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AUSTRALIAN ENERGY MARKET OPERATOR

GAS POWERED GENERATION FORECAST MODELLING – FINAL REPORT

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1 Introduction

1.1 Project Background

The Gas Services Information (GSI) Rules require AEMO to produce a Western Australian (WA) Gas Statement of Opportunities (GSOO) report on an annual basis. The GSOO must include a forecast of gas demand over a 10-year calendar horizon. One of the key drivers of gas demand is the amount of gas-fired generation which is expected to be dispatched over this horizon.

1.2 Purpose of this document

This document is the final deliverable of the GPG forecast project. This report includes:

- The finalised methodology and assumptions
- A summary of the modelling results
- Key insights and observations
- An assessment of limitation and gaps of the modelling methodology and results.

2 Final Methodology and Assumptions

In this section we specify the methodology and assumptions used to perform the GPG forecast analysis.

The input data assumptions to be used for the modelling is a combination of:

- Data provided by AEMO specifically for this project
- Publicly available data from AEMO and other sources
- RBP's own knowledge and insights

This section specifies the data that has been used for the modelling, the methodologies used to derive or obtain this data, the data sources that were used, and the simulation model used to obtain the results.

2.1 Simulation Model

We have used our in-house dispatch optimisation tool WEMSIM to conduct the analysis to produce the forecasts of market outcomes.

WEMSIM co-optimises energy dispatch and reserve provision using:

- Generation facility data such as capacity, outage rates, ramp rates, heat rates and cost information (fuel, Variable Operation and Maintenance Costs [VOM], Fixed Operation and Maintenance Costs [FOM])
- Transmission data, either via the specification of thermal limits of generic constraints (as used in the NEM and for the WEM Generator Interim Access [GIA] arrangement)
- Reserve requirement and provision data.

WEMSIM outputs can include (but is not limited to):

- Fuel use by generators
- Hourly energy dispatch and reserve provided
- Locational price forecasts (i.e. nodal prices)
- Capacity utilisation of generation facilities
- Revenues earned and costs incurred by facility and participant

- Emissions, such as total CO_2 equivalent.

2.2 Generation Facility Assumptions

2.2.1 Existing Generators

Assumptions for the technical parameters and operational costs of existing generators have been taken from the publicly available AEMO Costs and Technical Parameter Review, completed in 2018 by GHD[1]. AEMO provided updated values for the following parameters:

- Heat rates
- Unit capacities

2.2.2 Retirements

The following fixed retirements are assumed, consistent with the WA Government announcement on 5 August 2019[2]:

Unit	Retirement Date
MUJA_G5	1 October 2022
MUJA_G6	1 October 2024

2.2.3 New Build

There are a number of new generators coming online during the 10-year gas forecasting horizon that are not included in the 2018 Costs and Technical Parameter Review. The list of these generators was provided by AEMO to RBP to enable us to conduct the 2019 Reliability Assessment for the 2019 WEM Electricity Statement of Opportunities (ESOO)[3]. These generators are listed in Table 2.

[1] Available from https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies

[2] https://www.mediastatements.wa.gov.au/Pages/McGowan/2019/08/Muja-Power-Station-in-Collie-to-be-scaled-back-from-2022.aspx

[3] https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities

Table 1. New Build

Unit name	Commencement Date	Type
BADGINGARRA_WF1	2019	Wind
Ambrisolar1	2019	Solar
GREENOUGH_RIVER_PV1_UPG_1	2019	Solar
PHOENIX_KWINANA_WTE_G1	2021	Biomass
WARRADARGE_WF1	2020	Wind
Yandin_WF1	2020	Wind
MERSOLAR PVI	2020	Solar

2.2.4 Utility-Scale Intermittent Profiles

We have reapplied the methodology used in the 2019 Reliability Assessment to derive intra-day hourly profiles for each intermittent utility-scale facility. Using this methodology, we have used historical generation for existing facilities from non-loss adjusted metered quantities (supplied by AEMO) and participant provided estimated generation for new facilities to develop the profiles as follows:

- For each month (Jan, Feb, ..., Nov, Dec), we assign an intra-day hourly profile to each intermittent generator.
- This means each intermittent generator will have 12 intra-day hourly profiles (one for each month of the year).
- Hence, $\overline{Gen_{h,m}} = \frac{1}{T}\sum_{Y\ (Years)=1}^{T}\left(\frac{\sum_{d\ (days)\in Month\ m} Gen_{Y,h,d}}{\#\ days\ in\ month\ m\ of\ Year\ Y}\right)$

  For a given intermittent generator:
  - $\overline{Gen_{h,m}}$ denotes the average generation (MW) in hour h of month m (based on T years of historical or participant provided generation values)
  - $Gen_{Y,h,d}$ denotes the historical or estimated generation value in hour h or day d (in month m) of Year Y.

This approach captures both intra-day and seasonal variation, while ensuring the average hourly generation values are based on a sample size large enough to yield robust generation estimates.

This has resulted in 12 intra-day profiles for each of the 30 intermittent facilities, which were entered into the model do define each intermittent facilities' generation pattern.

2.2.5 DER Profiles – Solar PV

DER PV Capacity Forecasts

The AEMO has provided forecasts of DER Solar PV Capacity for 'Neutral', 'Fast Change' and 'Slow Change' scenarios under the 2019 WEM ESOO. Only the 'Neutral' forecast has been used for this project.

DER PV Capacity Profiles

The profile of solar PV generation is complex, with seasonal, daily variability and random intermittency caused by cloud cover that makes maximum power point (MPP) tracking difficult. For the purpose of modelling, this can be broken down into:

- Daily generation potential profiles for each month of the year, assuming zero cloud cover. These are deterministic (i.e. fixed and predictable) profiles and are expressed as capacity factors (i.e. fraction of installed capacity).
- An outage probability distribution function (PDF), expressing the probability that a given unit of generation output will be eliminated by cloud cover. This PDF is dependent on the outage (i.e. cloud cover) in the previous hour, and this dependency needs to be factored in to avoid excessive changes in solar PV output from one period to the next. This dependency is also a function of the season of the year. Therefore, PDFs have been computed for a range of previous hour outage factors and each season (summer, winter and shoulder).

The AEMO has provided historical solar PV capacity factor data for each trading period from 9 September 2011 to 20 February 2019 (2,722 days). Using statistical analysis of the historical data, we have processed this into daily generation profiles for each month and outage PDFs as described above. This data is shown in Figure 1 to Figure 4 below.

These two factors are combined to simulate a realistic solar generation profile for each model run. This is done by:

1. For each modelled hour, selecting the generation potential value (from Figure 1 below)
2. For each modelled hour, randomly generating an outage factor given the season and previous hour's outage factor from the PDFs shown in Figure 2 - Figure 3 for the applicable season (as defined in Table 2).
3. Multiplying these two factors by the forecast MW PV capacity for the period, to obtain a MWh generation value for the period.

Table 2. Season definitions for solar PV analysis

Month	Season
January	Summer
February	Summer
March	Shoulder
April	Winter
May	Winter
June	Winter
July	Winter
August	Winter
September	Winter
October	Winter
November	Shoulder
December	Summer

Figure 1. Daily solar PV generation potential profiles

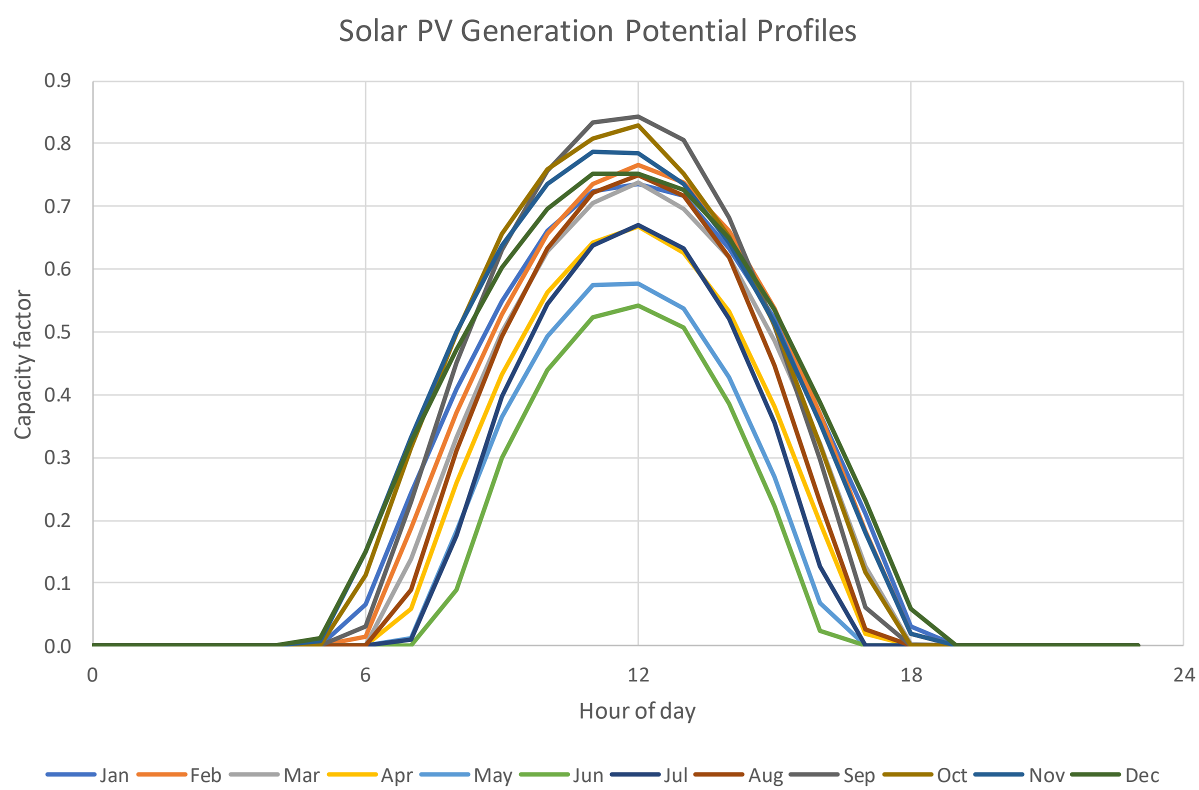


Figure 2. Summer PV outage factor PDFs

	Previous Outage Factor										
Outage Factor	**0**	**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**	**0.7**	**0.8**	**0.9**	**1**
0.00	0.1417	0.0316	0.0165	0.0122	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.05	0.2833	0.1158	0.0248	0.0061	0.0052	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.10	0.1417	0.1053	0.0413	0.0122	0.0000	0.0087	0.0024	0.0000	0.0000	0.0000	0.0000
0.15	0.1417	0.1684	0.0661	0.0122	0.0104	0.0087	0.0000	0.0000	0.0000	0.0000	0.0017
0.20	0.0583	0.0842	0.0661	0.0732	0.0155	0.0174	0.0121	0.0000	0.0000	0.0000	0.0000
0.25	0.0583	0.1053	0.1240	0.0488	0.0466	0.0304	0.0097	0.0000	0.0000	0.0000	0.0000
0.30	0.0333	0.0737	0.1240	0.0854	0.0311	0.0130	0.0097	0.0028	0.0007	0.0000	0.0000
0.35	0.0417	0.0842	0.1405	0.0671	0.0933	0.0478	0.0340	0.0055	0.0007	0.0000	0.0000
0.40	0.0417	0.0316	0.0661	0.0793	0.0570	0.0478	0.0316	0.0111	0.0013	0.0003	0.0000
0.45	0.0167	0.0632	0.0413	0.0976	0.1140	0.0696	0.0558	0.0152	0.0007	0.0003	0.0034
0.50	0.0000	0.0421	0.0992	0.1220	0.0674	0.0913	0.0728	0.0305	0.0007	0.0003	0.0000
0.55	0.0083	0.0421	0.0661	0.0976	0.1036	0.1087	0.0777	0.0637	0.0059	0.0009	0.0017
0.60	0.0000	0.0000	0.0331	0.0244	0.0725	0.0696	0.0850	0.0720	0.0059	0.0012	0.0000
0.65	0.0083	0.0105	0.0331	0.0671	0.0933	0.1130	0.1165	0.1399	0.0183	0.0006	0.0017
0.70	0.0000	0.0211	0.0165	0.0610	0.0984	0.1261	0.1019	0.1524	0.0944	0.0047	0.0000
0.75	0.0000	0.0211	0.0165	0.0488	0.0881	0.0739	0.1117	0.0803	0.1520	0.0056	0.0017
0.80	0.0000	0.0000	0.0000	0.0305	0.0259	0.0478	0.0631	0.1080	0.1265	0.0243	0.0084
0.85	0.0083	0.0000	0.0083	0.0183	0.0155	0.0478	0.0510	0.0928	0.1252	0.0909	0.0118
0.90	0.0083	0.0000	0.0083	0.0183	0.0259	0.0261	0.0850	0.0776	0.2110	0.1136	0.0152
0.95	0.0000	0.0000	0.0000	0.0000	0.0155	0.0261	0.0461	0.0512	0.1645	0.4177	0.2230
1.00	0.0083	0.0000	0.0083	0.0183	0.0207	0.0261	0.0340	0.0970	0.0924	0.3396	0.7314

Figure 3. Shoulder PV outage factor PDFs

	Previous Outage Factor										
Outage Factor	**0**	**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**	**0.7**	**0.8**	**0.9**	**1**
0.00	0.2000	0.0217	0.0000	0.0067	0.0053	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.05	0.1579	0.1522	0.0593	0.0200	0.0160	0.0038	0.0000	0.0000	0.0000	0.0000	0.0000
0.10	0.1684	0.0761	0.0932	0.0267	0.0428	0.0038	0.0026	0.0000	0.0000	0.0007	0.0000
0.15	0.1368	0.0978	0.0593	0.0533	0.0321	0.0639	0.0000	0.0000	0.0009	0.0000	0.0000
0.20	0.0842	0.1630	0.0508	0.0733	0.0374	0.0376	0.0128	0.0000	0.0009	0.0000	0.0000
0.25	0.0737	0.0761	0.1102	0.0533	0.0481	0.0263	0.0383	0.0016	0.0009	0.0000	0.0000
0.30	0.0632	0.0870	0.1017	0.0800	0.0642	0.0414	0.0281	0.0016	0.0000	0.0000	0.0000
0.35	0.0316	0.0870	0.1102	0.0733	0.0535	0.0338	0.0459	0.0063	0.0000	0.0000	0.0000
0.40	0.0316	0.0217	0.0763	0.1000	0.0749	0.0414	0.0612	0.0204	0.0046	0.0000	0.0000
0.45	0.0211	0.0652	0.0593	0.1133	0.1070	0.0714	0.0408	0.0314	0.0009	0.0007	0.0032
0.50	0.0105	0.0109	0.1017	0.0467	0.0802	0.0789	0.0587	0.0582	0.0046	0.0027	0.0032
0.55	0.0000	0.0326	0.0424	0.0667	0.0695	0.0789	0.0816	0.0818	0.0073	0.0027	0.0000
0.60	0.0105	0.0435	0.0339	0.0867	0.0856	0.0865	0.0765	0.0818	0.0165	0.0007	0.0000
0.65	0.0105	0.0217	0.0508	0.0267	0.0481	0.0940	0.1173	0.0818	0.0430	0.0007	0.0000
0.70	0.0000	0.0217	0.0085	0.0400	0.0588	0.0714	0.0791	0.0896	0.0704	0.0041	0.0000
0.75	0.0000	0.0109	0.0085	0.0467	0.0588	0.0752	0.0740	0.1431	0.0859	0.0130	0.0032
0.80	0.0000	0.0109	0.0254	0.0133	0.0588	0.0376	0.0510	0.1195	0.1161	0.0382	0.0159
0.85	0.0000	0.0000	0.0000	0.0200	0.0267	0.0376	0.0561	0.0912	0.1892	0.0696	0.0255
0.90	0.0000	0.0000	0.0085	0.0333	0.0214	0.0489	0.0587	0.0597	0.2331	0.1849	0.0223
0.95	0.0000	0.0000	0.0000	0.0067	0.0107	0.0414	0.0383	0.0503	0.1453	0.3854	0.2038
1.00	0.0000	0.0000	0.0000	0.0133	0.0000	0.0263	0.0791	0.0818	0.0804	0.2967	0.7229

Figure 4. Winter PV outage factor PDFs

	Previous Outage Factor										
Outage Factor	**0**	**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**	**0.7**	**0.8**	**0.9**	**1**
0.00	0.1961	0.0539	0.0092	0.0023	0.0000	0.0015	0.0017	0.0000	0.0000	0.0000	0.0000
0.05	0.2549	0.1146	0.0538	0.0185	0.0101	0.0037	0.0011	0.0005	0.0004	0.0000	0.0000
0.10	0.1373	0.1034	0.0584	0.0462	0.0110	0.0044	0.0023	0.0010	0.0000	0.0006	0.0000
0.15	0.1054	0.1011	0.0845	0.0370	0.0321	0.0191	0.0086	0.0029	0.0000	0.0006	0.0000
0.20	0.0809	0.0854	0.0922	0.0439	0.0321	0.0235	0.0155	0.0043	0.0000	0.0000	0.0000
0.25	0.0490	0.0966	0.1137	0.0624	0.0478	0.0323	0.0229	0.0095	0.0012	0.0000	0.0027
0.30	0.0539	0.1011	0.1152	0.0994	0.0707	0.0381	0.0287	0.0147	0.0024	0.0000	0.0000
0.35	0.0441	0.0854	0.1075	0.1029	0.0670	0.0389	0.0465	0.0185	0.0020	0.0006	0.0054
0.40	0.0196	0.0719	0.0876	0.1214	0.0781	0.0521	0.0390	0.0228	0.0060	0.0024	0.0027
0.45	0.0196	0.0382	0.0661	0.1017	0.1221	0.0667	0.0396	0.0299	0.0088	0.0018	0.0000
0.50	0.0123	0.0360	0.0568	0.0994	0.1157	0.1144	0.0425	0.0423	0.0099	0.0043	0.0000
0.55	0.0147	0.0225	0.0507	0.0647	0.1120	0.1107	0.0740	0.0428	0.0163	0.0043	0.0000
0.60	0.0025	0.0247	0.0215	0.0566	0.0918	0.1327	0.1015	0.0528	0.0223	0.0049	0.0000
0.65	0.0025	0.0225	0.0184	0.0312	0.0661	0.1210	0.1532	0.0699	0.0290	0.0091	0.0082
0.70	0.0025	0.0202	0.0138	0.0393	0.0487	0.0858	0.1234	0.1226	0.0640	0.0146	0.0109
0.75	0.0000	0.0135	0.0123	0.0162	0.0349	0.0579	0.1239	0.1407	0.0867	0.0316	0.0245
0.80	0.0000	0.0000	0.0138	0.0127	0.0174	0.0418	0.0797	0.1649	0.1396	0.0584	0.0163
0.85	0.0049	0.0067	0.0184	0.0197	0.0110	0.0249	0.0465	0.1069	0.2387	0.0815	0.0299
0.90	0.0000	0.0000	0.0031	0.0139	0.0119	0.0139	0.0212	0.0832	0.2243	0.2426	0.1223
0.95	0.0000	0.0022	0.0015	0.0092	0.0129	0.0044	0.0132	0.0447	0.0907	0.3660	0.1766
1.00	0.0000	0.0000	0.0015	0.0012	0.0064	0.0125	0.0149	0.0252	0.0577	0.1769	0.6005

2.2.6 Emissions Factors

The quantity of carbon emissions resulting from electricity generation has been calculated based on:

- The quantity of each fuel consumed for generation, as calculated by the model
- Emissions factors for each fuel, as published in the *National Greenhouse Accounts Factors – July 2018* by the Australian Government Department of the Environment and Energy[4]

2.2.7 Operational Stability Constraint

The AEMO have advised a minimum stable load that can be maintained. At this level of load, all generation must be synchronous thermal generation to maintain system stability. Above this level of load, a minimum of this level of synchronous thermal generation must be scheduled to maintain system stability.

To implement this requirement, we have added a constraint that a minimum level of thermal generation must be maintained at all times. Should demand fall below this level, a violation penalty

[4] https://www.environment.gov.au/climate-change/climate-science-data/greenhouse-gas-measurement/publications/national-greenhouse-accounts-factors-july-2018

price is incurred, which sets the resulting market price. The presence of this penalty in the market price results indicates an unstable level of system demand.

2.2.8 Other Operational Constraints and Offer Patterns

To replicate actual generation patterns, additional operations constraints are placed on some plant. These are based on advice provided by AEMO:

- Some groups of cogeneration units should have a minimum number of units operating at all times, to support the industrial process supplied by these units. This is implemented by a constraint such that the sum of the generation from the two units must be greater than or equal to a specified value at all times.
- Some units have seasonal availability.

The WEMSIM model assumes by default that generators offer their capacity at their Short Run Marginal Cost (SRMC). An analysis of actual balancing market offer (which are publicly available from the AEMO website) shows that many generators offer all or a portion of their capacity at negative prices to ensure that they are dispatched. For these units, we have overridden the SRMC-based offers with fixed negatively priced offers.

2.2.9 Virtual Power Plants

Virtual Power Plants (VPPs) are not considered in the modelling, as there are no specific plans to introduce them in the WEM, and they would not be expected to significantly impact gas consumption.

2.3 Transmission Network and Constraints

The WEM currently operates on an unconstrained basis, with GIA constraints used to manage the output of new GIA generators. Remaining generators are dispatched on an unconstrained basis using the Balancing Merit Order but can be constrained on or off in real-time to manage system security; when this occurs, participants are eligible to receive constraint payments.

It is expected that on 1 October 2022, Security Constrained Economic Dispatch (SCED) will be implemented on the basis of a single region hub and spoke model with a reference node located at Southern Terminal.

The GSOO horizon comprises 2020 to 2029. Hence, we have needed to form a view on what market design assumptions to adopt from 2022/23 onwards. We have adopted the following approach:

- Model the existing WEM with GIA constraints only for 2019/20, 2020/21 and 2021/22, excluding real-time interventions and subsequent constraint payments.
- From 2022/23 onward assume that NEM style SCED will apply (namely a single zone hub and spoke market with the reference node at Southern Terminal).

2.4 Demand

Electricity demand is characterised as the sum of the following data:

- Base demand, excluding block loads, EV charging and DER generation
- Block load demand
- EV charging demand
- Distributed battery charging demand and discharge

Each of these data items is described in the following sections.

2.4.1 Base Demand

Our base demand forecasting methodology is based on the following inputs:

- A base year hourly demand profile
- Forecast energy demand for each modelled year
- Forecast peak demand for each modelled year

The base year hourly demand profile is then scaled according to the forecast energy and peak values to produce hourly forecasts for each model year.

The base year demand profile is the average of the load shapes of the previous 5 years, with the load chronology of the most recent full capacity year (2017/18). Figure 5 presents the load duration curves (LDCs) of the previous capacity years along with the average load shape.

To produce forecasts that exclude DER generation and block loads, we have subtracted the historical DER and block load data provided by the AEMO from the historical load data before conducting the above analysis. We assume that historical EV charging and distributed battery charge/discharge is negligible.

Figure 5. Base year load duration curves

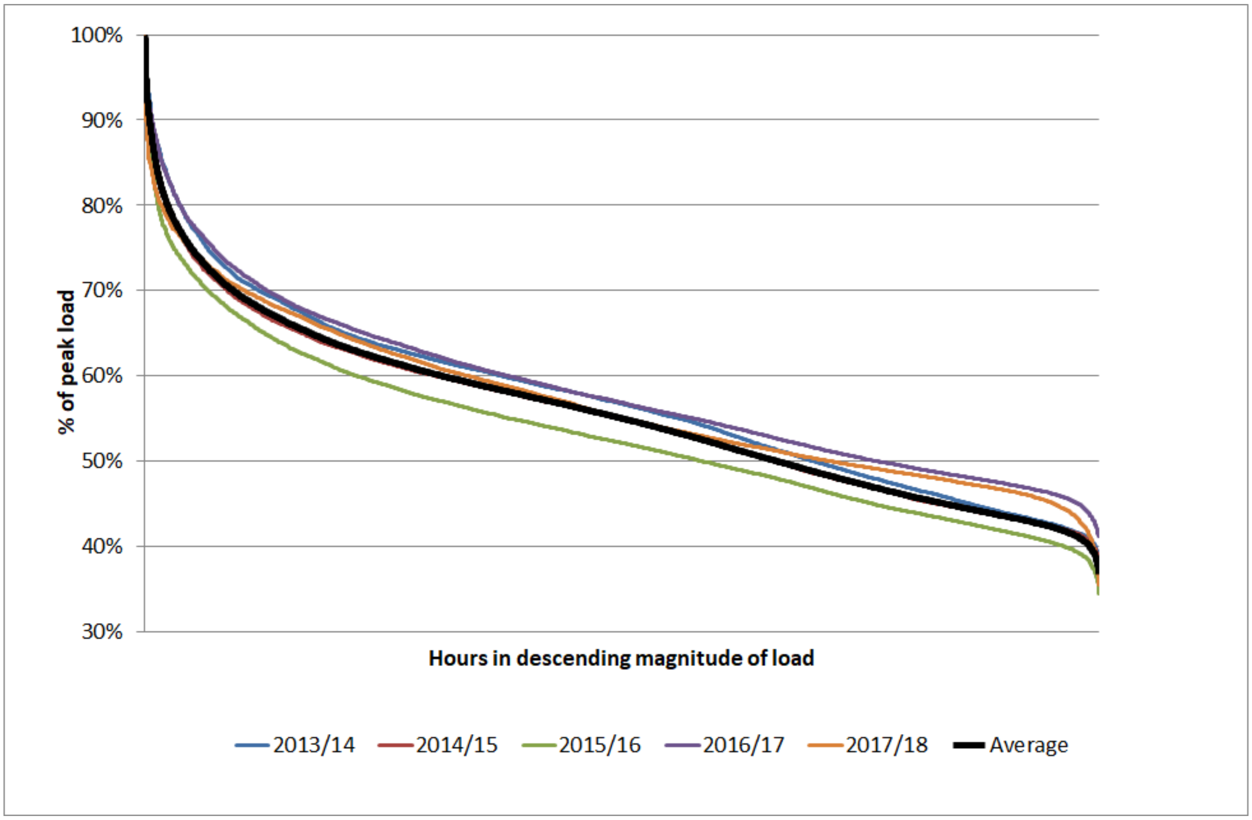


Table 3 and Table 4 summarise the base case annual demand forecasts and 50% POE peak demand forecasts provided by the AEMO:

Table 3. Demand forecasts (base load)

Capacity Year	Annual Demand - Expected (MWh)	Annual Demand – High (MWh)	Annual Demand – Low (MWh)
2019/20	16,552,269	16,555,151	16,549,260
2020/21	16,604,374	16,611,410	16,597,229
2021/22	16,661,720	16,674,510	16,649,021
2022/23	16,723,830	16,744,118	16,703,961
2023/24	16,790,071	16,819,794	16,761,261
2024/25	16,860,496	16,901,712	16,820,796

2025/26	16,935,197	16,990,101	16,882,518
2026/27	17,014,099	17,085,112	16,946,156
2027/28	17,096,223	17,185,699	17,010,989
2028/29	17,179,283	17,288,610	17,075,723

These forecasts are also exclusive of DER generation and block loads. Demand forecasts are specified in terms of sent out generation requirements, so transmission losses are not modelled.

Table 4. Peak demand (50% POE forecasts, base load)

Capacity Year	50% POE peak forecast - Expected	50% POE peak forecast - High	50% POE peak forecast - Low
2019/20	3507	3526	3492
2020/21	3521	3538	3507
2021/22	3539	3553	3514
2022/23	3554	3566	3535
2023/24	3570	3589	3544
2024/25	3587	3614	3556
2025/26	3610	3635	3577
2026/27	3632	3661	3604
2027/28	3652	3688	3617
2028/29	3677	3713	3633

2.4.2 Block Loads

AEMO defines block loads as "temperature insensitive large loads that operate almost continuously"[5]. AEMO have supplied us with historical block load data for the existing block load facilities.

[5] 2018 WEM ESOO Report

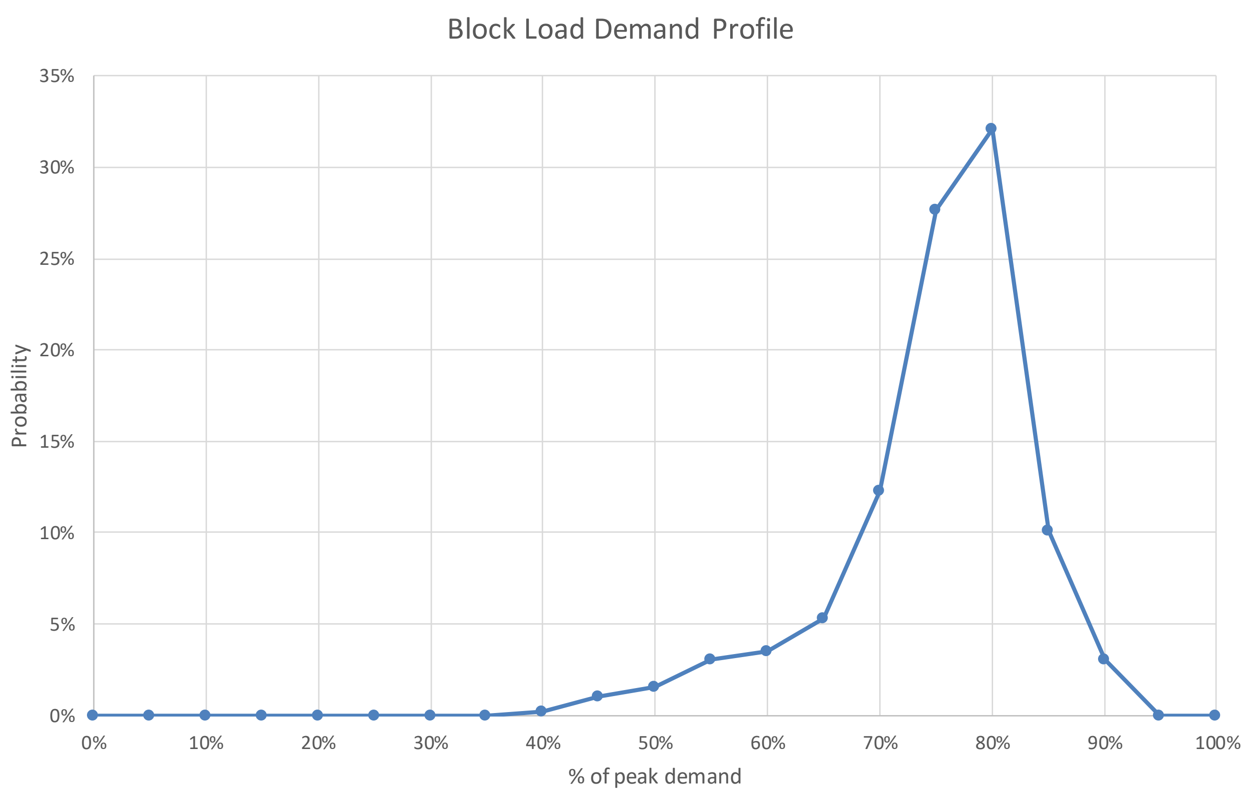
The peak load values (99.9th percentile values to eliminate outliers in data) have been determined from our analysis of data provided by AEMO – a total of 459.19 MW.

Future additional block loads have been added to the above list according to the profile supplied by AEMO.

Consistent with AEMO's definition (see above), our analysis shows that these loads are best characterised as constant loads, with random load variations (including full and partial reductions). The data does not demonstrate a strong seasonal demand reduction profile, so a seasonal pattern has not been modelled.

The probability distribution of the random load variations is as shown in Figure 6 (a demand-weighted average across all facilities). This distribution shows, for each level of demand (expressed as a percentage of peak load), the probability of the level of load occurring. For each year of the modelling run, an hourly block load MW sequence has been generated by applying this profile to the full load MW value for the year.

Figure 6. Probability density function of block load variations



2.4.3 EV Charging Demand

AEMO have supplied forecasts for the demand arising from electric vehicle (EV) charging. The supplied data takes the form of:

- Monthly forecast numbers for type of EV, for Expected, High and Low uptake cases:
  - Residential EV
  - Light Commercial EV
  - Electric Truck
  - Electric Bus
- Charging profiles for each type of EV, for 4 different tariff types:
  - Convenience charge
  - Incentivised night charging
  - Incentivised day charging (to offset PV)
  - Fast charge
- An expected percentage share for each charging profile by type of EV and year for Expected, High and Low case.

For each modelling scenario, an Expected/High/Low case and a subset of charging profiles has been selected (as specified in section 2.7). The EV charging demand for each period in a given model year is then calculated as follows:

$$EVLoad_{p,y} = \sum_{t \in EVTypes} \left(EVNum_{c,t,y,M(m)} \sum_{pr \in Profiles} ChProf_{t,pr,M(p),p} \frac{ProfShare_{c,t,pr,y}}{\sum_{pr2 \in Profiles} ProfShare_{c,t,pr2,y}} \right)$$

Where:

$EVLoad_{p,y}$	is the calculated EC charging demand for period p in model year y
$EVTypes$	is the set of EV types
$EVNum_{c,t,y,m}$	is the forecast number of EVs for case c, EV type t, year y, month m
$Profiles$	is the selected subset of charging profiles for the modelling scenario
$ChProf_{t,pr,m,p}$	is the charging profile MW value for EV type t, charging profile pr, month m, period p

$M(p)$	is the number of the month that period *p* is in
$ProfShare_{c,t,pr,y}$	is the charging profile share for case *c*, EV type *t*, charging profile *pr*, year *y*

2.4.4 Distributed Battery Charging Demand and Discharge

Distributed batteries include installations in domestic and commercial properties.

AEMO has supplied charge and discharge profile data for modelling purposes. The supplied data consists of:

- Charge and discharge profiles for domestic and commercial batteries, by period and month of year. These are expressed as a fraction of the installed kW battery capacity
- MW capacity and MWh duration forecasts by year and month for domestic and two classes of commercial batteries (up to 100kW and above 100kW), and for three uptake cases (Expected, High and Low)
- A forecast of the number of battery installations has also been supplied but has not been used by us.

The resulting net charge/discharge for a given period in a model year is calculated as:

$$\begin{aligned} BattNetCD_{y,p} = {} & 1000 \times \left(Charge^{Res}_{M(p),p} - Discharge^{Res}_{M(p),p}\right) \times BatMW^{Res}_{c,y,M(p)} \\ & + 1000 \times \left(Charge^{Com}_{M(p),p} - Discharge^{Com}_{M(p),p}\right) \times \left(BatMW^{ComSml}_{c,y,M(p)} + BatMW^{ComLge}_{c,y,M(p)}\right) \end{aligned}$$

Where:

$BattNetCD_{y,p}$	is the net battery charge/discharge for period *p* in year *y*
$Charge^{Res}_{m,p}$	is the residential charge profile for month *m*, period *p*
$Discharge^{Res}_{m,p}$	is the residential discharge profile for month *m*, period *p*
$Charge^{Com}_{m,p}$	is the commercial charge profile for month *m*, period *p*
$Discharge^{Com}_{m,p}$	is the commercial discharge profile for month *m*, period *p*
$M(p)$	is the number of the month that period *p* is in
$BatMW^{Res}_{c,y,m}$	is the forecast residential battery capacity in MW
$BatMW^{ComSml}_{c,y,m}$	is the forecast small commercial battery capacity in MW
$BatMW^{ComLge}_{c,y,m}$	is the forecast large commercial battery capacity in MW

This net charge/discharge is a negative value when discharge exceeds charge demand, so reduces the total demand.

2.5 FUELS

Fuel prices are specified in real 2018 AUD terms, so the market prices produced by the model are also in Real 2018 AUD terms.

2.5.1 Pipeline Natural Gas

The prices for pipeline natural gas have been supplied by AEMO for the purpose of this analysis with 'base', 'high' and 'low' price scenarios. A notable feature of these prices is the significant increase in gas prices in the high scenario from 2024 to 2025, which will have a significant impact on the results for the 'Low' gas demand scenario (which used the high gas price data).

2.5.2 Coal

Coal-fired generators in WA receive coal directly from WA coal mines under a contract between the mining companies and the WA government. The terms of this contract are not public, so the cost of this coal needs to be estimated for modelling purposes.

WA coal is not exported beyond WA, so does not receive global market prices.

Data on the value of WA coal is provided in the *Western Australian Mineral and Petroleum Statistics Digest 2017-18*, published by the Government of Western Australia Department of Mines, Industry Regulation and Safety[6]. This provides data on the quantity and value of coal produced in WA. Assuming a calorific value of 19.7 GJ/t[7], this yields the following historical prices:

Table 5. Coal price results from published statistics

Year	Volume (t)	Value (AUD)	AUD/t	AUD/GJ
2017	6,806,389	338,435,045	49.72	2.52
2018	6,679,935	331,959,622	49.70	2.52

Based on these results, we have used a constant price (in real 2018 AUD terms) of AUD 2.52/GJ.

[6] http://www.dmp.wa.gov.au/About-Us-Careers/Statistics-Digest-3962.aspx

[7] Guide to the Australian Energy Statistics 2017: https://www.energy.gov.au/sites/default/files/guide-to-australian-energy-statistics-2017_0.docx

2.5.3 Distillate

Historical "Perth Terminal Gate" prices for distillate (i.e. Diesel) are available from the Australian Institute of Petroleum[8]. Diesel prices are strongly correlated with global (e.g. Brent) crude oil prices, and a linear correlation can be obtained based on historical diesel and crude oil prices. By applying this correlation to crude oil price forecasts[9] , a distillate price forecast can be obtained as provided in Table 6.

Table 6. Distillate price forecast

Year	Price (Real 2018 AUD/GJ)
2019	25.18
2020	25.22
2021	22.38
2022	22.65
2023	23.19
2024	22.05
2025	22.63
2026	23.19
2027	23.68
2028	23.99
2029	24.17

The following parameters are also assumed in this forecast:

- Excise tax (currently 0.416 c/l) and GST (10%) are rebated
- Calorific value is 3.86 MJ/l[10]
- Transport cost to Parkeston area is 3.2 c/l[11]

2.6 ANCILLARY SERVICES

In all years we have modelled Spinning Reserve (SR) and Load Following Ancillary Services (LFAS) as currently defined in the WEM Rules:

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8 https://www.aip.com.au/pricing/terminal-gate-prices/perthDiesel

9 Figure 2.4 of the Core Energy and Resources report "Delivered Wholesale Gas Price Outlook 2019-2040"

10 from AEMO 2018 Energy Price Limits Review report by Jacobs: https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/Price-Limits/Jacobs-Final-Report.pdf (note 3.86 is MJ/l, not GJ/l as in Jacobs report)

11 Also from AEMO 2018 Energy Price Limits Review report by Jacobs

- SR: 70% of the largest generating unit
- LFAS: 85MW (5:30AM – 7:30PM); 50MW (7:30PM – 5:30AM)

We note that there is currently reform work under way defining new ancillary services (referred to as "Essential System Services" in the context of the reform project) that may be required in the future. As it is still unclear what those services may look like and how they may be procured, we assume that the above quantities remain in force. However, it is reasonable to assume that the market for SR will be opened up post-reform, so that a larger number of facilities will be able to provide this service. We have not assumed the same for LFAS, as there are entry barriers to providing LFAS.

2.7 Scenario Definitions

In consultation with AEMO, we have developed a range of scenarios to be modelled for the GPG forecast study, as specified in Table 7:

Table 7. Scenario definitions

	Base (expected)	Low	High
Peak demand	50% POE - expected	50% POE - Low	50% POE - high
Operational energy	expected	low	high
Behind the meter PV	expected	expected	expected
Behind the meter Battery storage	expected	expected	expected
EV	expected	low	high
Block loads	expected	low	high
Generation retirement	Muja C retirement	Muja C retirement	Muja C retirement
Gas prices	Base	High	Low
New entrants (as per section 2.2.3)	2019 ISP Central	2019 ISP Slow change	2019 ISP Fast change

3 Summary of Modelling Results

In this section we provide a summary of the key modelling results. Full modelling results, down to an hourly time resolution, have been provided to AEMO in spreadsheet form.

In the following sections, we provide summaries of the following results on an annual basis:

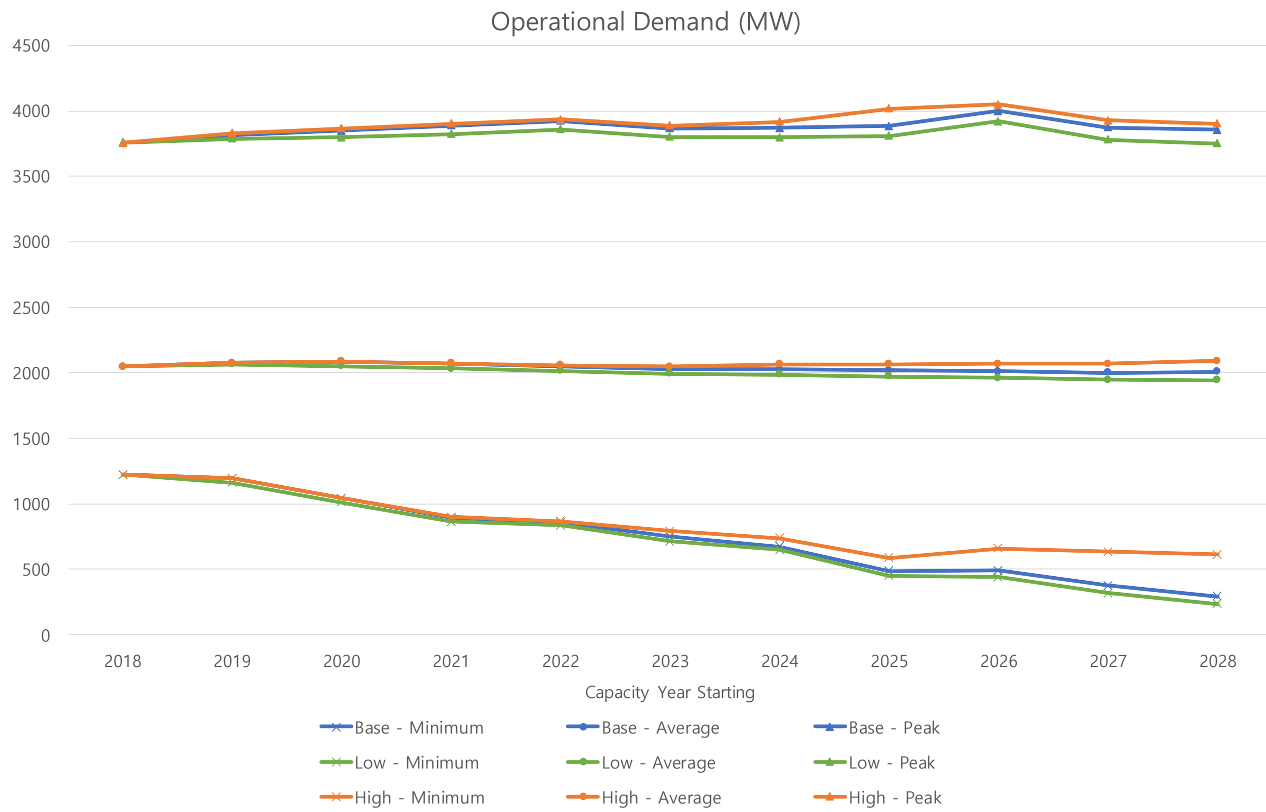
- Operational demand: Wholesale market demand, incorporating the impact of distributed solar PV, block loads, EV charging and distributed batteries
- Gas consumption
- Coal consumption
- Carbon emissions

3.1 Operational Demand

Operational demand is the wholesale market demand, incorporating the impact of distributed solar PV, block loads, EV charging and distributed batteries.

Figure 7 shows the resulting hourly average, peak and minimum demand for each year in the modelling horizon.

Figure 7. Minimum, average and peak operational demand



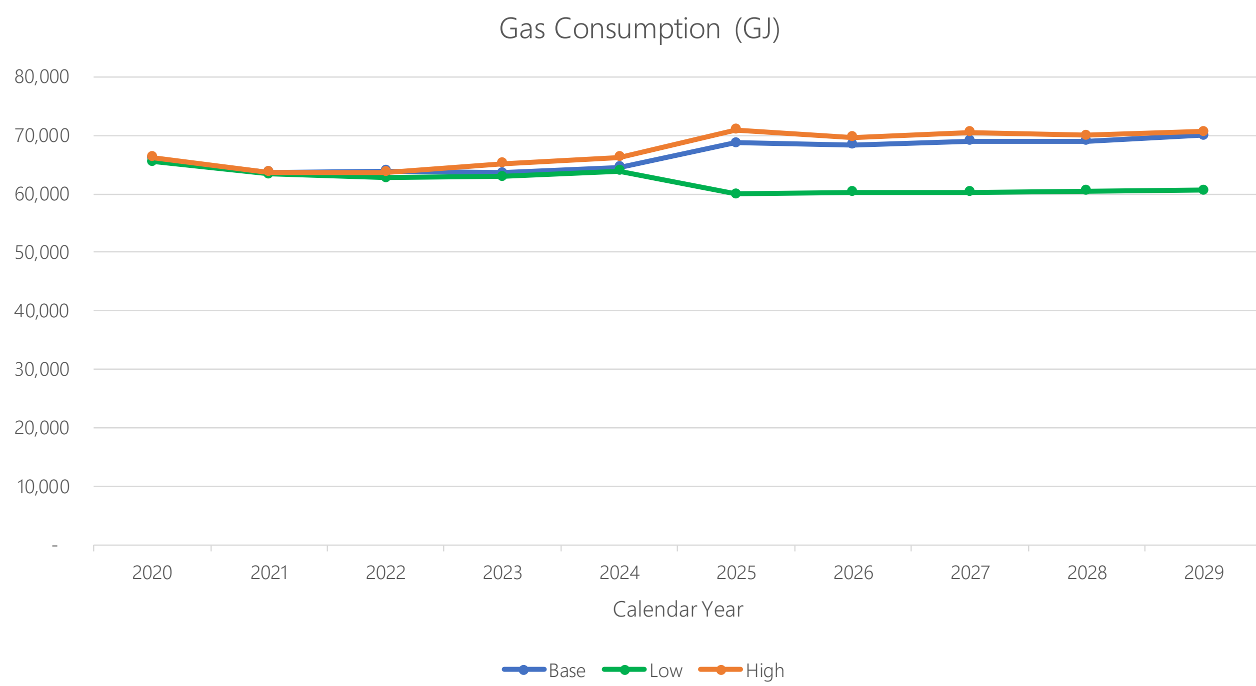
From these results, we can see that:

- There is very little differentiation in the average and peak loads between the scenarios. This is driven by the very narrow range of the 2019 WEM ESOO base demand forecasts on which these forecasts are based.
- Most of the differentiation is in the minimum demand level – In the High forecast, this is driven somewhat by the higher level of EV charging.

3.2 Gas Consumption

Figure 8 shows the annual total gas consumption from GPG from the model results.

Figure 8. Gas consumption



There is very little differentiation between the Base and High scenarios. As noted in section 3.1, there is little differentiation between the underlying demand forecasts for these two scenarios. Gas prices are also insufficiently differentiated to significantly impact gas demand.

In all scenarios, gas demand declines from 2020 to 2021 due to increased competition from renewable generation. Gas demand then increases in 2023 due to the retirement of Muja G5 in October 2022.

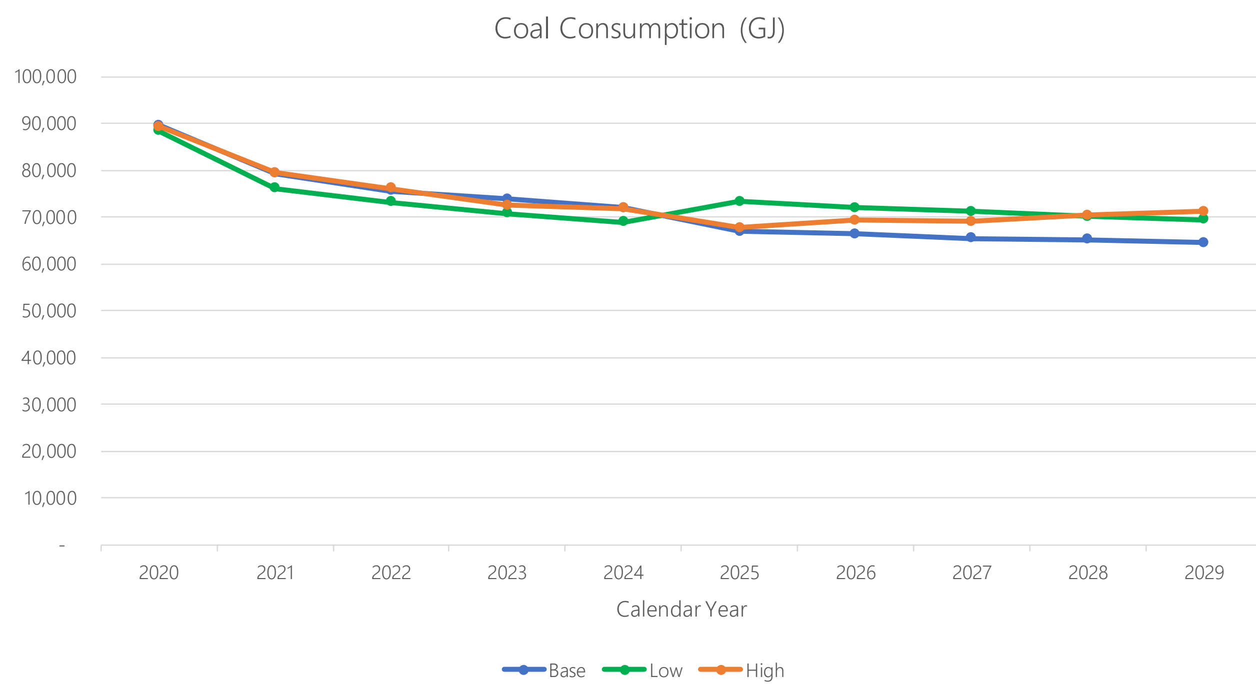
In the base and low scenarios, gas demand increases again in 2025 due to the retirement of Muja G6 in October 2024.

The gas demand in the low scenario drops in 2025, due to the significant increase in gas prices in the high gas price forecast between 2024 and 2025. This makes gas generation less competitive relative to other fuels, resulting in a drop in gas-powered generation. This effect more than offsets the impact of the Muja G6 retirement.

3.3 Coal Consumption

Figure 9 shows the annual total coal consumption for electricity generation from the model results.

Figure 9. Coal consumption



The small increase in average operational demand between the Base and High scenarios is largely met by an increase in coal generation rather than gas generation, leading to an increase in coal consumption in the High scenario.

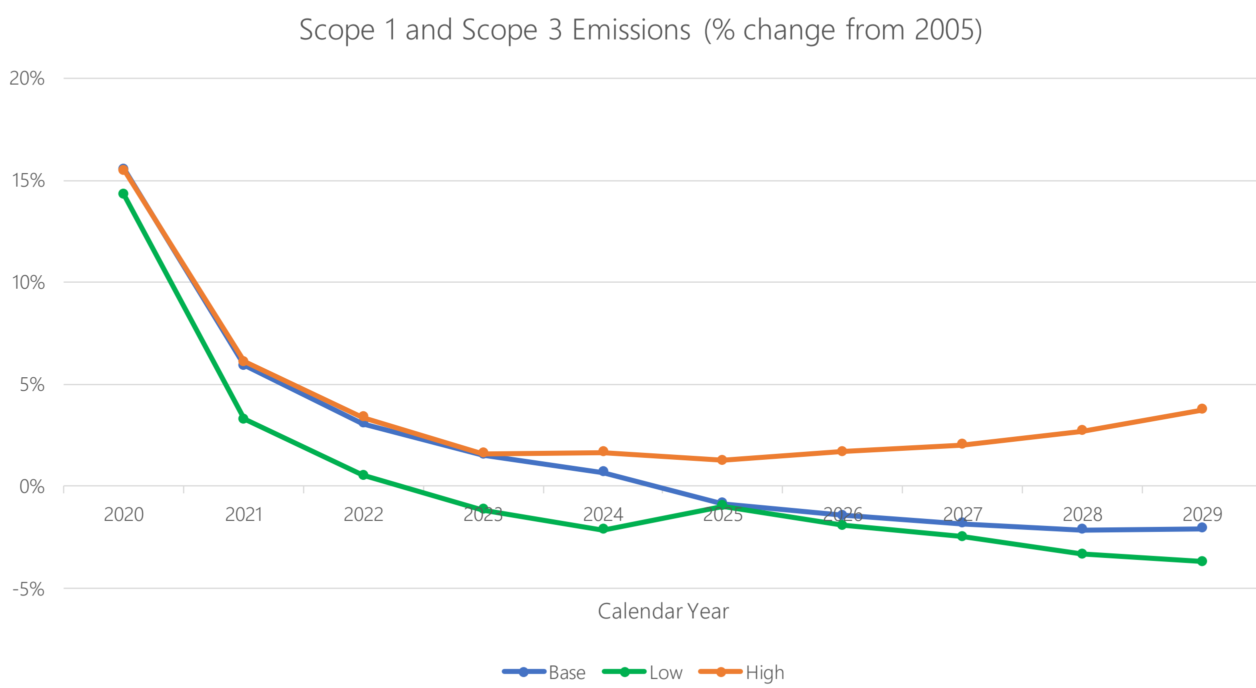
In the Low scenario, coal consumption increases in 2025, as the increase in gas prices makes coal-powered generation more competitive.

3.4 EMISSIONS

Figure 10 shows total annual Scope 1 and Scope 3 emissions from the modelling results, in terms of the percentage change from 2005 levels (positive percentage values showing higher emissions than 2005 levels, negative values showing lower emissions).

The emissions presented here are the direct (Scope 1) and indirect (Scope 3) emissions from the combustion of fuels to generate electricity, so do not include emissions related to the use of electricity, nor the construction or decommissioning of generation plants.

Figure 10. Emissions



In all 3 scenarios, emissions drop rapidly from 2020 to 2024 due to increased renewable generation and a resulting drop in coal generation.

None of the 3 scenarios result in emissions reductions that approach the Australian government target of 26-28% reductions by 2030.

Emissions are significantly higher in the High scenario, due to increased coal utilisation to meet the additional demand. Emissions also rise in the Low scenario in 2025, as an increase in gas prices results in greater coal utilisation.

4 CONCLUSIONS

4.1 KEY INSIGHTS

The following key insights can be drawn from this analysis:

- The 2019 WEM ESOO electricity demand forecasts on which this modelling is based fits within a narrow range, resulting in a narrow range of gas consumption forecasts.
- Gas price assumptions (especially relative to coal prices) have a significant impact on gas consumption, as it affects the competitiveness of gas units against coal units.
- None of the 3 scenarios presented here result in emissions reductions that approach the Australian government target of 26-28% reductions by 2030. Meeting this target will require measures such as further coal plant retirements and significant increases in renewable generation, both of which will significantly impact gas demand for GPG.