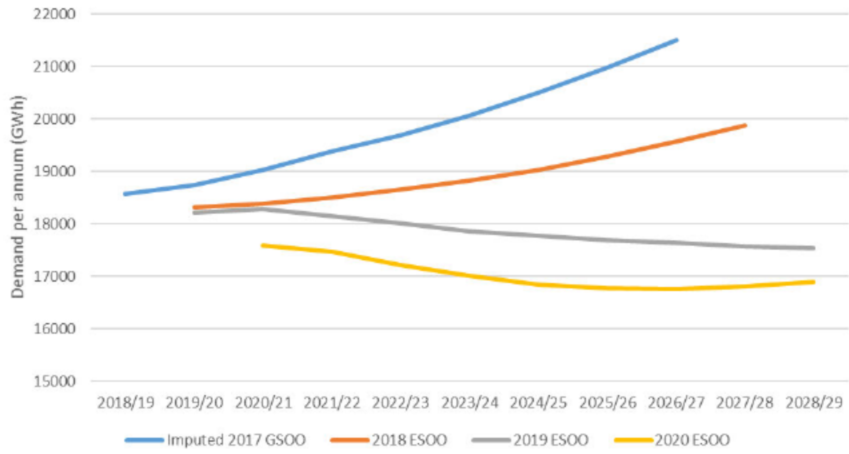
It appears that the impact of some of these trends are somewhat muted in the 2019 GSOO, and ACIL Allen notes (footnotes omitted):

> *We consider these gas for power generation projections by AEMO's consultant and which we understand AEMO relied upon for its 2019 GSOO forecast, to be unreliable as they:*
>
> - *appear to be out of date*
> - *appear inconsistent with the expected entry of renewables and displacement of gas-fired generation*
> - *appear inconsistent with the expected exit of Muja C and increased requirement for gas-fired generation*
>
> *In contrast, ACIL Allen's projected reduction in gas-fired generation is consistent with the stable demand environment and the entry of large-scale renewable energy generators into the WEM.*
>
> *In relying on the consultant's projections for the 2019 GSOO, AEMO forecasts a relatively small 5.3 per cent reduction in demand for gas for power generation in the SWIS from 2020 to 2021 which remains stable through to 2024 and then grows again substantially from 2024 (around 6.5 per cent higher in 2025 compared with 2020).*
>
> *The ACIL Allen projection, which has later information and a more consistent treatment of gas and renewables, shows a 13.3 per cent reduction from 2020 to 2021, a further 11.4 per cent fall from 2021 to 2022, a 6.7 per cent increase from 2022 to 2023 (exit of first Muja C unit in 2022), stable gas usage from 2023 to 2024 and then a 9.3 per cent increase from 2024 to 2025 (exit of second Muja C unit in 2024).*
>
> *AEMO states that part of the increase is caused by increased ramping of generators because of increased rooftop and grid-based solar. However, the GSOO gas forecasts do not appear to take account of this increased solar penetration displacing gas for power generation. The AEMO projections for*

> *the SWIS do not appear consistent and appear to underestimate the effect of renewables entering and displacing gas-fired generation.*
>
> *In conclusion, AEMO appears to rely on out of date information and potentially flawed modelling of the entry of renewable energy and its effect on gas-fired generation in the SWIS. This raises valid concerns about relying on the 2019 GSOO in determining DBP throughput forecasts for AA5*

As the GSOO tends to be influenced by the Electricity Statement of Opportunities (ESOO) published 6 months earlier, DBP anticipates that the forecasts in the 2020 GSOO will more properly reflect the factors discussed above. Over the past four years, the pattern in the ESOO has been one of significant drops, year on year. This is shown in Figure 5.

Figure 5: AEMO ESOO Forecasts – 2017 to 2020



Source: AEMO, Electricity Statement of Opportunities 2018 (p40), 2019 (p50) and 2020 (p68). The 2018 ESOO presents 2017 and 2018 figures in MW, and the 2019 ESOO gives 2018 figures in GWh. We thus use the percentage changes in the MW figures in the 2018 GSOO from 2017 to 2018 o impute the GWh figures for 2017.

The amount of electricity generation being forecast for the SWIS drops a significant 20% over the course of these four years; by contrast, prior to 2017, the AEMO ESOO forecast differed very little year to year.[15] It is also worth noting that the ESOO picks up electricity dispatched in the network and the drops from 2017 reflect only one part of the renewable power sector; behind the meter distributed generation. The much lower demand figures for 2020 also reflects much more grid-scale renewable generation than was forecast in 2017.

In addition to the ACIL Allen report above, we have also attached to this revised Final Plan a report from Mr Paul Keay of energyXL (Attachment 11.5). Mr Keay is an experienced independent WA electricity market consultant who works with large commercial and industrial and commercial customers and has a vast amount of experience in the market. Mr Keay explains that since the DBNGP commenced operation in 1984, there has been a significant market shift with Government renewable energy targets encouraging utility scale renewables and subsidies of rooftop solar pv resulting in a profound impact on the electricity market in Western Australia:

> *Now, the greatest challenge being faced by the WA energy market is the threat to stability and market mechanisms that is posed by integrating the huge influx of renewable generation. The growth in rooftop solar pv is now better understood but accelerating and several large wind projects are scheduled to commission in 2020.* [16]

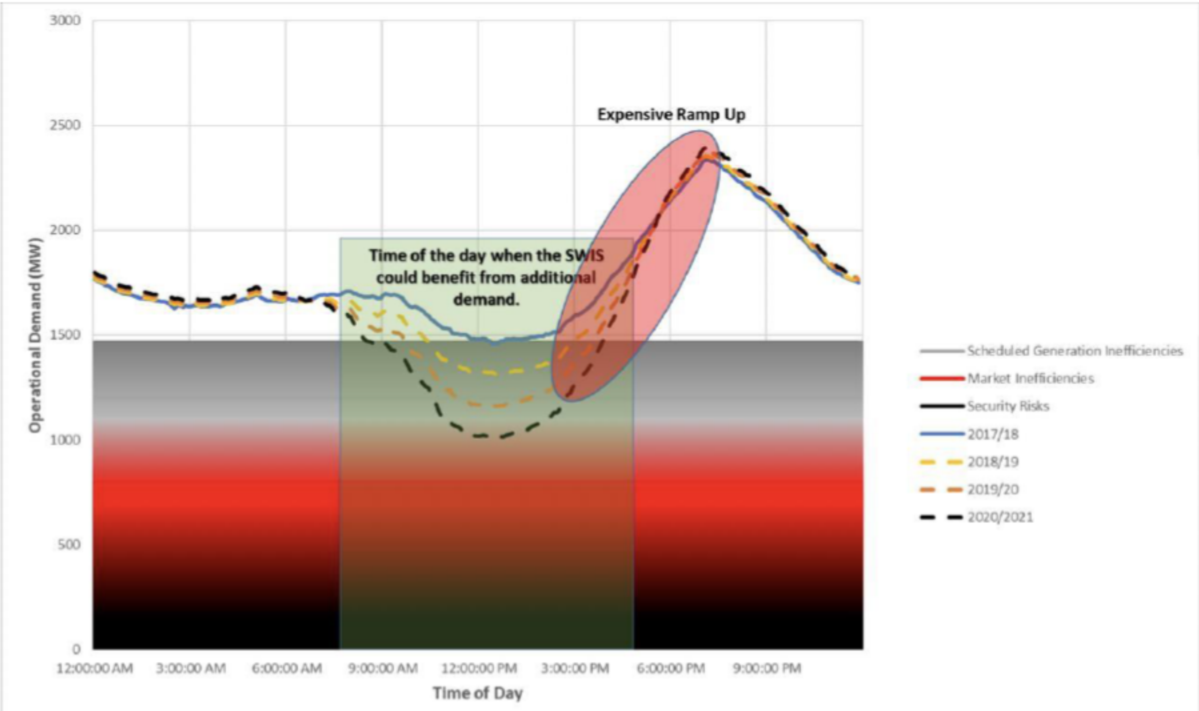
[redacted] The below chart shows the increasing, year on year "hollowing out" of electricity demand caused by rooftop solar pv.

[15] See 2017 ESOO, Figure 33.

[16] Report of Paul Keay, energy XL, 7 October 2020, page 2.

Mr Keay states that

> *Meeting the changing load shape below, year on year is the challenge that the power generators on the SWIS are having to meet.*[17]



Source: PUO Industry Reform Presentation – "The Duck Curve"

Mr Keay's report also comments that (page 5)

[redacted]

It is uncontroversial that the WA electricity market is going through a transformation to transition to a low carbon future, specifically driven by the introduction of renewable electricity (wind and solar) into the market. The changes in the market are having a profound impact on the demand of gas used for electricity generation in the SWIS over the AA5 period, impacting the major users of gas transported on the DBNGP. This has fundamentally changed the way in which our customers that use gas for electricity generation seek to use the DBNGP in AA5 as outlined in the next section.

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[17] Page 3-4

1.6. DBP’s contracted capacity - the best estimate.

Attachment 11.6 to this revised Final Plan is a statement of Mr Jon Cleary, General Manager Commercial of AGIG. My Cleary’s statement explains the drivers for the significant reduction in our major customer’s [redacted] It also addresses our actual contracted capacity overall for the AA5 period and why that is considered the best evidence of capacity over the forthcoming period.

The statement of Mr Cleary in Attachment 11.6 explains that:

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[18] Paragraph 5
[19] Paragraphs 8 to 9.
[20] Paragraph 11(a)
[21] Paragraph 11(a)
[22] Paragraph 11(b)
[23] Paragraph 11
[24] Paragraphs 16 to 27

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[25] Paragraphs 28 to 29

[redacted]

[redacted]

[redacted]

Table 4: Full haul capacity for AA5

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1.6.1. Summary of contracted capacity

Our actual contracted capacity over AA5 is the best evidence of our customers full haul requirements over that period. This is the same evidence used by the ERA to set capacity

[26] ACIL Allen:"Gas Demand Review, Dampier to Bunbury Natural Gas Pipeline, October 2020, section 2.1 p4

forecasts for AA4 and, as shown in [redacted] and summarised above, is a very good predictor of actual capacity requirements.

Copies of the schedules to our full haul contracts demonstrating the actual contracted capacity over AA5 have been provided to the ERA (see Attachment 2 to Mr Cleary's Statement). Mr Cleary's statement attaches the updated schedules to our full haul contracts. The reason for the reductions in full haul contracted capacity from AA4 have been explained above, by [redacted] themselves, in the statement of Mr Cleary, in ACIL Allen's report and Mr Keay's report. The reduction in contracted actual capacity is clear and evidence based.

In connection with capacity, the only remaining question that arises is whether there is any additional full haul contracted capacity likely to arise in the AA5 period. The statement of Mr Cleary sets out why there is no reasonable prospect of additional full haul contacted capacity, particularly substantial new contracted capacity equal to the reduced requirements of the electricity generators. This is also confirmed by the analysis of the WA gas market and expectations over the AA5 period from ACIL Allen.

As ACIL Allen note, in an environment where there is a large surplus of uncontracted pipeline capacity and significant structural changes in the WA electricity market, the strong incentives on gas-fired generators (making up the majority of our contracted capacity) is not to contract for full haul firm capacity and instead rely on shipping overrun gas when required.[27]

DBP's position is that it is clear that our actual full haul contacted capacity over AA5 represents the best estimate of forecast contracted capacity over that period. That contracted capacity shows a significant reduction from 2021 onwards. A forecast which holds contracted capacity flat from forecast 2020 levels cannot be the best estimate given the dramatic changes in the WA gas market and the resulting reduction in our customer's full haul actual contracted capacity over AA5.

1.7. The peaker service

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[27] ACIL Allen:"Gas Demand Review, Dampier to Bunbury Natural Gas Pipeline, October 2020, section 2.2 p5

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What this shows is that the peaker service, on any view, will not fill the gap left by the significant reductions in full haul contracted capacity.

Further and in any event, the ERA has correctly accepted the peaker service as a non-reference rebateable service. The forecast required by the NGR is of full haul contracted capacity. Demand for a non-reference service cannot be accounted for in a full haul reference service forecast. The

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[30] ACIL Allen:"Gas Demand Review, Dampier to Bunbury Natural Gas Pipeline, October 2020, section 2.2 p7

[31] Ibid

peaker service has been made a rebateable service reflecting that it is a non-reference service with substantial uncertainty in demand. This approach ensures shippers will receive any benefit from this new service.

1.8. Understanding the 2019 GSOO and throughput

The ERA's Draft Decision relies on the forecasts from the AEMO GSOO as part of its rationale for maintaining the 2020 forecasts of both throughput and capacity throughout AA5. For example [187]:

> *The ERA assessed DBP's throughput forecasts and supporting information and considers that the step decline in full haul throughput from 2020 to 2021 is inconsistent with AEMO's gas demand forecasts. AEMO has forecast a 1.9 per cent increase in gas demand each year between 2020 to 2024 in Western Australia. In aggregate, AEMO forecast a 15 per cent increase in gas demand from 2019 to 2029, supported by the closure of Muja C to maintain electricity system stability and to provide support to base load power over the period.*

And subsequently [198]:

> *The ERA considers that DBP's forecast is not the best forecast considering the concerns raised above (at paragraphs 185 to 194), including that it does not reflect the stable to small growth that AEMO is forecasting for Western Australia. AEMO is forecasting an annual growth rate of 0.6 per cent per year for gas services in the metro/south-west region which would include DBP's full haul customers.*

This EMCa report (see pp36-42) also focuses on differences between the GSOO and DBP's own forecasts.

The difference between DBP's forecast and the 2019 GSOO is, in reality, much smaller than the headline numbers appear. As we outline below, the differences essentially relate to demand for gas for power generation in the SWIS, which is the key driver of the decrease in actual contracted capacity discussed so far in this attachment. The differences are largely explained by new information which has become available since the 2019 GSOO was published, in particular:

- new renewable electricity projects; and
- changes to wholesale gas prices since North West Shelf Joint Venture gas has ceased to flow and shippers have shifted to new, more expensive gas.

1.8.1. The relevant region

The major focus of EMCa's assessment is between our forecasts for the DBNGP and the GSOO for WA as a whole. The DBNGP does not carry the entire gas demand for Western Australia, along even part of its length. Demand for gas in WA is not synonymous with gas demand for the DBNGP.

As noted above, the ERA's Draft Decision has accepted our forecasts of throughput and capacity for our part and back-haul services (see [201] of the Draft Decision). These services are provided north of CS9. This means that the relevant comparison between our forecasts and the GSOO should focus on the South West.

The GSOO does not include forecasts of demand on a pipeline-by-pipeline basis, and since its customer-based categories include operations all over the state (the category of "mining" includes nickel mines in the south west as well as iron ore mines in the Pilbara, for example), the most relevant point of comparison within the GSOO is between our full-haul forecasts of throughput and the GSOO forecasts for the South West region. These differences are shown in Table 6.

Table 6: GSOO 2019 South West and AGIG Full Haul forecasts (TJ/d)

	2021	2022	2023	2024	2025
GSOO South West	648.0	655.0	658.0	660.0	673.0
DBNGP Full Haul forecast	536.3	526.8	520.2	514.4	508.2

On the basis of this raw comparison, the difference ranges from 112 TJ/d in 2021 to 165 TJ/d in 2025. This is around a 40% smaller difference than the differences shown by EMCa (see Table 5.1 p39) in its report.

1.8.2. Relevant adjustments to the GSOO

Table 6 is only a starting point for the comparison, because demand for full-haul services on the DBGNP is not the same thing as demand in the South West as a whole. In particular:

- The Parmelia gas pipeline, with a capacity of 65TJ/d also serves the South West region of WA.
- Not all services to shippers in the South West of WA along the DBNGP represent full haul reference services; there are part services utilized by shippers in the South West.
- Not all gas transported on the DBNGP to the South West is reference service gas.

These differences are outlined in

Table 7 below, which points to an adjusted difference between our forecasts and those of the 2019 GSOO of between 31 TJ/d in 2021 and 54TJ/d in 2025.

We identify below gas flowing down the Parmelia Gas Pipeline (PGP) by the relevant contract we have with the relevant shipper, rather than amalgamating or making a forecast based on what is currently shipped down that pipeline.

Table 7: Adjusted GSOO 2019 South West and AGIG Full Haul forecasts (TJ/d)

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1.8.3. Explaining the remaining difference

After making the adjustments referred to above, the relevant difference, (not accounted for by throughput pursuant to the Parmelia Gas pipeline specific contracts that constitute demand in the South West and full haul demand on the DBGP) is between 31 and 54TJ/d; a difference of between six and 12% of our forecasts (and a smaller proportion of the GSOO forecasts). There are two sources of demand which might account for this difference:

- New projects which have been accounted for by the GSOO but not by us.
- Differences due to "demand destruction"; demand that might have been plausible when the 2019 GSOO forecast was made but which subsequent events now make implausible.

New projects

The GSOO lists the following major projects in its various scenarios (see p 19):[32]

- BHP's South Flank project, due to commence operation in 2021.
- Rio Tinto's Koodaideri iron ore project, with first production planned for late 2021.
- Albemarle Corporation's Kemerton lithium processing plant, near Bunbury, scheduled to commence in 2021.
- FMG's Iron Bridge magnetite processing project (stage 2), due to commence in mid-2022.
- Gold Field's Agnew Gold Mine renewable electricity microgrid, expected to be completed in 2020. Renewable power generation from the project is anticipated to reduce existing gas demand by approximately 0.5 TJ/day.
- Hazer Group's biogas to hydrogen and graphite project, expected to reduce existing gas consumption by approximately 2 TJ/day, beginning in 2020.

Of these, only the Albermale project in Kemerton and the Hazer Group hydrogen projects are in the South West, and thus relevant for comparative purposes. The Albermale project, which is currently on hold indefinitely was forecast to use 1 to 2 TJ/d in its first stage, and the Hazer project is covered by existing supply.

Demand destruction

In order to ascertain whether there is some "demand destruction" which has been reflected in our actual contracted capacity but not by the GSOO, we look in this section at demand by sector.

The GSOO does not provide a breakdown of its south-west demand into industry segments. All that it says about throughput in the South West is as follows (p24):

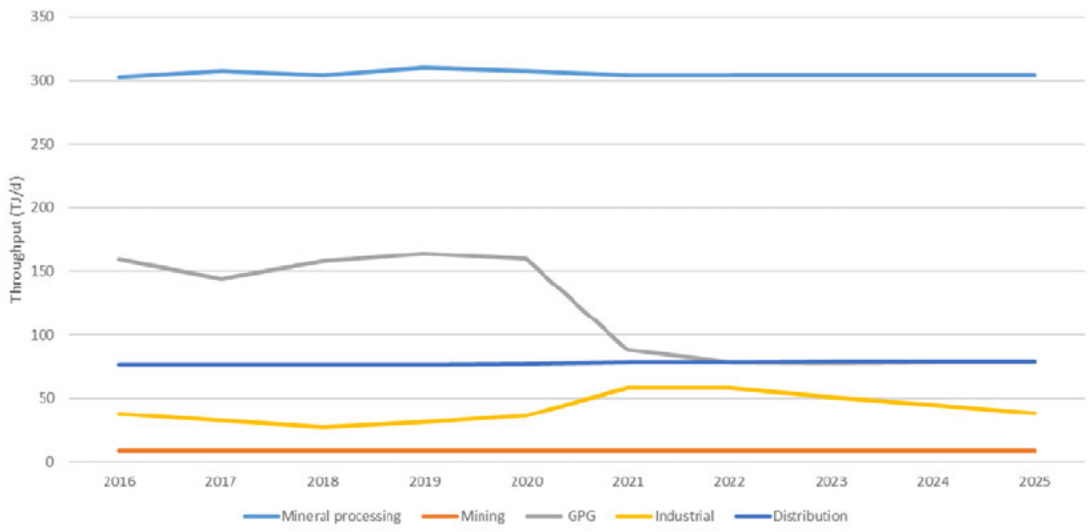
> *Growth in both mining and new projects is forecast in the Metro/South West region, but at a smaller scale than in the North. New projects are estimated to contribute an additional 2.8 TJ/day demand by the end of the outlook period. This is partially offset by the forecast reduction in demand from SWIS GPG associated with the entry of renewable generation, as discussed in Sections 2.2.2 and 2.2.3.*

By way of context, the addition in mining in the North comes in 2023 and is 57TJ/d. The South West is much smaller than that because the total increase in the period in the South West is around 25TJ/d from 2021 to 2025, with most of this coming between 2024 and 2025. This is associated with the retirement of Muja C, which AEMO suggests will impact demand in 2022 and 2024.

To provide some basis of comparison, we have grouped our throughput forecasts into AEMO's groups, with the exception of "Distribution". Gas for the distribution network is shipped by retailers and shippers of gas for power generation and so we have taken our actual and forecast throughput for our gas for power generation customers and subtracted AEMO's actual and forecast distribution gas demand forecasts from these.

[32] AEMO also include another 10 prospective projects in their "high" scenario.

Figure 7: Actual and forecast gas throughput by AEMO category in the AGIG forecasts



In the Draft Decision, the ERA points to capacity and throughput forecasts that are relatively constant from AA4 to AA5 as a reason to accept our part and back-haul forecasts (see Draft Decision [201]) and notes an expectation on its part of generally stable demand through AA5 (see Draft Decision [200] and [201]). It is therefore useful to consider Figure 7 in this context.[33]

Our mining demand is relatively flat, whilst the GSOO has some (unspecified) rise. We consider this likely to give rise to a relatively minor difference; the total rise in the South West in the GSOO is 25TJ/d, and it appears most of this is associated with what AEMO believe will happen around Muja C.

The obvious stand-out is gas for power generation. [redacted]

By contrast, AEMO believes the drop is about 5.3% and then a recovery towards the end of the period consequent upon Muja C closing. The central issue appears to be the 2019 GSOO forecast for gas for power generation.

Gas for power generation forecasts

ACIL Allen's October 2020 report considers the differences between the 2019 GSOO gas for power generation forecasts with our own forecasts. ACIL Allen's conclusion (see quotation above) is that the projections by AEMO's consultant relied upon in the 2019 GSOO are unreliable because they are out of date, appear inconsistent with the expected entry of renewables and displacement of gas fired generation and with the expected exit of Muja C.[34]

Having considered the AEMO consultant forecast, ACIL Allen also considered our adjusted GSOO forecasts as set out in the table above. After adjusting for the concerns identified with AEMO's consultant's forecasts, the remaining difference ranges between 3.8PJ/annum in 2022 and 13.4PJ

[33] We note that, on a shipper-by-shipper basis, demand is also relatively flat for almost all shippers [redacted]

[34] ACIL Allen:"Gas Demand Review, Dampier to Bunbury Natural Gas Pipeline, October 2020, section 3.2 p12

per annum in 2025. ACIL Allen consider this remaining difference to be within reasonable error estimates for this type of forecasting.[35]

1.9. Summary

The ERA's Draft Decision proposes capacity and throughput forecasts for AA5 which are based upon initial forecasts for 2020 and held constant from that point. This is motivated partly on an assessment of the 2019 GSOO gas throughput forecast compared to contracted capacity in our Final Plan (but throughput and contracted capacity are very different), and on a view that much of the drop in demand might be associated with a shift to non-reference services (but the ERA proposes to make these rebateable anyway).

This response shows that the ERA's forecast in the Draft Decision is not the best forecast available under the circumstances as it, in particular:

- Does not sufficiently take into consideration actual contracts signed by our shippers which cover the AA5 period and which represent the best forecast of contracted capacity and have been accepted as such in past regulatory decisions.
- Is methodologically incorrect, as it inappropriately uses a throughput forecast (the GSOO) to support a forecast of contracted capacity, an 'apples and pears' comparison of two very different things, and contains a double count because the peaker services are rebateable. This results in it being impossible for us to recover anything close to the ERA's proposed allowed revenues.
- Overstates the difference between our forecasts and the GSOO which, properly considered, are relatively small. The GSOO itself is not the best available forecast of throughput as it is out of date and appears to contain some flaws, and it is not a forecast of actual contracted capacity at all.
- Does not adequately respond to the significant changes in the electricity market in WA which have led to the changes in the contracting position of our shippers involved in electricity generation. These changes represent almost all of the differences in capacity and throughput for full-haul shippers between AA4 and AA5.

The best available forecast is that provided in Table 1 in this attachment (with detail in the appendix). [redacted]

[35] ACIL Allen:"Gas Demand Review, Dampier to Bunbury Natural Gas Pipeline, October 2020, section 3.3 p14

Appendix A Detailed capacity and throughput forecasts

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