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Upper Spencer Gulf energy demand pilot

Pilot report

Cataloguing data

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Acknowledgement of Country

We acknowledge the Traditional Owners of Country throughout Australia and recognise their continuing connection to land, waters and culture. We pay our respects to their Elders past and present.

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Understanding industrial demand to support infrastructure planning

The energy transition and other economic developments are driving significant change in Australia's industrial centres. Industries are modernising and decarbonising, and new industrial opportunities are emerging. This transition brings with it potential for enormous growth and change in electricity demand, but also significant uncertainty about the likely timing of that change.

The challenges of coordinating investment in electricity supply and network infrastructure for new industry are increasing. Policies to support the energy transition – such as the Australian Government's Future Made in Australia initiative and National Hydrogen Strategy, and the South Australian Government's State Prosperity Project – will drive new industrial electricity demand.

Without adequate planning there are credible risks of both over- and under-investment in electricity network infrastructure. Overestimating demand risks overbuilding the infrastructure, but underestimating could leave network service providers (NSPs) and the market unable to service the needs of future clean energy industries that will help drive economic growth and contribute to climate goals. Both scenarios could impose significant costs on energy consumers.

In this context, the Australian and South Australian governments have partnered on the Upper Spencer Gulf (USG) pilot. The USG region's transmission and distribution NSPs – ElectraNet and SA Power Networks (SAPN), respectively – and the Australian Energy Market Operator (AEMO) participated in the pilot Advisory Working Group, in recognition of the project's potential to inform planning and forecasting.

Driving the urgency to conduct the pilot, which commenced in the second half of 2024, was the need to better understand the implications of a rapidly emerging group of new industrial projects seeking to develop in the region. There was a growing gap between this unprecedented level of evolving demand and what was reflected in periodically-published official demand forecasts, which form the basis for future network investment.

Some pressure has been relieved by the decision to defer the development of the South Australian Government-backed hydrogen project at Whyalla. However, this has brought forward the modernisation of the Whyalla Steelworks and ElectraNet is still receiving a large volume of network connection enquiries from industrial project developers relative to prior years.

Given the size of the individual projects seeking to connect to the transmission network, even if a handful were to proceed, significant additional investment in electricity generation and network infrastructure assets in the region could be required. Governments and market participants need ways to better understand and manage this uncertainty about changing demand, to avoid over- or under-investment in electricity assets.

Alternative large industrial load demand forecasts produced for the Upper Spencer Gulf

The USG pilot developed a new, probabilistic approach to forecasting demand in the USG that extended the forecasting approaches currently used by AEMO and the NSPs. The aim was to develop an approach that could incorporate new industrial projects in the electricity forecasts before they had reached a Final Investment Decision (FID). This would provide improved and earlier insights into possible large demand changes that could begin to be considered in planning processes.

The pilot developed an approach that provides a robust means of incorporating pre-FID large industrial loads in forecasts. It makes use of a rich set of independent data on the observed completion of resources and energy projects in Australia since 2012 (provided in the Australian Government's Resources and Energy Major Projects (REMP) publications). This data is used to assess the likelihood that identified new industrial projects would proceed, producing empirically-based forecasts that have less reliance on developers' views on the likely completion of their projects.

Probability distributions of possible demand outcomes based on the empirical forecasts were also developed using Monte-Carlo modelling. This provides better insights into the distribution of possible demand outcomes and their likelihood, rather than relying on single chosen scenarios where the probability of the chosen scenario is less well understood.

Given the different methodology used to produce the pilot forecasts, they differ to the scenario-based forecasts produced by AEMO and the NSPs. In general, the empirically-based method for including industrial projects is less conservative than the method used for AEMO's 2024 Electricity Statement of Opportunities (ESOO)[1] and Integrated System Plan (ISP)[2] forecasts because it includes projects at earlier stages of development. However, the forecasts themselves are still conservative compared to AEMO's central forecasts in the 2024 ESOO, as many new industrial projects in the USG are at an early stage of development and the empirical data suggests these have a lower probability of proceeding.

Therefore, while the midpoint forecasts were not significantly different to AEMO's central forecasts, the spread of potential demand outcomes shown in the Monte-Carlo distribution is large. Significantly higher industrial and overall demand outcomes are possible in the USG, although these outcomes are less likely.

AEMO, which has been an important contributor to the USG pilot, amended its forecasting approach in a July 2025 update to its Electricity Demand Forecast Methodology (EDFM).[3] The new EDFM allows for inclusion of prospective LIL projects and probability weightings for these projects where provided by the NSP (and subject to AEMO's review). AEMO was still developing and consulting on its proposed approach throughout most of the pilot. While AEMO's new method differs from the pilot approach, it reflects on prospective load opportunities in a similar way, using information able to be provided by the NSPs. AEMO will consider refinements to reflect the pilot approach in future.

The implications for required transmission network investment were tested

As part of the pilot ElectraNet modelled a range of forecasts produced using the methodology to test the implications for required transmission network investment. In this grid impact modelling, it was important to test not only forecasts that differed in terms of the extent of electricity demand, but also in terms of the location and timing of the development of individual large projects that have material impacts on the network.

AEMO's 2024 ISP, which accounted for the recently-deferred Whyalla hydrogen production facility, had identified the need for transmission investment in the mid-north region of South Australia to support the expected increase in renewable generation and growing demand in Adelaide, and to ensure adequate network capacity to supply large industrial loads. AEMO identified two cumulative needs. Firstly, the Mid North SA Renewable Energy Zone (REZ) Expansion was listed as an actionable ISP project that could add up to 1,200 MW of additional network capacity by 2029-30, and secondly, the Mid North SA REZ Extension was listed as a future ISP project (signalling the need for further additional network capacity, but in the mid to late 2040s).[4]

The pilot grid impact modelling excludes the Whyalla hydrogen facility, but includes other potential new industrial loads in the USG. The modelling, which tested the distribution of possible industrial demand outcomes in the region, suggests that additional network capacity would only be required to meet industrial demand under the higher demand cases modelled, and could be deferred to the mid-2030s. The relative location of new generation and loads will also impact on required network augmentation, reducing required investment when generation and load are co-located.

As highlighted in ElectraNet's recently published 2025 Transmission Annual Planning Report (TAPR),[5] the emergence of LILs remains a highly dynamic situation in the USG. Ongoing efforts by the Australian and South Australian governments to support new industry, along with other factors driving development, will continue to change the landscape in ways that could substantively increase electricity loads in the near future, beyond those factored into this report. ElectraNet will continue to evolve its analysis of required grid investments to support the Mid North SA REZ Expansion project identified in the ISP (which ElectraNet refers to as the Northern Transmission Project or NTx).

While there remains uncertainty about eventual industrial demand outcomes and locations, the grid impact assessment has been useful to demonstrate the different levels of network investment that could be needed, including by showing how different forecasting methods affect predicted needs.

Key observations and learnings

The pilot has been able to develop a methodology that allows a robust assessment of the probability of future industrial projects proceeding, which can be considered in demand forecasts. Using empirical information on the timing and completion of industrial projects in Australia provides a more systematic approach to considering the likelihood and timing of these projects proceeding than a sole reliance on project proponents' own (or others) view of the likely timing and completion of projects, which could be subject to optimism bias.

There could be reasons that the empirical data based on historical outcomes does not accurately capture future outcomes. The probability estimates may currently under-estimate the timing and likelihood of completion of projects involving new industries and/or technologies which dominate in the USG, but are not well represented in the REMP sample. This includes hydrogen production and green steel projects. The REMP database is expected to become more representative of new industries and technology over time as the energy transition progresses, and hence could produce more accurate probability estimates for these sectors in future.

The pilot also found that there are challenges in accessing the confidential information on new projects needed to gain a proper understanding of their potential for operating in a flexible manner or their intentions to invest in embedded energy supply, both of which could reduce their impacts on required grid augmentation. However, this is information that AEMO and the NSPs can gather as part of their network planning and forecasting processes. The arrangements for sharing data, in a manner that protects confidentiality, may warrant further consideration to ensure relevant governments are also able to access the information needed to adequately inform planning and investment.

The work undertaken to improve the current understanding of demand uncertainty, and to reflect this in demand forecasts, demonstrates that more sophisticated approaches to demand forecasting and infrastructure planning are both feasible and warranted.

Future application and extension

There is substantial scope to build on the lessons of the USG pilot and the tools developed. This could include:

- repeating the key elements of the pilot in other regions, with involvement from the relevant state or territory governments, network service providers and AEMO
- using the REMP empirical model to inform all planners with a need to understand the implications of potential future industrial developments – not just those with an energy focus
- extending the application of the probability-based forecasts to inform real options analysis, which can be a useful tool for economic assessment of network investments (for instance, for the Regulatory Investment Test for Transmission (RIT-T)). Real options analysis enables an assessment of the benefit of acting early, with incomplete information, relative to waiting to act until more information becomes available. The USG pilot's approach to identifying key project uncertainties and the probabilities of different outcomes, for example, would form key inputs into such analysis.

Future projects may also be able to place more focus on the impacts of electrification, demand flexibility and behind-the-meter generation if greater access to project-specific data could be gained than was possible for the USG pilot.

There is also an opportunity for governments and/or market bodies to work with NSPs to consider what more could be done to facilitate the collection and publication of consistent, granular information on future demand. In 2024, in response to the Review of the ISP, Energy Ministers tasked AEMO to support distribution NSPs (DNSPs) and jurisdictions 'to develop [demand] projections and undertake analysis in a consistent manner to support the ISP's development'. This pilot suggests there may also be value in taking another look at the type of information transmission NSPs (TNSPs) provide.

This could potentially include the NSPs maintaining a historical database of enquiries for new connection from industrial project proponents that enables the outcomes for the projects seeking new connection to be traced through time, in particular the observed timing and likelihood of completion of the projects. The USG pilot made use of the significant and useful data on project development available in the REMP publications. However, this could be bolstered by data from NSPs, which may provide more specific or accurate probability estimates.

1. Introduction

This report has been prepared to document the analysis and outcomes of a pilot conducted to improve understanding of the future of industrial electricity demand in a key industrial region that is undergoing substantial change because of the energy transition.

This pilot focused on the Upper Spencer Gulf (USG) region of South Australia, which is on the precipice of a potentially substantial increase in industrial electricity load. This is partly driven by private-sector development of the region's resources (including mineral and renewable energy resources), but also by government investments and policies to support the energy transition – such as the Australian Government's Future Made in Australia initiative and National Hydrogen Strategy, and South Australia's State Prosperity Project.

Examining and re-forecasting residential and commercial electricity demand was not an area of focus for the pilot given that these loads account for only a very small proportion of demand in the region. While not a focus for the USG, it may be important for pilots in other industrial regions within Australia where commercial and residential demand accounts for a greater proportion of overall demand and where there is significant penetration of Consumer Energy Resources (CER) such as rooftop solar, batteries and electric vehicles.

The pilot has been sponsored by the Australian Government Department of Climate Change, Energy, the Environment and Water (DCCEEW) and the South Australian Department for Energy and Mining (DEM). The pilot was undertaken by Frontier Economics, with guidance and support from the South Australian NSPs - ElectraNet and SAPN - and AEMO.

The remainder of the pilot report is structured as follows:

- Section 2 describes the development of industries in the USG.
- Section 3 outlines the new demand forecasting methodology that was developed and applied in the pilot project.
- Section 4 provides the electricity demand forecasts produced for the USG region.
- Section 5 presents the modelling undertaken by ElectraNet to understand the potential impacts of the forecast demand outcomes on required electricity transmission network augmentation.
- Section 6 evaluates the key learnings and outcomes of the pilot and considers potential next steps.

Supporting appendices provide additional detail on data and forecasting methodologies.

2. Changing industrial load in the USG

The USG is a significant industrial area in South Australian and national terms. The South Australian Government has advanced plans to invest in the region's industrial development via the State Prosperity Project and the electricity transmission network operator (ElectraNet) is receiving a large volume of network connection enquiries for that region from industrial project developers.

The Australian Government is also supporting industrial redevelopment and the energy transition in the region, consistent with its Future Made in Australia and National Hydrogen Strategy policies, and has recently partnered with the South Australian Government to invest in the future redevelopment of the Whyalla Steelworks.

This section provides an overview of the USG industrial region and current industrial loads. It explores how industrial electricity demand is changing, including due to the electrification of loads, expansion of existing industries and development of new industries such as hydrogen and green metals.

The analysis in this section is based on publicly available information. For future loads, publicly available information provides general insights into the new projects. However, it does not provide specific information on the size or patterns of the projects' electricity demand to support the pilot demand forecasting. As explained below, this demand information must be sourced either directly from the project proponents or from the NSPs and AEMO who also receive this information (confidentially) from new loads.

2.1 Current industrial load

As shown in Figure 1, the USG is a region north-west of Adelaide that incorporates the upper reaches of the Spencer Gulf and reaches north to key mining operations, including BHP's Olympic Dam. The region includes the industrial towns of Whyalla, Port Augusta and Port Pirie. (As discussed at section 2.2 below, a tailored definition of the USG region was developed for the purposes of the pilot.)

Whyalla, on the upper western side of the Spencer Gulf, is the location of the region's steelworks, which is currently being managed with support from the Australian and South Australian Governments to enter a new phase of re-development. Other key industrial activity in Whyalla relates to the Whyalla Port, which handles a range of commodities, mining consumables and other equipment.

Port Pirie, on the upper eastern side of the gulf, has a multi-metal smelter operated by Nyrstar that produces refined lead, silver, copper, gold, tellurium and other by-products such as sulphuric acid. There are also significant port facilities in Port Pirie that handle grain, fertiliser, metal ores and concentrates.

The other key population centre is in Port Augusta at the top of the gulf. This is more of a service centre than an industrial centre, but there are large renewable energy projects such as the Bungala Solar farms and the Port Augusta Energy Park in the area.

Figure 1: State Prosperity Project: USG key industries and planned projects

Source: Adapted from Government of South Australia 2024, [State Prosperity Project [PDF 9.65 MB]].

North of the gulf, BHP operates mines producing copper, silver, gold and uranium. In the USG region the current major mines are:

- Carrapateena: underground mine producing copper, silver and gold in concentrate. In FY2024, 5.2Mt of ore was mined and 68kt of copper produced.
- Prominent Hill: underground mine producing copper, silver and gold in concentrate. This mine processed 4.5Mt of ore in 2024 and produced 50Kt of copper.
- Olympic Dam: underground mine and integrated smelting operation. In FY2024, 10.8Mt of ore was mined and 508.9kt of concentrate produced (copper, uranium and gold).[6]

In 2023-24, USG large industrial load electricity consumption was 2,593 GWh or 99.7% of electricity consumed in the region and around 23% of total South Australian electricity consumption.[7] Further information on current electricity demand in the USG region, including industrial demand, is provided in Section 4 of this report.

2.2 New industrial load

The USG pilot region has become an area of intense interest for industrial expansion and re-development, given the area's significant resources, including mineral resources (such as copper and magnetite iron ore), renewable energy resources and scope to host new 'green' industries such as green steel production and hydrogen production.

There is multi-level government support being provided for redevelopment of steel manufacturing capability and the development of hydrogen production in the region. In summary, the largest of the potential new industrial developments in the USG (discussed further below) include:

- Redevelopment, expansion and decarbonisation of the existing USG industrial base, particularly green steel and iron industries, supported by the South Australia State Prosperity Project.
- Desalinated water to support mining and other industrial expansion, also supported by the State Prosperity Project.
- Mining and minerals processing development and expansion, including at BHP's mines, and potential for further magnetite ore mining to support green steel production.
- Hydrogen production facilities. The most advanced project was the South Australian Government-backed hydrogen production facility at Whyalla. This project will no longer be proceeding at this stage, but other prospective hydrogen projects (such as Port Bonython and Cape Hardy) in the region remain.
- Development of data centres.

The growing interest in industrial development in the region is also highlighted in ElectraNet's recently-published 2025 TAPR. Figure 2, on the following page, shows the increasing number of connection enquiries ElectraNet is receiving, along with the introduction of key government policies. A number of these enquiries relate to potential industrial projects in the USG.

Many of the projects are at a relatively early stage of development. However, publicly available information on the projects is provided below.

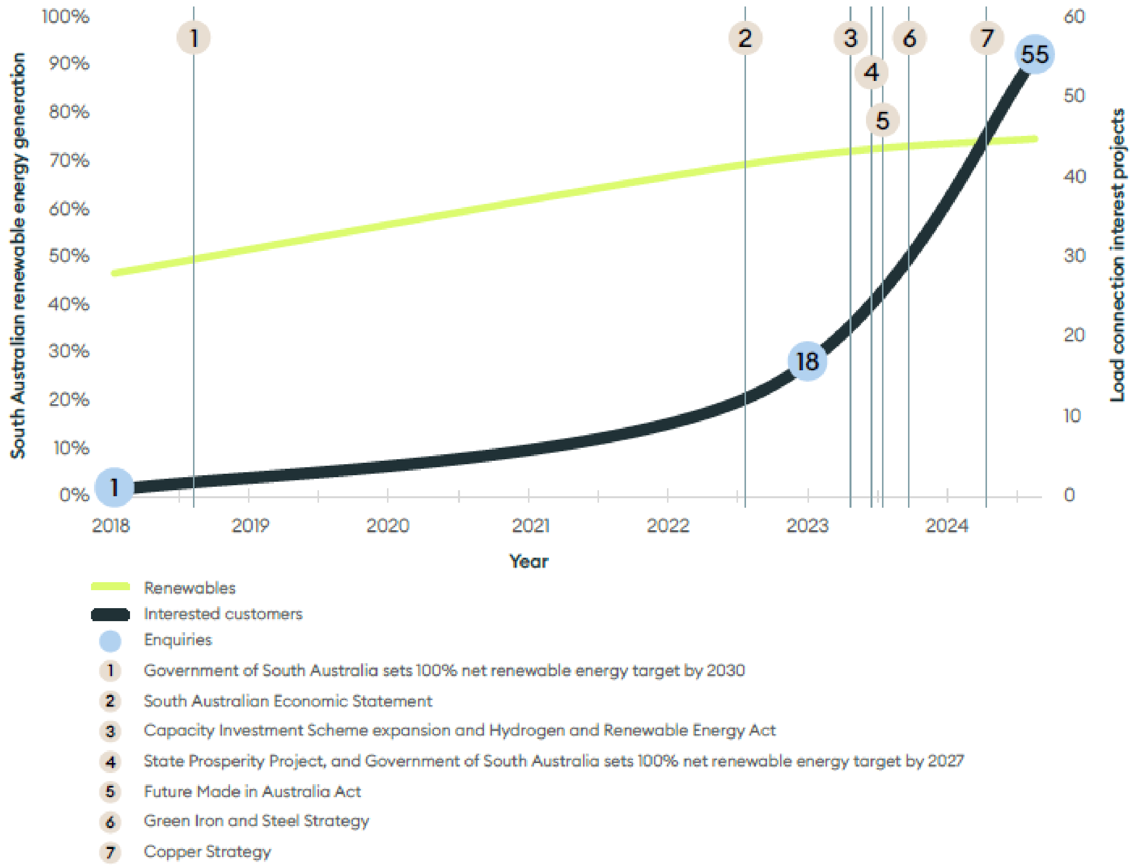
2.2.1 Electrification

One source of potential new electricity demand in the USG is electrification of existing industrial facilities. Natural gas is currently available in specific parts of the USG (as discussed below). The majority of the gas is used by two industrial facilities: the Whyalla Steelworks and Nystar smelter. These industrial facilities could, in principle, convert to using electricity.

Information on gas supply to the USG provides an indication of the potential for additional electricity demand in the USG as a result of industrial electrification. AEMO publishes data on gas pipeline flows by pipeline connection point, which can be used to identify each of the gas connection points in the USG and the amount of gas that is supplied to each of these gas connection points.[8]

The USG is supplied with natural gas through a lateral pipeline from the Moomba to Adelaide Pipeline System, which runs from the Whyte Yarcowie Compressor Station to Whyalla. Gas is

Figure 2: ElectraNet: Increase in industrial connection interest



Source: ElectraNet 2025, 2025 Transmission Annual Planning Report, p. 23.

supplied to customers at six connection points along this lateral pipeline: Port Pirie, Port Bonython, Pacific Salt, Whyalla Township, Whyalla Cogen and Whyalla BHP.[9]

Over the last three years, annual average gas supply to the USG has been between 10 TJ/d and 17 TJ/d,[10] with the variation largely driven by the operation of the Whyalla Steelworks. This gas supply to the USG represents between 5% and 10% of South Australia's total gas demand. The overwhelming majority of this gas is supplied to two connection points in the USG: to Whyalla BHP, for the Whyalla Steelworks, and to Port Pirie, primarily for use at the Nystar smelter. The Whyalla Steelworks has accounted for an average of 70% of the gas used in the USG over the last three years, while Port Pirie has accounted for an average of 20% of the gas used in the region over this period.[11] Only very small amounts of natural gas have been supplied to the other connection points in the USG.

Electrification of natural gas used by the Whyalla Steelworks, and to a lesser extent by the Nystar smelter, would have a material impact on electricity demand in the USG.

Of the two facilities, plans for electrification of the Whyalla Steelworks are more progressed, with announced plans for conversion of the Whyalla Steelworks to green steel. Following the steelworks being placed into administration, the South Australian and Australian governments announced joint funding to enable the steelworks to continue operating and to invest in new infrastructure to produce green steel.

These potential new electricity loads include a new electric arc furnace (EAF) for the steelworks and potentially also new electricity load for the production of green hydrogen for use in the steelworks (should this be pursued in the future). For this reason, electrification of the gas used in the Whyalla Steelworks has not been separately accounted for.

For the Nystar smelter, there are options for electrification of lead, silver and zinc smelters, but the heat requirements of these options are challenging. A report by ITP Thermal[12] identified that most of the heat requirement for processing and refining non-ferrous metals is high temperature heat (greater than 800 degrees Celsius), which is currently more challenging to electrify.

There is a third small project that may electrify LPG demand, noting that the electrolyser is not proposed to be grid connected. This is the Green Cement Decarbonisation Project by the Hallet Group at Port Augusta. Further details of this hydrogen project are provided below. The Hallett Port Augusta facility consumes approximately 15 million litres of LPG per annum. The hydrogen produced by its proposed 6 MW electrolyser plant would replace around 20% of that volume.[13]

2.2.2 Expansion of existing industries

Apart from the redevelopment of the Whyalla Steelworks discussed above, the majority of the potential industrial expansion in the USG relates to mining expansion. Key mining expansion projects announced for the USG including the following.

BHP mines

BHP has plans to expand copper production and the copper smelter and refinery facilities at the Olympic Dam mine. The first phase of the project would expand capacity to 500,000 tonnes per annum (tpa) of refined copper cathode production by the early 2030s, as part of a strategy to produce up to 650,000 tpa in South Australia from the mid-2030s, up from approximately 322,000 tonnes in 2023-24. BHP intends that the expanded smelter and refinery will take additional ore mined at the Olympic Dam, Carrapateena, Prominent Hill, and the yet-to-be-constructed Oak Dam. BHP expects to make a final investment decision (FID) on the first phase of the expansion of the smelter and refinery in the first half of FY27.[14]

BHP has recently awarded the engineering, procurement and construction management (EPCM) contract and has entered contracts worth $1.5 billion with Aurizon to shift the transport of copper concentrate and cathode from BHP’s Olympic Dam, Carrapateena, and Prominent Hill mines from road to rail between Pimba and Port Adelaide.[15]

SIMEC Middleback Magnetite Expansion Project (MEP)

The Middleback Ranges iron ore mines are located approximately 60 kilometres from Whyalla and supply the Whyalla Steelworks. Prior to February 2025, the mines and steelworks were owned by OneSteel Manufacturing Pty Limited (trading as OneSteel Whyalla Steelworks and SIMEC Mining), which is part of the GFG Alliance. Following intervention by the South Australian Government in February 2025, OneSteel Manufacturing Pty Limited is currently under administration.

Planning for expansion of magnetite mining had been underway, supporting the re-development of the Whyalla Steelworks to an EAF operation. The MEP had three planned phases:[16]

- MEP1: New technology in the existing operations to improve efficiency and extend the project life, and upgrade the existing processing facilities to increase production from 2.2 Mtpa to 2.5 Mtpa of Direct Reduction (DR) grade concentrate. The SA Director of Minerals Regulation approved a Change in Operations application in May 2025 which will facilitate MEP1.[17]
- MEP2: Triple magnetite concentrate production and extend mine life by over 20 years. This is expected around 2028.
- MEP3: Possible capacity expansion beyond MEP2 that would require identification and development of additional ore resources.

The future of the MEP is tied with the future of the Whyalla Steelworks and the outcomes of the administration process.

2.2.3 Development of new industries

New industrial projects in the USG are reviewed below, and include new mining, water desalination, hydrogen production and data centre projects.

Northern Water

The South Australian Government is developing the Northern Water desalination project within the USG (location yet to be determined) to provide additional water supply for a broad range of users including mining operations, industry (including hydrogen), Department of Defence, remote communities, pastoralists and SA Water.

It is planned that the desalination plant would be constructed in stages, with capacity of between 130 and 260 ML/day. Water would be supplied via pipelines (over 600km) and storage tanks to the Olympic Dam and Carrapateena mines as well as to Whyalla, Port Augusta, Woomera and Roxby Downs. The project would require additional electricity transmission capacity including line, connection point, transformer and substation assets.[18]

Under current timelines, the desalination plant would be designed and constructed between 2026 and 2030 and commence operation from 2031.[19]

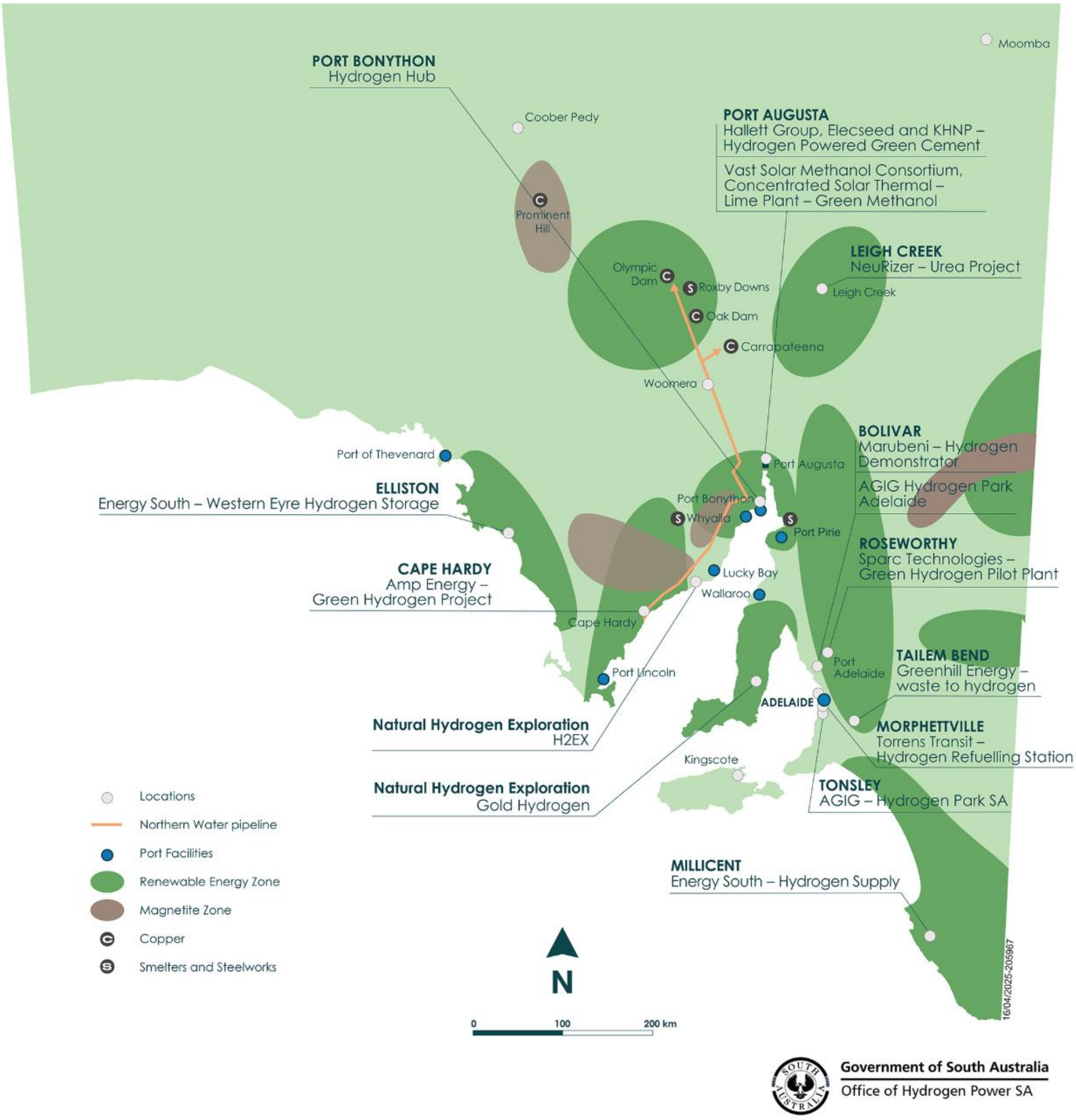
Hydrogen

While the opportunity for future hydrogen project development in the USG is significant, the realistic timing of these projects is highly uncertain.

At the commencement of the pilot, the Whyalla hydrogen production facility – a government-sponsored project – was already well advanced and had been included in electricity system planning forecasts (including AEMO's 2024 ISP and ElectraNet's 2024 TAPR). In early 2025 this project was deferred and state government funding redirected to an assistance and transformation package to underpin long-term jobs and economic resilience for the Whyalla and the USG, including the modernisation of the Whyalla Steelworks.[20] Therefore, this project is excluded from the electricity demand forecasts developed for this pilot.

However, other hydrogen production projects are being considered within the USG region. These are shown in Figure 3 below, from the South Australian Government. The CSIRO also tracks the progress of hydrogen projects with its HyResource tool.[21] Progress on individual projects that are relevant to the USG are reviewed below.

Figure 3: SA hydrogen project opportunities



Source: SA Department for Energy and Mining 2025, Hydrogen projects in South Australia.

Details of the key project opportunities are as follows:

Port Bonython Hydrogen Hub: The Port Bonython Hydrogen Hub is located near Whyalla and is intended to be a common user facility for the production and export of hydrogen-centred projects. The hub will involve port works, hydrogen storage and pipelines, and electricity transmission. This project is at an early stage of development. The Australian Government has committed $70 million in matched funding, with $30 million from the South Australian Government and $40 million expected to be contributed by participating developers. The future of this project will rely on attracting viable projects to the site. The South Australian Government has signed Development Agreements with potential developers of hydrogen production facilities at the site including Amp Energy (green hydrogen and ammonia production), Fortescue Energy, the Hydrogen Utility (H2U), Origin Energy and Santos.[22] There is no clear indication that any of these partners are progressing their projects at this stage.

Active projects: Other projects in the USG that are listed as active in CSIRO's HyResource include the following.

Table 1: HyResource active USG hydrogen projects

Project name and location	Proponent	Status	Production method & use	Power source	Timing
Cape Hardy Green Hydrogen Project Location: Cape Hardy	Revera Energy (previously Amp Energy) – with involvement from Iron Road Ltd	Under development Secured Major Project Status from Australian Government (October 2024)	Electrolysis Stage 1: 1 GW Stage 2+: 5 GW Green ammonia (export and domestic) and clean fuels	Wind and solar – not grid connected	FID: 2027 Stage 1 operation: 2030
Eyre Peninsula Gateway Project – Demonstrator Stage Location: Whyalla / Cultana / Port Bonython area	The Hydrogen Utility (H2U)	Under development - Front-End Engineering Design	75 MW electrolysis plant and 120 tonnes per day ammonia production facility Potential later expanded Export Stage	Grid connected	Not reported
Green Cement Decarbonisation Project Location: Port Augusta	Hallett Group, Elecseed, Korea Hydro and Nuclear Power Company	Under development - Front-End Engineering Design	Electrolysis 6 MW for Industrial process - heating	Onsite solar – not grid connected	Not reported
SM1 Location: Port Augusta	Vast, Mabanaft German-Australian HyGATE Initiative: ARENA-administered Australian funding of AUD$19.48 million awarded to Vast and German funding of €12.4 million received by Mabanaft	Under development	10 MW PEM electrolyser, with 7,500 tonnes per annum of methanol production	Onsite solar – not grid connected	Not reported

Source: CSIRO HyResource, June 2025

Recent developments suggest an easing in momentum for new hydrogen projects, reflecting broader shifts in investor sentiment across the sector over the past year. The economics of hydrogen production – with high production costs and limited demand – have not supported large scale development of projects at this stage.[23] However, as shown for the projects that continue to be developed in the USG, consideration is being given to projects that combine hydrogen production with its direct application such as in cement or ammonia production. In addition, apart from state and federal government efforts to support the industry, a range of private sector and university-backed projects continue to show promise. These include the University of Adelaide / SPARC Tech / Fortescue photocatalytic water splitting project.[24]

Magnetite mining, Direct Reduced Iron (DRI) and green iron and steel

Green iron is a priority for both state and federal governments as a new industry and carbon abatement opportunity. The South Australia Government released a Green Iron and Steel Strategy in June 2024 as part of the State Prosperity Project and the Australian Government is currently progressing work on the Green Iron Investment Fund, as well activities through the Whyalla Taskforce. Realising this opportunity would create demand for hydrogen and potentially new demand for electricity and gas.

This strategy identifies the opportunity to utilise the state's abundant magnetite resources, renewable energy and other resources to develop a green iron and steel industry. Much of this opportunity is centred in the USG. The development of the existing Whyalla Steelworks and the Middleback MEP, which are important projects, is discussed above.

There is potential for additional projects related to this opportunity across the production chain, from mining through to production, as shown in the Figure 4 below.

Figure 4: Green iron and steel production chain

Source: Government of South Australia 2024, South Australia's Green iron and steel strategy, p. 5.

In the USG, key centres of opportunity exist in Port Augusta, Port Pirie, Whyalla, Port Bonython and Cape Hardy.

In addition to the government-supported redevelopment of the Whyalla Steelworks and the Middleback MEP, other key magnetite mining, DRI and green iron and steel projects identified in the USG are as follows:

- Central Eyre Iron Project (CEIP): This project involves the development of magnetite deposits at Warramboo on the central Eyre Peninsula. Associated with this project is the opportunity for a DRI plant, potentially supplied by green hydrogen, at Cape Hardy. This project is still at an early stage of development.[25]
- Green Iron SA: This project is being developed by a consortium including Magnetite Mines, Aurizon Holdings, Flinders Port Holdings, and GHD. The proposed project involves development of the Razorback Iron Ore Project to mine and produce high-purity magnetite, production of direct reduction (DR) grade pellets, and manufacturing and exporting DRI in the form of Hot Briquetted Iron (HBI) from Port Pirie by the early 2030s.[26]

Data centres

ElectraNet's 2025 TAPR indicates that 17% of the connection interest across South Australia, in terms of anticipated maximum demand, relates to data centres. Publicly available information on proposals for new data centres in the USG in not available at this stage.

2.3 Plans for USG electricity transmission augmentation

Plans for investment to augment the region's electricity network are already underway. AEMO's 2024 ISP had identified the need for transmission investment in the USG region to support the expected increase in renewable generation and support growing demand in Adelaide, and ensure adequate network capacity to supply large industrial loads.

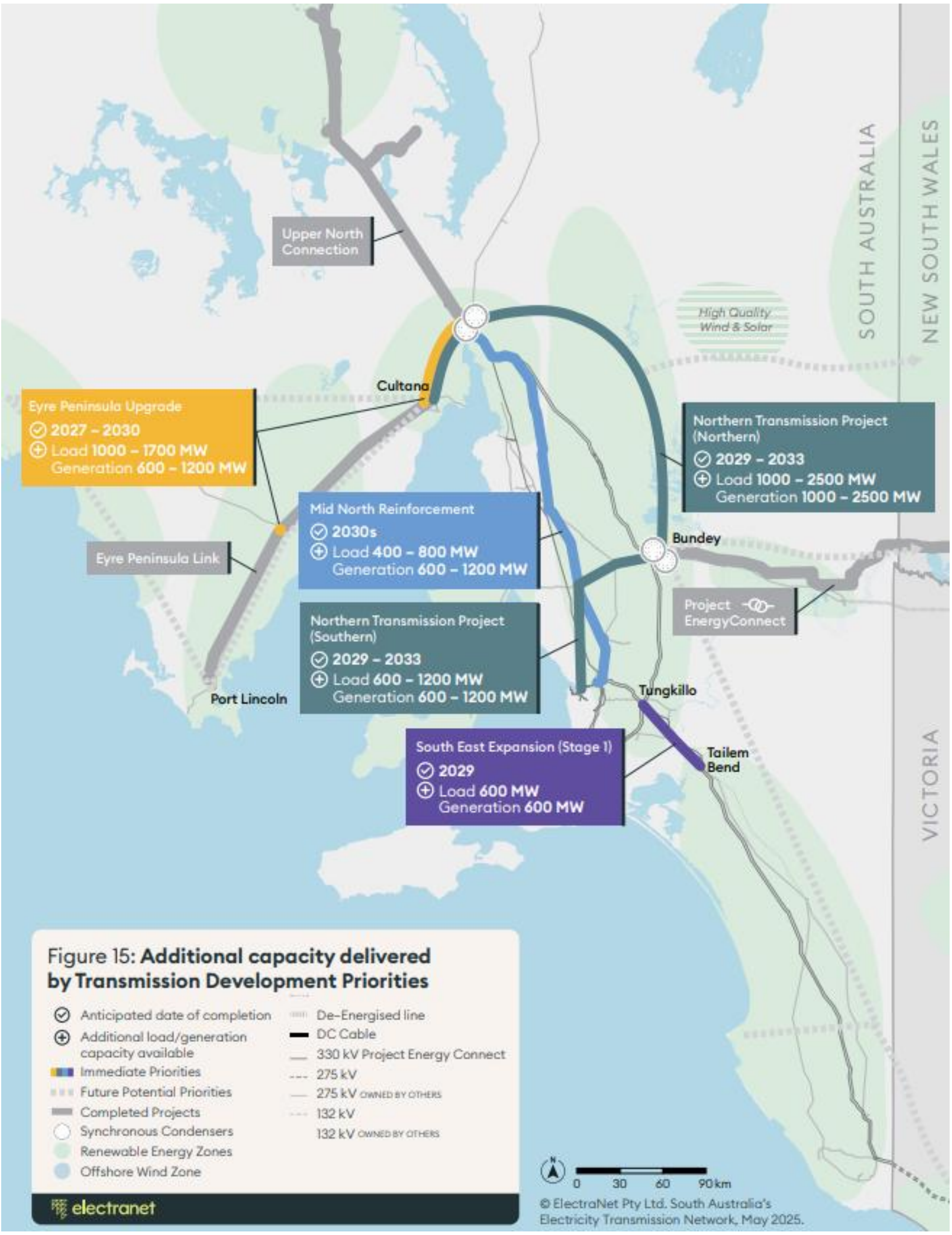
The Mid North SA REZ Expansion was listed as an actionable ISP project, which could add up to 1,200 MW of additional network capacity by 2029-30. The Mid North SA REZ Extension was listed as a future ISP project, signalling the need for further additional network capacity, but in the mid to late 2040s.[27] Actionable ISP projects are deemed to be most urgent and should be progressed. Future ISP projects are forecast to become actionable in the future, but are not needed for some period and hence only require preparatory work. (The actionable expansion project would involve the construction of 275 kV and 132 kV transmission lines to connect renewable generation to Adelaide and to supply increasing industrial load. The future extension project would enable capacity in Mid North, Yorke Peninsula, Leigh Creek, Roxby Downs, Eastern Eyre and Western Eyre Peninsula REZs to supply the Adelaide region.)

The preparation and the recommendation of the USG network augmentations assumed that the Whyalla hydrogen production facilitywould proceed in 2026**,** which included a 250 MW electrolyser for hydrogen production and a 200 MW hydrogen powered electricity generator. As noted, this project has since been deferred and the funds redirected to stabilise and modernise the Whyalla Steelworks. This change may slow down the required transmission augmentation, but is dependent on the timing of other generation and industrial load developments in the region.

ElectraNet is progressing the work on the required transmission augmentation. This project has been renamed as the Northern Transmission Project (or NTx) in their 2025 Transmission Annual Planning

Report or TAPR (identified in Figure 5).[28] The AER has approved funding of early works and ElectraNet plans to publish a Project Assessment Draft Report (PADR) under the RIT-T by the end of 2025. This will identify network augmentation solutions and their costs and benefits.

Figure 5: ElectraNet transmission development priorities



Source: ElectraNet 2025, 2025 Transmission Annual Planning Report, p. 56.

3. Demand forecasting methodology

To meet the aims of the pilot to gain improved insights into transitioning electricity demand in the USG region, new data was collected and new methodologies applied to produce forecasts of large industrial demand in the USG region. This demand forecasting approach differs to the approach used by AEMO for the 2024 ISP and ESOO and by the NSPs in terms of the:

- **Smaller size of the geographic area:** Forecasts are produced for the smaller USG-specific 'sub-region'. AEMO's 2024 ISP and ESOO sub-regional forecasting approach (which produced forecasts for the larger Central South Australia area of South Australia) is downscaled to produce the baseline demand forecasts for the USG pilot region. South Australia itself is considered a 'region' in the context of the NEM, but this pilot uses 'region' to refer to the USG.
- **Approach used to forecast LILs:** Formal NEM forecasts apply strong tests before including a LIL in a demand forecast. Specifically, for the scenario that represented AEMO's best estimate of forecast demand in the 2024 ISP and ESOO, AEMO included a new LIL if: the project had obtained the required environmental approvals; the project had obtained approvals from the NSP to connect; a positive FID had been announced and/or the project had commenced construction.

A new LIL forecasting approach has been developed for the pilot that uses historical data on the timing and completion of similar industrial projects in Australia, to develop probability-driven forecasts of prospective LIL demand in the USG. The aim is that these probability-based forecasts produce a more granular set of information that could support more efficient and responsive network investment pathways.

AEMO amended its forecasting approach in a July 2025 update to its EDFM, which now allows for inclusion of prospective LIL projects and probability weightings for these projects where provided by the NSP (and subject to AEMO's review). AEMO was still developing and consulting on its proposed approach throughout most of the pilot. While AEMO's new method differs from the pilot approach, it reflects on prospective load opportunities in a similar way, using information able to be provided by the NSPs. AEMO will consider refinements to reflect the pilot approach in future.

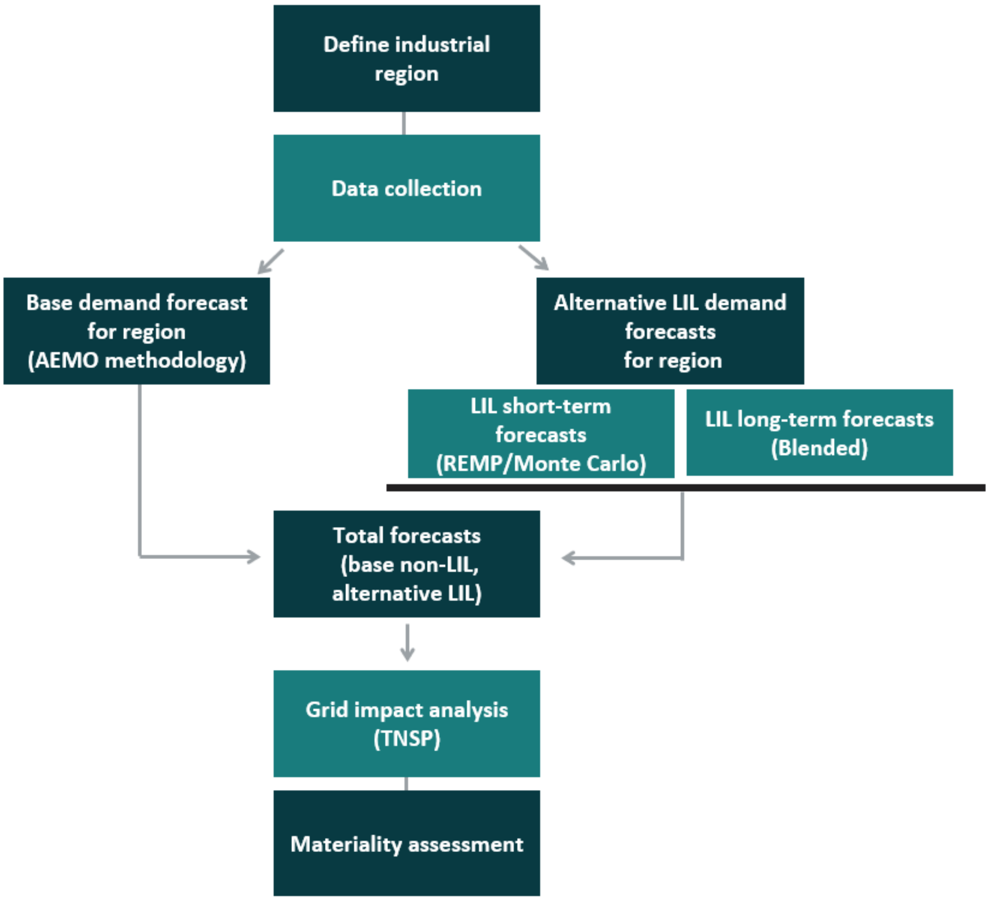
In forecasting LIL demand, the pilot also sought to test the potential for more flexible operation of the USG LILs and whether this could materially reduce demand. This could not be done using actual information from USG project proponents as the pilot was unable to access project-specific data (see Section 6 regarding future applications and extension). However, qualitative analysis was undertaken to understand the potential for flexible operation of the industrial enterprises relevant to the USG and how this may impact demand. AEMO assumptions about the flexible operation of hydrogen were used to develop a scenario with flexible hydrogen operation that was included in the grid impacts assessment, as discussed in Section 5.

3.1 Pilot methodology and steps

The pilot methodology comprised the elements shown in Figure 6 below. The first step was to define the USG region. The second step was to identify and collect relevant data, especially data on LILs that would support the development of more granular forecasting approaches. Then baseline and alternative demand forecasts for the USG region were produced. Finally, a number of feasible alternative forecasts were tested by ElectraNet in their network planning model to assess whether the alternative forecasts would have material impacts on future network investment.

Each of these steps is discussed in the remainder of this chapter, with additional detail provided in supporting appendices.

Figure 6: Pilot methodology



3.2 Defining the USG pilot region

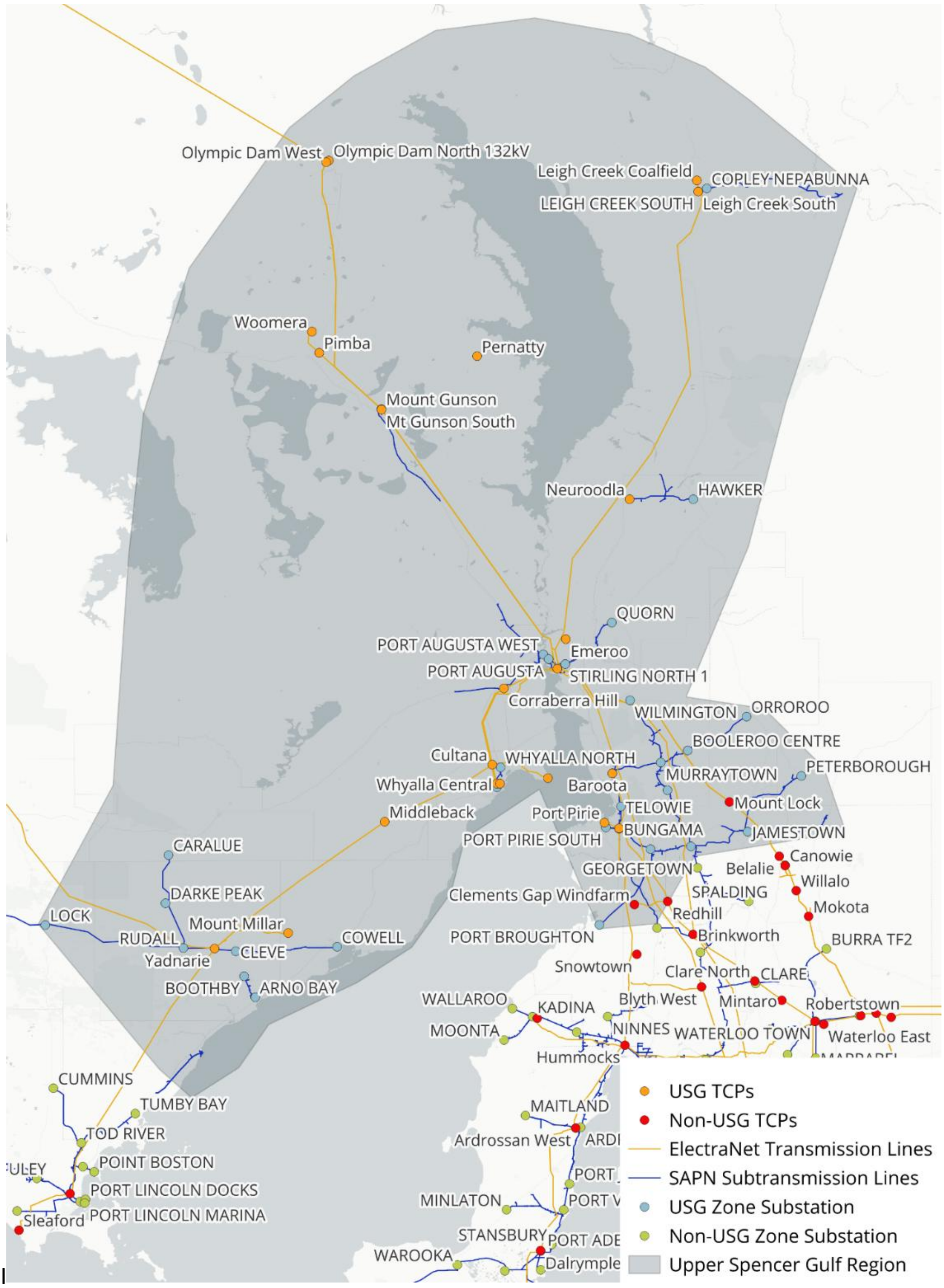
The USG industrial region was defined for the purpose of the pilot to capture:

- Geographic areas in which potential new industrial facilities have expressed an interest in connecting to the grid
- The areas within the transmission and distribution networks and assets that are relevant to future connecting loads and the industrial load forecasts, and
- The elements of the transmission and distribution networks that are related to key assets in the USG. For example, if a particular connection point was included, zone substations that are supplied by this particular connection point in the USG region were also included.

Geographic areas with interest from new connecting industrial loads were identified using information from ElectraNet about expressions of interest for connection, including the industrial projects and locations in the South Australian Government's State Prosperity Project.

The resulting definition of the USG region, shown in Figure 7, extends north to key areas of existing and potential mining loads, southwest down the Eyre Peninsula to incorporate potential water desalination and iron concentrate projects, and southeast to Port Broughton. The figure shows both transmission and distribution network connection points that fall within and outside the region. A listing of the transmission connection points and postcodes within the USG region is included in Appendix A: Transmission connection points and postcodes in the USG.

Figure 7: Definition of USG industrial region for the pilot



3.3 Sourcing new region and project-specific data

The data and information collection process for the pilot was wide-ranging, encompassing key market participants, government, industry and research/academic sources. The aim was to gain data to support granular forecasting of industrial demand and to provide deeper insights into potential behaviour and patterns of industrial demand in the USG. Detail on the data collection is provided in Appendix B: Data collection.

Primary data was sought from:

- The existing market participants with responsibility for demand forecasting and system planning in the USG, including ElectraNet (TNSP), AEMO (and CSIRO, which provides long term forecasting inputs to AEMO) and SAPN (DNSP). Existing forecasting data was collected that could be used to produce more granular forecasts for the USG.
- Proponents of industrial projects seeking to expand or connect new industrial loads in the USG. This would allow the pilot to access more detailed data on planned technologies, likely project development timeframes and their potential for flexible operation. ElectraNet issued a data request to the proponents.

Strong confidentiality arrangements were put in place to support data sharing for the pilot. The pre-existing confidentiality obligations on the market participants (AEMO, ElectraNet and SAPN) meant that some data could not be shared, particularly any data that could identify individual industrial projects or proponents. This meant that the pilot was dependent on the project proponents themselves providing responses to the pilot survey in order to gain access to project-specific data.

The response to the pilot survey was quite limited. The pilot ultimately used data provided by ElectraNet under a confidentiality agreement, based on approaches ElectraNet had received from prospective LILs regarding connection in the USG. For each prospective load, the data identified:

- the location of the project
- the relevant industry
- forecast average load and maximum load for each year of the forecasting period, although based on a single point-in-time estimate of average load and maximum load
- an ElectraNet assigned status for each project
- an ElectraNet assessment of the probability that each project would proceed to connect to the transmission network.

It did not include information on:

- the project development stage, funding details or technology or commercial readiness levels
- behind-the-meter electricity generation or storage at the site
- expected changes in load over time, including due to expansion, electrification or energy efficiency improvements, or

- demand flexibility, including intentions to participate in DSP, technologies for DSP, intentions to operate flexibly or expected price responsiveness.

The information provided by ElectraNet was augmented and cross-checked using publicly available information. Key sources of information used were company reports, the REMP publication[29] (discussed below) and CSIRO's HyResource listing of hydrogen projects.[30] Desktop research was able to identify the majority of prospective LILs in the USG pilot region and the relevant industry for each prospective LIL. This included prospective LILs in the mining, green steel and hydrogen sectors.

The pilot was able to use a combination of the de-identified data from market participants and public data sources to produce alternative demand forecasts for the USG. However, the available data could not be used to assess the extent and impact of behind-the-meter generation and storage, energy efficiency or demand flexibility in the USG. The pilot sought to address this primarily through qualitative analysis, outlined in Section 4.3, which suggests that there is good reason to expect hydrogen projects to have flexible demand, but less reason to expect flexibility from green steel projects or data centres. Based on this, a flexible hydrogen operation scenario was developed using AEMO assumptions and incorporated in the grid impacts assessment.

3.4 Producing an AEMO-compliant base forecast

There are no official forecasts of demand produced by AEMO, ElectraNet or SAPN for the defined USG pilot region. AEMO produces forecasts at a larger geographic scale. While the NSPs produce forecasts at smaller geographic scales (by transmission network connection point), these have not previously been combined for the USG pilot region. Therefore, the first step was to produce a 'base' demand forecast for the defined USG region, prepared using the same method as currently used by AEMO to produce official demand forecasts for the existing sub-regions of the NEM. This scaling down to the USG region is shown in Figure 8 on the next page.

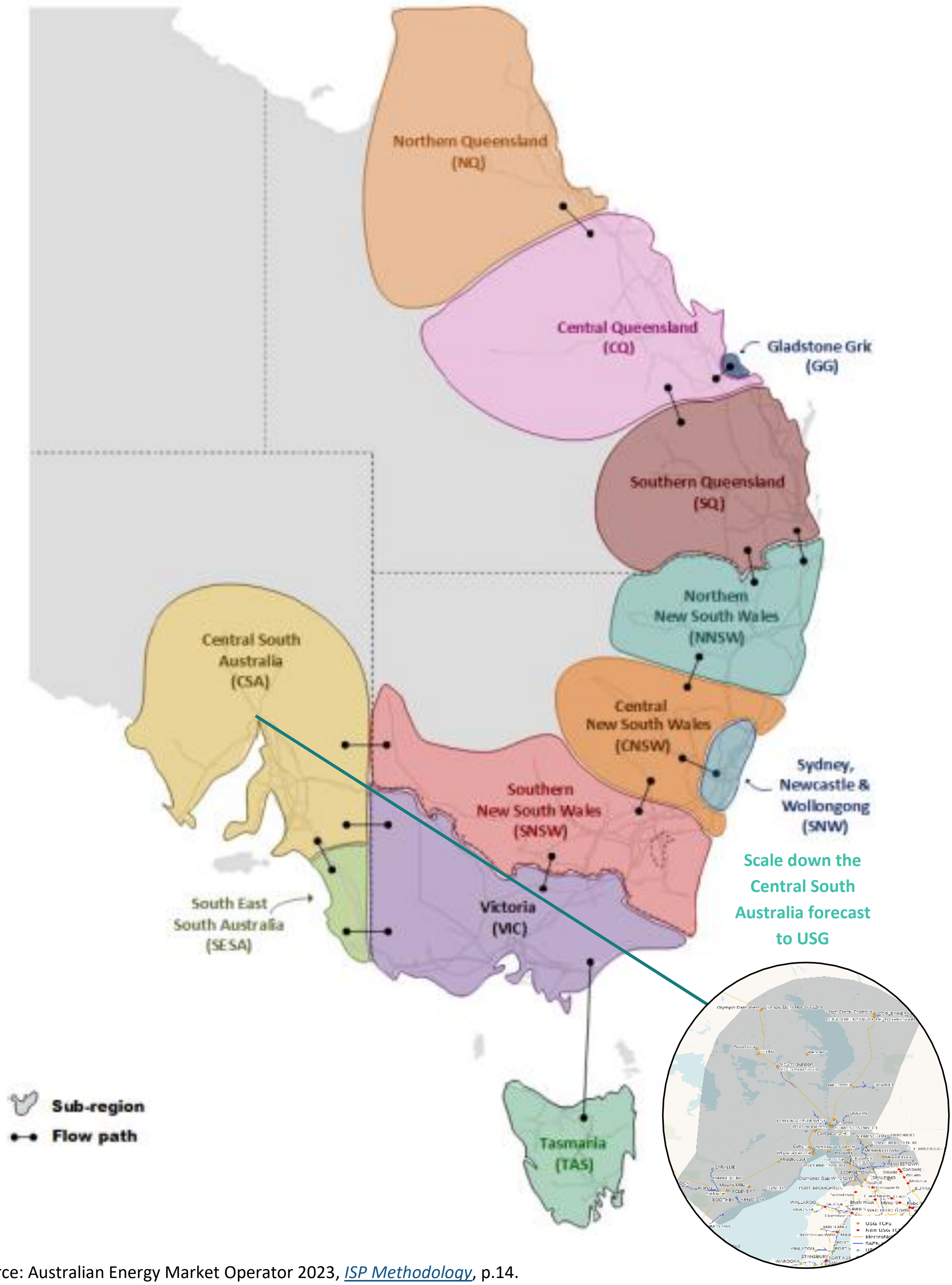
AEMO's sub-regional forecasting methods can change over time. The method that was current at the time of the pilot was used to produce the base forecast for the USG pilot region. This was the method applied by AEMO in the 2024 ISP and ESOO.[31] Further detail on this method is provided in Appendix C: AEMO forecasting methodologies**.**

The base forecast, which used AEMO's central Step Change scenario from the 2024 ESOO, covers the period from 2025 to 2050 and includes all sources of electricity demand. Demand is forecast in the following components (which can increase or reduce overall demand):

- **Residential and commercial 'underlying demand':** This is a measure of how much electricity a business or household consumes regardless of whether it is consumed from the grid or from behind-the-meter generation such as rooftop solar photovoltaics (PV). Underlying demand accounts for rooftop solar PV but does not include the impact of new technologies (e.g. EVs) or behaviours (e.g. electrification). Underlying demand is scaled to the sub-regional level using historical connection point demand to estimate its share of overall demand.[32]
- **CER, electrification and energy efficiency:** The effect of CER (distributed PV, batteries, electric vehicles etc.), electrification (substituting gas for electricity), and energy efficiency on consumption levels and patterns. CER forecasts are made at the postcode level and aggregated to the sub-region level.

- **LIL demand:** LIL demand is pro-rated to a sub-region level. The South Australian Government's hydrogen production facility was excluded from all of the USG demand forecasts due to the deferral of this project for the foreseeable future.

Figure 8: Producing a base forecast for the USG region



Source: Australian Energy Market Operator 2023, *ISP Methodology*, p.14.

3.5 Novel electricity forecasting method

The key focus for the USG pilot was to develop more granular forecasts of the electricity demand of large-scale, grid-connected industrial loads in the USG incorporating existing, new and altered industrial loads. The non-industrial components of the base demand forecasts were not modified due to their negligible contribution to demand within the USG region.

The pilot adopted AEMO’s definition of LILs as:

- any transmission network connected load, or
- any distribution network connected loads with demand greater than 10 MW for more than 10% of last financial year.

The pilot service provider (Frontier Economics) developed an alternative methodology to produce short-term forecasts of demand for LILs, which differs to that currently applied by AEMO. These forecasts were blended with longer-term forecasts produced by AEMO.

More detail on AEMO’s current demand forecasting method for LILs is provided in Appendix C: AEMO forecasting methodologies. This information is provided to assist understanding of how the approach to forecasting LIL demand has been modified in the pilot. The new forecasting approach is explained below, with additional detail provided in Appendix D: Alternative methodology for forecasting LIL demand.

3.5.1 New short-term LIL forecasting approach

Under the demand forecasting methodology used by AEMO for the 2024 ISP and ESOO,[33] which was recently updated, AEMO developed short-term LIL forecasts based on historical data and information collected directly from businesses and project proponents via surveys and interviews. These short-term forecasts were used exclusively for the first 5 years of the forecasting period and then gradually blended with long-term forecasts over years 6 to 15 of the forecasting period. A conservative approach was taken to including new LILs in the central (Step Change) forecasts whereby those included must have:

- obtained the required environmental approvals
- obtained approvals from the network service provider to connect to their system, and
- publicly announced a positive FID and/or commenced construction.[34]

The new LIL forecasting approach developed in the USG pilot uses historical data on the timing and completion of similar industrial projects in Australia to develop probability-driven forecasts of LIL demand in the USG. The empirical estimates of a prospective LIL project’s probability of completion and timing of completion are based on data from the Resources and Energy Major Projects (REMP) database complied by the Australian Government and updated annually since 2012.[35]

Data collection and preparation of the publication is currently undertaken by the Office of the Chief Economist within the Australian Government Department of Industry, Science and Resources. The REMP database currently includes around 1,150 unique projects. More detail on the REMP database is provided in Box 1 below, and in Appendix D: Alternative methodology for forecasting LIL demand.

Box 1: Details of the REMP database

Scope

Major resource and energy projects across Australia confidently valued at over $50 million. The projects include oil and gas projects, a range of resource and mining projects, including for critical minerals, resource and energy infrastructure projects such as pipelines and electrification of resource processing, and hydrogen projects.

Source data

The Australian Government actively collects information and data on the major projects, including from company websites and media releases, government departments and agencies, industry associations, and Australian Stock Exchange reports.

Project classification

Projects are classified as new, expansion or reactivation projects. Expansions are projects that already exist and are expanding to neighbouring areas. Reactivation projects are mines returning from care and maintenance or announced projects that were abandoned but have since been re-started.

Project stages

Projects are allocated to four development stages:

1. 'Publicly announced': To be included at this stage there must be publicly available information on the preliminary project schedule, planned output or cost. Projects at this stage are typically undergoing feasibility studies but may not have finalised any engineering designs or construction cost estimates.
2. 'Advanced feasibility': Projects that have completed a detailed or bankable feasibility study and which are considered to have a strong business case are included at this stage. These projects would also have been fully scoped and have a detailed Front-End Engineering Design (FEED) study.
3. 'Committed': Projects that have completed all commercial, engineering and environmental studies, received all necessary government regulatory approvals, and finalised the financing of the project (i.e. have reached FID) to allow construction are included at this stage.
4. 'Completed': Projects reach this stage when all construction and commissioning steps are completed, and commercial production has commenced.

Length of time series

The database contains project data for the 12-year period from 2012 to 2024.

Individual project data

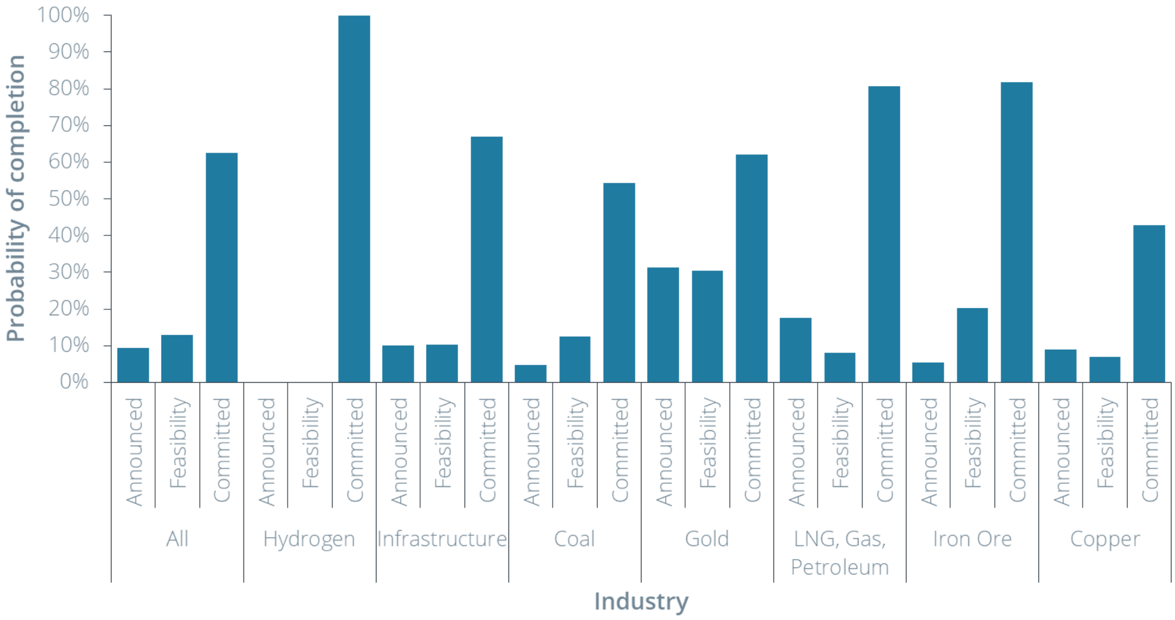
Project data contained in the database in addition to the project classification and project stage outlined above include: project name; project developer; stage; location; resource; project cost estimate; size/capacity; and employment.

The result of this process is an empirical methodology for assessing the probability and timing of project completion, which avoids the optimism bias and significant uncertainty that are particular challenges when producing LIL forecasts (as explained in Box 2 on the following page).

It should be noted that project likelihood estimates based on the REMP could differ to those that would be estimated from the much smaller subset of projects that seek connection to the transmission network through their local NSP. If NSPs were to collect data on the progress of industrial projects that seek connection, that data could also be used in this method.

As shown in Figure 9, across all projects in the REMP database, the estimated probability of completion for an industrial project is: 9.4% at the 'publicly announced' stage; 13% at the 'feasibility' stage; and 62.5% at the 'committed' stage. Figure 9 also shows the estimated probability of completion for projects in specific sectors of the REMP database.

Figure 9: REMP-derived probabilities of completion



Source: Frontier Economics analysis of REMP publications

Note: For the LNG, Gas and Petroleum industry, 'announced' probabilities are higher than 'feasibility' due to the low usage of the 'feasibility' stage for identified projects. For the Copper industry, historical REMP data indicates that projects in the 'feasibility' stage are often not completed.

Due to lack of completion of any major hydrogen projects that were in a REMP category other than 'committed', and the relative immaturity of the hydrogen sector in Australia and in the REMP database, hydrogen projects that have not reached the 'committed' stage are estimated to have a 0% chance of being completed. This is likely to change as additional committed hydrogen projects reach completion.

To mitigate this immaturity problem, an alternative scenario was developed where potential grid-connected hydrogen projects were assigned the probabilities of the 'All' industry subcategory, under the assumption that in the future hydrogen projects will have the same chance of completion as any other project. Prospective LILs provided by ElectraNet that are in sectors not represented in the REMP, such as data centres, are also assigned the probabilities of the 'All' industry subcategory.

Box 2: Managing optimism bias and uncertainty

Optimism bias

Optimism bias refers to the tendency to overestimate the likelihood of positive events and underestimate the likelihood of negative events.

Demand forecasts for prospective LILs based on survey data and interviews with project proponents may be subject to optimism bias. In this context, optimism bias may result in assigning too high a probability to the likelihood that a prospective LIL will proceed which may, in turn, result in an overstatement of likely LIL demand.

Project proponents may also have a strategic incentive for providing optimistic forecasts for their large industrial projects, to ensure network capacity is available on a secure and reliable basis to meet their needs. The detailed follow-up interviews that AEMO conducts with the largest existing LILs are designed to examine key assumptions and drivers underpinning the demand forecasts, which could help mitigate optimism bias. AEMO's forecasting accuracy assessment process can also provide a mechanism to address any optimism bias, although the long lead times for large industrial projects can mean that forecasting accuracy cannot be assessed for a number of years. To the extent that optimism bias has not been mitigated, an adjustment can be made to correct for any residual bias. Currently, AEMO accounts for short-term optimism bias in its central scenario by using the committed load threshold in the first three years of the forecast. After this period, more speculative loads are introduced to the forecast, which may represent optimism bias in the forecasts.

The use of the empirical data from the REMP database for the USG pilot is intended to avoid optimism bias by basing the assessment of the likelihood of large industrial projects proceeding on empirical data. The REMP database is available going back to 2012, which provides a time-series of data long enough to cover even projects with long lead times.

Uncertainty

Even if demand forecasts do not suffer from optimism bias, they will be subject to uncertainty. For instance, there is uncertainty about the prospect that each of the LILs included in ElectraNet's dataset will proceed to completion.

AEMO deals with uncertainty by asking large industrial users to provide forecasts for three economic pathways: (i) the most likely economic pathway, (ii) a stronger economic pathway, and (iii) a weaker economic pathway. In practice these economic pathways are dominated by assumptions relating to electrification and the uptake of new technologies across the residential, commercial and industrial sectors, which raises the potential for inconsistency with LIL forecasts. One limitation of this approach is that there are no probabilities attached to these scenarios and different stakeholders may interpret these scenarios in different ways. It would be preferable if the uncertainties about demand forecasts could be expressed as a probability distribution.

The use of the empirical data from the REMP database for the USG pilot enables the development of a probability distribution for demand from prospective LILs.

To turn the REMP-derived probabilities into forecasts of the probability of completion for prospective LILs in the USG, and therefore of LIL demand in the USG, a generalised Monte-Carlo simulation model was developed. The Monte-Carlo model accepts probability distributions derived from the REMP as inputs (reflecting the outcomes shown in Figure 9) and uses them to develop probability-driven simulations of outcomes for prospective LILs in the USG and timings of these outcomes. Further detail on the Monte Carlo Simulation is provided in Box 3.

Box 3: Monte Carlo Simulation

What is a Monte Carlo Simulation?

A Monte Carlo simulation is a computational method used to determine a distribution of outcomes from a range of uncertain events. It does this by taking random samples from all the random independent variables that comprise a potential outcome, and repeating this process until a range of outcomes has been obtained.

Monte Carlo simulations are widely used in a range of applications, as they are able to replicate any detailed system of random outcomes and provide detailed results that allow for the quantification of all risks and outcomes. For the purposes of the USG pilot, a Monte Carlo simulation is useful because the simulation can account for the probability of each prospective LIL being completed, and produce a regional load distribution that reflects the aggregate outcome for the USG from these individual prospective LILs.

The Monte-Carlo model was used to develop 10,000 simulations, each of which determined an outcome (completion or non-completion) and timing for each of the LIL projects in the pool of prospective projects. The aggregation of outcomes for the projects in a single simulation determines the additional demand for that simulation. For instance, in the first simulation it might be the case that the Monte Carlo model determines that only one of the LIL projects in the pool of prospective projects reaches completion, so that the additional demand for that simulation consists only of the demand for that single LIL. Similarly, in the second simulation it might be the case that the Monte Carlo model determines that two of the LIL projects in the pool of prospective projects reach completion, so that the additional demand for that simulation consists of the demand for both of those LILs. A distribution of potential LIL demand outcomes was observed across the 10,000 simulations, along with mean outcomes, median outcomes, maximum and minimum outcomes and percentile outcomes (such as 10th percentile or 90th percentile).

The key benefits of this alternative LIL forecasting approach developed in the pilot are as follows:

- More information on the observed development timing and completion of industrial projects in Australia is used to inform forecasts of new LILs. This provides a systematic approach to measuring and understanding uncertainty.
- The current reliance on project proponents' views of the likely timing and completion of projects, which could be subject to optimism bias, is avoided.

Detailed information on the LIL forecasting methodology that has been developed and applied is provided in Appendix D: Alternative methodology for forecasting LIL demand. The short-term forecasts are for the 10-year period from 2025 to 2035.

3.5.2 New short-term forecasts blended with AEMO's long term forecasts

Consistent with AEMO's approach to produce longer-term forecasts, the new short-term forecasts produced for the pilot are blended with AEMO's long-term forecasts (derived from the multi-sectoral modelling of the future economy that informed the 2024 ISP and ESOO). AEMO develops these long-term LIL forecasts at the sub-regional level, which is reasonable given there is lower certainty around the exact locations of new loads in the long term, especially those from industries that do not yet exist at scale.

In the pilot, the new short-term forecasts produced are blended with AEMO's long-term forecasts. As the new short term forecasts differ to those produced by AEMO, the blending approach uses the growth rates in AEMO's long-term forecasts rather than the MWh value of AEMO's long-term demand forecasts to avoid a mismatch in the series. This is necessary as there can be a significant difference in the level of AEMO's forecasts and the new short-term demand forecasts produced for the pilot. It ensures that all growth captured by the new short-term forecasts is reflected in the long-term forecasts, and long-term growth is applied to the entirety of short-term growth.

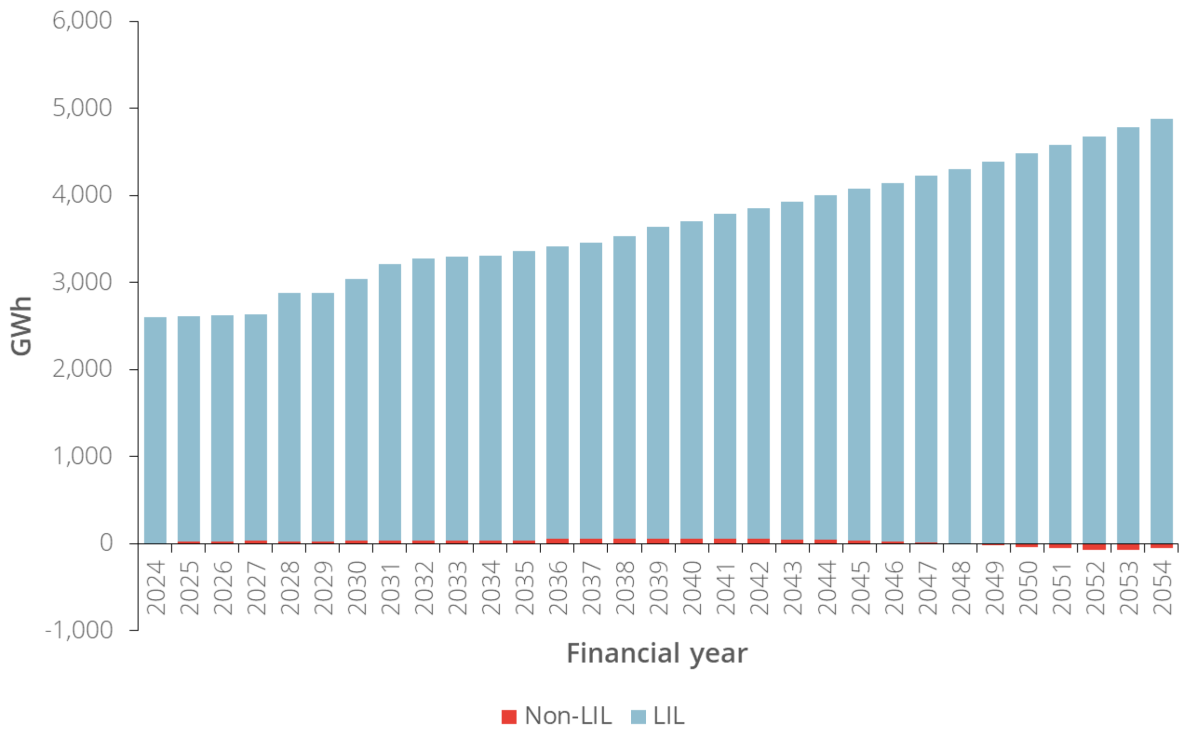
4. USG electricity demand forecasts

This section sets out, and explains the basis for, the USG sub-region demand forecasts produced by the pilot. The forecasts represent annual consumption, measured in gigawatt hours (GWh), not peak demand measured in gigawatts (GW). It is more meaningful to provide annual consumption forecasts (rather than peak demand forecasts) as peak demand in the USG is currently flat due to the predominance of industrial demand. While the forecasts presented are generally annual consumption forecasts, the forecasts used to assess grid impacts include both peak demand and annual consumption. This is particularly important when considering the potential for industrial demand (such as hydrogen projects) to be flexible in future. Unless otherwise stated, 'demand forecast' is used in this report as an umbrella term for a 'consumption' or 'demand' forecast, as defined by AEMO.[36]

4.1 AEMO-consistent base demand forecast

The base demand forecast for the USG sub-region for the period from 2024 to 2050, including all consumption (LIL and non-LIL), is shown in Figure 10. As described in Section 2.4, this forecast is prepared using AEMO's 2024 ISP and ESOO demand forecasting approach at the sub-region scale. The forecast is based on AEMO's central demand forecast scenario, the 'Step Change' scenario and SA regional forecast from the 2024 ESOO. This demand forecast does not include the outcomes of the pilot's novel approach to forecasting demand for prospective LILs.

Figure 10: Base demand forecast - Step Change scenario (GWh)



Source: Frontier Economics

Note: Uses 2024 ESOO data and sub-regional methodology.

Figure 10 shows that electricity consumption in the USG is absolutely dominated by demand from large industrial customers, such that non-LIL demand is barely visible.

The dominance of industrial demand is also evident in the flat load profile for the USG region shown in Figure 11 on the next page. This illustrates the distribution of half-hourly electricity consumption for selected months (January, April, July and October 2023) for the USG region ('USG' on the chart) and for the balance of South Australian consumption ('NONUSG' on the chart).

The 'NONUSG' region (top row) is dominated by residential and commercial customers as evident by the load shapes, reflecting higher load in the morning as people prepare to leave for work or school, and in the evening as people arrive home from work and use appliances in the evening. The 'NONUSG' region also exhibits distinctive seasonality reflecting use of different appliances (e.g. heaters, air conditioners) across the year. In particular, it can be seen for the 'NONUSG' region that demand in the evening is much higher in January (reflecting air-conditioning use) and in July (reflecting heating use) than in April and October.

The 'USG' region (bottom row) is largely flat, which is typical of LILs, indicating that there are few residential and small commercial customers in the region. The 'USG' region also exhibits minimal seasonality, with much less of the variability in summer and winter (due to cooling and heating load) than is seen in the 'NONUSG' region.

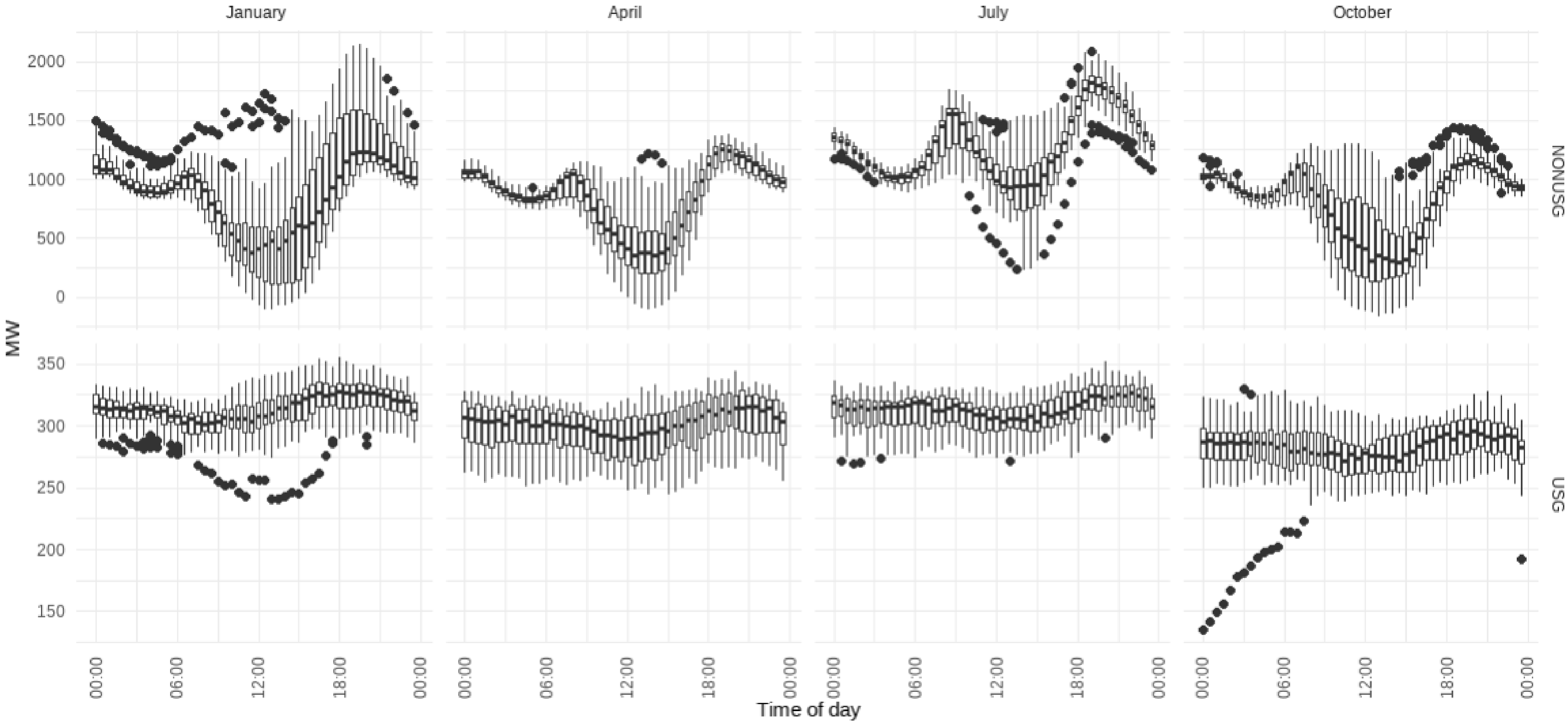
This dominance of flat industrial demand in the 'USG' region also means that the issue of minimum operational demand that is being experienced elsewhere in the South Australian NEM region is not occurring in the USG.

Minimum demand conditions typically occur when there is significant output from rooftop solar and more moderate demand such as when temperatures are mild or on weekends and public holidays. For South Australia a record low minimum operational demand of -205 MW (sent-out) was reached on Saturday 19 October 2024.[37] These conditions can create risks for system security and opportunities for large loads to soak up the excess solar power at low cost. However, Figure 10 and Figure 11 demonstrate that neither this risk of minimum demand nor opportunity for extensive excess solar usage currently exist in the USG.

In the base demand forecast, LIL demand is flat until 2028, after which there is almost consistent growth to 2050. As noted earlier, this base forecast excludes the South Australian Government's hydrogen production facility, which was recently deferred to fund the ongoing operation and modernisation of the Whyalla Steelworks. Also in the base forecast, non-LIL demand falls towards the end of the period due to forecast high uptake of rooftop solar by the residential and commercial sectors in the USG, with limited offsetting rises in demand (e.g. due to growth and electrification).

The non-LIL portion of the base demand forecast in Figure 10 is shown separately in Figure 12**.** Figure 12 also provides detail on the components of the non-LIL portion of the base demand forecast.

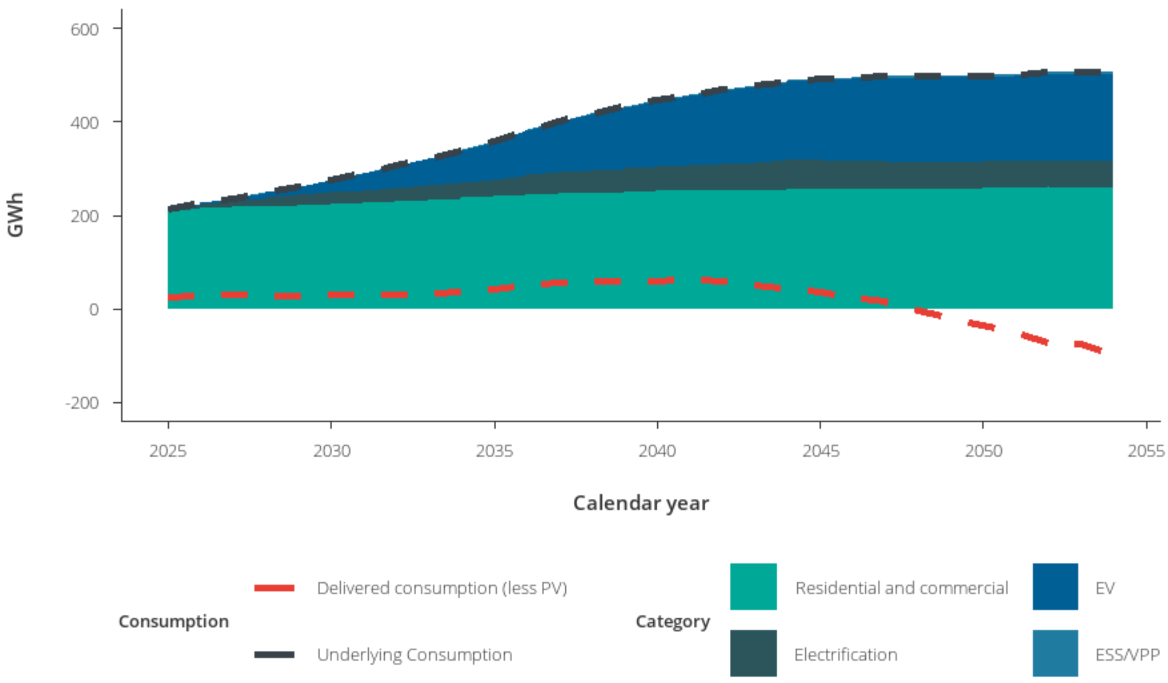
Figure 11: Load patterns in the USG region and in the balance of South Australia (NONUSG) (2023)



Source: Frontier Economics, data provided by AEMO.

Note: Distributions are represented as box-and-whisker plots and specifically 'Tukey' box plots. The lower and upper bounds of the box represent the 25th and 75th centile respectively. The thick line in the middle of the box represents the median value. Whiskers extend to the smallest/largest value within the inter-quartile range (75th centile – 25th centile) from the lower/upper centile. Outliers are represented as dots and are data points outside the inter-quartile range.

Figure 12: Non-LIL base consumption forecast components



Source: Frontier Economics

The non-LIL consumption components are:

1) **Residential and commercial electricity consumption**, which is standard residential consumption (e.g. for lighting and appliances) and standard commercial consumption. This includes both consumption from the grid and from behind the meter generation. However, it excludes additional consumption arising from electrification and adoption of new technologies, such as electric vehicles (EVs) and storage, which are forecast separately.

2) **Electrification**, which accounts for the impact of fuel-switching on consumption, that is, substitution of gas consumption for electricity consumption.

3) **EV** and **Energy Storage System/Virtual Power Plant,** which accounts for the impact of EVs and storages on consumption. Because storages largely net out from a consumption perspective, the impact on demand is small.

Underlying consumption is the sum of 1, 2 and 3. Growth in underlying consumption is largely driven by electrification and the uptake of EVs.

Delivered consumption is total consumption less production from behind-the-meter solar PV. Delivered consumption is forecast to start small and become negative in the late 2040s due to rising PV and a plateau in the growth of electrification and EVs.

4.2 Alternative demand forecasts

The alternative demand forecasts for the USG region combine the following forecasts:

- **LIL demand:** New short-term LIL forecasts to 2035, then trended to 2054 using AEMO’s 2024 ESOO industry growth rates
- **Non-LIL demand:** The AEMO-consistent non-LIL forecasts shown in Figure 12.

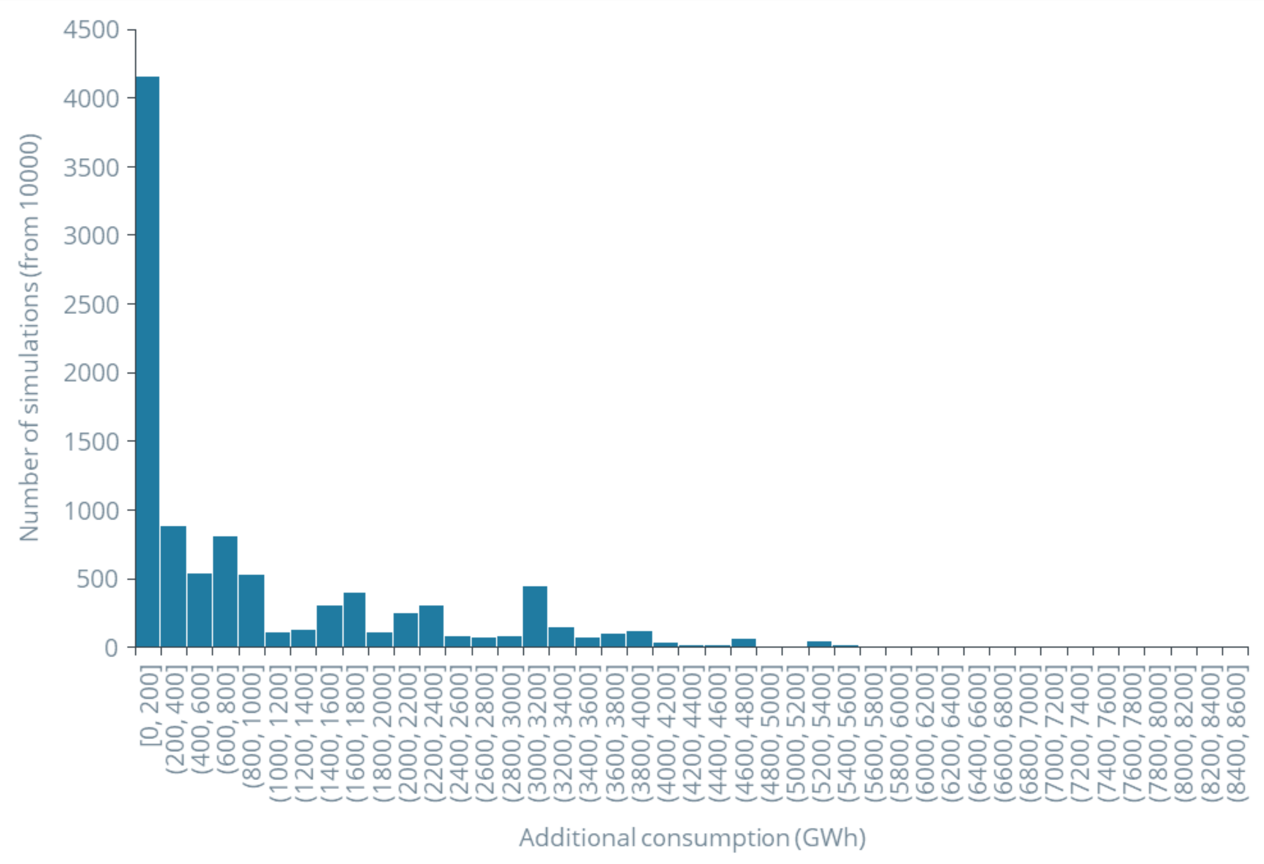
4.2.1 Monte Carlo simulation outcomes

As outlined above, the Monte-Carlo model was used to run 10,000 simulations, each of which produced an alternative LIL demand forecast reflecting a different potential mix of USG prospective LIL projects. ElectraNet provided de-identified data on prospective LIL projects, their associated industry type and expected demand as inputs to this. The probability of individual prospective LILs identified by ElectraNet in the USG proceeding is based on the REMP data. The simulation process provided the distribution of additional consumption shown in the histogram in Figure 13. This figure summarises the additional consumption outcome for the 10,000 Monte Carlo simulations. Further details on the Monte Carlo methodology are available in Appendix D: Alternative methodology for forecasting LIL demand.

Figure 13 shows that the modal, or most frequent, outcome from this alternative methodology is no additional demand for LILs in the USG. There is a 17% chance of this outcome. This is because many of the projects on ElectraNet’s prospective LIL list are categorised as being at the Publicly Announced stage and the estimated probability from the REMP database for projects at the Publicly Announced stage to reach completion is low (9% across all industry categories). This means that there are many Monte Carlo simulations in which the randomly drawn outcomes for all prospective LILs show non-completion rather than completion (i.e. projects do not proceed to the Completed stage). Figure 13 shows that the mean additional gigawatt-hours of consumption from the Monte Carlo simulations is 975 GWh. Even with many prospective projects, as is the case on ElectraNet’s network, the low probabilities observed through the REMP database mean that on average, a small amount of additional load enters the network.

However, Figure 13 also shows that there are outcomes with lower probability that would result in substantial additional demand. For instance, there are clusters of simulations that would result in a 7% chance of 1,400 to 1,800 GWh of additional consumption, a 6% chance of 2,000 to 2,400 GWh of additional consumption and a 5% chance of 3,000 to 3,200 GWh of additional demand.

Figure 13: Simulation outcome histogram



Source: Frontier Economics analysis

Note: The numbers on the horizontal axis show the range of additional load from each simulation e.g. [0,200) is a range of load from 0 to 200 GWh. There are just under 4,500 simulations that result in this range of additional load.

4.2.2 Short-term LIL forecasts

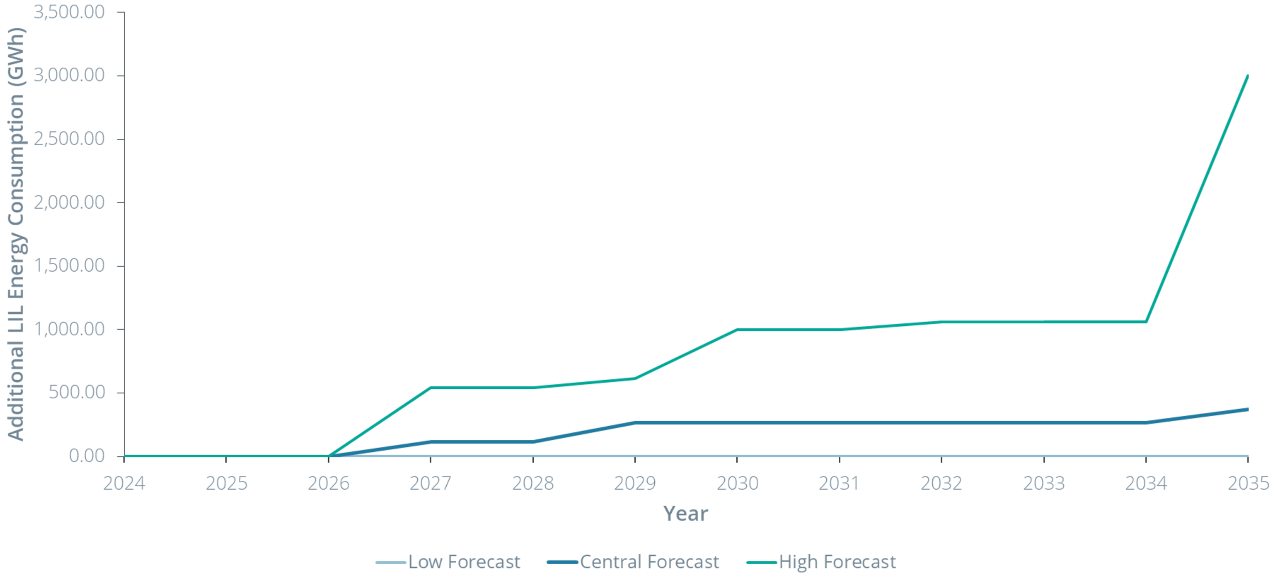
For the short-term LIL forecasts, the outputs of the Monte Carlo simulations are used to develop low, central and high LIL demand scenarios determined as follows:

- The **low forecast** represents the 10th percentile[38] of the Monte Carlo simulation outcomes. Based on the information on prospective LILs available at the time of the pilot, this low forecast resulted in no additional LIL load commencing in the period to 2035. That is, the empirically-observed probabilities of project completion from the REMP database suggest that for the lowest 10% of outcomes none of the currently-identified prospective LILs in the USG proceed before 2035.
- The **central forecast** is the outcome that represents the median (or middle value) of the Monte Carlo simulation outcomes. Based on the information on prospective LILs available at the time of the pilot, the central forecast adds approximately 350 GWh of additional LIL consumption by 2035, which represents an increase of around 15% on current LIL consumption in the USG.
- The **high forecast** is the outcome that represents the 90th percentile of the Monte Carlo simulation outcomes. Based on the information on prospective LILs available at the time of the pilot, the high forecast adds approximately 3,000 GWh of additional LIL consumption by 2035,

which would more than double the current total LIL consumption in the USG (i.e. an increase of around 130%).

The low, central and high forecasts of LIL demand to 2035 are shown in Figure 14. As discussed, based on the information available at the time of the pilot, the low forecast has no additional non-FID LILs, which is equivalent to AEMO's current approach. The central and high cases include additional non-FID load, with the commencement of this consumption staggered over the next decade.

Figure 14: Short-term LIL demand forecasts (low, central and high)



Source: Frontier Economics

4.2.3 Long-term LIL forecasts

The short-term forecasts of LIL demand (to 2035) are blended with AEMO's long-term industry growth rates, as explained in Section 2.5.2. AEMO produces different long-term industrial growth forecasts under its different forecasting scenarios. The low, central and high short-term LIL forecasts were combined with the long-term growth rates from the Progressive Change, Step Change and Green Energy Export scenarios, respectively.

4.2.4 Total LIL and non-LIL forecasts

The three USG LIL forecasts are combined with the base USG non-LIL forecasts to obtain three long-term total demand forecasts for the USG. Table 2 summarises the basis for the short-term and long-term LIL forecasts and the non-LIL forecasts for the USG.

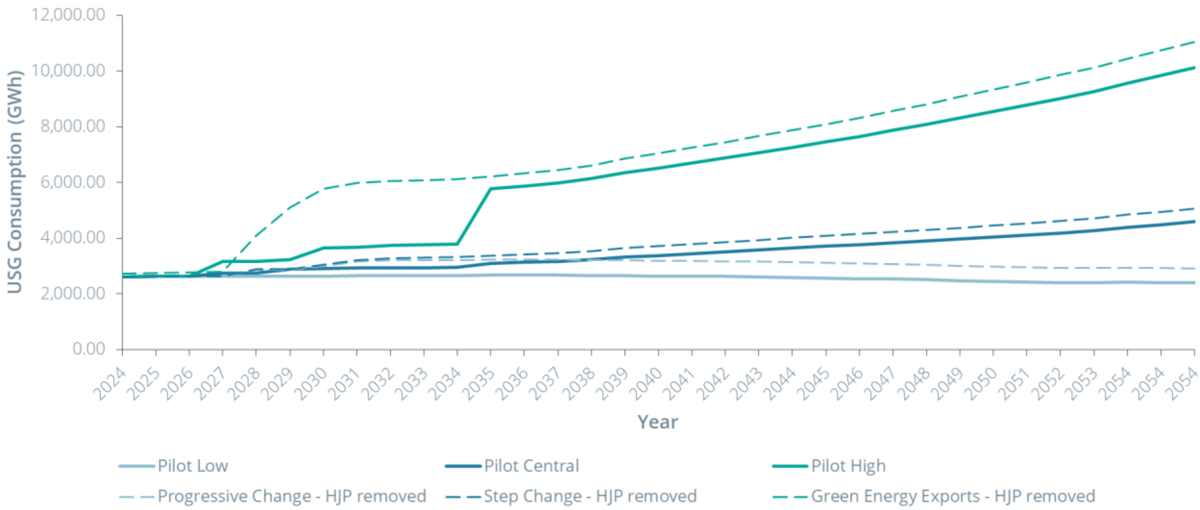
The resulting three forecasts are shown in Figure 15 below, and include the alternative LIL forecasts (i.e. the combined short-term and long-term LIL forecasts) with USG non-LIL demand. The USG non-LIL demand that is used in each scenario is the base USG non-LIL demand forecast (reflecting AEMO's Step Change scenario).

Table 2: **Alternative USG forecasts of total demand – 3 scenarios**

Scenarios			
	LIL demand		**Non-LIL demand**
	Short term LIL forecast	**Long term AEMO growth rate**	
Pilot Low	Low	Progressive Change	Base USG (step-change)
Pilot Central	Central	Step Change	Base USG (step-change)
Pilot High	High	Green Energy Exports	Base USG (step-change)

The forecasts of total energy consumption in the USG for the three scenarios (Pilot low, Pilot central and Pilot high) are shown in Figure 15. These are the solid lines. The dashed lines of the same colour represent scenarios that have been developed based on information provided by AEMO on LIL and non-LIL demand allocated to the USG, and include calculations to apply long-term growth rates that were also provided by AEMO. The demand forecasts for the three scenarios are consistent with the demand forecasts for these three scenarios from AEMO's 2024 ESOO (noting that the estimated load from the recently-deferred South Australian Government's hydrogen production facility was removed from the USG forecasts provided by AEMO).

Figure 15: Alternative demand forecasts for the USG – total demand (GWh)



Source: Frontier Economics

Each pilot forecast (Low, Central and High) is forecasting lower demand than the comparable AEMO forecasts, over the long term. A key reason for this is likely to be the difference in the treatment of expansions to existing loads in the alternative and AEMO forecasts. The alternative pilot forecast treats expansion of existing loads (such as mining loads) probabilistically in the same way as new LILs (i.e. based on the REMP probabilities), whereas AEMO's forecasts include identified expansions in full. AEMO may also have additional expansion load reflected in their forecasts that was not available to the pilot. As a result, AEMO forecasts can be higher than the pilot forecasts, even though the pilot forecasts incorporate new LIL demand from prospective proponents that are not accounted for in AEMO's forecast. AEMO's Green Energy Exports scenario also includes an assumption of additional demand from new LILs, although this assumption varies from the empirically-based forecast of the probability of prospective LILs proceeding that has been developed for the USG pilot.

Because the demand forecasts in Figure 15 are not on a perfectly like-for-like basis, the results in Figure 14 are also important to consider, since the demand forecasts from Figure 14 provide a clear indication of the additional demand from prospective LILs in the USG developed through this pilot (i.e. up to 3000 GWh of new consumption by 2035 in the high scenario). This additional demand from prospective LILs would not meet AEMO's criteria for inclusion in demand forecasts (as applied in the 2024 ISP and ESOO) due to the projects being at early stages of development.

4.3 Analysis of scope for industrial demand flexibility

One of the aims of the pilot was to understand the scope for greater flexibility in the way in which industrial demand could operate in the USG to moderate demand for electricity, particularly for newer loads such as hydrogen and green steel production. The limited response to the survey of LILs in the USG meant that this analysis could not be project-specific. Therefore, the assessment of potential demand flexibility in the USG for future industry types that may emerge was conducted using available research and Frontier Economics' previous analysis.

The analysis suggests that while hydrogen production is likely to respond flexibly to electricity prices, green steel and data centres are less likely to do so.

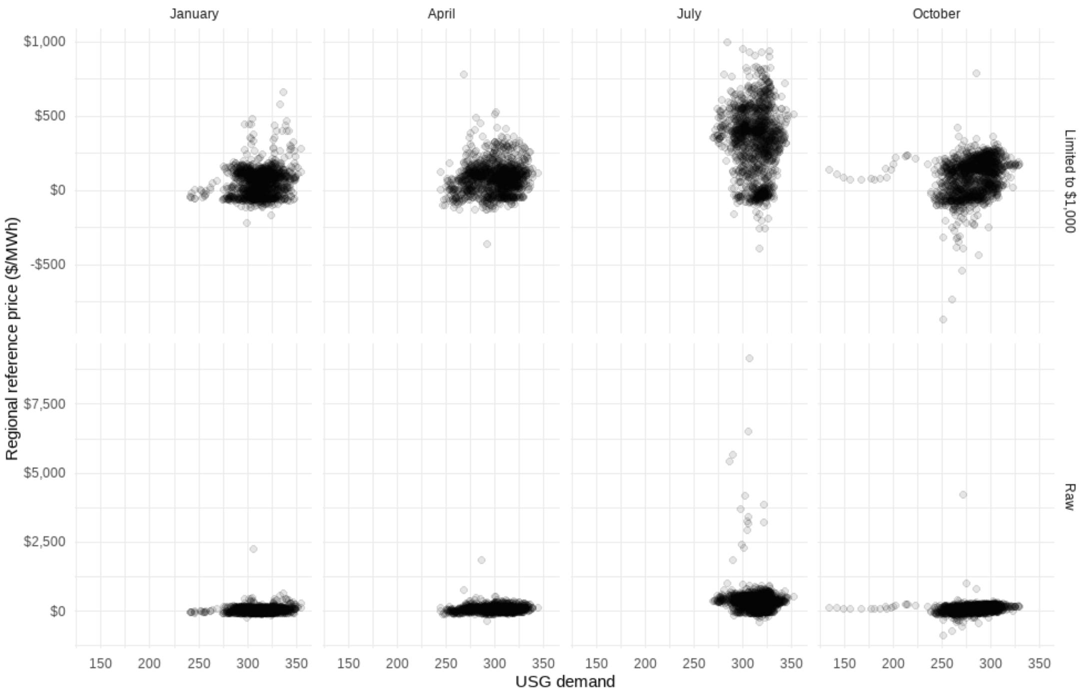
4.3.1 USG demand not currently flexible

It appears there is very little 'flexible' LIL demand in the USG at present. This is based on the analysis shown in Figure 16:

- Analysis of the USG load traces provided by AEMO indicates that the profile of large loads is relatively constant, indicating that they do not appear to be price responsive. If USG loads were flexible, reductions in load at times of high prices would be expected (i.e. a downward sloping trend). However, this does not appear to be the case.
- AEMO and ElectraNet advised that existing loads in the USG region are flat loads and existing LILs in the USG are treated as flat loads in AEMO's demand forecasts.

There are a number of reasons that can explain existing industrial facilities in the USG having little demand flexibility. For some industrial facilities it can be challenging to vary output (and therefore electricity demand) because the facility has equipment that needs to run constantly. Some chemical processes, smelting, and some heating and cooling processes require continuous operation or have long start up and shut down periods. For some industrial facilities it may simply be uneconomic to operate flexibly in response to variations in electricity prices. If electricity costs are a relatively small proportion of total costs, any savings in electricity prices due to flexible operation may simply be insufficient to compensate for the lost output from flexible operation or the cost of modifications required to enable flexible output.

Figure 16: USG consumption and price scatterplot



Source: Frontier Economics, USG load data provided by AEMO

While it appears there is currently very little 'flexible' LIL demand in the USG, there is the potential that newly emerging industries in the USG may be able to operate flexibly. Potential new industries in the USG that may be able to operate flexibly are hydrogen production, green steel and data centres.

4.3.2 Hydrogen

Hydrogen electrolysers (either via alkaline or proton exchange membrane production) may become a source of new industrial load in the USG. Such electrolysers have the potential to operate as large highly flexible loads that can be ramped up and down to balance electricity supplied from renewable energy sources and provide ancillary grid services that can contribute to power system security.

The key reason that electrolysers would operate flexibly is to minimise the cost of electricity through arbitrage, given electricity is a substantial proportion of the total cost of producing hydrogen. Electrolysers may also operate flexibly to ensure that hydrogen production is powered by renewable generation.

The economics of operating electrolysers flexibly is likely to be reflected in the plans for hydrogen projects in the USG. For instance, the electrolyser of the South Australian Government's hydrogen production facility was intended to 'operate as a flexible load to manage excess renewable energy in the system'.[39]

A simple comparison of electrolyser capital costs with electrolyser electricity costs highlights the benefits of operating electrolysers flexibly. Electrolyser fixed costs (capital costs and operating costs) are currently in the order of:

- $3.48/kg of hydrogen, assuming that the electrolyser operates at a 100% capacity factor, or

- $6.97/kg of hydrogen if the electrolyser operates at a 50% capacity factor.[40]

That is, the *fixed* cost per unit of hydrogen rises as the capacity factor reduces.

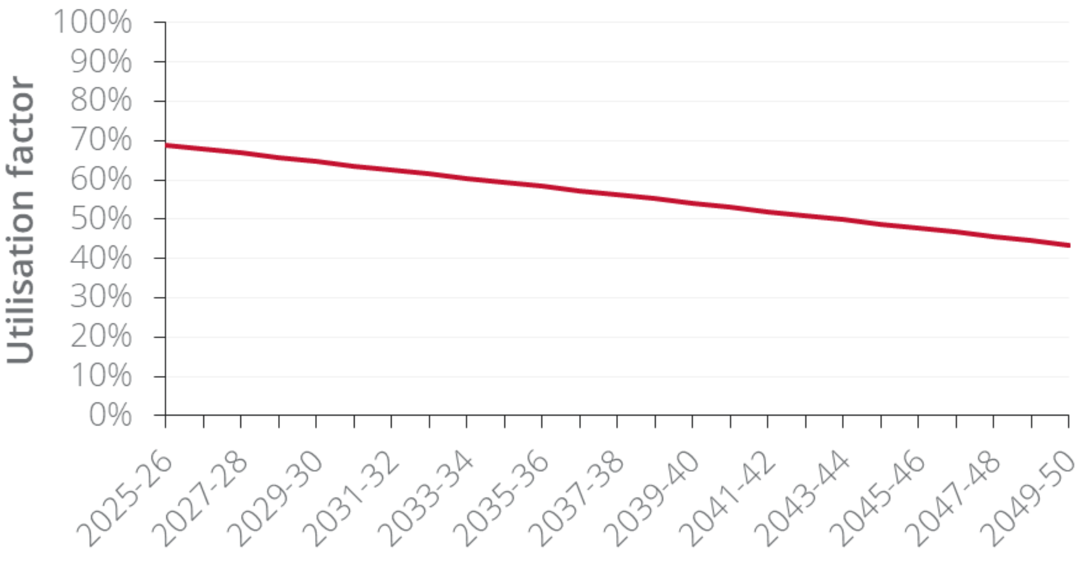
Although fixed costs are higher at lower capacity factors, this may be offset by savings in the price of electricity from the flexible operation of an electrolyser:

- Assuming an annual average electricity price of $120/MWh (including wholesale and network costs), the electricity cost is $7.66/kg for an electrolyser operating at 100% capacity factor. Combined with the fixed cost above ($3.48/kg at a 100% capacity factor), the result is a total cost of hydrogen of $11.14/kg.
- For an electrolyser operating at 50% capacity factor, the electrolyser can operate when electricity prices are lowest. Assuming this lowers the average electricity price to $60/MWh, the cost of electricity falls to $3.83/kg. Combined with the fixed cost above ($6.97/kg at a 100% capacity factor), the result is a total cost of hydrogen of $10.80/kg.

Under these assumptions, the overall cost of hydrogen production is lower when operating flexibly (i.e. despite the otherwise higher fixed costs associated with lower capacity factors). However, this simple example does not account for the cost of storing hydrogen, which, depending on the required offtake of hydrogen, may increase as a result of hydrogen production operating flexibly (e.g. if hydrogen is used as an input to ironmaking). Where constant offtake of hydrogen is required, the additional cost of hydrogen storage may make flexible operation more costly. The most cost-effective operating profile for hydrogen production will likely vary depending on the project.

The USG pilot did not receive survey responses from prospective new hydrogen projects to inform the understanding of potential for flexible operation. However, in undertaking the grid impacts assessment, a scenario that includes flexible hydrogen production was developed using the minimum annual electrolyser utilisation factor published by AEMO as part of the Draft 2025 Inputs, Assumptions and Scenarios Report (IASR).[41] This is shown in Figure 17.

Figure 17: Assumed electrolyser utilisation factor



Source: Australian Energy Market Operator 2025, Draft 2025 Stage 2 Inputs and Assumptions Workbook.

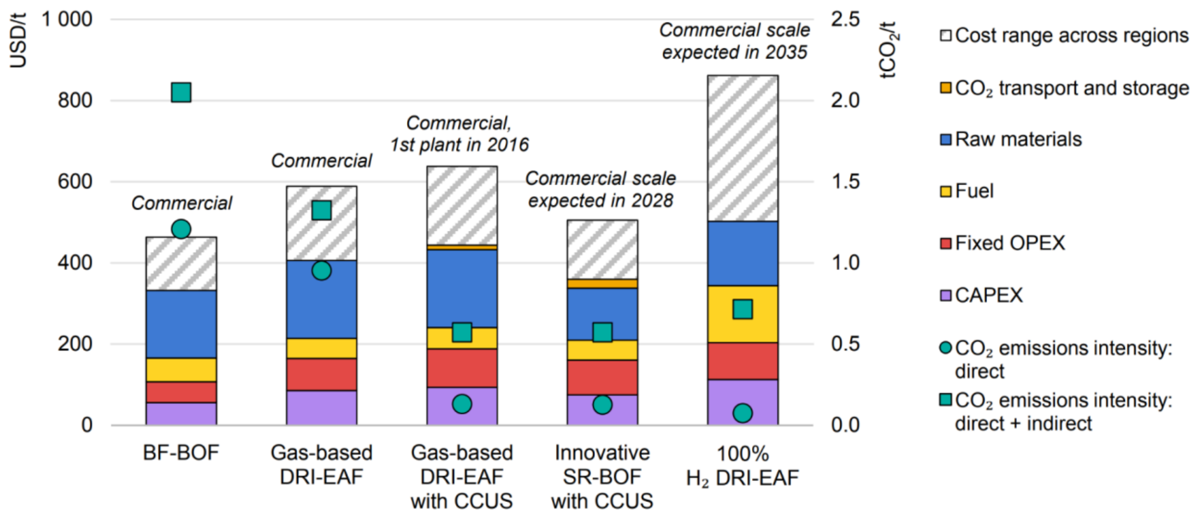
4.3.3 Green steel

Green steel, which is produced without the use of fossil fuels, may be a feature of the redevelopment of the Whyalla Steelworks in the USG. Electricity is a significant input into the manufacture of green steel, raising the prospect that green steel facilities may choose to operate flexibly – similar to the way that hydrogen electrolysers are expected to operate.

However, while electricity is a significant input cost for green steel production, publicly available information suggests that electricity costs do not account for the same share of total costs for green steel as they do for hydrogen production, and that savings in electricity costs for green steel from operating flexibly are unlikely to be sufficient to justify the additional capital costs that would be required to operate flexibly.

This view is based on estimates of the levelised cost[42] of steel production from the IEA. Figure 18 shows estimates of the levelised cost of steel production for varying production methods. Figure 19 shows how these estimates of the levelised cost of steel production vary with different prices for gas, electricity and carbon dioxide.

Figure 18: Levelised cost of steel production

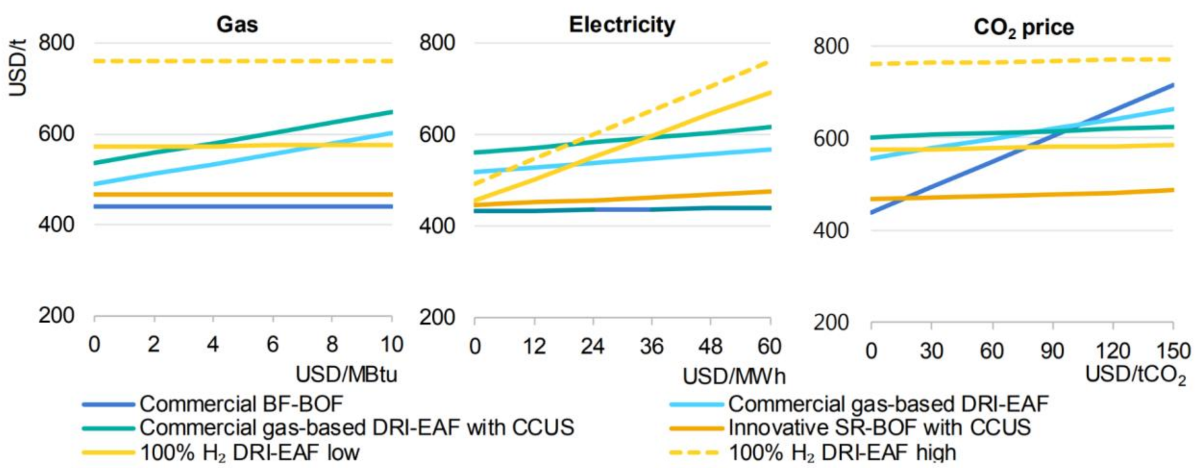


Source: International Energy Agency 2020, Iron and Steel Technology Roadmap, p. 108.

First, consider the *gas-based* DRI-EAF production route, Figure 18 shows that fuel costs (including gas and electricity) account for a relatively small component of levelised costs (the fuel component of the cost stack for gas-based DRI-EAF is a relatively small proportion). Figure 19 shows that the levelised cost of production increases by a relatively small amount as the electricity price increases (the gas-based DRI-EAF line in the middle panel of Figure 19 increases relatively slowly as the electricity price increases). For instance, the levelised cost of production is around 575 USD/t at an electricity price of 60 USD/MWh, and around 550 USD/t at an electricity price of 30 USD/MWh.

If this reduction in electricity price (from 60 USD/MWh to 30 USD/MWh) were achieved by reducing the capacity factor from 100% to 50%, enabling flexible operation, this would imply a requirement to double the capacity of the plant. This reduction of around 25 USD/t due to lower electricity prices would require an increase in fixed costs of around 150-200 USD/t. This suggests that the electricity costs of operating a gas-based DRI-EAF production route are not so high that it would be economic to increase the capacity of the plant in order to operate flexibly.

Figure 19: Levelised cost of steel production at varying gas, electricity and CO2 prices



Source: International Energy Agency 2020, Iron and Steel Technology Roadmap, p. 109.

Second, consider the 100% H2 DRI-EAF production route. For this route, the case for operating flexibly is stronger – presumably as a direct result of the benefits of operating hydrogen production flexibly – but increasing the capacity of the DRI-EAF plant to operate flexibly is still unlikely to be cost-effective overall. Figure 18 shows that fuels costs (including hydrogen and electricity) account for a larger component of levelised costs for a hydrogen DRI-EAF plant. Figure 19 shows that the levelised cost of production increases materially as the electricity price increases.

For instance, the levelised cost of production is around 675 USD/t at an electricity price of 60 USD/MWh, and is around 575 USD/t at an electricity price of 30 USD/MWh. If this reduction in electricity price were achieved by reducing the capacity factor from 100% to 50%, which would imply a requirement to double the capacity of the plant, this reduction of around 100 USD/t due to lower electricity prices would require an increase in fixed costs of around 200 USD/t. In other words, while there may be reason to operate hydrogen production flexibly to minimise electricity costs (as discussed above) the evidence suggests that there is not the same reason to do so for a DRI-EAF plant.

It may be that it would be economic for a DRI-EAF plant to provide demand flexibility on shorter time frames, such as reducing demand at times of local or system peak demand. The European Steel Association cites analysis suggesting that the iron and steel sector offers potential for short-term flexibility, but not for daily cycling or assisting with managing renewable droughts.[43] Frontier Economics has not been able to independently assess the case for a DRI-EAF plant to provide demand flexibility on shorter time frames and, in the absence of information from potential new LILs on this, this potential flexibility has not been tested as part of the pilot.

4.3.4 Data centres

Data centres may be developed in future in the USG region. Electricity is a significant input into the operation of data centres. However, publicly available information suggests that electricity costs do not account for the same share of total costs for data centres as they do for hydrogen production or green steel.

The limited available information on the cost structure of data centres suggests that electricity costs make up less than 20% of total costs. For similar reasons as for DRI-EAF green steel plant, this suggests that any savings in electricity costs from operating flexibly would be insufficient to make operating at less than full capacity economic. In addition, it is unclear how much ability data centres would have to operate flexibly while still meeting the needs of their clients, which may be constant.

As with DRI-EAF plant, it may be that it would be economic for a data centre to provide demand flexibility on shorter time frames. It might do this by scaling back operation to reduce demand at times of local or system peak demand or by investing in behind-the-meter generation or storage for use at times of local or system peak demand. Frontier Economics has not been able to independently assess the case for a data centre to provide demand flexibility on shorter time frames and, in the absence of information from potential new LILs on this, this potential flexibility has not been tested as part of the pilot.

5. Grid impact analysis

A central aim of the USG pilot was to test the grid impacts of the alternative demand forecasts produced, including the implications for network investment and broader network planning processes. With the key focus of the pilot on alternative forecasts of LILs, the resulting focus of the grid impact analysis is at the transmission level.

5.1 Range of demand outcomes tested for grid impacts

It was important to test a broader range of alternative forecasts in the grid impact modelling than the Low, Central and High pilot forecasts presented in Section 3. This broader range of alternative forecasts is necessary to test the impacts of LIL location and flexibility.

The alternative demand forecasting approach produced various possible futures with different probabilities and different levels and configurations of new LIL demand in the USG. The Low, Central and High pilot forecasts from Section 3 show plausible alternative forecasts that differ in terms of the relative magnitude of new LIL demand. However, these forecasts did not explicitly consider the grid impacts.

For the grid impact modelling, it is equally important to test the possible futures with different magnitudes of new LIL demand, and to consider how the alternative forecasts differ in terms of factors that would drive quite different network investment outcomes. This includes:

- the mix of LIL projects, which can impact the grid in different ways. For example, the technology/type of LIL project, flexibility of the load, and links between projects e.g. between mining and desalination projects
- the location of new LILs relative to existing areas of network capacity or constraint.

5.1.1 Location-based considerations

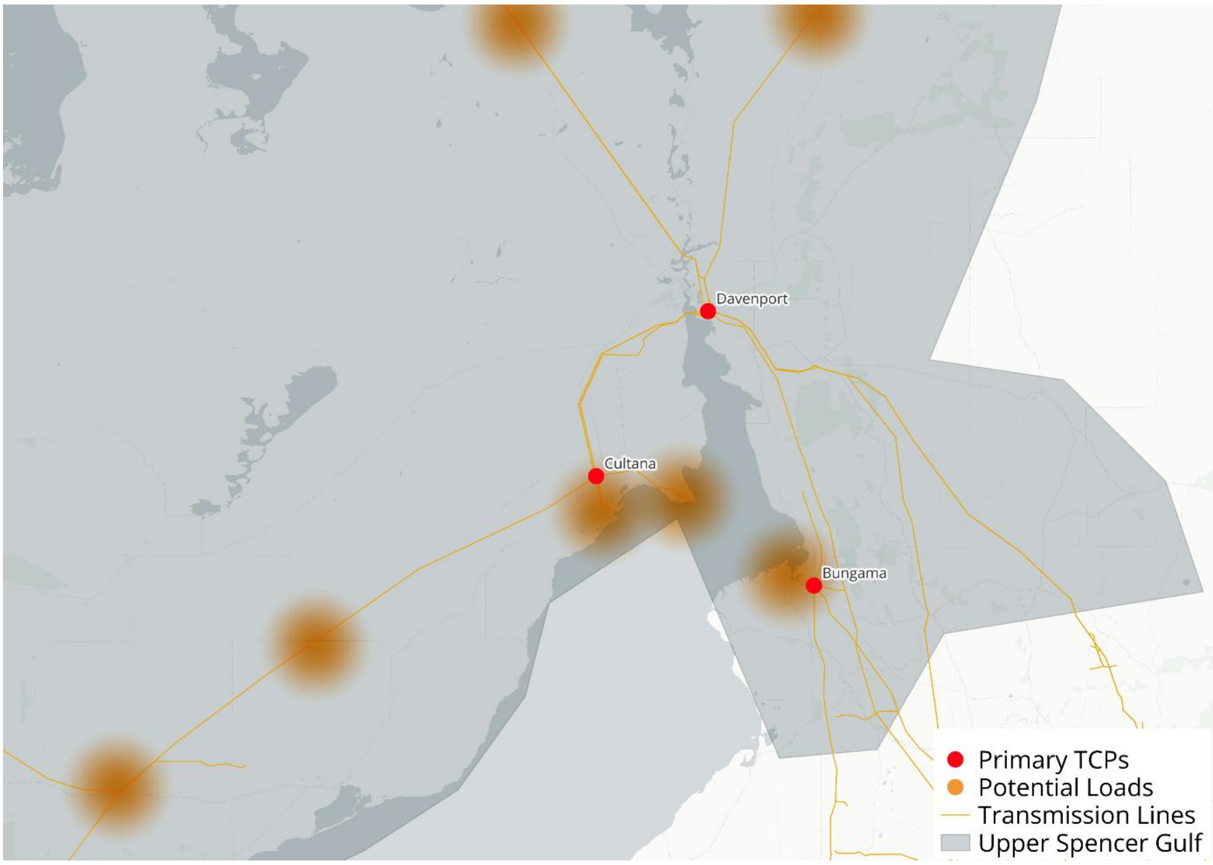
The Monte Carlo simulation provided a wide range of forecasts, as well as information on the relative likelihood of its 10,000 simulations. Just as the alternative forecasts presented in Section 3 represented a 10th percentile, a median and a 90th percentile, the scenarios selected for the grid impacts assessment represent different points on the distribution of outcomes from the Monte Carlo simulations. Since each of the individual Monte Carlo simulations represents a specific combination of prospective LILs proceeding, each of the 10,000 Monte Carlo simulations also identifies specific locations of new load.

ElectraNet provided information and advice on the current transmission network configuration in the USG area that is material to identifying relevant forecasts for the grid impact analysis. The transmission connection points at Cultana, Bungama and Davenport are the key transmission connection points likely to face capacity constraints in the USG, yet a number of potential new LIL projects could require connection via the three locations.

Figure 20 shows a selection of potential new LIL connection locations within the USG, demonstrating that new industrial loads can be located in different parts of the USG, with potentially different implications for connection point constraints and network asset loading/capacity.

To reflect this, a range of outcomes from the Monte Carlo simulation, representing different points on the total additional load distribution, and consisting of new loads in different locations, were chosen for testing in the grid impact modelling.

Figure 20: USG and potential loads



Source: Frontier Economics analysis of ElectraNet and AEMO data

5.1.2 Scenarios tested in grid impact modelling

Nine scenarios were identified for testing with their impact on the grid expected to vary due to differences in the extent of new demand, the location of new demand and the relative flexibility of new demand. These are shown in Table 3 below.

Table 3: **Scenarios for grid impact modelling**

Scenario		Distribution	Rationale	Testing
1	**Baseline scenario – no new LILs**	NA	Providing a baseline against which to assess grid impacts of alternative forecasts.	Baseline.
2, 3	**(2) Medium Scenario A and (3) Medium Scenario B**	REMP probabilities – Mean	Selected two different configurations of LIL load around the mean (or 70th percentile of the skewed distribution) of the REMP-driven probability distribution. The two scenarios involve the LIL projects proceeding at different locations.	Impact of expected amount of additional LIL demand. Impact of location of additional demand.
4, 5	**(4) High Scenario A and (5) High Scenario B**	REMP probabilities – 90th percentile	The high case involves a mix of mine expansions and green mineral production projects proceeding. This is at the 90th percentile of the pilot distribution. The two scenarios involve the larger projects proceeding at different locations.	Impact of 90th percentile estimate of additional LIL demand. Impact of location of additional demand.
6, 7	**(6) Hydrogen Scenario and (7) Hydrogen Scenario with Flexibility**	REMP probabilities – different hydrogen – 90th percentile	Based on the REMP, a hydrogen project that has not yet reached FID has a 0% chance of proceeding. Scenarios 6 and 7 change the treatment of hydrogen to be under the 'all projects' categorisation of REMP projects – on the basis that the low probability of hydrogen projects in the REMP is due to the industry's current infancy, and these projects may develop in a similar way to other resource and energy projects. Two scenarios are run to test the impacts of load flexibility: • A smaller, baseload (inflexible) electrolyser, and • A larger, flexible electrolyser.	Impact of assuming that hydrogen projects are just as likely to proceed as other projects in the REMP database Impact of location of additional demand. Impact of demand flexibility.
8, 9	**(8) ElectraNet Scenario A and (9) ElectraNet Scenario B**	ElectraNet probabilities	Two more collections of potential LILs, drawn from the median of a distribution driven by ElectraNet's internal probabilities of project completion. **Note:** These forecasts of LIL demand were higher than LIL forecasts reflected in ElectraNet's 2025 TAPR, which was prepared at a later date.	Impact of estimate of additional demand from LILs based on ElectraNet's estimates of likelihood of completion. Impact of location of additional demand.

In summary, the key rationale for the selection of the nine scenarios was to test:

- **Medium and high additional LIL load scenarios (Scenarios 2, 3, 4 and 5):** The medium and high scenarios test new LIL load at the 70th and 90th percentiles of the REMP-driven distribution, respectively, and seek to test the impact of location on network build. The high scenarios are essentially equivalent to the high scenario from Section 3, with the exception that the high scenarios for the grid impacts assessment reflect specific combinations of new load in specific locations. No low scenario was tested as load would be insufficient to drive new network investment. For each of medium and high scenarios, two separate spatial configurations of a similar magnitude of new demand are modelled, with the different outcomes between these configurations illustrating the different requirements for network development when load enters at different locations.

- **Hydrogen (Scenarios 6 and 7):** These are scenarios designed to test the inclusion of a hydrogen electrolyser project in the USG and different assumptions about their flexibility. In these scenarios two cases are presented where the same volume of hydrogen is produced in each. In one scenario, a larger hydrogen electrolyser is assumed to run optimally against spot prices (flexible load), subject to a minimum capacity factor drawn from AEMO's draft 2025 IASR (as shown in Figure 17 above). In the second scenario, a smaller hydrogen electrolyser is assumed that operates at a constant load (inflexible load) producing the same total volume of hydrogen as in the first scenario. The different specification of the scenarios provides insights into the impact of price-sensitive flexible hydrogen electrolyser load for grid planning, and the results may be extended to other potentially flexible loads in the future.
- **High scenarios using ElectraNet's assumed probabilities of LIL projects proceeding (Scenarios 8 and 9):** This tests the impact of location of network development in scenarios with higher overall demand.

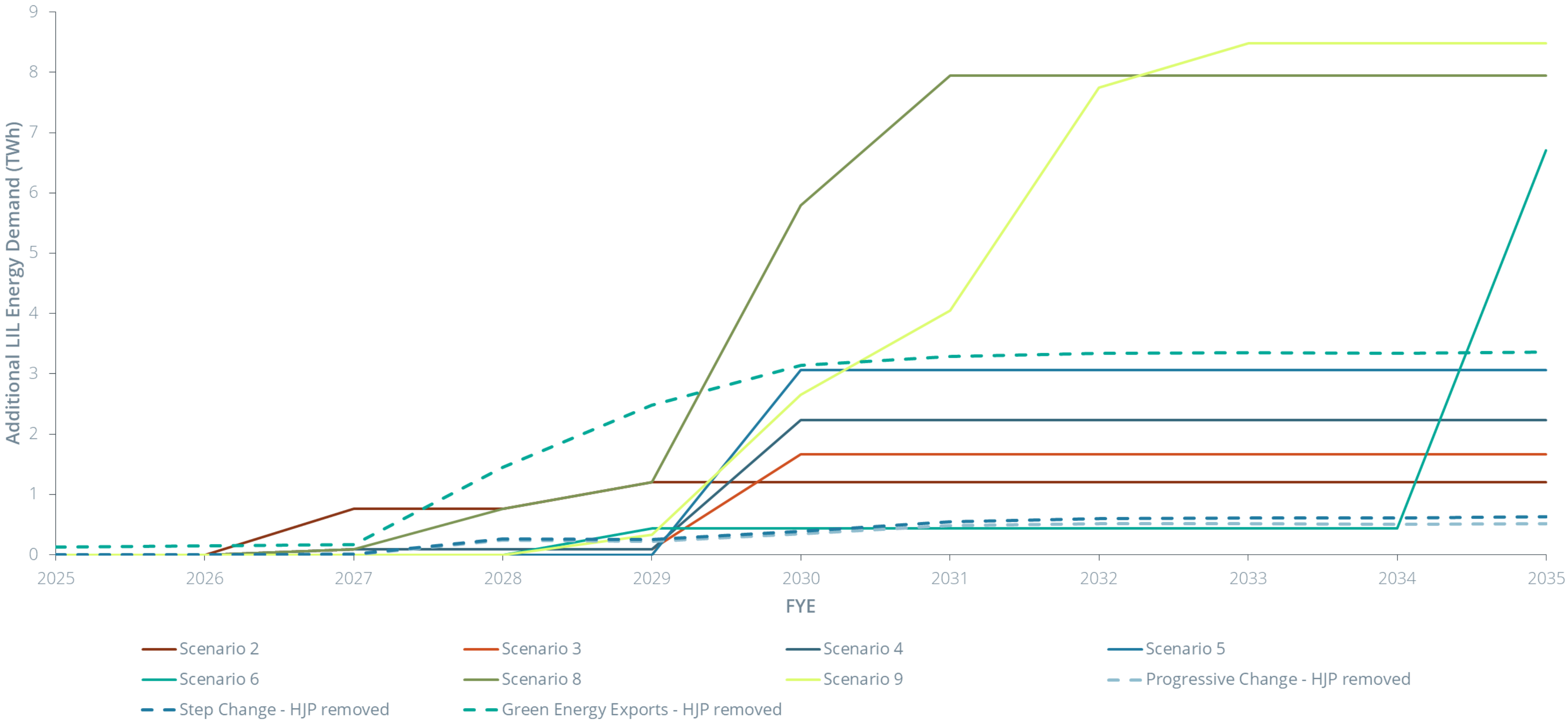
The nine scenarios also only provide short-term alternative LIL forecasts to 2035 that are based on a specified mix of new USG LIL projects. Given the importance of specifying location and types of loads for meaningful grid impact modelling, it did not make sense to include generalised long-term growth rate-based forecasts that are not location specific.

Figure 21 shows the alternative energy consumption forecasts for each of the nine scenarios, and how they compare to the existing AEMO-consistent USG LIL forecasts (under the Step Change, Progressive and Green Energy Export scenarios). The nine scenarios are distributed around AEMO's 2024 ESOO scenarios. The more likely medium and high scenarios based on REMP probabilities (i.e. Scenarios 2, 3, 4 and 5) sit between the existing Step Change and Green Energy Export LIL forecasts.

It is important to note that none of the grid impact scenarios discussed in Table 3**,** and presented in Figure 21**,** are demand scenarios that ElectraNet has developed or used in its own modelling or forecasting. There are two key reasons for this:

- First, the grid impact scenarios are each based on the novel methodology developed for this pilot, which is not a methodology used by ElectraNet. Even scenarios 8 and 9, which use ElectraNet's assumed probabilities of LIL projects proceeding, have been generated using the novel methodology developed for the pilot rather than being demand scenarios that ElectraNet has developed.
- Second, while the grid impact scenarios are all based on the same information about prospective LILs that was provided by ElectraNet as part of the pilot, it is important to understand that this information on prospective LILs changes over time and is regularly updated by ElectraNet as more information is received.

Figure 21: Grid impact scenarios – additional LIL load



Source: Frontier Economics analysis, ElectraNet project and AEMO forecast data

Note: This chart does not show baseline consumption because this chart is additional LIL consumption and there are no additional LILs in the baseline scenario. Also, this chart shows only one hydrogen scenario (Scenario 6). The reason is that both hydrogen scenarios (Scenario 6 and Scenario 7) have the same annual consumption, it is just the timing of that consumption during the year that differs.

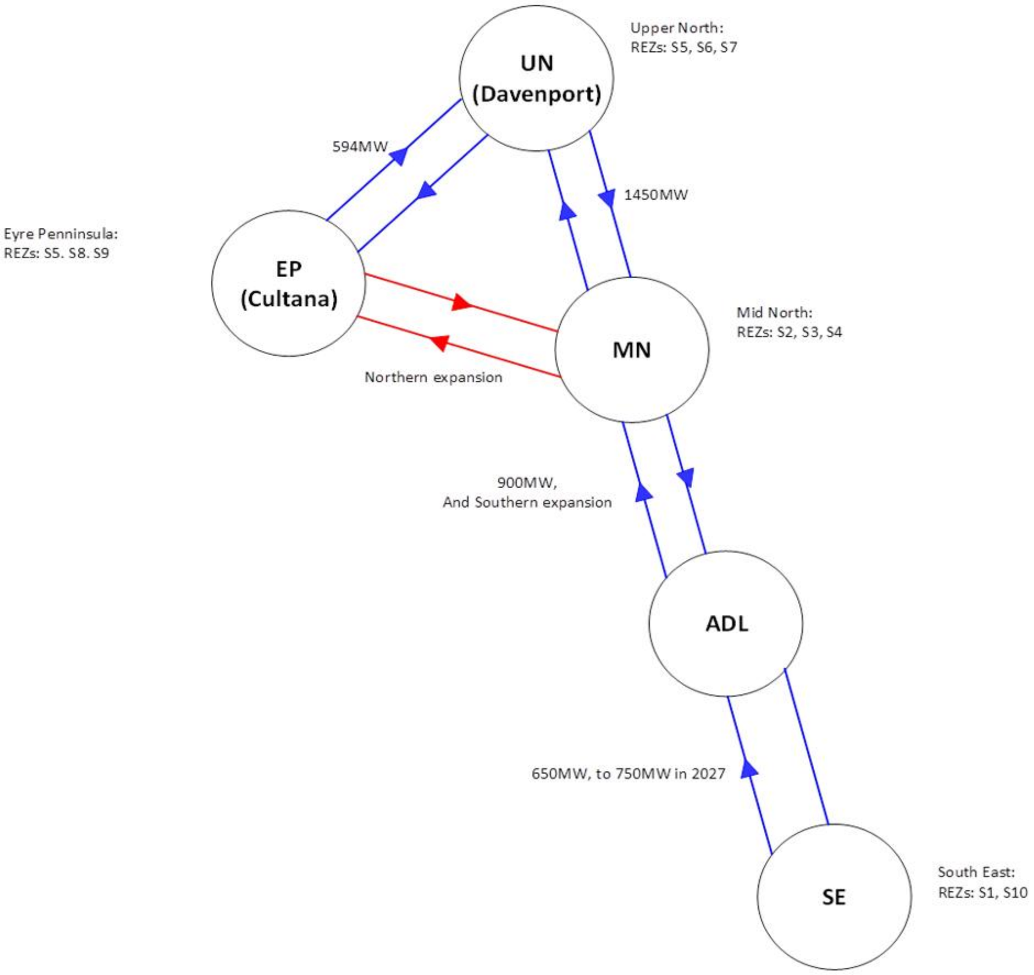
5.2 Grid impact modelling approach

To assess the impacts of the nine scenarios, ElectraNet undertook PLEXOS-based market modelling on a simplified representation of the transmission network to determine the optimal network configuration for each scenario. This modelling is similar to that undertaken by AEMO for the ISP.

ElectraNet's modelling of these scenarios incorporated the additional LIL demand specified in each scenario, and otherwise maintained baseline demand forecasts for the USG and elsewhere. ElectraNet compared each of the modelled outcomes against the baseline outcome (Scenario 1) to assess the grid impacts of the alternative demand forecasts (Scenarios 2 to 9).

The modelled transmission network configuration for the USG pilot region is shown in Figure 22. This model includes a granular representation of the transmission network in the USG, including electricity load and generation in REZs for each of the key three connection points in the USG (represented by the network regions of Eyre Peninsula (EP), Upper-North (UN) and Mid-North (MN)).

Figure 22: ElectraNet modelled network configuration



Source: ElectraNet.

Note: The Northern expansion (represented by the red lines) and Southern expansion refer to ElectraNet's 2024 ISP actionable projects. The Northern expansion is referred to as the 'Mid North SA REZ Expansion' in AEMO's 2024 ISP, see discussion above at 2.3.

The primary output from the grid impact modelling is an annual time series of transmission investment from which can be determined when additional investment is required (as shown in Table 4 below). This represents the total amount of additional transmission capacity that ElectraNet's modelling identifies as optimal to invest in between any two nodes in the network diagram shown in Figure 22. This approach maintains confidentiality of individual prospective loads whilst still providing insight into the magnitude of investment required in each scenario.

5.3 Results on required network investment

ElectraNet's modelling found that additional network investment to support the USG is optimal in all scenarios, although the amount of investment and optimal timing of investment differs across scenarios as discussed in the sections below. Optimal timing indicates when network investment is required to be completed by, so as to meet new demand.

5.3.1 Impact of additional demand

In the baseline case (Scenario 1), additional network investment becomes optimal in 2045. This investment is driven by the need to supply Adelaide with sufficient renewable energy.

In those scenarios (scenarios 4 to 9 inclusive) that involve a significant increase in LIL demand (i.e. above 200 MW), the grid impacts are such that the timing of optimal network investment is brought forward and its scale is increased, compared to the baseline scenario. ElectraNet's modelling found that additional load in the USG of around 500 MW is the threshold at which additional load in the USG generally drives an investment requirement (although the threshold is sensitive to the location of load within the USG). 500 MW of additional load is a point that sits around the 90th percentile of the probability distribution for additional LIL demand from the Monte Carlo modelling – that is, it is an amount of additional load that the Monte Carlo modelling suggests would only occur in 1 in 10 simulations.

This threshold of 500 MW of additional load is met in scenarios 4 to 9, and in these scenarios there is greater transmission investment, earlier transmission investment or both. This threshold *is not met* in scenarios 2 and 3, which is why transmission investment outcomes in these scenarios are very similar to outcomes in the baseline scenario. While these results are consistent with the observation that additional load beyond around 500 MW results in the need for additional investment, it is not always the case that a scenario with higher load will result in a requirement for more investment in the USG since the requirement for transmission investment is also driven by investment in generation and storage, which varies between scenarios.

A summary of the annual time series of transmission investment, which was produced for the grid impact analysis from ElectraNet's modelling of the nine USG pilot scenarios, is provided in Table 4**.** Table 4 summarises the timing and magnitude of investment at both 2035 and 2052 (the end of ElectraNet's modelling period), along with a brief explanation of the drivers of the results in each scenario.

There is additional and substantial network investment towards the end of the modelling period in almost all scenarios that is driven by largely non-LIL factors, such as the need to increase renewable electricity supply to meet increasing residential demand from population growth, electrification and EVs in Adelaide. The assessment of grid impacts for the pilot focuses on those driven by the introduction of new LILs in the USG, consistent with the pilot forecasts.

Table 4: **Grid impact modelling results**

Scenario		Optimal timing (and build quantity)	2035 transmission built	2052 transmission built	Rationale
1	**Baseline scenario – no prospective LILs**	2045 (321 MW)	0 MW	1,156 MW	Additional network required to supply Adelaide with renewable energy from the USG.
2	**Medium Scenario A**	2045 (297 MW)	0 MW	1,162 MW	No additional investment on the baseline as additional load is under 200 MW.
3	**Medium Scenario B**	2045 (342 MW)	0 MW	1,222 MW	No additional investment on the baseline as additional load is under 200 MW.
4	**High Scenario A**	2043 (10 MW in 2043, and 672 MW in 2045)	0 MW	1,607 MW	Optimal investment time brought forward to 2043 due to additional LIL demand. 500 MW threshold breached in 2030, but due to the locational split of the load (which occurs in Cultana and Davenport) there is no additional augmentation required. This is driven by local renewable supply available to meet load at Cultana, so is sensitive to wind and BESS output assumptions at times of network stress. If wind and BESS were assumed to be less available to meet demand at times of network stress, additional network augmentation would be required.
5	**High Scenario B**	2034 (4 MW in 2034, and 37 MW in 2035)	37 MW	1,132 MW	Optimal investment brought forward to 2034 due to additional LIL demand. There is slightly less load than in High Scenario A, however because it is all located at Cultana the result is greater load at Cultana than in High Scenario B. As a result, some augmentation is required by 2034 to supply this node. Longer term the transmission build is very similar to Baseline and Medium scenarios.
6	**Hydrogen Scenario**	2035 (771 MW)	392 MW	1,116 MW	High demand, baseload hydrogen electrolyser requires additional investment.
7	**Hydrogen Scenario with Flexibility**	2035 (518 MW)	518 MW	764 MW	Higher initial network investment than the non-flexibility case but significantly reduced investment in the longer term. (i.e. lower than all other scenarios in 2052).
8	**ElectraNet Scenario A**	2030 (291 MW)	431 MW	1,113 MW	High demand case requires accelerated network investment of increased magnitude.
9	**ElectraNet Scenario B**	2034 (647 MW)	862 MW	1,466 MW	High demand case requires accelerated network investment of increased magnitude. Investment is delayed four years from breaching the 500 MW threshold, likely due to the presence of load at Bungama.

5.3.2 Locational impact

Locational grid impacts can be assessed by comparing scenarios with similar amounts of additional LIL demand, but in different locations. These results are derived from ElectraNet's PLEXOS market modelling, as summarised above.

There are three pairs of USG pilot scenarios that have similar levels of demand, but for which demand is located on different parts of the network. These can be used to assess the extent to which location is important in determining grid impacts. These pairs are Scenario 2 and 3 (Medium Scenario A and Medium Scenario B), Scenario 4 and 5 (High Scenario A and High Scenario B) and Scenario 8 and 9 (ElectraNet Scenario A and ElectraNet Scenario B). For each pair of scenarios, the results were as follows:

- **Scenarios 2 and 3 - Medium Scenarios:** Both scenarios have additional demand from new LILs in the USG that falls far below the 500 MW notional threshold for additional transmission investment. So, the locational difference of load does not impact network configuration.
- **Scenarios 4 and 5 - High Scenarios:** Both scenarios have additional demand from new LILs in the USG that exceeds the 500 MW notional threshold for additional transmission investment. The location of load has a significant impact on transmission investment for these scenarios. Scenario 3 (High Scenario A) has load dispersed across two zones, and optimal investment timing in 2043. Scenario 4 (High Scenario B) has a slightly lower total load that is all located at one node, and the optimal timing for investment is in 2034. ElectraNet explains this difference as being driven by the reduced requirements for network augmentation when demand is co-located with generation from REZs. This near decade-long difference in grid augmentation timing for a similar magnitude of additional load is a significant takeaway from the pilot.
- **Scenarios 8 and 9 - ElectraNet Scenarios:** Both scenarios have additional demand from new LILs in the USG that is much greater than the other scenarios. As a result, both require augmentation in the near term, crossing the indicative threshold of 500 MW in 2030. Scenario 9 (ElectraNet Scenario B) has substantially more demand than Scenario 8 (ElectraNet Scenario A). However, the optimal investment timing in Scenario 9 (ElectraNet Scenario B) is delayed to 2034. Again, ElectraNet found that this outcome is due to location; this time due to the presence of load in the Bungama (Mid-North) region of the network.

5.3.3 Flexibility impact

The effect that load flexibility for LILs has on the grid was tested by comparing a scenario with inflexible hydrogen production (Scenario 6 - Hydrogen Scenario) with a scenario with flexible hydrogen production (Scenario 7 - Hydrogen Scenario with Flexibility). As previously outlined, the Hydrogen Scenario with Flexibility involved a larger hydrogen electrolyser that is able to operate flexibly in the electricity market to avoid times of high electricity prices. The Hydrogen Scenario involved a smaller hydrogen electrolyser that is required to operate constantly. The amount of hydrogen produced (and therefore the total annual electricity demand) is the same under the two scenarios.

Perhaps unexpectedly, ElectraNet's modelling found that the flexible operation of an electrolyser increases the requirement for transmission in the near term (although not in the longer term). ElectraNet's interpretation of the increased requirement for transmission in the near term is that the flexible arrangements may result in higher network utilisation at times (when compared to the baseload operation). There are a few reasons that this result might have occurred.

First, it may be driven by a lack of alignment between transmission constraints and spot prices in a heavily renewable, zonal market. This could result in the electrolyser operating flexibly to minimise spot prices, but in doing so, operating at times of constraints on the local transmission network.

Second, it may be that the assumed level of flexibility for the hydrogen electrolyser is not sufficient to effectively avoid it driving the need for transmission augmentation. For instance, if AEMO's assumptions about the extent to which electrolysers will operate flexibly do not provide sufficient flexibility in this case to avoid network augmentations, then the flexible operation scenario may simply result in an electrolyser with higher capacity that is nevertheless not sufficiently flexible to avoid operating at times that drive the need for transmission augmentation.

That the requirement for transmission in the long-term is lower in the case with flexible operation may be because these factors are temporary factors or may be due to the effects of different generation and storage investments between the two cases.

Overall, ElectraNet's grid modelling implies that flexible loads that have lower capacity factors may drive increased requirements for grid infrastructure, at least in the shorter-term, as locational generation and co-located flexible demand may be misaligned. Over the long term, however, the modelling supports the need for flexible operations in achieving a least-cost system, given that the transmission investment needed in the flexible scenario by 2052 is lower than in all other scenarios.

6. Pilot outcomes and learnings

This section draws together the key outcomes and learnings from the USG pilot and considers how this work could be extended into the future.

6.1 Key pilot outcomes

The pilot, undertaken over the period from October 2024 to June 2025, produced a number of useful outcomes and learnings that are explored below.

6.1.1 Outputs produced

As well as providing an opportunity to undertake detailed research on potential industrial development in the USG being driven by both policy and market forces, the pilot produced two main outputs. These were alternative forecasts of future industrial demand in the region, produced using a new methodology developed in the pilot, and testing of requirements for electricity network investment based on these forecasts.

On the demand forecasts, the pilot implemented a novel approach to forecasting that:

- makes use of data from REMP publications to assess the likelihood that specific prospective LILs identified by ElectraNet would proceed
- uses a Monte-Carlo approach to develop a probability distribution of additional demand resulting from prospective LILs proceeding.

These forecasts differ to those typically produced by AEMO and NSPs. First, the forecasts are produced for the defined USG region. Forecasts are not typically produced by AEMO or the NSPs for this regional definition. Second, the forecasting method uses a different methodology for the inclusion of LILs. Key learnings in relation to this new method are discussed below.

To gain insights into the grid impacts, ElectraNet undertook the network modelling, which was able to test forecasts that differed in terms of the amount of electricity demand and the location and timing of the development of individual large projects that could have material impacts on the network. This analysis found that additional network capacity would only be required to meet the highest potential industrial demand outcomes, and that required network investment may be smaller when generation and load are co-located.

6.1.2 Barriers and challenges

At the commencement of the pilot, it was also hoped that greater insights could be gained into whether new and altered loads present opportunities for flexible demand and their intentions to invest in behind-the-meter energy supply and storage. A better understanding of the potential for demand flexibility and co-located supply could change understanding about the required level of network augmentation.

Gaining this information for prospective projects requires access to information provided directly by the project proponents, as it is not available in public documents. A comprehensive survey of prospective LILs was developed for the pilot to gather this information. The surveys were issued by ElectraNet, but unfortunately there was very limited response.

Past efforts to obtain information from proponents of industrial projects have been hampered by confidentiality concerns, the perceived administrative burden associated with a request that is voluntary rather than mandated, and proponents' own lack of clarity about future electricity loads and demand flexibility potential. The pilot team, in consultation with ElectraNet, sought to address such concerns by requiring confidentiality agreements from all project partners, and having ElectraNet issue the surveys to build trust. Ultimately, these measures proved insufficient, suggesting the need for alternative approaches where parties other than the NSPs and AEMO need such data, as discussed below.

The lack of survey data limited the ability to account for behind-the-meter supply and storage, and demand flexibility, in the pilot forecasts. However, hydrogen flexibility assumptions were tested in the grid impact modelling.

6.1.3 Key learnings

The pilot has been able to develop a new methodology to include future industrial projects in demand forecasts at an earlier stage. The new methodology uses empirical information (from the REMP) on the timing and completion of industrial projects in Australia. This is a more systematic method to inform assumptions about the likelihood and timing of new projects proceeding as it draws on historical experience. It also removes the sole reliance on project proponents' own (or others) view of the likely timing and completion of projects, which could be subject to optimism bias.

The REMP is based on historical data on resources and energy project progression, and as such, may not accurately represent future industrial make-up, or changes to the likelihood of projects proceeding. This means that the REMP may under-estimate the likelihood of completion for industrial projects applying new technologies. The probability estimates reflect that many of the potential USG projects are at early stages of development, and the REMP data suggests that there is a low probability that projects at early stages of development will proceed to completion.

Given the different methodology used to produce the pilot forecasts, they differ to the particular scenario-based forecasts produced by AEMO and the NSPs. In general, the empirically-based method for including industrial projects is less conservative than the method used to produce AEMO's 2024 ESOO forecasts because it includes projects at earlier stages of development. However, the forecasts themselves are still conservative compared to AEMO's central forecasts, as many new industrial projects in the USG are at an early stage of development and the empirical data suggests these have a lower probability of proceeding.

Therefore, while the midpoint forecasts were not significantly different to AEMO's central forecasts, the spread of potential demand outcomes shown in the Monte-Carlo distribution is large. Significantly higher industrial and overall demand outcomes are possible in the USG, although these outcomes are less likely. If the REMP database produces higher probability estimates for new industries and technology over time, this would be reflected in higher potential demand scenarios.

As highlighted in ElectraNet's recently published 2025 TAPR, the emergence of large industrial loads remains a highly dynamic situation in the USG. ElectraNet will continue to evolve its analysis of required grid investments to support the Mid North SA REZ Expansion identified in AEMO's ISP (which ElectraNet refers to as the Northern Transmission Project).

While there remains uncertainty about eventual industrial demand outcomes and locations, the assessment of grid impacts has been useful to demonstrate the different levels of network investment that could be needed. As particular projects develop and become more certain, this provides ready information about likely investment requirements.

6.2 Future application and extension

There is substantial scope to build on the lessons of the USG pilot and to build on the tools developed. This could include:

- repeating the key elements in other regions, with involvement from the relevant state or territory governments, NSPs and AEMO
- using the REMP model to inform all planners with a need to understand the implications of potential future industrial developments – not just those with an energy focus
- extending the application of the probability-based forecasts to inform real options analysis, which can be useful for economic assessment of network investments (for instance, for the RIT-T) – more detail on how the pilot methodology can inform real options analysis is in Box 4 below.

Box 4: Real options analysis

What is real options analysis?

Where there may be material benefit from deferring an investment decision, or pursuing smaller or shorter-lived investments until new information becomes available, real options analysis can be used as a quantitative tool to value this flexibility. It does this by modelling the prospective value that may result from responding to new information in the future (when uncertainty is likely to be resolved) and identifying the pathway that maximises the expected payoff. Real options analysis is most useful for more complex decision making where there are credible opportunities to alter the inputs or actions over time as new information becomes available.

In the presence of significant risk, standard cost benefit analysis will not identify the approach that generates the highest benefit-cost ratio, as it assumes a fixed investment strategy that remains unchanged as circumstances change (i.e. it ignores the flexibility to respond to new information and does not account for the fact that achieving the outcomes may be uncertain). In contrast, real options analysis recognises upfront that:

- there is uncertainty about future outcomes (e.g. demand from a prospective LIL)
- this uncertainty may be resolved as new information emerges over time (e.g. new information about the progress of a prospective LIL)
- the investment can, in certain circumstances, be adapted in response to the new information
- this flexibility to adjust the investment can be valuable, as it can be used to exploit beneficial outcomes, while avoiding negative outcomes.

How can the pilot methodology inform a real options analysis?

The results of the pilot show that the requirement for network investment can depend on whether specific LILs reach completion (or on what combination of specific LILs reach completion). The results also show that there is significant uncertainty about the probability that specific LILs reach completion, and that this uncertainty will diminish over time as the project progresses towards completion (or non-completion). This combination of circumstances means that real options can be useful for assessing the economics of investment in specific network assets.

Real options analysis extends traditional cost benefit analysis (based on discounted cash flow (DCF) or net present value (NPV) analysis) to include the value of options (costs and benefits of alternative real options) so that this can be considered in decision making rather than relying on a single forecast or projections of key variables. DCF valuations contain implicit assumptions, which can be glossed over in practice, but which real option valuations make explicit. For example, real options valuation requires an explicit estimate of the probability that cash flows might turn out to be more or less than expected.

There are a range of simpler to more complex approaches to undertaking real options analysis of a network investment. Options include simulation analysis (assessing a probability distribution of possible outcomes), decision analysis (including decision trees which test the outcomes of sequential decisions such as on the timing and scale of investment) and a range of options pricing methods (such as Black-Scholes or Binomial Option Pricing).

One of the challenges in undertaking real options analysis is that the analysis requires as an input an estimate of the probability of different outcomes. It is this estimate of the probability of different outcomes that enables a real options analysis to assess the benefit from, for instance, deferring an investment decision. In many cases there is little data available to inform this estimate of the probability of different outcomes, which can be a barrier to undertaking robust real options analysis.

However, the analysis of the REMP data undertaken for the pilot provides insight into the probability of specific LILs reaching completion, and the probability of combinations of specific LILs reaching completion. This can provide an empirical basis for estimates of probability used in real options analysis, providing the opportunity to improve the robustness of real options analysis of investments in specific network assets. Future projects may also be able to place a greater focus on the impacts of electrification, demand flexibility and behind-the-meter generation if greater access to project specific data could be gained than in the USG pilot.

As discussed, the USG pilot did not receive responses to surveys requesting the project specific data that would have enabled a focus on electrification, demand flexibility and behind-the-meter generation. Instead the pilot relied on existing information from ElectraNet. However, the tools developed in the USG pilot could be applied in future to richer datasets with more project specific information, if these datasets are available from NSPs, from AEMO or through surveys.

There is also an opportunity for governments and/or market bodies to work with NSPs to consider what more could be done to facilitate the collection and publication of consistent, granular information on future demand. In 2024, in response to the Review of the ISP, Energy Ministers tasked AEMO to support DNSPs and jurisdictions 'to develop [demand] projections and undertake analysis in a consistent manner to support the ISP's development'. This pilot suggests there may also be value in taking another look at the type of information TNSPs provide.

This could usefully include the NSPs maintaining a historical database of enquiries for new connection from industrial project proponents that enables the outcomes for the projects seeking new connection to be traced through time. The USG pilot made use of the significant and useful data on project development available in the REMP publications. However, this could be bolstered by data from NSPs which may provide more specific or accurate probability estimates.

Appendix A: Transmission connection points and postcodes in the USG

Transmission connection points (TCPs) within the defined USG region

Transmission Connection Point	TNSP Code	Transmission Connection Point	TNSP Code
Baroota	T310	Mt Gunson South	H590
Bungama	H396	Neuroodla	T331
Clements Gap Windfarm	T423	Olympic Dam North 132kV	T550
Corraberra Hill	H517	Olympic Dam West	H551
Cultana	H512	Pernatty	T591
Davenport	H426	Pimba	T505
Davenport West	H426	Port Pirie	T397
Emeroo	T589	Redhill	T434
Leigh Creek Coalfield	T452	Stony Point Distribution	T363
Leigh Creek South	T440	Whyalla Central	T575
Middleback	T514	Whyalla Terminal	T134
Mount Gunson	T528	Woomera	T433
Mount Lock	H583	Yadnarie	T262
Mount Millar	T142		

Postcodes within the defined USG region

Postcodes		
5419	5493	5640
5420	5495	5641
5421	5521	5642
5422	5522	5650
5431	5523	5700
5432	5540	5701
5433	5555	5710
5434	5600	5713
5464	5601	5715
5472	5602	5717
5473	5603	5719
5480	5604	5720
5481	5605	5722
5482	5607	5725
5483	5608	5730
5485	5609	5731
5490	5611	5732
5491	5633	5733

Appendix B: Data collection

This appendix provides an overview of the process and outcomes of the data collection processes to support the USG pilot.

The pilot initially identified and confirmed data and information sources that could be accessed for the USG pilot.

Frontier Economics then issued data requests to the below organisations, and met with ElectraNet to discuss the formal data requirements**.**

As a result of developing a consistent confidentiality agreement between the pilot sponsors and the network service providers, there were delays in receiving confidential energy data.

Table 5: **Data identification and requests**

Organisation	Data requested	Outcomes
DCCEEW	• Sources of information on industrial projects, particularly in relation to hydrogen.	• A number of branches within DCCEEW assisted to identify information and data inputs, including relating to hydrogen projects. • DCCEEW also called on an expert reference group (Regional and Cross-sectoral Demand Transition) to help identify sources of research on the types of large industrial projects announced in the USG, including hydrogen and green iron projects. The identified research provided potential insights on the technology likely to be applied in the USG, its maturity, and likely operating parameters including flexibility.
SAPN	• 30-minute (or more granular where available) historical traces by TCP separated out into LIL, CER and 'underlying' components. • Diversity factors for each transmission connection point that are used to reconcile SAPN's connection point forecast with AEMO's regional forecast.	• Challenges arose accessing this data due to the delay in agreeing the required confidentiality agreement with SAPN. SAPN advised that it could not provide LIL data by TCP as this may identify individual LILs and hence would breach their confidentiality requirements. • Alternative data was provided by AEMO.
ElectraNet	• Data on prospective LILs in the USG, including nature of the project and demand and energy requirement. • Historical data on network connection enquiries by LILs including how many proceeded to completion and the time taken for the projects to proceed through their development phases.	• Discussed required pilot data inputs and ElectraNet's ability to provide these, including information on prospective LILs in the USG. • With a confidentiality deed in place, ElectraNet were able to provide information on prospective USG LILs. • ElectraNet were unable to source internal data on historical network connection enquiries. As an alternative, Frontier Economics used the REMP database to interrogate industrial project development timing and completion rates.
Climateworks, CSIRO	• From the macro-economic modelling results used as an input into the multi-sector energy modelling, the following long-term forecasts for South Australia:	• Discussed provision of multi sector model outputs for the South Australian region, including potential to provided updated forecasts being prepared for the 2026 ISP. This could provide a longer-term forecast of industrial load relevant to the USG.

Organisation	Data requested	Outcomes
	○ annual forecasts of economic activity (e.g. real gross value added) by industry sub-sector ○ annual forecasts of energy demand, disaggregated by industry sub-sector. • From the multi-sector modelling, the following long-term forecasts for South Australia: ○ Annual forecasts of electricity consumption (and peak demand if available), disaggregated by industry sub-sector ○ The above forecasts of annual electricity consumption disaggregated by final electricity consumption, energy efficiency and electrification. • Annual forecasts of annual electricity consumption for hydrogen production.	• CSIRO preferred that the pilot use the updated multi-sector modelling forecasts produced for the 2026 ISP. However, this was not available in the timeframes of the USG pilot. • In any case, AEMO provided the multi-sector modelling forecasts produced for the 2024 ISP and ESOO.
Heavy Industry Low-carbon Transition Cooperative Research Centre	• Information on heavy industry in the USG region.	• Identified relevant papers and research available including on hydrogen and green iron.
AEMO	• 30-minute demand traces broken out by component (including, in particular, LILs) for the South Australian region. • Further detail on the allocation of electrification traces to subregion, and the data on which electrification allocation to sub-regions is based. • Historical demand by transmission connection point for the South Australian region separated out into CER, LIL and underlying components as used to 'downscale' underlying regional demand. • Forecasts of CER uptake at a postcode level. • LIL forecasts by TCP. • CSIRO/ClimateWorks multi-sector model (MSM) LIL forecasts for the South Australian region. • AEMO's 'calibrated' MSM forecast for the South Australian region and each of the two South Australian subregions (CSA and SESA). • AEMO's blended MSM forecast for the South Australian region and the two South Australian subregions (CSA and SESA).	• AEMO provided the data relevant to the 2024 ESOO, except for the demand traces where 2024 ISP data have been provided. • To ensure compliance with confidentiality requirements including ensuring that it did not identify any individual LIL, AEMO was able to provide the data sought separated into the defined USG region and the remainder of the South Australian region.

Appendix C: AEMO forecasting methodologies

C.1 2024 ISP sub-regional forecasting methodology

AEMO produces forecasts of electricity demand for sub-regions of the NEM that are included in the ISP. The Draft 2025 IASR is proposing to increase the number of sub-regions from 12 to 15, and some changes are proposed to the method used to produce the sub-regional forecasts (discussed below). However, for the USG pilot, the methodology in the 2024 ISP (12 sub-regions) has been applied to produce the sub-regional forecast for the defined USG region. This methodology is summarised below.

C.1.1 2024 ISP method applied

AEMO produces sub-regional forecasts separately for three demand components:

- Underlying demand excluding LILs: This is residential and commercial demand with any impact of generation provided by CER removed. That is, this underlying demand includes all residential and commercial consumption, even if some of this consumption was met by behind-the-meter generation systems.
- CER: This comprises distributed PV, battery storage, and EV profiles.
- LILs: Separate LIL forecast for each sub-region.

The 'downscaling' process differs for each of these components, as discussed in the following subsections.

Underlying demand

The allocation of underlying demand to a sub-region is undertaken by half hour. A share of underlying demand for the sub-region is calculated from historical half-hourly connection point total residential and commercial demand. This percentage share is maintained over the forecast period.

As AEMO point out, the strengths and weaknesses of this approach are that daily, weekly and seasonal variations are captured as the sub-regional share of demand is calculated for each half hour. However, as the share does not change over the forecast period, if demand growth in the sub-region varied from the historical pattern, this would not be captured.

CER

The regional CER forecast is prepared by CER component and by postcode. The sub-regional share of CER is calculated monthly. This monthly share is applied to the region-level half hourly forecast for the relevant CER component to produce the sub-regional forecast. AEMO notes that aggregated storage is excluded from this forecast. This is modelled with the capacity outlook model.

LILs

Each LIL is mapped to the relevant sub-region. The demand for each LIL is forecast individually. The individual LIL forecasts within a sub-region are aggregated. As noted above, the pilot's methodology for LIL forecasting will differ from AEMO's approach and is outlined in more detail below.

C.1.2 Recent changes to sub-regional forecasting not applied in the pilot

As part of its 2024 review of the EDFM for the NEM, AEMO considered an alternative approach to sub-regional forecasting. AEMO's draft proposal[44] was to continue with its regional forecasting methodology, but also produce subregional forecasts which would then be reconciled to the regional forecast. AEMO proposed to use the same forecasting methodology for subregions as for regions and then scale the subregional forecasts so that in each half-hour the sum of the subregional forecasts equals the regional forecast.

AEMO has implemented this approach in its 2025 EDFM (published in late July 2025). This means that subregions and regions will in future have different load shapes (i.e. when and how much energy is used during a period of time), unlike the 2024 ISP methodology, which to some degree adopts the regional shape for all subregions.

C.2: NEM LIL demand forecasting methodology (2024 ISP)

This appendix provides information on the demand forecasting methodology applied by AEMO for the NEM forecasts used in the 2024 ISP and ESOO, with the 2024 ESOO providing the basis for the baseline demand forecast for the USG pilot region. The intent is to clarify the differences between the alternative forecasting methodology applied in the pilot and AEMO's 2024 method. The key point of difference relates to the method for including LILs in demand forecasts that have not yet reached FID.

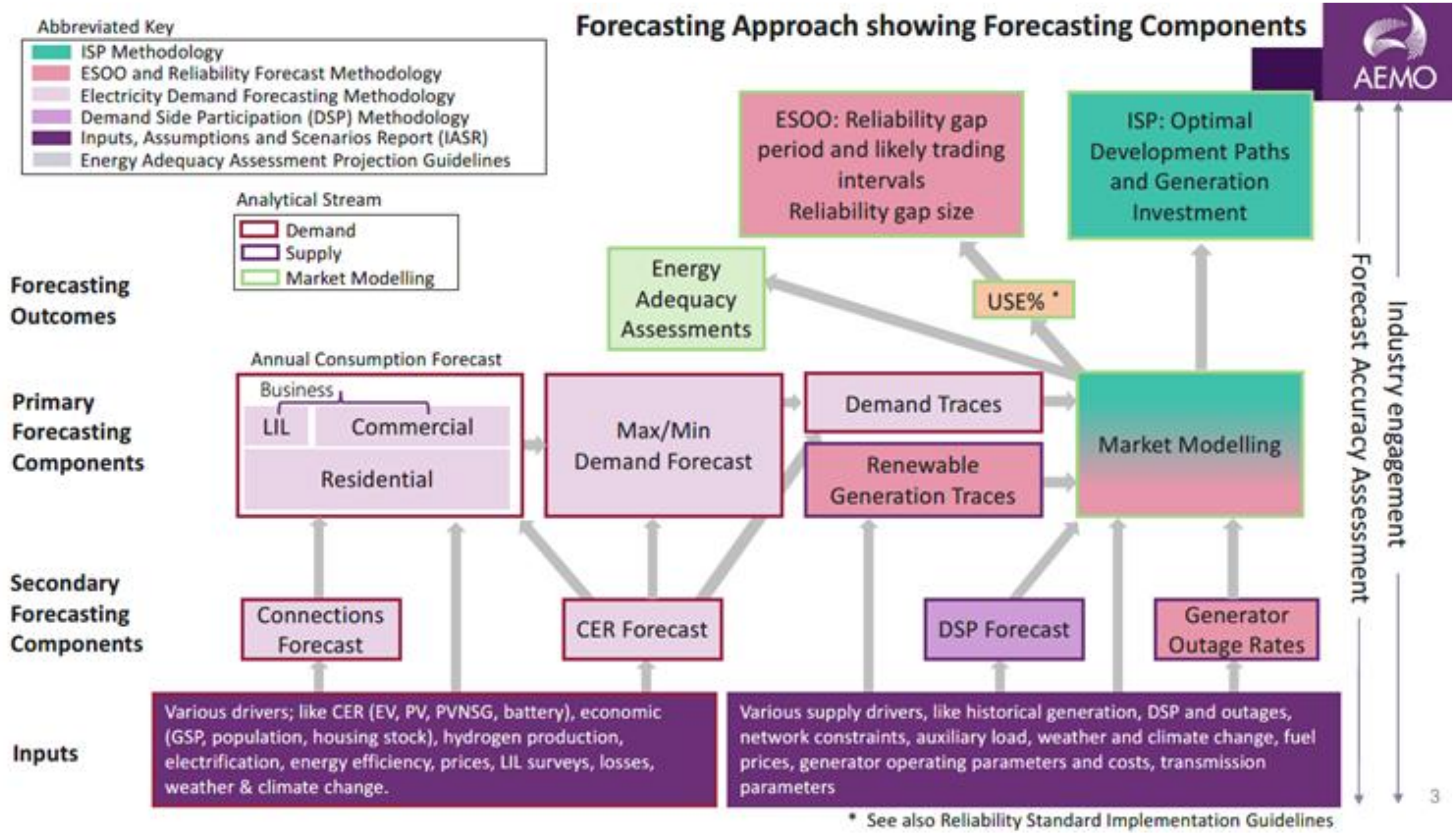
As well as explaining the 2024 ISP and ESOO demand forecasting methods applied by AEMO, changes to these methods that were developed in the context of AEMO's review of the 2024 EDFM and consultation on the Draft 2025 IASR are also explained. The methodology developed for forecasting LIL demand in this pilot has had regard to these recent developments.

C.2.1 AEMO demand forecasting methodology

In its role as market operator and national transmission planner, AEMO is required to produce electricity demand forecasts for the NEM and the WEM. AEMO uses these demand forecasts to prepare a number of publications. For the NEM, key publications that use AEMO's demand forecasts include the ESOO and the ISP.

Figure 23 provides an overview of AEMO's forecasting approach and components as applied for the 2024 ISP.

Figure 23: AEMO's medium and long term electricity forecasting in the NEM



Source: Australian Energy Market Operator 2024, [Forecasting approach](#).

C.2.2 LIL forecasts: 2024 ISP forecasting method

A key focus of the USG pilot is exploring ways to forecast and understand the potential operation of LILs in the USG.

AEMO adopts a two-part approach to forecasting demand for LILs:

- In the near term, AEMO relies on detailed surveys and interviews of LILs to develop its demand forecasts. Demand forecasts are modelled at a facility level and categorised by subsector and region. In order to undertake sub-regional network modelling, AEMO also allocates its regional demand forecasts to specific sub-regions defined for each state.
- In the longer term, AEMO relies on aggregate statewide sectoral forecasts determined through multi-sector modelling undertaken by expert consultants (currently CSIRO and Climateworks Centre). Contrary to the short-term LIL forecasts – which are modelled at a site level and aggregated to the sub-regional level – AEMO's longer-term projections are aggregated at the state-level, but are not granular enough to understand the outlook for individual regions or industries.

Near-term forecasting approach

AEMO's approach to forecasting demand is set out in its EDFM report. AEMO forecasts demand in energy intensive sectors separately from the broader business sector. The business sectors that AEMO models are:

- LILs – these can be either transmission or distribution connected
- Data centres – any loads associated with serving IT infrastructure that manages data storage, computation and networking
- Hydrogen – any loads associated with the production of hydrogen
- Business Mass Market – any business sector loads not included above
- Business electric vehicles (EVs) – covering commercial fleet, trucks and buses.

In the NEM, LILs are defined as:

- any transmission-connected load
- distribution-connected loads with demand greater than 10 MW for more than 10% of the latest financial year.

Demand forecasts for LILs are modelled at a facility level, and categorised by subsector and region. Each LIL is mapped individually to a region based on its electrical connection. The regional LIL forecast is an aggregation of the forecasts of all LILs in that region. To maintain confidentiality, AEMO aggregates all subsector forecasts with the other LILs before publishing the LIL forecast.

AEMO adopts a survey-based approach to develop demand forecasts for LILs. It is a five-step process:

4) **Identify large industrial users:** In the NEM, AEMO identifies existing and new LILs through its metering data for each region. This list is validated and updated by surveying DNSPs and TNSPs, and from public information including media, conferences and industry forums. In the WEM,

AEMO engages with a range of stakeholders, including Western Power, in deciding whether to include prospective and committed LILs in the electricity forecasts.

5) **Collect historical data and analyse**: AEMO will analyse historical consumption data for each LIL to understand consumption trends at each site, develop targeted questions, and prioritise interviews of industrial users.

6) **Request survey responses:** AEMO surveys all identified LILs by requesting historical and forecast electricity consumption information by site. The survey requests annual electricity consumption, maximum demand and minimum demand forecasts for scenarios in the NEM and the WEM that can be mapped to scenarios in the latest IASR, while considering the burden to industrial customers of providing this information. This will include a central scenario. If the IASR is undergoing re-development, which for scenarios occurs biennially, the most recent finalised scenario collection is provided for LIL surveying purposes.

7) **Conduct detailed interviews:** After the survey is issued, prioritised large industrial users are directly contacted to expand on their survey responses.

8) **Finalise forecasts:** AEMO will produce a central demand forecast for each subsector and region which is based around current state and federal government environmental and energy policies and best estimates of all key drivers. AEMO will also develop alternative scenarios based on likely opportunities and risks for the LILs, which is formed using survey responses. This can be driven by the overall economic conditions of the scenarios, and any specific, defined purpose of the scenario (e.g. to test the power system's ability to operate under low demand conditions, or to meet new load).

Prior to the 2025 EDFM, AEMO only included a new LIL in its central scenario if:

- the project had obtained the required environmental approvals
- the project had obtained approvals from the NSP to connect to their system
- the project proponent had publicly announced that it has taken a positive FID and/or the project had commenced construction.

For alternative scenarios, AEMO may have included new LILs that did not meet all of the above criteria.

The third criterion was amended in the 2025 EDFM (published in late July 2025), as outlined at C.2.3 below.

Longer-term forecasting approach

In the medium to long term, information on likely changes in the loads of individual plants, or the loads of new plants, is unknown or only known with great uncertainty. AEMO relies on the CSIRO's AusTIMES model to inform its longer-term forecasts for LILs and other industrial loads, as well as the loads for the commercial and residential sectors. AusTIMES is the implementation for Australia of the TIMES model developed by the International Energy Agency. Several other countries use their own tailored versions of the TIMES model, including the UK, Ireland and Sweden. The US is in the process of converting its MARKAL model, which is a precursor of the TIMES model.[45] The objective of the model is to minimise costs, whilst ensuring energy demand is met by supply within the bounds of a carbon constraint.

Multi-sector modelling undertaken by CSIRO and Climateworks is based around a least cost optimisation that assesses the development of energy supply and energy consumption under given decarbonisation scenarios. The multi-sector model includes a number of energy supply and end-use sectors, and ultimately provides an electricity carbon budget, forecasts of electrification, energy efficiency and demand for hydrogen and biomethane that are then used in subsequent stages of AEMO's ISP modelling. AEMO consults with CSIRO to define the assumptions for each of the scenarios which it models, making decisions across a range of parameters such as economic growth, technology uptake rates, future costs of different technologies and policy frameworks.

Forecasts generated by this modelling are blended with short-term approaches over the period of AEMO's forecasting. For the first five years, forecasts are entirely constructed from industrial user surveys and committed loads, after which the short-term forecasts are blended into the longer-term aggregate statewide sectoral forecasts determined through the AusTIMES modelling.

The process of multi-sector modelling is appropriate for producing emissions pathways in the context of long-term, high-level policymaking, but is not sufficient for regionally forecasting demand within its scenarios. The shortfalls of multi-sector modelling for this purpose include that the modelling is undertaken at the state level and considers supply and demand at a coarse level of detail. Beyond these issues with the granularity of forecasting at the sub-regional level required for this pilot, the model is extremely sensitive to assumptions, as a model with a firm constraint of net-zero will be highly reliant on the costs of the different options to reach it.

C.2.3 LIL forecasts: changes to forecasting method

As discussed, AEMO included new LILs in its 2024 ISP forecasts if: a project had obtained the required environmental approvals, the project had obtained approvals from the NSP to connect to their system, and the project proponent had publicly announced that it had taken a positive FID and/or the project has commenced construction.

One of things that the USG pilot investigated was alternative approaches for including new LILs in regional demand forecasts. This is also something that AEMO considered as part of its 2024 review of the EDFM for the NEM,[46] which resulted in the following modifications to its LIL forecasting approach in the 2025 EDFM:[47]

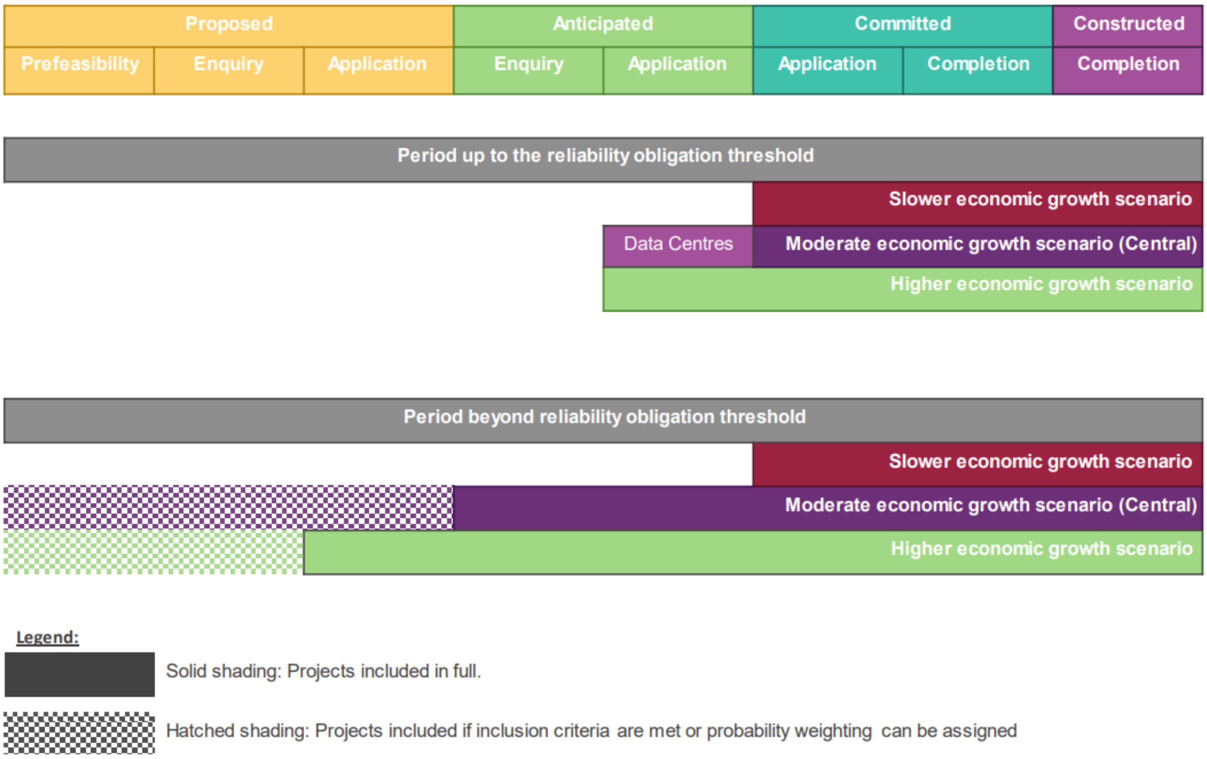
- prospective LIL projects are defined according to a commitment status as 'committed' (very high likelihood of being developed), 'anticipated' (high likelihood of being developed) or 'proposed' (not classified by AEMO as 'committed' or 'anticipated')
- in addition to existing information gathering from LILs, AEMO will engage further with NSPs to confirm whether projects are committed, anticipated or proposed
- probability weightings are included for proposed LIL projects where provided (subject to AEMO's independent review of survey data and other market research)
- LILs are included at each of the commitment stages in forecasts as shown in Figure 24.

‘Proposed projects’ are identified explicitly based on the following information:

- The project is at least at application stage of the connection process, or
- The project has not yet reached application stage of the connection process but is assessed as likely, that is, it either:
  - aligns with government policy, or
  - is of state significance (for example, state significant developments in New South Wales), or
  - is otherwise assessed as likely based on the LIL survey process, NSP information requests or market research.

The USG pilot has also applied a methodology for the inclusion of LILs that have not reached FID. However, the pilot method uses historical data from REMP publications on the observed timing and likelihood of industrial projects in Australia to inform the inclusion of LILs.

Figure 24: AEMO proposed project status inclusion in forecasts



Source: Australian Energy Market Operator 2025, Electricity Demand Forecasting Methodology, p. 23.

C.3 Hydrogen forecasts

C.3.1 2024 ISP forecasting method

The hydrogen sector within AEMO’s demand forecasting methodology is forecast separately to LILs and captures all grid supplied electricity consumption used to produce hydrogen within the Australian economy.

Hydrogen consumption is forecast as two components: location-specific production for existing customers and flexible location for new customers or export industries. Location-specific consumption is factored into AEMO's modelling as additional demand, and transmission and generation is developed to supply it. Flexibly-located hydrogen has its location optimised within the ISP modelling to minimise total system cost, accounting for additional transmission, generation and firming required to support the facility.

Given that the hydrogen sector is still emerging, AEMO consider the most prudent means of including hydrogen within its electricity demand forecasting is to consider hydrogen a scenario parameter, with the scale and type of hydrogen varying across scenarios based on scenario design and informed by the multi-sectoral modelling.

The assumed domestic and export hydrogen demands are modelled as separate flexible loads, with minimum production requirements on a monthly timeframe. Green steel demand for hydrogen is included with the export hydrogen demand, whereas green steel demand for electricity is modelled as inflexible demand.

C.3.2 Change to forecasting method

As part of its 2024 review of the EDFM for the NEM, AEMO evaluated the most appropriate method to include hydrogen demand within its consumption and demand forecasts. AEMO's 2025 EDFM update provides that AEMO will:[48]

- model committed hydrogen projects (location bound hydrogen) in the region or sub-region where the facility is located
- locate flexible location hydrogen according to the ISP Methodology
- include storage and transport costs for firm supply of hydrogen for domestic use, green commodities and exports
- implement, within the ISP model, a minimum utilisation factor to ensure realistic economic modelling of electrolysers
- continue to forecast on/off grid electrolyser load in the multi-sectoral modelling.

Appendix D: Alternative methodology for forecasting LIL demand

This appendix provides additional detail on the alternative methodology used to forecast LIL demand in the USG including information on the REMP database, on the production of project probabilities using this data, and on the production of probability distributions of possible demand outcomes based on the empirical forecasts that use Monte-Carlo modelling.

D.1 Resources and energy major projects (REMP) database

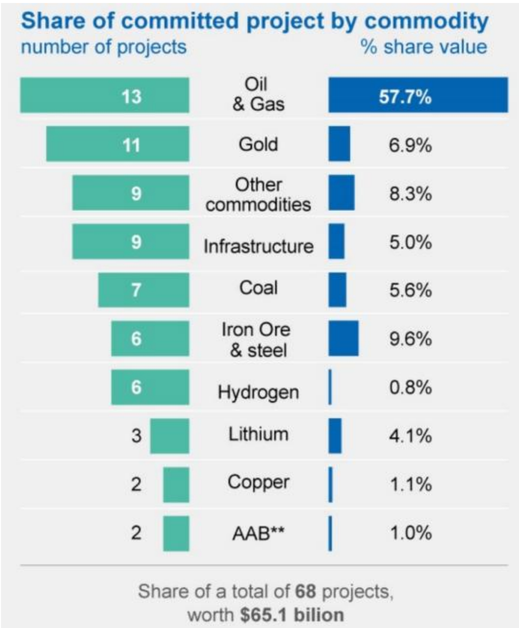
Information on the progression of projects and their likelihood of proceeding was taken from the REMP database.

Frontier Economics collected data from all available REMP publications (annual publications from 2012 to 2024) and undertook substantial work to clean and consolidate this data into a useable form, including importing the data into the R package. This process is provided below.

The composition of the REMP database changes over time as the specific projects listed in the REMP database changes. The following information provides insight into the composition of the database from the most recent 2024 REMP report.

Figure 25 shows the composition of projects that have reached the committed stage in the 2024 REMP report. Committed projects in the database are dominated by oil and gas projects and mining projects (particular gold mining and coal mining). The database also includes committed resources and energy infrastructure projects and mineral processing projects.

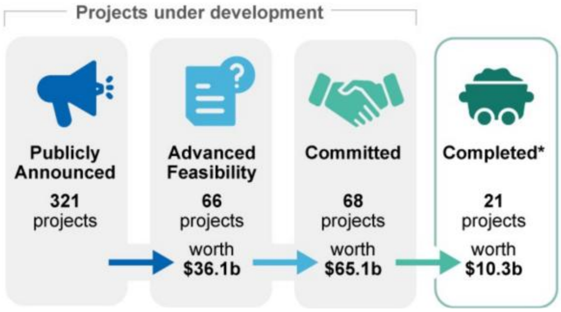
Figure 25: REMP committed projects by commodity (2024 REMP)



Source: Department of Industry, Science and Resources 2024, *Resources and energy major projects: 2024, p. 3.*
Note: Infrastructure = Resource & energy infrastructure projects including CCS; AAB = Aluminium, Alumina, Bauxite

Figure 26 shows the share of projects at each development stage in the 2024 REMP report. The number of projects in the REMP database broadly declines for each project stage, with the majority of projects at the first stage – publicly announced – and the fewest projects at the final stage – completed.

Figure 26: REMP number of projects at each project stage (2024 REMP)

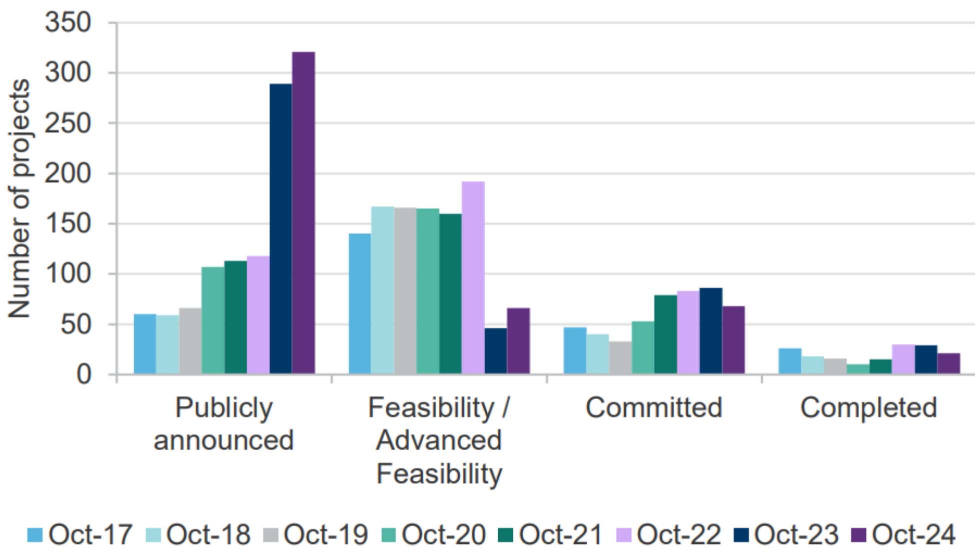


Source: Department of Industry, Science and Resources 2024, *Resources and energy major projects: 2024, p. 3.*

Figure 27 shows the number of projects at each project development stage over a longer period, from 2017 to 2024. This tracking of projects through time assists in determining an evidence-based estimate of the likelihood of project progressing to completion and the time taken to reach completion. In the 2023 edition of the REMP, the category definitions were modified, with the feasibility category being changed to 'advanced feasibility'. This raised the bar for a publicly announced project moving to the next stage, now defined as 'being close to reaching final investment decision'.

Figure 27 shows the resulting step change in publicly announced projects in this edition, with a large number of projects moving backwards from the feasibility stage to the announced stage. As time goes on with these new definitions, it can be expected that projects in the feasibility stage will be more likely to commence, widening the marginal difference currently seen between announced and feasibility projects.

Figure 27: REMP number of projects by project stage 2017-2024



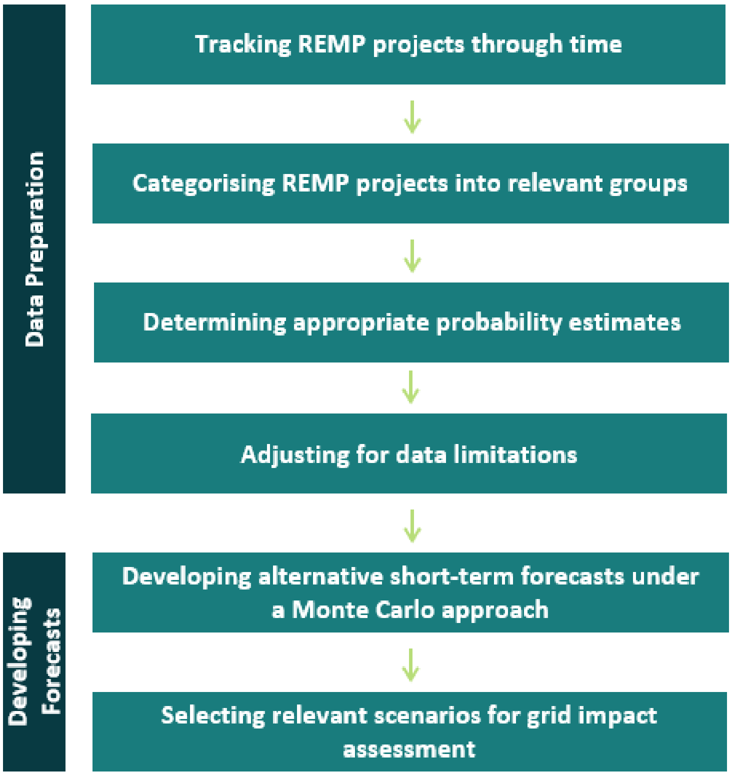
Source: Department of Industry, Science and Resources 2024, *Resources and energy major projects: 2024, p. 5*

D.2 Producing empirically-based estimates of industrial project progression and likelihood of completion

To develop an empirical, unbiased estimate of a prospective LIL project's probability of completion and timing of completion Frontier Economics used the REMP database to develop a probability distribution that can be applied to these prospective LILs. These estimates can be generated for a generic project or applied to a specific subset of projects that sit within the REMP.

A summary of the key steps in this estimation process is as follows:

Figure 28: Forecasts development process



More details on these steps are provided in the sections that follow.

D.3 Tracking REMP projects through time

To assess the probability and timing of project completion using the REMP database it is necessary to track individual projects on the REMP database through time. Taking the individual publications of the database and combining them into a singular, panel dataset. With a panel dataset being one that tracks the same entity across time, so the panel version of the REMP tracks individual projects through time, allowing for the observation of project outcomes, and duration of these outcomes.

To track projects on the REMP database through time, Frontier Economics has manually tracked individual projects through their stages by accounting for any changes in names of projects that occur from one REMP publication to another REMP publication. This involved assessing projects of similar names and assessing if their characteristics indicate that they are the same project.

Categorisation of projects in the REMP has changed over time. Frontier Economics developed the commodity groups category for older editions of the REMP to group similar projects, such as different types of resource projects that produce the same product. Groups assessed include iron ore, copper, coal, gold and hydrogen projects. Grouping by industry allows the probability measure to vary to reflect the characteristics of the underlying industry, such as likelihood and duration to achieve environmental approvals and the international competitiveness of different industries.

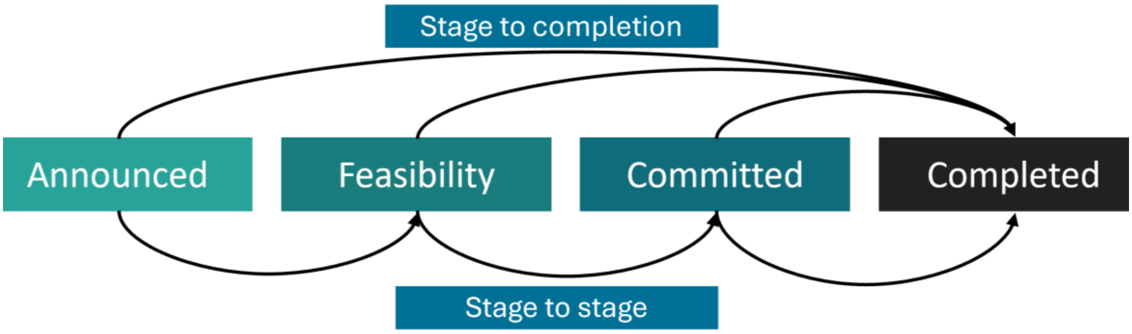
D.4 Determining an appropriate probability measure

Identifying appropriate transition stages

In developing a distribution of project completion from the REMP database it is necessary to determine what outcome will be measured, in terms of probability, and what distribution should be fitted to the empirical data.

When tracking projects from stage to stage, probability can be assessed from each stage to the next stage, or from each stage to completion. These two approaches are visualised in Figure 29.

Figure 29: Probability measure



After careful consideration Frontier Economics modelled from each stage to completion, rather than tracking from each stage to the next, which would be characterised as a Markov chain approach. This was selected as the preferred approach for several reasons. The first reason is that projects do not necessarily move sequentially through the REMP stages, which may distort transition probabilities measured as the probability of moving from one stage to the next.

The second reason is that there are potential biases within a transition matrix as transition probabilities are conditional. This is because the probability of a project's completion is influenced by its previous stage. For example, a 'committed' project that first enters the REMP as a 'committed' project has a greater probability of reaching the 'completed' stage than a 'committed' project that first enters the REMP at an earlier stage. In probability terms this means that the probability of reaching the 'completed' stage, given the project entered at the 'committed' stage, is greater than the unconditional probability of reaching the 'completed' stage given a project reaches the 'committed' stage, where all projects are looked at without consideration of their prior stages. Mathematically, this means:

$$P(Completion \mid Entered\ at\ committed) > P(Completion \mid Committed)$$

This effect is seen in the panel dataset comprised of multiple editions of the REMP database. This panel dataset shows that, of projects that entered the database as ‘publicly announced’, only 9% of those have reached the ‘completed’ stage. But if looking at the probability of a project going from ‘publicly announced’ to ‘feasibility’, then from ‘feasibility’ to ‘committed’, then from ‘committed’ to ‘completed’, a project’s probability of completion is only 4%.

The approach of using start to end probabilities also better reflects the information that is available for prospective LILs in the USG. Whilst the stage a project is currently in is known, there may be limited knowledge of past stages that the project has been in. Given this, modelling from each stage to completion allows an assessment of the unconditional probability of a project’s completion without regarding its previous stages. However, it will also reduce the sample size of the dataset, with more stage-to-stage transitions having occurred than project’s having reached completion or non-completion.

D.5 Treatment of data limitations

When assessing a time-series dataset like the REMP, there are many observations that have not yet reached an outcome and are still in a non-terminal stage (that is, completed or failed) in the newest edition of the REMP. For instance, there are many projects listed in the latest edition of the REMP (the 2024 REMP report) that remain at an announced, feasibility or committed stage, and have not yet reached completion or non-completion.

In statistical terms, this is referred to as right censoring. This occurs where truncated observations are present in the dataset that allow observation of how long a project has been ‘ongoing’, but do not allow observation of the end result for the project. The approach that has been adopted to treat censoring is described in detail below in Box 5.

D.6 Fitting distributions

With the cleaned REMP dataset, which has data on the progression of each individual project in the dataset, probability distributions can be fitted. For a dataset like the REMP, where the projects exist in an ‘alive’ (ongoing) stage until they transition to a terminal stage, a distribution able to capture the duration between events is required. Options for this include distributions commonly used in survival analysis, such as the exponential, gamma and Weibull distributions. Frontier Economics has adopted a Weibull distribution as it is best able to capture the shape of project completions that vary over time. This is a bi-variate distribution which can model the probability and duration of a project’s completion over time, this is captured in both a ‘shape’ and a ‘scale’ parameter.

Figure 30 gives an example of how varying these parameters can modify the form of the distribution, with the vertical axis representing the probability of a project being completed after a given number of years.

Box 5: Censoring

What is censoring?

Censoring is a statistical term that describes a situation where there are partial observations in a dataset, which potentially introduces bias into the dataset. Censoring is a common problem in panel datasets like the REMP. Using statistical techniques to treat censoring allows the best available, unbiased dataset to be formed.

In the case of the REMP data, ‘right’ censoring is the primary concern. Right censoring occurs where there is not full visibility of a project's outcome as it is not at a terminal stage (completed or failed) in the latest REMP publication. This may be because a project:

- appeared in the REMP recently and is still ongoing in the most recent publication
- may have been ongoing in the REMP for a long period of time and consequently has lower prospects of completion.

The REMP dataset shows that the chance of completion for a project tends to decrease over time. This information can be used to treat censoring by assigning censored projects to a terminal stage in the relevant timeframe.

How is censoring treated?

To obtain an unbiased probability estimate of project outcomes information about completed observations is used to infer the outcomes of censored observations. From the REMP dataset it is observed that if censored projects are new, they will have a higher probability of completion than if they have been lingering in the dataset for several years. Censoring is treated by assigning probabilities of completion and non-completion to each censored projects, which will depend on how long a project has been ongoing.

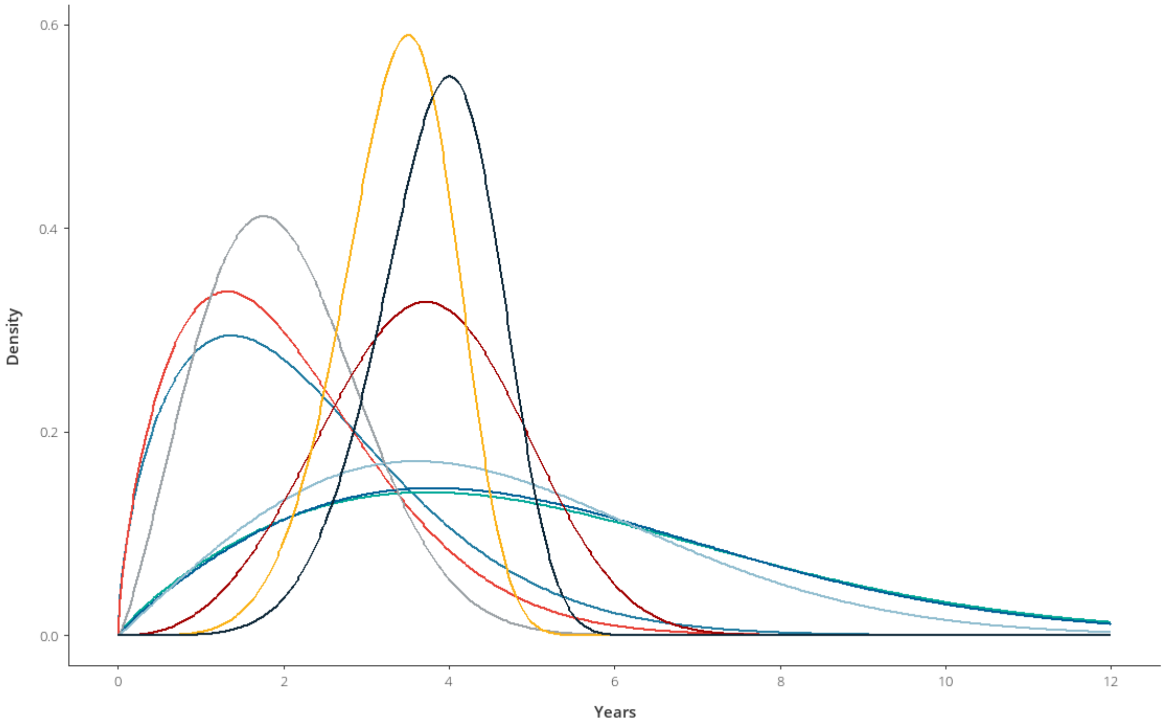
For example, if a project entered the dataset in 2023, it is only two years old when censored, and projects are most likely to be completed from years 4 to 8. This two-year-old project would have a greater chance of being completed than a project that entered the dataset in 2015 and has already passed the years where it has the highest likelihood of completion.

Treatment of censoring is undertaken for each industry category.

Outcome of censoring treatment

The outcome of the censoring treatment is an unbiased panel dataset to completion for all projects, which can be used to inform the alternative LIL forecasts.

Figure 30: Examples of Weibull distribution shapes



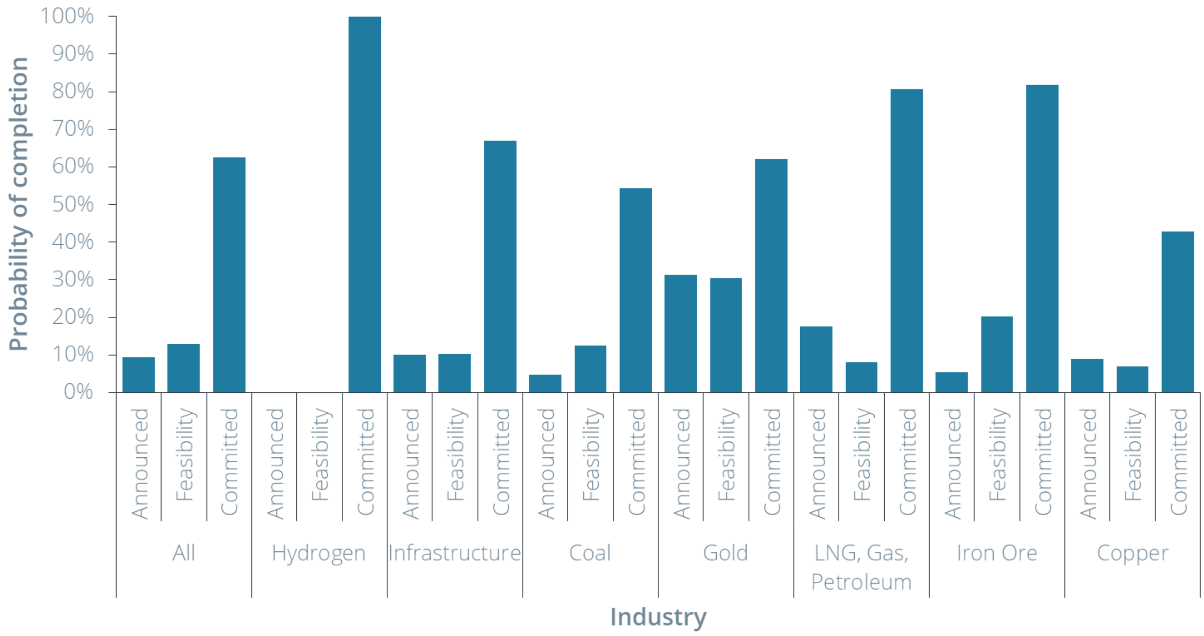
Source: Frontier Economics analysis

To fit these distributions, a maximum likelihood estimation method – from the *fitdistrplus* package in R[49] – is used. This method is applied to completion or non-completion from each project stage, for every industry subcategory modelled. In order to generate a distribution at least two unique finishing times are required. However, in some industry subcategories there is insufficient data to fit a distribution; that is there is not two unique finishing times that a distribution can be fitted to, in these cases, it is assumed the duration to completion is as informed by the NSP. To ensure adequacy of fits, diagnostic plots were produced for all fitted distributions and checked manually.

The result of this process is an estimate of the probability of a project's completion that is driven by the empirical REMP data. The result is summarised in Figure 31. Figure 31 shows that, for example, looking at all projects in the REMP database, the estimated probability of completion for a project at the 'publicly announced' stage is 9.4%, the probability of completion for a project at the 'feasibility' stage is 13% and the probability of completion for a project at the 'committed' stage is 62.5%. Figure 31 also shows the estimated probability of completion for projects in specific sectors of the REMP database.

Since the REMP database is a historical database, it will take time before the database provides a reasonable empirical basis for estimating the probability of completion for emerging new industries. While the probabilities of the 'All' industry class can be used for these emerging new industries in the interim – as has been done for the hydrogen sector – it will be unclear whether the probabilities of the 'All' industry class are a good estimate for the emerging new industry, and in particular whether they overstate the likelihood of completion or whether they understate the likelihood of completion.

Figure 31: REMP-derived probabilities of completion



Source: Frontier Economics analysis of REMP publications

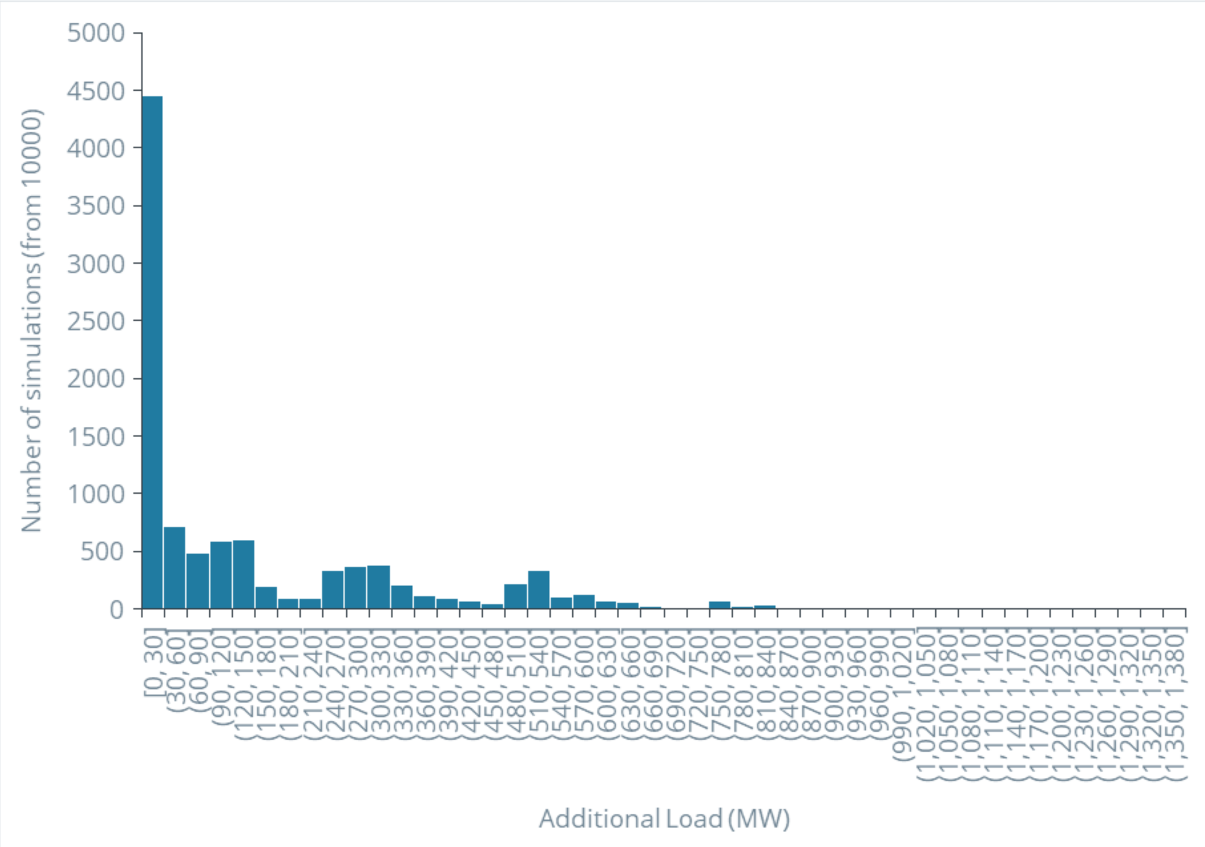
D.7 Approach to data censoring

Censored projects in the REMP dataset are projects that have not yet reached completion or fail status. Treatment of censored projects is undertaken to allow the best available, unbiased, distribution of project completion to be identified.

At the outset, the progression of projects as observed in the REMP is assessed, with projects assigned to one of the four states (ongoing, failed, committed or censored) in each year after a project enters the REMP database.

The progression of projects through these stages can be seen in Figure 33, which shows that over time an increasing proportion of projects move to the censored category. As expected, committed projects have the greatest chance of completion, with completions for these projects occurring in the first few years, as indicated by the incremental difference in the completed bar between years. The feasibility and announced stage projects have a much lower probability of completion, with these completions also occurring later than for committed projects.

Figure 32: Simulation outcome histogram



Source: Frontier Economics analysis

Note: The numbers on the horizontal axis shows the range of additional load from each simulation e.g. [0,30) is a range of load from 0 to 30 MW. There are just under 4,500 simulations that result in this range of additional load.

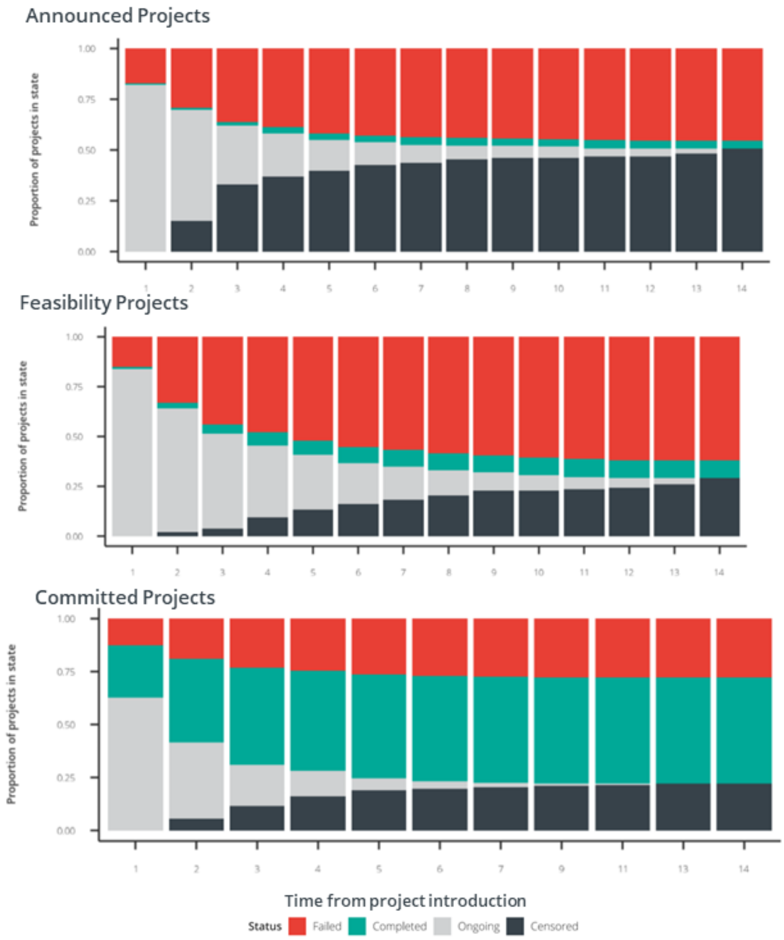
Prior to the treatment of censoring, the outcomes of projects across all industries from each stage are as follows:

- Announced projects: 5% completed, 53% failed, and 42% censored
- Feasibility projects: 10% completed, 59% failed and 31% censored
- Committed projects: 55% completed, 26% failed, 19% censored.

To remove the censoring within the dataset to produce unbiased estimates, an empirical correction method is applied, which uses all information available to impute the values of censored observations. This method involves assigning the censored projects to completed, failed or ongoing based on the observed rates of completion and non-completion in each year.

The result of the censoring removal process is seen in Figure 34, with the previously censored observations allocated between the completed, failed and ongoing stages. Some projects remain in the ongoing stage as a result of the underlying data, and as a result some right censoring persists at the limit of the REMP database. For the purposes of the pilot methodology a project being ongoing in the long term is equivalent to non-completion, as the load is not realised.

Figure 33: Censored project outcomes



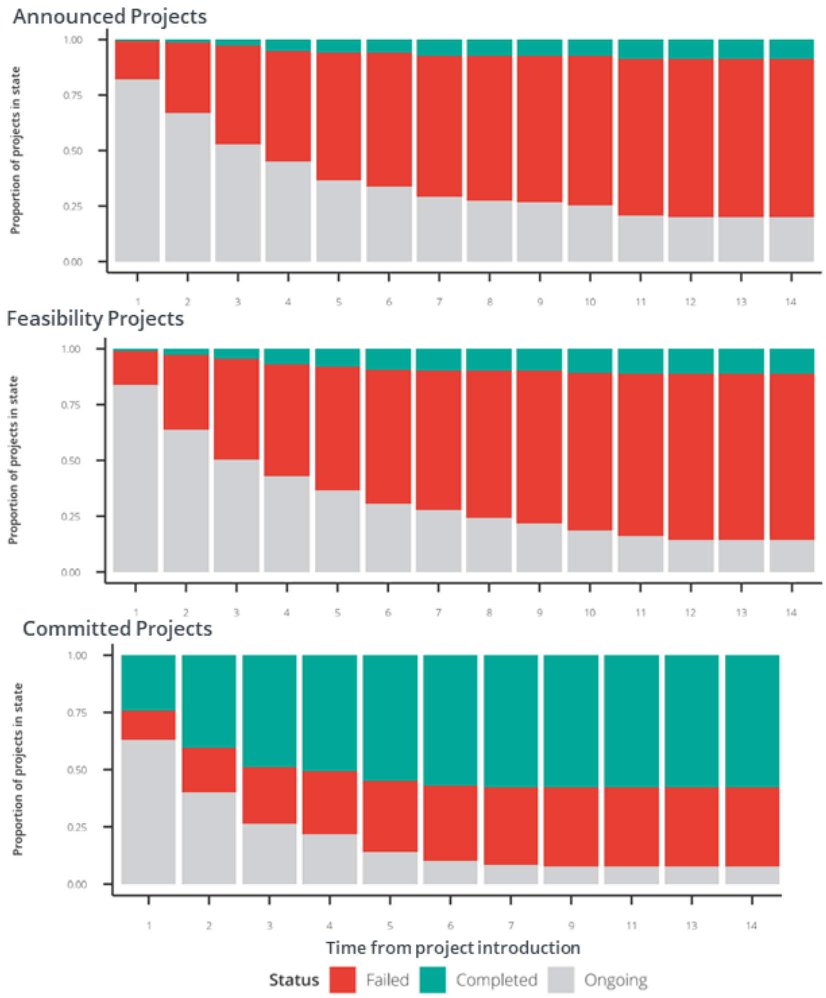
Source: Frontier Economics analysis, REMP data

This treatment of censoring was replicated for every subcategory of projects that is assessed within the REMP, noting that the performance of censoring treatment is greater within groups that have a larger sample size.

After the treatment of censoring, the outcomes of projects across all industries from each stage are as follows:

- Announced projects: 9.4% completed, 90.6% failed or ongoing
- Feasibility projects: 13% completed, 87% failed or ongoing
- Committed projects: 63% completed, 47% failed or ongoing.

Figure 34: Non-censored project outcomes



Source: Frontier Economics analysis, REMP data

D.8 Using a Monte-Carlo simulation to develop short-term forecasts

To turn the REMP-derived probabilities into forecasts of the probability of completion for prospective LILs in the USG, and therefore of LIL demand in the USG, Frontier Economics developed a generalised Monte-Carlo simulation model. The model accepts the distributions derived from the REMP and uses them to develop probability driven simulations of outcomes for prospective LILs in the USG and timings of these outcomes.

A summary of the Monte-Carlo simulation process is outlined in Box 3. The Monte Carlo simulation includes outcomes of every prospective LIL on the list provided by ElectraNet, with a range of different metrics available to assess the completed project sets.

The inputs to the Monte-Carlo simulation for each project are as follows:

- The project name.

- Any project dependencies, for example, if a project is stage two of a different project, then it is only able to succeed if stage one is also completed, and for projects that are supporting infrastructure for another project, they are tied to the other projects going ahead.
- The project industry, from the industry categories available in the REMP database. There is also the ability to assign projects to the generic category (all industries) if they do not fit neatly into another industry category.
- The project progression, reflecting whether the project is judged to be in the 'publicly announced', 'feasibility' or 'committed' stage, which will tie it to a specific distribution for a given industry category.
- A manual probability override, if more information is known about a project's unique chance of completion. This manual probability override can also be used for the purposes of sensitivity and scenario analysis.

For this pilot, the Monte-Carlo model had 10,000 simulations. Each of these simulations captured a simulation of which prospective LILs on ElectraNet's prospective LIL list went ahead, and when they were completed. Based on this, and the load included for each prospective LIL on ElectraNet's prospective list, it is possible to determine for each Monte Carlo simulation an alternative forecast of LIL demand in the USG.

The simulation process provided the distribution of additional maximum demand shown in the histogram in Figure 32 on the next page. This figure summaries the additional demand outcome for the 10,000 Monte Carlo simulations.

Figure 32 shows that the modal, or most frequent, outcome from this alternative methodology is no additional demand for LILs in the USG. There is a 17% chance of this outcome. This is because many of the projects on ElectraNet's prospective LIL list are categorised as being at the *Publicly Announced* stage and the estimated probability from the REMP database for projects at the Publicly Announced stage to reach completion is low (9% across all industry categories). And with the recent deferral of the South Australian Government's hydrogen production facility, there are currently no committed projects on ElectraNet's prospective LIL list. This means that there are many Monte Carlo simulations in which the randomly drawn outcomes for all prospective LILs are non-completion rather than completion.

Figure 32 also shows that the mean additional megawatts of demand from the Monte Carlo simulations is 154 MW. Even with many prospective projects, as is the case on ElectraNet's network, the low probabilities observed through the REMP database mean that on average, a small amount of additional load enters the network.

However, Figure 32 also shows that there are outcomes with lower probability that would result in substantial additional demand. For instance, there are clusters of simulations that would result in around 300 MW of additional demand and around 550 MW of additional demand.

Glossary

Term	Definition
AEMO	Australian Energy Market Operator
AWG	Advisory Working Group for the Upper Spencer Gulf (USG) demand pilot
DAPR	Distribution Annual Planning Report
DCCEEW	Australian Department of Climate Change, Energy, the Environment and Water
DEM	South Australian Department for Energy and Mining
DNSP	Distribution Network Service Provider
DRI	Direct reduced iron
EAF	Electric arc furnace
EDFM	AEMO's electricity demand forecasting methodology
Electricity consumption	Total electricity consumed in a specified period measured in MWh, GWh or TWh
GW	Gigawatt
GWh	Gigawatt hour
IASR	AEMO's Inputs, Assumptions and Scenarios Report
ISP	Integrated System Plan
LIL	Large industrial load. LILs are defined in the same way as AEMO as: - Any transmission network connected load, or - Distribution network connected load greater than 10 MW for more than 10% of the latest financial year.
MSM	Multi-sector modelling
MW	Megawatt
MWh	Megawatt hour
Maximum electricity demand	Maximum electricity demand required at a point in time which may be measured in MW, GW or TW
NSP	Network service provider
REMP database	Resources and Energy Major Projects database published by the Australian Department of Industry, Science and Resources. https://www.industry.gov.au/publications/resources-and-energy-major-projects
REZ	Renewable Energy Zone
SAPN	SA Power Networks
TAPR	Transmission Annual Planning Report
TCP	Transmission connection point
TNSP	Transmission Network Service Provider
TPA	Tonnes per annum
TW	Terawatt
TWh	Terawatt hours
USG	Upper Spencer Gulf

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forecast is the average of the outcomes for the simulations ranking from the 85th to 95th percentiles. The reason for using an average of multiple simulations, rather than a single simulation, is that each simulation has a specific set of prospective LILs proceeding, in specific years. Given that the LILs are large lumpy loads, this means that the forecast prospective LIL demand for any single simulation is also quite lumpy – with step increases in demand occurring as prospective LILs proceed. When forecasting representative scenarios for the USG as a whole, averaging outcomes from a number of simulations, in the way described above, provides a better representation of expected outcomes.

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