Modelling the impacts of constrained access – Methodology and assumptions

Public Utilities Office

28 February 2018

Building a better working world

Notice

Ernst & Young ("we" or "EY") has been engaged by the Public Utilities Office ("you", "PUO" or the "Client") to provide electricity market modelling services to assist the PUO in investigating the relative financial impacts of implementing a constrained network access regime on existing and new generators in the Wholesale Electricity Market (the "Services"), in accordance with our Letter of Appointment dated 21 November 2017 and the Panel Contract.

The enclosed report (the "Report") sets out the modelling methodologies and key data inputs and assumptions to be used in delivering the Services. The methodology described, together with the scenarios and assumptions used, will form the basis for the outputs produced and either have been, or will be, agreed with the PUO, following the end of this public consultation process and after due consideration of the submissions received.

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1. Introduction

EY has been engaged by the PUO to provide electricity market modelling services to assist the PUO in investigating the impacts of implementing a constrained network access regime in the Wholesale Electricity Market (WEM) in Western Australia (the Project).

The objective of the modelling is to quantify the relative financial impact to generators and whole of system outcomes as a result of this transition, for the period from 1 July 2022 to 1 July 2032 (the Study Period). The outcomes of the modelling may inform PUO advice to the State Government on the potential need for transitional assistance for generators that may be adversely impacted by the constrained access reform[1].

The objective of this report is to describe the proposed modelling methodologies and the data and input assumptions proposed to be used in undertaking the electricity market modelling for the Project. The objective of this report is to facilitate public consultation and to seek feedback on the methodology and the data and input assumptions.

This report forms a single complementary part in a broader set of public consultation papers related to implementing a constrained network access regime. The three papers are:

- "Improving access to Western Power's network – Consultation Paper".
- "Allocation of capacity credits in a constrained network – Consultation Paper".
- "Modelling the impacts of constrained access - Methodology and assumptions – Consultation Paper" (this Report).

In preparing this Report, we have used information that has been made publically available through industry consultations and various industry publications to the extent practicable. We note that the initial set of scenario assumptions have been selected by PUO based on consultation between EY and the PUO. We note that there is a significant range of alternative scenario assumptions that, in isolation or in aggregate, could transpire to produce outcomes that will differ to those that will be modelled.

This public consultation process seeks feedback on the scenario assumptions and the methodology proposed. A list of specific matters for comment is provided for initial consideration in the covering sheet. Feedback need not be limited to these matters.

Details on these consultation processes and how to make a submission have been provided by the PUO in the covering sheet.

All prices in this Report refer to real June 2017 dollars unless otherwise labelled. All annual values refer to the fiscal year (1 July – 30 June) unless otherwise labelled.

1.1 Background

The State Government is working towards improving access to Western Power's network by implementing a fully constrained network access regime.

As part of this, the PUO is investigating the impacts of transitioning from the present network access regime in the WEM towards a fully constrained network access regime. These impacts are to

[1] The modelling performed here may be used by the PUO to inform the need for transitional assistance. It does not quantify the amount of assistance in dollar terms nor does it establish the proposed mechanism. . The PUO is consulting on the high level design considerations for the mechanism with detailed design to follow subject to a Government decision and public industry consultations.

be informed by electricity market modelling that quantifies potential changes to generator dispatch outcomes, revenue projections and generation supply adequacy.

The implementation of constrained access in the WEM will alter the way that generators are currently dispatched. All generators participating in the Australian Energy Market Operator's (AEMO's) central dispatch process are dispatched according to an economic least-cost algorithm, taking into account generator offers and transmission loss factors, whilst adhering to power system security limitations defined within the dispatch engine.

The PUO, Western Power and AEMO are currently developing and implementing the Generator Interim Access (GIA) tool, which will facilitate the connection of new entrant generators to the Western Power Network (WPN) on a constrained basis whilst preserving the network access rights of incumbent generators. These parties[2] have stated that the GIA tool is interim in nature and will be decommissioned following the implementation of a constrained network access regime, enabled by a redesign of the WEM dispatch engine.

1.2 Proposed implementation cases

To quantify the relative financial impact to generators and whole of system outcomes as a result of constrained access, the PUO have proposed to compare outcomes in a Fully Constrained Access environment against the counterfactual of a Partially Constrained Access environment. Table 1 provides a summary of the two cases.

Table 1: The two cases to be modelled by EY

Case	Description
Fully Constrained Case	From 1 October 2022, existing generators and any new entrant generators connecting to the Western Power Network (WPN) are subject to generation curtailment in response to network congestion[3]. Network constraint equations[4] are defined to set power transfer limits for use in the dispatch engine. Consideration of which generators(s) are constrained will be based on achieving a least cost objective.
Partially Constrained Case (counterfactual)	From 1 October 2022, the existing GIA connected generators and any new entrant generators connecting to the WPN are subject to generation curtailment in response to network congestion. Existing generators will retain their existing access entitlements[5]. Network constraint equations are defined to set power transfer limits for use in the dispatch engine. Consideration of which generators(s) are constrained will be based on achieving a least cost objective.

[2] AEMO WA Generator Forum (5 April 2017)

[3] Not all generators will be required to participate in the central dispatch process. This will be dependent on registration class requirements.

[4] Network constraint equations define the power system transfer limits and are formulated according to AEMO's constraint equations formulation guidelines. They are derived by Western Power. These network constraint equation sets for the Fully Constrained Case and the Partially Constrained Case define the same network limitations, that is, there is no change in the power transfer limit across both cases. Differences in the formulation are based on which generator may be subject to curtailment.

[5] We have been advised that existing generators access entitlements only apply under operation conditions where all relevant network elements are in service. Generators may still be subject to loss of generation associated with an existing generation runback scheme or via manual intervention by AEMO to manage power system security. These provisions are provided for in access contracts. These aspects will not be explicitly modelled.

In the Fully Constrained case, the output of all generating units can be constrained in a least cost manner by market dispatch processes in order to maintain power system security. All generators may be constrained on or off in this case, to an amount anywhere between zero and a defined limit. The PUO have advised that they have identified 1 October 2022[6] as the likely date for commencement of constrained access, which aligns with the commencement of the Capacity Year for 2022-23. The PUO are currently consulting on the implementation timeline and commencement date as part of the consultation paper "Improving access to the Western Power network"[7].

The Partially Constrained Case represents the generator connection access environment in 2022 should constrained access reforms not proceed and represents a continuation of the current status-quo treatment of generators but with the implementation of a redesigned WEM dispatch engine. In this case, generators with an existing access entitlement retain their current level of access with their dispatch effectively prioritised over generators that have been connected on a constrained basis. All future generator connections will be on a constrained basis. The PUO have advised that the GIA tool is assumed to be decommissioned in this case and that development of a new market dispatch engine capable of security constrained dispatch to facilitate new generation connections is implemented. The PUO have advised that 1 October 2022 is the start date representing the starting date of the Capacity Year for 2022-23.

1.3 Purpose of the modelling

The outcomes of this modelling may inform PUO advice to the State Government on the need for transitional arrangements to implement constrained access and may include measures to mitigate the potential adverse impacts of the reform on generators such as the provision of transitional assistance.

The modelling is intended to quantify potential changes to generator dispatch outcomes and to identify trends in revenue projections. It does not seek to quantify the amount of transitional assistance to generators or the proposed mechanism for that assistance. The PUO is separately consulting on the high level design considerations of a mechanism to deliver transitional assistance with detailed design to occur subject to a Government decision on the need for transitional arrangements.

The modelling undertaken here is not intended to be, and should not be taken as a market projection or an assessment of the commercial viability of generation assets in the WEM. We recognise that there may be existing contractual arrangements that EY does not have access to and therefore cannot model due to information constraints. EY's modelling task is to quantify the overall relative impact on generators and whole of system outcomes of Fully Constrained Access compared to the counterfactual of Partially Constrained Access.

The PUO has requested EY to consider the relative financial implications to individual generators as a result of network limitations constraining generators on or off in central dispatch. Aspects of generator revenues considered in the modelling are:

- ► Wholesale electricity market revenue.
- ► Revenue from Large-scale renewable energy Generation Certificates (LGCs).
- ► Capacity credit allocations and reserve capacity price outcomes.

[6] Though 1 October 2022 represents the start date for constrained access, modelling will be performed for the Study Period beginning 1 July 2022. No material impacts are expected in the modelling outcomes.

[7] The PUO have indicated that the likely commencement date for Fully Constrained Access is 1 October 2022 but have identified this may present issues and is currently consulting on this matter.

A number of other market and power system parameters will be assessed and reported on. This is detailed further in Section 3.2.

The PUO are consulting on whether there are other types[8] of financial losses that could be attributed to constrained access in the consultation paper "Improving access to Western Power's network".

1.4 Out of scope

A number of explicit items have been excluded from this Project. This list includes (but is not limited to):

- An assessment of net market benefits that may result from implementation of constrained access reforms. The assessment performed here does not seek to quantify the overall net benefit of implementing constrained access, which has been identified by the PUO as an essential reform necessary for the WEM[9].
- An assessment of net market benefits that may be derived as a result of Western Power augmenting parts of the transmission network that are constrained. EY has not been requested to assess net market benefits for any specific network augmentation option. The modelling assumes committed and very advanced network augmentation projects (discussed in Section 6.1.6) when formulating constraint equations only to provide upper bounds for network congestion. This also recognises that generation connections typically lead network augmentation due to project execution timeframes.
- An assessment of network curtailment outcomes for network conditions other than system normal. The constraint equations are formulated on the basis of the transmission network without any planned or unplanned outages on transmission elements. EY has been advised that provisions are contained in existing connection contracts such that generation curtailment can occur in response to outage conditions that occur during conditions other than system normal. Additionally, long term transmission planning and subsequent network investment is based on N-1 planning philosophies under system normal conditions.
- Modelling elements of a reserve capacity auction and/or other proposed options associated with reforms to the Reserve Capacity Mechanism (RCM), such as demand curves for capacity pricing, auction parameters or others. Further consultation will be conducted by the PUO on reforms to the design of the RCM. Notwithstanding the above, modelling of capacity credit allocations will be consistent with the methodology described in the consultation paper "Allocation of capacity credits in a constrained network"[10].
- Future changes in transmission marginal loss factors (MLF) as a result of the generation development in the market. EY has been provided MLFs from the PUO based on proposed changes to the Regional Reference Node (RRN) that will be implemented into the modelling.
- Along with a constrained access regime, another reform under consideration for the WEM is to reduce the dispatch cycle from 30 minutes to five minutes[9]. Modelling five-minute dispatch is beyond the scope of this Project. However, it involves preparing five-minute input profiles for demand wind and solar generation and solving the same dispatch algorithm as for 30-minute modelling, just over a five-minute time step. In the modelling outcomes, generator ramp rate limitations are more likely to bind over a five-minute time step rather than over 30-minutes, which can change dispatch outcomes. While dispatch and price outcomes with five-minute dispatch may differ, EY considers it unlikely to have a significant impact on the overall impact of constrained access on generators.
- All other items not explicitly discussed in this Report.

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[8] Not all financial losses are able to be modelled in electricity market modelling. Consideration will be given to the type of financial losses incurred and whether it is feasible to assess.

[9] Improving access to Western Power's network – Consultation Paper

[10] Allocation of capacity credits in a constrained network – Consultation Paper

1.5 Proposed timeline for the modelling Project

A high level summary of the key modelling phases and timeline for this project is shown in Figure 1. Table 2 provides a high level description of each of these phases.

Figure 1: High level diagram of modelling phases

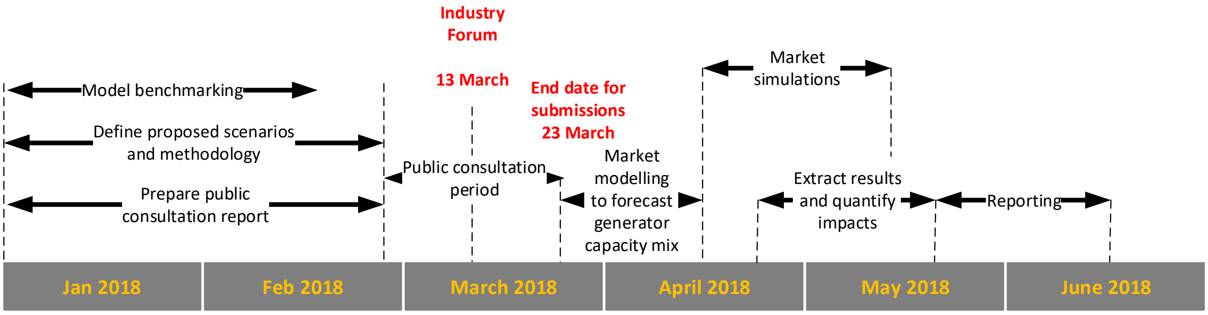


Table 2: High level description of each modelling phase

Phases	Description
Define scenarios and methodology	PUO and EY determine an initial set of assumptions that defines three electricity market development scenarios including the input data to be used for each. Define the modelling methodology. Model benchmarking exercise. Publish a report (this Report) for public consultation.
Public consultation	PUO and EY consider public submissions on the proposed scenarios and the content of this Report. A public consultation forum is proposed to facilitate questions and answers with key personnel on 13 March 2018. PUO and EY finalise the scenarios and data inputs taking into consideration the feedback received. Publish the final Report with benchmarking results.
Market modelling to forecast generator capacity mix	For each electricity market development scenario, EY will conduct market modelling to forecast the generator capacity mix based on an economic market-driven approach.
Market simulations	For each electricity market development scenario, use the capacity mix forecast in the previous phase to conduct two market simulations: one with the constraint equations for the Partially Constrained Case and with constraint equations reflecting a Fully Constrained Case.
Extraction of results and quantification of relative impacts	Extraction of modelling outcomes on various metrics to quantify the impact of Fully Constrained network access, with respect to Partially Constrained network access.
Reporting	Preparation of final data workbooks, reports and necessary deliverables for the PUO to publish.

1.6 Report structure

The following summarises the structure of the remainder of this Report:

- Section 2 presents a high level introduction to elements of wholesale electricity market modelling.
- Section 3 provides an overview of the modelling methodology proposed for this Project.
- Section 4 summarises the three proposed electricity market development scenarios, including their rationale and an overview of the assumptions.
- Section 5 describes the market modelling methodology in detail, including the methodology for forecasting the generator capacity mix.
- Appendix A presents the proposed input assumptions in detail.
- Appendix B provides a description of weightings used in market modelling simulations.
- Appendix C provides a list of acronyms and glossary of terms.

2. Overview of market modelling

2.1 Wholesale electricity market modelling

Wholesale electricity market modelling in this Project is conducted using EY's in-house market dispatch modelling software 2-4-C®. 2-4-C® seeks to replicate the functions of the real-time dispatch engines used in wholesale electricity markets with dispatch decisions based on market rules, considering generator bidding patterns and availabilities to meet regional demand.

2-4-C® models the generation dispatch in the WEM at a trading interval (30 minute) granularity in a time-sequential manner. This captures the intermittency of renewable projects as well as the underlying changes to demand, operation and transmission capabilities. The model takes into account generator outages, half-hourly renewable energy generation availability as well as transmission network limitations. The dispatch of generators is based on a least-cost objective to minimise the overall cost of supplying demand.

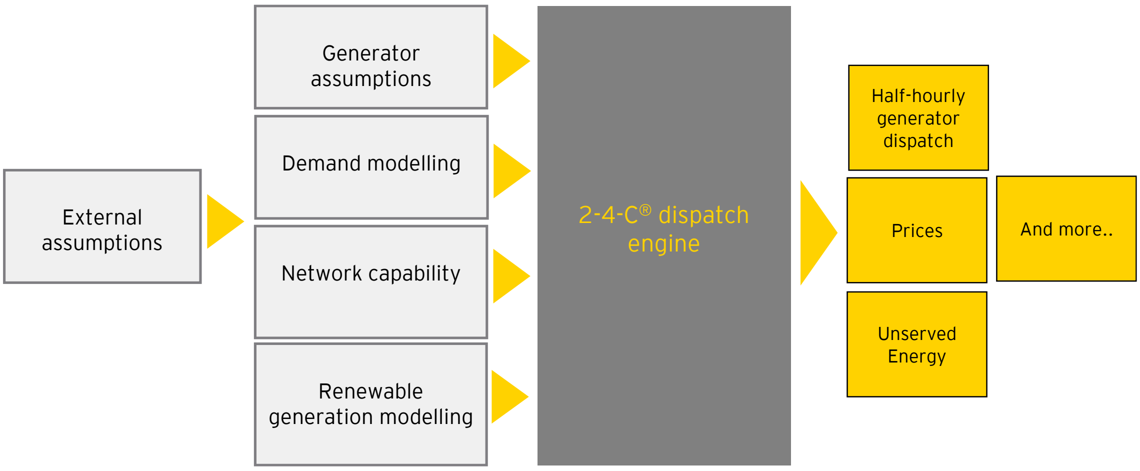
At a high level, for each 30-minute trading interval in the defined study period, 2-4-C® simulates the dispatch of generators to meet a forecast load demand target subject to defined constraints. Constraints in the model can represent a range of physical limits associated with network power transfer limits, generator plant capability, contractual supply limits and more.

The outputs that are reported from the model will depend on the purpose of the assessment but may typically include the output of each generator (in MW or GWh), the market clearing price (in $/MWh), presence of unserved energy (USE) and generator availability amongst many other potential metrics. EY analyses these outputs to provide insights tailored for the modelling purpose and objective.

2.2 Data and input assumptions

In practice, market modelling of this nature is highly complex and involves establishing a large set of data and input assumptions that are often inter-related. Assumptions are grouped into five general categories which are described at a high level below. Some of the input assumptions are processed in models external[11] to the 2-4-C® dispatch software to determine the quantities to be used. Figure 2 provides a high level overview in diagram form.

Figure 2: Simplified high level overview of 2-4-C®



[11] An example of an external assumption not used directly in dispatch modelling for the WEM is the Reserve Capacity Requirement. This assumption and its application in the modelling will impact generator capacity development by setting the capacity credit requirement and the surplus used in calculating the Reserve Capacity Price.

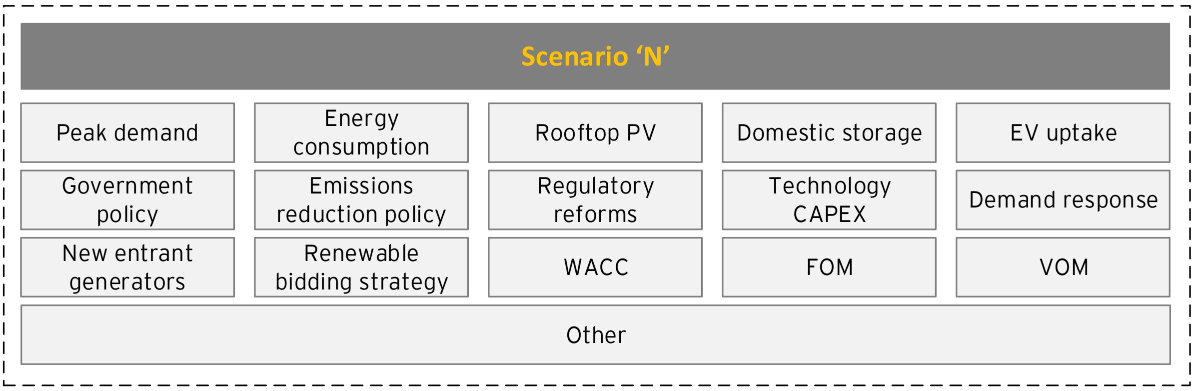
- Generator assumptions detailing the relevant generation plant parameters for existing and new entrant generation units and their assumed behaviour in the market. These inputs involve assumptions around generator bidding profiles, generator heat rates, fuel costs, fixed and variable operating and maintenance costs, emissions, new entrant technology capital costs, outage rates, marginal loss factors, maintenance periods and more.
- Demand modelling involving assumptions around the peak demand and annual energy projections for different growth scenarios, assumed time-of-day profiles for demand, uptake of rooftop solar PV and the impact on the assumed time-of-day profile and the expected impact on peak demand reduction, the uptake of electric vehicles (EVs) and behind-the-meter battery storage and the corresponding assumed daily charging and discharge profiles for each.
- Network capability defining power transfer limits and network limitations that constrain the physical dispatch of generator units and dispatchable loads. These are input in the form of a network constraint equation[12].
- Renewable generation modelling involving assumptions around half-hourly generation profiles derived from wind and solar resource data, expected annual energy production, availability, time-of-day profiles and connection locations and more.
- External assumptions around market policy drivers such as emissions reduction, the Reserve Capacity Mechanism (RCM), assumed wholesale electricity market design reforms. These assumptions are not necessarily used in the dispatch model explicitly but can influence the inputs that are.

2.3 Scenarios

A complete set of data and input assumptions collectively defines a scenario. In the context of this modelling, a scenario represents a plausible future with respect to the data and input assumptions that may impact development of wholesale electricity markets, but is independent of the constrained access regime that is employed (two cases are considered for each scenario, as described in Table 1). The data and input assumptions in a scenario should be internally consistent considering the interactions between different inputs. Certain metrics associated with the dispatch and market development outcomes will be more sensitive to particular input assumptions relative to others.

Figure 3 presents a diagrammatic representation of the input assumptions that make up a scenario.

Figure 3: High level overview of a scenario and possible settings



It is common to model multiple scenarios when undertaking market modelling as a test for robustness and/or to capture the wide range of possible outcomes that might eventuate. Modelling a number of different scenarios recognises that the future is inherently uncertain and a wide range of plausible outcomes may eventuate depending on the actual development of the market and the

[12] A network constraint equation is used by the dispatch engine to manage power flows across the transmission network by dispatching generation on or off for a particular constraint.

input assumptions that drive it. Modelling multiple scenarios provides the data to quantify the materiality of these changes and the sensitivity of outcomes to changes in scenario settings. The suite of scenarios to be modelled are developed giving consideration to the modelling objective and these sensitivities. The scenario settings proposed for this modelling and the rationale is discussed in Section 4.1 in further detail.

2.4 Simulation parameters

The potential for any particular outcome in the electricity market is probabilistic. Various combinations of prevailing customer demand, availability and costs of conventional and intermittent generation, energy storage devices, demand side participation, transmission network capability and generator availability will influence market outcomes.

Within a single scenario, Monte Carlo simulations of generator outages, multiple reference years of historical data and consideration to probability of exceedance (POE) peak demand forecasts are all taken into account. This captures the probabilistic nature of key half-hourly variations in the market in the overall outcomes reported.

Each Monte Carlo simulation iteration models different profiles of unplanned outage events on generators according to assumed outage rate statistics. Each of the scenarios modelled will simulate 25 Monte Carlo iterations of generator outages for the Study Period, for each demand and reference year modelled. For this Project, EY will model two reference years for atmospheric conditions and load shape and to manage the problem size, we limit POE peak demand samples to 10% and 50% POE scenarios. All simulated iterations of half-hourly results are collated with results reported on a weighted-average between iterations[13]. Table 3 provides a summary of key simulation parameters.

Table 3: Simulation parameters

Simulation parameter	Description
Demand profiles	For each future simulation year, both the 10% POE and the 50% POE values for each forecast will be modelled. Results will be presented as a weighted average from the two profiles.
Reference years	The 2015-16 and 2016-17 reference years will be modelled. Applying different reference years will introduce variability in terms of the half-hourly demand, wind and solar profiles according to the weather patterns in those years. Key outcomes for the individual reference years 2015-16 and 2016-17 will be assessed to explore the robustness in the outcomes to choice of reference year as well as on a weighted average from the two years.
Monte Carlo iterations	On each demand profile we will model 25 Monte Carlo iterations[14] of generator unplanned full and partial outages.

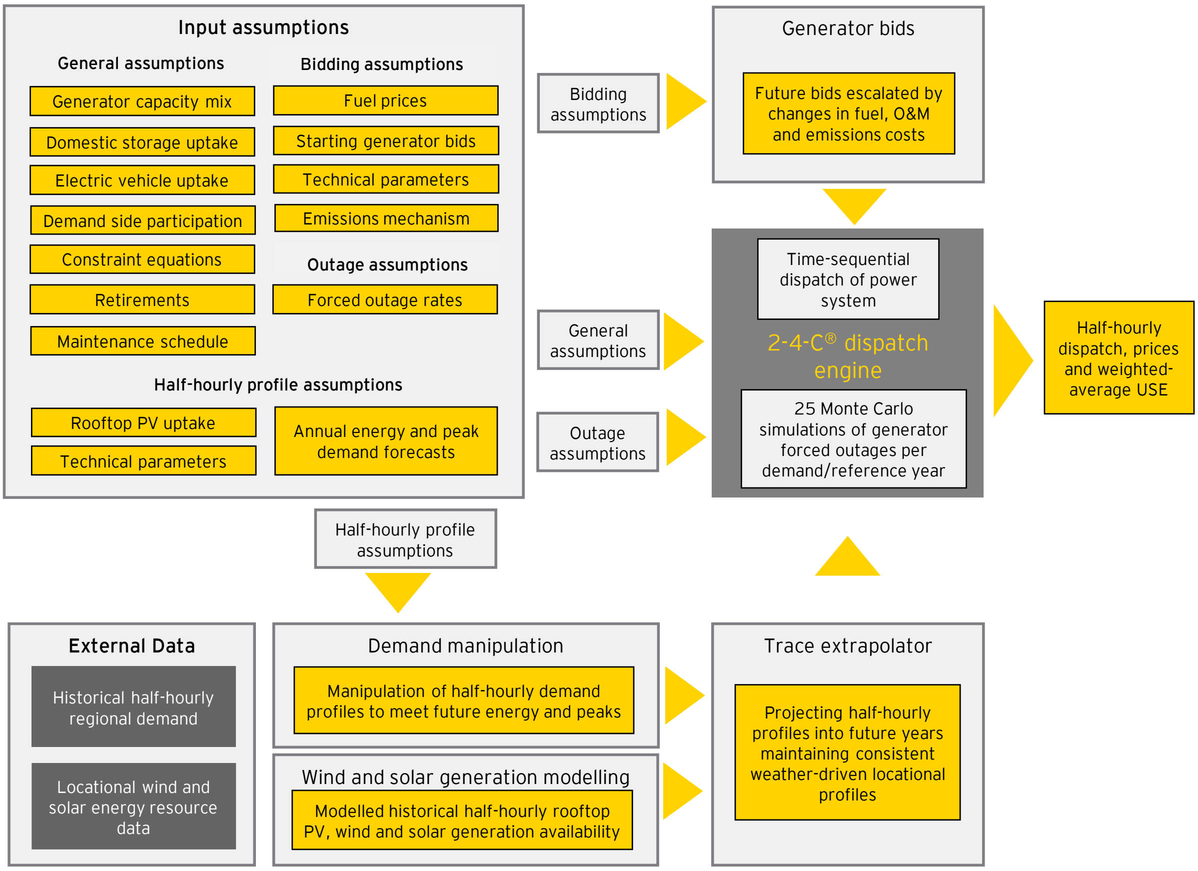
[13] EY applies a rounded 0.3 weighting on all 10% POE outcomes and 0.7 weighting on 50% POE outcomes as described in Appendix B. All modelled Monte Carlo iterations and historical reference years are considered equally likely.

[14] 25 iterations of Monte Carlo simulations produces converged revenue outcomes suitable for the purposes of the modelling

Simulation parameter	Description
Results	All results will be provided as a weighted average over all 100 iterations. These iterations are made up of two reference years, each with two demand profiles, each with 25 Monte Carlo iterations of forced outage profiles (as described above). Comparing results for individual reference years will also be made available. Some of the results will refer to the iteration with the maximum or minimum result for a particular outcome, such as the maximum total curtailment for a generator over all iterations.

Figure 4 shows a consolidated flow diagram detailing the interactions between 2-4-C®, input assumptions, external tools and simulation parameters.

Figure 4: Data flow diagram for the market simulations



3. Modelling process

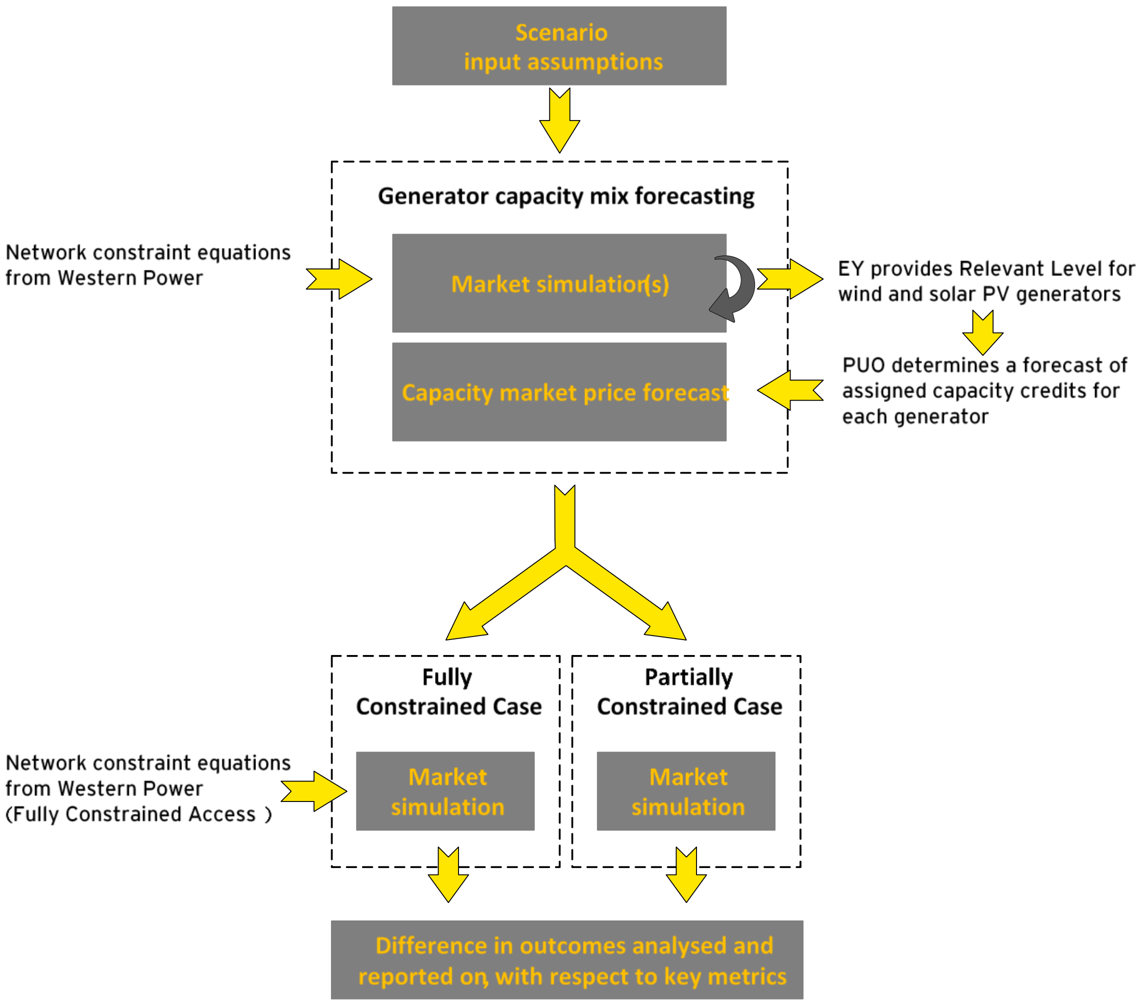
3.1 Overview

The modelling process for this Project is split into the following four stages:

- **Stage 1: Define and prepare the scenario input assumptions.** An overview of the proposed data and input assumptions is provided in Section 4.1 and in detail in Appendix A.
- **Stage 2: Generator capacity mix forecasting.** EY's methodology for forecasting the generator capacity mix involving iterative, time-sequential market simulations to forecast new entrants and retirements of generators in the WEM over the Study Period. This is described in Section 5.
- **Stage 3: Conduct market simulations.** For the Fully Constrained Case and the Partially Constrained Case, simulate market dispatch based on the generator capacity mix forecast. EY's model and approach to this is described in detail in Section 6.
- **Stage 4: Analysis and reporting.**

Figure 5 presents a general overview of the modelling methodology used for each scenario.

Figure 5: Overview of modelling methodology[15]



[15] EY will also explore the potential materiality of changes in the capacity mix arising from the Fully Constrained Case and the Partially Constrained Cases.

3.2 Results analysis metrics

Table 4 provides a summary of the key data metrics that EY use in assessing the overall impact of the transition to constrained network access and for reporting purposes. Each of these metrics will be reported on an annual basis, i.e., for each forward-looking financial year in the Study Period.

Table 4: Key data metrics for reporting on a financial year basis[16]

Category	Key metrics reported on	Units
System outcomes	WEM balancing market prices (time-weighted)	$/MWh
	Reserve capacity price	$/MW capacity credit
	Total fixed and variable operation and maintenance costs for the SWIS	$m
	Expected unserved energy (involuntary load shedding)	% sent-out energy
	Voluntary load shedding outcomes (demand-side participation)	MWh
	Frequency at which each constraint equation binds or violates	% of trading intervals
Generator outcomes	Annual energy production	GWh
	Capacity factor	%
	Frequency of network constraints impacting individual generator	% of trading intervals
	Constrained-on generation	MWh
	Constrained-off generation	MWh
	Dispatch-weighted price	$/MWh
	Fixed and variable operation and maintenance cost	$
	Capacity credit assignment[17]	Capacity credits
Generator revenues	WEM balancing market revenue	$M
	Reserve capacity market revenue	$M
	Large-scale generation certificates revenue	$M
	Generator constrained-on payments[18]	$M

[16] A single capacity year in the WEM is defined from 1 October to 1 October of the following calendar year. EY reports revenue outcomes based on a financial year basis. For simplicity, the capacity revenue is calculated on a financial year basis assuming that the assignment of capacity credits and the calculated RCP is equal to the values in the corresponding capacity year.
[17] This is not an explicit output from the 2-4-C® simulations. These are values are provided by the PUO.
[18] For the purposes of this modelling generators are assumed not to receive constrained-off payments

4. Scenarios and input assumptions

4.1 The proposed scenarios

To explore the potential impact of a Fully Constrained Access regime in the WEM against the counterfactual of a Partially Constrained Access regime, three market development scenarios, selected by the PUO are explored as described in this section.

The purpose of the scenarios is to explore a central outlook for the WEM (the Base Scenario) and to explore a range of possible outcomes to understand underlying trends associated with the introduction of Fully Constrained Access, with respect to the key metrics.

The scenarios explore the Expected, High and Low demand scenarios as published by AEMO in the WEM Electricity Statement of Opportunities (2017 WEM ESOO) in June 2017[19]. Two alternative[20] scenarios are also discussed in Section 4.3 for consideration in this public consultation. Table 5 summarises the proposed scenarios.

Table 5: Core scenarios

Scenario	Base Scenario	High Scenario	Low Scenario
Demand forecast	Expected	High	Low
Study Period	1 July 2022 – 1 July 2032		

4.1.1 Rationale of the proposed core scenarios

The proposed scenarios are being consulted on for the following reasons:

- The objective of this modelling is to investigate the impact of transitioning to a constrained network access regime and the impact of network constraints on market outcomes. Consideration is given to which input assumptions are likely to drive material differences in generation curtailment outcomes.
- The level of demand is considered to have the most significant impact on constrained access outcomes, through demand being a factor in determining potential constraints as well as influencing the volume of generation that is required to be dispatched.
- They explore different levels of electricity demand, including the impact of the uptake of small-scale technologies including rooftop PV, behind-the-meter battery storage and EVs[21].
- They are based on published potential outlooks for the WEM by AEMO.

4.2 Overview of input assumptions

Table 6 shows an overview of the key input assumptions for the three proposed scenarios for public consultation and industry feedback. The table provides justification for each assumption. It is recognised that market participants are likely to possess information that may be more accurate to date regarding their own facilities. The PUO objective for undertaking this public consultation process is to use it as an avenue to bridge this potential gap.

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

[20] Alternate scenarios are proposed to replace either the expected, high or low scenarios. Three scenarios are proposed to be modelled.

[21] Changes in the uptake of small-scale technologies will alter the half-hourly profile of operational demand (to be met by large-scale generators), changing generation dispatch and market pricing outcomes and in turn, network constraint outcomes.

Table 6: Overview of key assumptions for the core scenarios

Input assumption	Data source and value	Justification
Input assumptions affecting demand / energy consumption		
Electricity demand - energy and peak demand	AEMO's 2017 WEM ESOO[22]: Expected, High and Low scenarios. Both 10% and 50% POE peak demands modelled.	This is the latest demand outlooks published for the WEM. All three trajectories are proposed to be modelled under three scenarios, with the Expected outlook to be used in the Base Scenario.
Rooftop PV uptake	As above.	As above.
Behind-the-meter storage uptake[23]	As above.	As above.
EV uptake[24]	As above.	As above.
Reserve Capacity Target (RCT)	AEMO's 2017 WEM ESOO[22]: The Expected, High and Low scenarios will use the corresponding 10% POE peak demand forecasts to calculate the RCT.	As above.
Assumption regarding market policies		
Large-scale Renewable Energy Target (LRET)	No change to the present legislated national target[25] of 33,000 GWh by 2020 and constant until 2030. WA's assumed contribution to the LRET is as per renewable capacity list.	There is currently no indication in the public domain that the LRET will not continue and be fulfilled. The current expectation is that LRET obligations will be largely met by generation projects built in the NEM.
Emissions reduction policy	No explicit policy, or carbon price.	There is currently considerable uncertainty surrounding new emissions reduction policies in Australia.
External assumption affecting market supply		
New renewable capacity connected by 2022	List of named new entrant renewable projects assumed to be installed by 2022 as part of the WEM's contribution to the LRET.	Each project has an advanced status in the public domain, such as having an offtake contract and/or funding and network access.
Thermal generator developments	Synergy's announced thermal generator retirements[26]. Units retire at 50 years of age based on information on their first year of operation[27].	Based on committed and announced retirements. Generator units retiring at 50 years represents maximum asset life.

[22] 2017 Electricity Statement of Opportunities for the WEM
[23] Charging profiles are detailed in Section 6.1.2
[24] Charging profiles are detailed in Section 6.1.3
[25] Available at: https://www.legislation.gov.au/Details/C2016C00286
[26] Synergy announcement - 380 MW retirement
[27] Western Power Annual Planning Report 2011

External assumption affecting market supply continued		
Generator bidding	Benchmarking process as part of this Project developed by EY.	Based on model benchmarking outcomes to be completed.
Generator outage rates (Forced and planned)	IMO Planning Criterion review[28]	Publically available data based on IMO assessment of SWIS data.
Fuel prices	2017-18 margin peak and margin off-peak review.[29] 2017 Gas Statement of Opportunities[30]: Base scenario	Publically available information on fuel prices, taking into account a public consultation process.
New entrant parameters including technology capex	AEMO's NTNDP 2016 with adjustments to wind and solar in early years in line with recent public announcements, plus CSIRO/Jacobs 2016 storage capex neutral trajectory	The most up-to-date published technology parameters and capex estimates from market data.
Weighted-average cost of capital (WACC)	IPART Review of Regulated Retail prices (Aug 2015)[31], adjusted by EY for a higher assumed gearing ratio: pre-tax, real WACC of 7.5%.	Agreed between EY and the PUO as an applicable WACC for generation investment.
External assumptions regarding network and market design reform		
Network augmentation	Committed and very advanced[32] network augmentations.	Including uncommitted network augmentation projects may understate congestion outcomes.
Regional reference node (RRN)	RRN assumed to be at the Southern Terminal 330 kV node	The RRN is proposed to move from Muja to a demand centre as part of implementing constrained network access. This is discussed in "Improving access to the Western Power network – Consultation Paper".
Marginal loss factors (MLF)	As provided to EY by the PUO.	The calculation of loss factors is based on the RRN at a demand centre location with historical data.

[28] IMO Planning Criterion review
[29] AEMO 2017-Margin-Peak-and-Margin-Off-Peak-Review-Assumptions
[30] WA-Gas-Statement-of-Opportunities 2017
[31] iPart Spreadsheet_of_WACC_model_-_August_2015
[32] Committed and very advanced network augmentation projects are defined by Western Power. Committed projects are discussed in the Western Power Annual Planning Report 2017. EY has not verified the status of these projects.

4.3 Alternative scenarios and assumptions to consider

Each of the assumptions presented in Table 6 have a plausible alternate assumption. Given the dynamic nature of the electricity industry there are many possible futures that may drive electricity market developments in different ways.

Two possible alternative assumptions are discussed below. A part of this public consultation is to seek feedback on other alternative scenarios or assumptions that may be varied.

Two significant assumptions discussed are a national emissions reduction policy and a very low demand scenario. The following section presents a summary of the discussion and analysis on these two alternative assumptions.

4.3.1 National emissions reduction policy

Over the past year or two, there have been many different mechanisms discussed in reports and by the Federal Government to reduce emissions from Australia's stationary electricity sector. There is currently considerable uncertainty surrounding the nature, implementation and timing of such a policy. The most recent potential scheme, the National Emissions Guarantee (NEG) was announced by the Federal Government in October 2017[33]. However, there is to date little information about how this scheme will work in practice, and it is focussed on the NEM with no explicit mention of the WEM.

If a national emissions reduction scheme were to be established during the 2020s, the emissions target for 2030 is currently typically discussed as being for the electricity sector to meet its pro-rata contribution to Australia's committed national targets from the United Nations on Climate Change Paris Agreement[34]. Australia's agreed targets are a 26-28% reduction on 2005 levels by 2030. To ascertain what would be required for the WEM to achieve a pro-rata 26% emissions reduction contribution to the Paris Agreement, EY made the following analysis:

- Estimated the historical total WEM combustion emissions in 2005, based on the available historical data that is closest to this year. Hourly generation data is available on the AEMO WA website[35] for complete months from October 2006. EY summated the generation data for each generating facility for October 2006 to September 2007 and calculated the total combustion emissions to using emissions factors by generator type from the 2015-16 Margin Review[36].
- Calculated the emissions target required for the WEM to meet its pro-rata 2030 Paris Agreement as 26% less than the 2005 estimate.
- Estimated the total emissions for 2020, based on indicative half-hourly market modelling by EY with a capacity mix consistent with the proposed assumed WEM's contribution to the LRET in this Report (see Appendix A.7).

These three estimates are shown in Figure 6 (following page). The estimated total WEM combustion emissions for 2005 and 2020 are similar at around 11 MW Co_2-e. This is the result of the total demand in the WEM increasing during that time, offsetting the increases in the proportion of renewable energy being dispatched during the same period. As such, EY estimates the WEM would need to achieve around a 26% reduction in emissions in the 2020s alone to meet the target.

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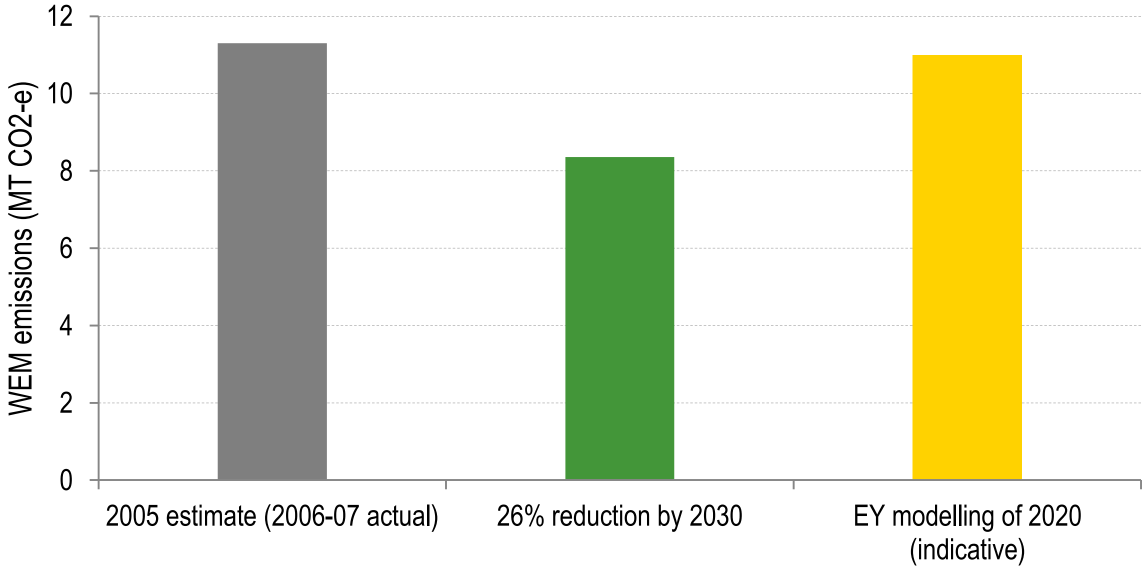
[33] https://www.pm.gov.au/media/national-energy-guarantee-deliver-affordable-reliable-electricity
[34] http://unfccc.int/paris_agreement/items/9485.php
[35] http://data.wa.aemo.com.au/#facility-scada
[36] http://www.imowa.com.au/docs/default-source/rules/other-wem-consultation-docs/2015_16-margin-review-assumptions-report---public.pdf?sfvrsn=0

Figure 6: WEM combustion emissions analysis



A 26% reduction in WEM combustion emissions in the 2020s would likely require retirements from coal capacity and additional renewable and gas capacity in the same period. Since none of the existing coal power stations will reach the end of their 50-year asset life during the 2020s, it is likely that an emissions reduction policy would be required to incentivise change in the capacity mix to occur.

Whilst a change toward lower emissions capacity in the WEM would potentially lead to different outcomes with respect to constrained access, the relative impact compared to the proposed core scenarios is unclear. Furthermore, the impact on some existing generators may be negligible if they are assumed to retire in an emissions reduction scenario. Given the present uncertainty in emissions reduction policies, and lack of discussion around WEM emissions, such a scenario has not been initially proposed as a core scenario.

4.3.2 Very low demand outlook

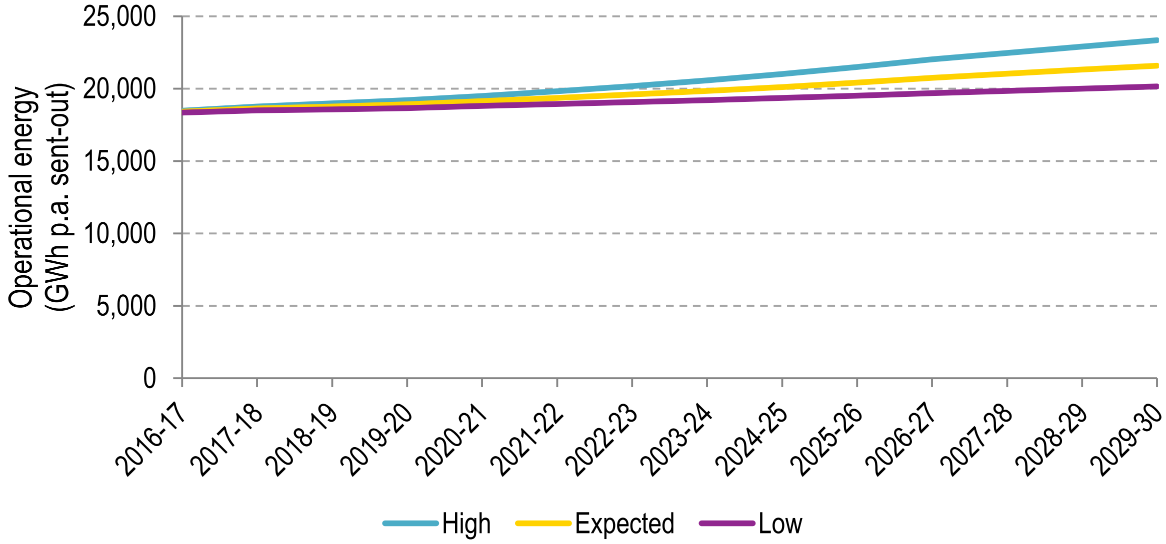
As illustrated in Figure 7 (following page), the 2017 WEM ESOO Low demand scenario forecasts operational energy demand in the WEM to still increase, albeit at a slower rate than in the Expected and High scenarios.

The potential for energy efficiency, industrial load closures and grid defection driven by a reduction in the costs of behind the meter storage technologies and stand-alone power systems compared against a backdrop of increasing electricity network prices could result in a demand outlook that is lower than the 2017 WEM ESOO Low demand scenario.

Grid defection would typically be at the fringe of the SWIS where long network distribution connections are required to service a smaller proportion of customers and demand. As such, the overall impact of grid defection may have minimal contribution to total demand reductions (at least across the Study Period). There is additionally a lack of relevant public data directly related to the SWIS to support the potential for grid defection as well as additional energy efficiency or industrial load closures. As such, a very low demand scenario is not proposed as a core scenario.

If it could be justified however, a very low demand outlook may represent a lower 'low case' than what has currently been proposed and could be modelled as an alternative to the 'low case'.

Figure 7: 2017 WEM ESOO annual operational energy forecast in the WEM



5. Generator capacity mix

5.1 General

The term 'generator capacity mix' in this Report refers to the schedule of generator capacity that is installed in the WEM during the Study Period. It can include information on the amount of capacity installed in each year, the type of technology and the location.

For this Project, EY will forecast the economically-driven generator capacity mix for each of the proposed scenarios, as an outcome of the assumptions used in each scenario. To investigate the sensitivity of the forecast generator capacity mix to the constrained-access regime, EY will first forecast the generator capacity mix in the Base Scenario under the Partially Constrained and the Fully Constrained Cases, separately. Depending on the materiality of the differences between the two generator capacity mix outcomes, EY intends to base the capacity mix for each scenario on either the Partially Constrained or Fully Constrained Case. If feasible, using the same capacity mix for each case has the advantage of quantifying the relative financial impact of constrained access on all generators in all modelled years.

5.2 An iterative approach

For this Project, the procedure employed by EY to forecast the generator capacity mix involves running multiple market simulations with the 2-4-C® model to arrive at a final set of outcomes. The process involves the following steps:

1. **Determine a set of input assumptions.** A summary of the input assumptions used for each scenario is provided in Section 4.2. The various input assumptions impact different aspects of the market modelling in different ways and to varying degrees. Section 6 details how several of these input parameters are used within a market simulation.

2. **Set up an initial market simulation.** Using all the assumptions, conduct an initial time-sequential half-hourly market simulation over the Study Period using the constraint equations formulated for the case being modelled. Section 5.2.1 discusses modelling network constraints in the generator capacity mix and potential impacts on market development.

   Assess the commercial viability of each generator using the method of calculating net revenue described in Section 5.2.1 to determine if any new entrants or retirements would be commercially driven for net revenue outcomes outside a tolerance range.

3. **Iterative modelling to achieve final simulation.** Adjust the new entrants and retirements; re-simulate several times until all generators have a net revenue within a specified tolerance.

   For example, if a new entrant generator is installed in response to price signals observed in the previous simulation but fails to make positive net revenue in the next simulation iteration for multiple years after it is in-service, it is removed (or reduced in size) from the generator capacity mix as it is considered not commercially viable.

   Retirements can be driven by age considerations (i.e., a coal fired power station reaching 50 years of age) or when the generator makes a loss for consecutive years of operation. It is assumed that when wind and solar PV generators reach their project lifetime, the sites are upgraded to new wind and solar PV generators.

   Since wind and solar PV generators are typically capital intensive investments with very little ongoing costs, it is considered very unlikely that a wind or solar PV farm would be retired for economic reasons. As such EY does not consider retirements of wind and solar PV generators in the modelling.

4. **Capacity credit allocation by the PUO and finalisation of generator capacity mix.** The total installed capacity and allocation of capacity credits is checked against the Reserve Capacity Requirement (RCR). This is discussed in Section 5.2.3. Final capacity credit allocations for constrained access are calculated by the PUO based on the final generator capacity mix. If material changes are required after assessing the impact on RCR, Reserve Capacity Price (RCP) and generator capacity outcomes, EY adjusts the new entrants and retirements[37] before finalising the generator capacity mix.

5.2.1 Modelling network constraints in the generator capacity mix

Whether a generator can be constrained off or on may impact the development of generator capacity in the market. This is accounted for in the modelling by forecasting generation development using the two constraint equation sets provided to EY.

Table 7 provides an overview of which generators can be constrained by the market dispatch engine in the two cases.

Table 7: Overview of the treatment of generators when undertaking generator capacity forecasting

Case	Treatment of existing generators with access rights, from July 2022	Treatment of existing generators with no access rights, from July 2022	Treatment of all new entrant generators not currently connected
Partially Constrained Case	Cannot be constrained off[38] Can be constrained on	Can be constrained off/on	Can be constrained off/on
Fully Constrained Case	Can be constrained off/on		

All future new entrant generators and existing generators currently connected with no access rights can be constrained off and on (if dispatchable) in both cases by the market dispatch engine.

Incumbent generators with network access rights cannot be constrained off by the dispatch engine in the Partially Constrained Case[38]. This can result in a situation where despite it being potentially more economic to constrain off an incumbent generator to relieve network congestion, another generator is constrained off instead, impacting on generation revenues and market development outcomes. Although generators with network access rights cannot be constrained off in the Partially Constrained Case they can be constrained on to avoid violation of a network limitation if required. Constrained-on payments will be quantified in these circumstances.

5.2.2 Calculating a generator's net revenue

Generator capacity developments made within the market modelling procedure are determined by assessments of the net revenue of generators modelled within 2-4-C® and the interactions with the capacity market. A generator's net revenue is calculated for any particular year using the equation (1) below.

[37] This process will be conducted once and towards the end of the iterative generator capacity mix forecasting process allowing the capacity mix to be potentially refined based on the assignment of capacity credits to each facility.

[38] Due to the present unconstrained planning framework adopted by Western Power, the incidence of generation being constrained during system normal conditions is rare. Despite this, the potential remains for generation to be constrained from time to time to accommodate planned and forced network outages, such as during a period of a transmission line outage or for system security events. AEMO manages this in accordance with the WEM Rules. The potential for these events remains in the status-quo access environment, or whether transitioning to the Partially Constrained Case or the Fully Constrained Case. As such, EY's forecast modelling does not take such contingencies or events into account as they are possible in all access environments and the relative financial impact is negligible.

$$\text{Net revenue} = \text{pool revenue} + \text{capacity payment} + \text{LGC revenue} + \text{constrained-on payments} \\ - \text{O\&M costs} - \text{capital cost repayment} - \text{fuel costs} \tag{1}$$

Where:

Pool revenue is the total annual wholesale market revenue earned over each trading interval in the year. In the modelling, this is the sum-product of the modelled dispatched generation and the wholesale market price over all trading intervals, multiplied by an assumed loss factor for the generator.

Capacity payment is the total annual capacity payment earned over the year[39]. In our modelling, this is equal to the amount of capacity credits allocated to a particular facility taking into account the impact of constrained access, multiplied by the calculated RCP for that year. This is discussed in Section 5.2.3 and Section 5.2.4.

LGC revenue is the total annual revenue earned associated with the sale of LGCs. With the Study Period starting on 1 July 2022, EY believes there is a high certainty that the LRET will be met by this time. The specific renewable projects commissioned in the WEM that contribute to the LRET are assumed for each scenario (as presented in Table 9 in Appendix A.8). With the LRET met, all new entrant generators commissioned in the WEM within the Study Period are unlikely to receive LGC revenue and as such EY assumes this revenue source is zero. For the purposes of estimating the impact of the Fully Constrained Case on the LGC revenue on existing renewable generators, EY assumes an LGC value of $40/LGC. Most existing renewable generators have power purchase agreement contracts with various agreed values for LGCs that are not available in the public domain.

Constrained-on payments is a mechanism in the WEM where generators are compensated for being constrained-on at balancing market prices below their short-run marginal cost (SRMC)[40].

O&M costs is the total fixed and variable operation and maintenance costs. The variable operational costs do not include an emissions cost based on the proposed scenario assumptions to date.

Capital cost repayments is the annualised capital cost of the generator, taking into account the assumed economic life and WACC for the study.

Fuel costs is the total cost of the fuel used in the generator's modelled production of electrical energy throughout the year. The fuel cost is always zero for wind and solar PV.

Constrained-off payments will not apply in a fully constrained access regime when a generator is constrained-off due to network constraints.

Ancillary service revenues are excluded from generator net revenue calculations. The co-optimisation of energy and ancillary service markets is a part of the essential reforms outlined by the PUO[41]. Whilst we consider that it is an important consideration, it is also secondary to the focus of this investigation and scope of work. Of the current ancillary services required in the WEM, load following, spinning reserve, and load rejection reserve are the services that may be impacted by a transition to constrained network access. Whilst it is possible to model the impact of constrained access on ancillary service markets, we consider that the overall benefit in quantifying the impacts will be second order compared to outcomes associated with the curtailment of energy in the balancing market and potential impacts on capacity credit allocations and RCP. EY proposes to include the impact of ancillary service participation in the bidding behaviour of generators in the market modelling, but not explicitly conduct any modelling of the ancillary services themselves.

[39] A single capacity year in the WEM is defined from 1 October to 1 October of the following calendar year. EY reports revenue outcomes based on a financial year basis. For simplicity, the capacity revenue is calculated on a financial year basis assuming that the assignment of capacity credits and the calculated RCP is equal to the values in the corresponding capacity year.

[40] Constrained-on payments are made to compensate generators for being dispatched in bid bands where they bid higher than the pool price. The calculation of constrained-on payments is discussed in Section 4.1.2.

[41] "Improving access to Western Powers network – Consultation Paper"

Assessing a generator's net revenue is conducted differently depending on whether they are existing or a new entrant:

- **Existing generators**: There is no publically available data for an existing generator's capital cost repayments and in many cases the capital cost might be already paid off. As such EY assesses the year-on-year net revenue of existing generators in the modelling assuming no capital cost repayments are required, and retires them on a commercial basis if the net revenue is negative (and persists with negative revenue in subsequent years).
- **New entrant generators**: Commercially driven new entrant decisions are based on the net present value (NPV) of a generator's net revenue over its assumed economic lifetime. Since the Study Period modelled is only until 1 July 2031, each generator's net revenue is extrapolated by repeating the final year in order to calculate an NPV of its assumed economic lifetime.

5.2.3 Reserve capacity requirement

The relevant reserve capacity requirement (RCR) for a particular capacity year is defined as the RCT for that year and sets the amount of capacity credits to be procured. The RCT is based on meeting the Long Term Planning Criterion by ensuring sufficient generation capacity is available to meet peak demand, a reserve margin, load following requirements and intermittent loads[42].

The RCT for each scenario is set taking into account the 10% POE peak demand assumption for that scenario. An initial assessment of capacity credits is allocated to each generator assuming unconstrained access and an assessment of historical outcomes of technology types.

In determining whether the installed capacity on the SWIS meets the RCR in a constrained access environment, the PUO provides EY with final capacity credit allocations to assess the materiality of changes to the capacity credit allocations and to assess the impact of any change in surplus on the RCP and generator revenues over the Study Period. The generator capacity mix is adjusted to account for material changes.

It is understood that the PUO calculates the capacity credit allocation based on the methodology proposed in the consultation paper "Allocation of capacity credits in a constrained network" and is consistent with the principles of the Relevant Level calculation in the Market Rules but modified to account for the impact of constrained access.

5.2.4 Calculating capacity payments

The RCP is the administered price for all capacity that is not bilaterally traded in the WEM. EY applies the RCP to all generators assuming that the RCP influences contract prices in a similar way to balancing market prices affecting the energy price negotiated in an off-take contract.

The following formula from the Market Rules applies:

$$\mathrm{RCP} = \mathrm{MIN}\left\{\left(\frac{\mathrm{BRCP} \times \text{'Intercept'}}{1 - \left((\text{'Surplus'} + 0.03) \times \text{'Slope'}\right)}\right), \mathrm{BRCP} \times 1.1\right\}$$

Where:

BRCP denotes the benchmark reserve capacity price;

[42] It is noted that whilst the Long Term Planning Criterion is reviewed every 5 years, it is assumed that it remains for the length of the study. No change is assumed to this criterion when assessing the reserve margin. Load following requirements and intermittent loads are assumed to remain constant throughout the period.

The 'Intercept' term is used to adjust the price curve so that it passes through the BRCP at the RCR, where the RCR is equal to the RCT for the capacity year commencing on Year 3 of the Reserve Capacity Cycle.

The 'Surplus' term relates to the number of capacity credits assigned in excess of the RCR, expressed as a percentage of the RCR.

The 'Slope' term is a negative number to be steepened over time putting downward pressure on the RCP for any given level of surplus.

For the length of the Study Period, RCP is calculated based on the values for 'intercept' and 'slope' as per the Reserve Capacity Administered Price Table. The surplus value is calculated based on the capacity credits available in the market and the initial allocation discussed in Section 5.2.3. The RCP calculation does not include modelling a capacity auction. Proposed reforms to the RCM will be publically consulted on by the PUO in the future.

5.2.5 Calculating constrained-on payments

The existing Market Rules allow for generators to be constrained-on by AEMO in response to system security limitations. A constrained-on generation payment is paid on the amount of 'Upwards Out of Merit Generation' as defined in the Market Rules. The PUO have identified that this payment is to be retained in the WEM[43].

To determine the constrained-on payments received by a generator for a market simulation, EY collates the trading intervals where the generator is dispatched at a balancing market price that is lower than their bid for that generation. All the dispatched generation that is bid at prices (adjusted for the generator's loss factor) greater than the balancing market price in that trading interval is the constrained-on generation. The constrained-on payment is equal to the price as bid for the constrained-on generation, minus the balancing market price, multiplied by the constrained-on generation and the loss factor of the generator. In any given trading interval this could apply to generation bid in multiple price/quantity bands.

To determine the impact of Fully Constrained Access on constrained-on payments for a generator, a difference between the outcomes in the Fully Constrained and Partially Constrained Cases is only required for new entrant generators that are constrained-on in the Partially Constrained Case. Otherwise, it is just the total constrained-on payment in the Fully Constrained Case. Equation (2) describes the calculation of the total constrained-on payment for a generator over a simulated year.

$$Y = \sum_{k=1}^{N}\left(P_k \times \sum_{u=1}^{W}[G_u \times M_u]_k\right) + \sum_{k=1}^{N}\sum_{i=1}^{J_{k,u}}\left(\left[b_{i,u} - P_k\right] \times {g^+}_{i,u,k} \times M_u\right) \tag{2}$$

where:

k represents each trading interval out of the total number of trading intervals simulated for the year, N

u represents each generator out of the total number of generators, W

i represents each bid band (price-quantity pair) at which there constrained-on generation is bid up to the total number of applicable bid bands for each trading interval and generator, J,k,u, and

${g^+}_{i,u,k}$ is the applicable constrained-on generation applying to the bid price, i, generator u and trading interval, k.

[43] "Improving access to Western Power's network – Consultation paper"

6. Market modelling methodology

This section describes the methodology associated with the different aspects of market modelling including the market simulations that produce forward looking half-hourly generation dispatch and wholesale electricity prices.

6.1 Forward-looking half-hourly modelling

EY's approach to forward-looking half-hourly modelling is to base all the inter-temporal and inter-spatial patterns in electricity demand, wind and solar energy on the weather resources and consumption behaviour in one or more historical years (reference years).

Figure 8 (following page) depicts EY's methodology.

The top section of Figure 8 on the following page highlights the rationale behind what features in the historical half-hourly data are projected forward, and what features are modified to capture future conditions. These are described in more detail as follows:

- The historically observed **inter-temporal and inter-spatial impact of weather patterns** are maintained in the forecast. Historical hourly locational wind and solar resource data is used by EY to model half-hourly[44] generation from rooftop PV, large-scale solar PV[45] and wind generation. All the correlated interactions between wind and solar generation at different sites are projected forward consistently, maintaining the impact of actual Australian weather patterns. The available half-hourly large-scale wind and solar PV generation profiles are bid[46] into the market to meet grid demand in the 2-4-C® dispatch modelling. These may not be fully dispatched in case of binding network constraints or being the marginal generator and setting the price, with the volume above the marginal price being curtailed.

- **Inter-temporal and inter-spatial (regional) electricity consumption behaviour** is maintained in the forecast. Historical half-hourly operational[47] grid demand is obtained from AEMO and added to EY's historical modelled rooftop PV to produce the historical native electricity consumption. By projecting consumption forward instead of grid demand, EY maintains the underlying half-hourly consumer behaviour while specifically capturing the future impact of increasing rooftop PV generation in changing the half-hour to half-hour shape of grid demand during each day. EY also separately models behind-the-meter (domestic) storage profiles and EV charging profiles to capture their impact on the shape of grid demand without changes to the total underlying operational energy forecast by AEMO. As per AEMO's assumptions, EY assumes negligible contributions to peak demand from domestic battery storage and EVs.

- The historical year(s) used in the modelling consist of various types of weather, which may or may not be considered typical or average. With respect to demand, the historical electricity consumption is processed to convert it into two types of weather-years for each future year modelled. One could be considered a **moderate year**, which uses AEMO's 50% POE peak demand forecast[48], while the other is considered a year with more **extreme weather**, using AEMO 10% POE peak demand[49].

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[44] Hourly historical resource data is interpolated to half-hourly data.

[45] The same applies to solar thermal generation.

[46] EY's bidding methodology is described in Section 6.1.4.

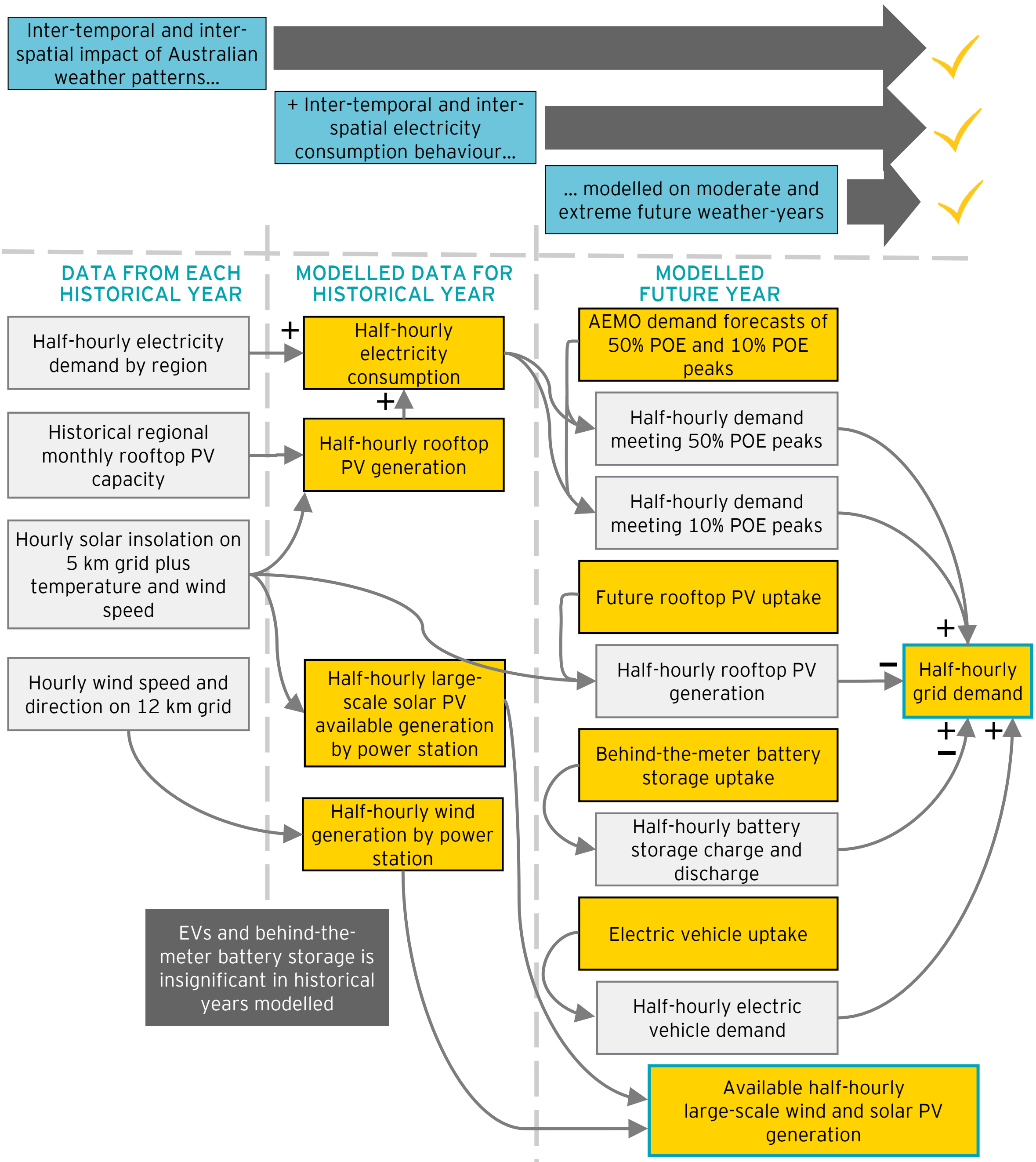
[47] Operational demand refers to the demand used by residential, commercial and large industrial customers, supplied by scheduled, semi-scheduled and significant non-scheduled generating units as defined in the NEM.

[48] The 50% POE peak demand forecast is expected to be exceeded for one half hour once in every 2 years.

[49] The 10% POE peak demand forecast is expected to be exceeded for one half hour once in every 10 years.

- Overall, the half-hourly modelling methodology allows for the underlying weather patterns and atmospheric conditions to be projected in the forecast capturing a consistent impact on demand, wind and solar PV generation. For example, a heat wave weather pattern that occurred in the historical reference year is maintained in the forecast for each future year. The forecast is developed in the context of a moderate or extreme weather year from a demand perspective. The modelled half-hourly availability of renewable generation during that event is a function of the assumed operational individual generators and the atmospheric conditions for each generator location as occurred[50] during the event.

Figure 8: Flow diagram showing EY's use of an historical year of electricity and atmospheric conditions data to make a half-hourly forecast



[50] According to the resource data.

The methodologies to produce the forecast half-hourly demand, wind and solar profiles for the modelling are briefly described in more detail in the following sections.

6.1.1 Half-hourly locational renewable generation modelling

As described earlier, and depicted in Figure 8, EY models future half-hourly generation availability for forecast uptake of individual wind and large-scale solar PV power stations, based on historical wind and solar resource data. An overview of the methodology for wind and solar is as follows:

- **Wind:** EY's wind energy simulation tool (WEST) uses historical hourly short-term wind forecast data[51] from the Bureau of Meteorology (BOM) on a 12 km grid across Australia to develop wind generation profiles for existing and future potential wind power stations used in the modelling. WEST scales the BOM wind speed data for a site and processes this through a typical wind farm power curve to target a specific available annual energy in the half-hourly profile for each power station. The scaling is usually required to convert the modelled wind speed to the representative wind speed received by the wind farm. Existing wind farms use the historical average achieved annual energy from actual data, while all new wind farms use an assumed annual energy that varies depending on their location in the WEM For this Project, EY is assuming 44% for North Country and 39% for the rest of the WEM, based loosely on observed capacity factors.

- **Solar PV**: EY's solar energy simulation tool (SEST) uses historical hourly satellite-derived solar insolation data on a 5 km grid across Australia, obtained from the BOM, along with BOM weather station data of temperature and wind speed. The resource data from the BOM is processed using the System Advisory Model (SAM) from the National Renewable Energy Laboratory (NREL) to develop locational solar PV generation profiles. The annual energy output varies from site to site as a result of calibration to the performance of existing solar farms and the locational resource data.

6.1.2 Behind-the-meter battery storage

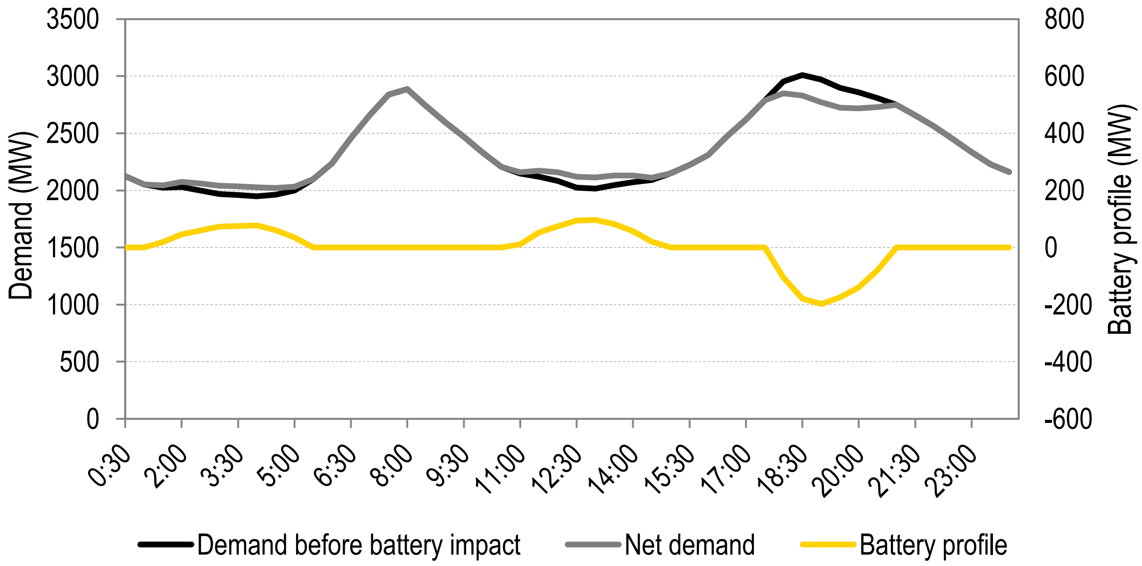
EY's behind-the-meter battery storage profile tool produces a seasonal time-of-day charge and discharge profile for behind-the meter battery storage for the WEM. The tool aims to produce an aggregate profile that responds to peak demand usage tariffs and lower priced daytime effective tariffs due to battery owners also owning rooftop PV systems. Rather than assuming a particular retail tariff structure for future battery owners, it is assumed that the tariffs will relate to the net demand profile on the distribution network – consumption minus rooftop PV generation. As a result the tool produces a fixed time-of-day discharge profile that reduces the seasonal peak net demand and a charge profile that operates during the lowest periods of residual demand.

EY has also incorporated imperfection into the aggregated profile of the batteries to meet the peak demand reduction forecasts as projected in the 2017 WEM ESOO scenarios.

Figure 9 below illustrates an example day in winter on how the aggregate battery charge and discharge cycle alters the operational demand profile.

[51] An historical hourly profile is comprised of many historical hourly forecasts made every six hours by the BOM throughout the historical years modelled.

Figure 9: Example day showing impact of behind-the-meter battery storage on operational demand in the WEM



This behind-the-meter storage profile is added/subtracted to the operational demand for 2-4-C® modelling. EY uses the same assumptions as AEMO, including that behind-the-meter battery storage has a negligible contribution to peak demand. Accordingly, the energy and peak-demand contributions of the battery storage profile is taken into account in the overall demand profile modelled. The amount of behind-the-meter storage modelled in each future year is provided by AEMO as part of the 2017 WEM ESOO demand scenarios. The trajectories used are shown in Appendix A.4.

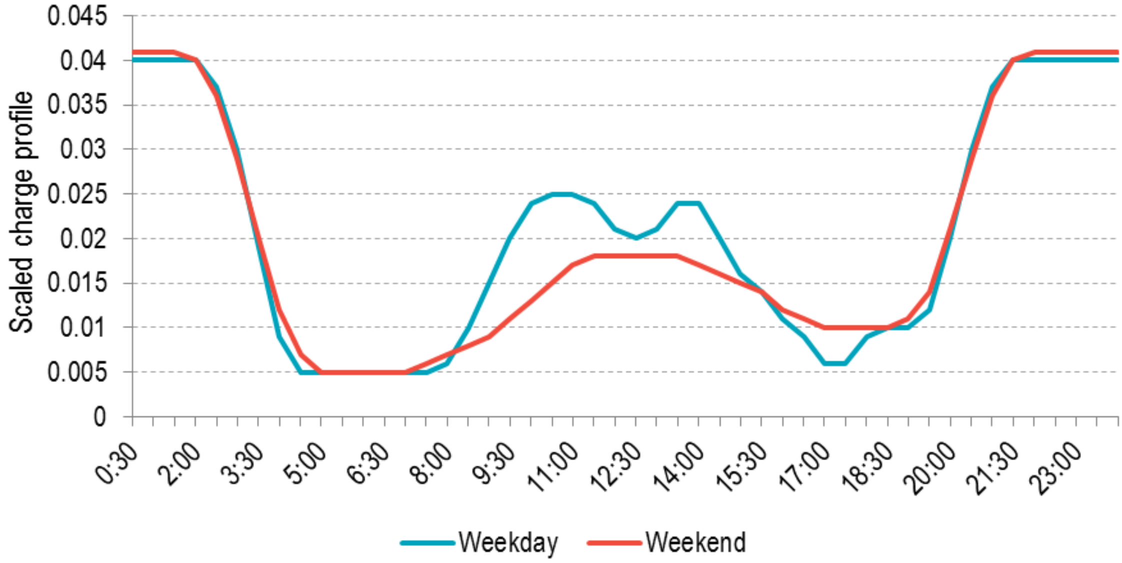
6.1.3 Electric vehicle demand

EY converts the annual energy expectation from EVs forecast by AEMO into half-hourly profiles to add to the grid demand used by 2-4-C®. The trajectories are provided in Appendix A.5.

Little is yet understood on when EVs will be charged in aggregate. EY has developed two alternative time-of-day EV demand profiles, one for weekdays and one for weekends. These profiles assume that overnight charging rolls off early in the morning, followed by an extended low period during the morning period of high electricity demand and commuting activity. Charging then increases again after people arrive at their destinations, and persists throughout the day before decreasing again in the afternoon when commuting activity commences again. Overnight charging commences significantly after the evening peak demand driven by time-of-use and peak demand tariff signals.

Figure 10 below shows the assumed time-of-day average energy used by EVs in the modelling. EY uses the same assumptions as AEMO, including that EVs have a negligible contribution to peak demand. Accordingly, the energy and peak-demand contributions of the EV profile is taken into account in the overall demand profile modelled.

Figure 10: Percentage of daily energy use for EVs in each half-hour of the day



6.1.4 Generator bidding

In the forward-looking simulations for this Project, EY uses a set of bidding profiles for each generator that depict their typical bidding behaviour as reflected in the market data, with respect to their SRMC. For most generators their bidding behaviour can be represented with one static bid for a given SRMC and for others multiple bidding profiles that apply to particular periods of time (such as off-peak and peak periods) to reflect patterns in varying operating conditions due to fuel availability or other reasons.

A bidding profile for a generator may have up to ten bands of quantities of capacity at different prices (price-quantity pairs) taking into account energy price limits[52]. For example, a coal unit may typically bid a certain proportion of its load at a negative price or near the market floor price (-$1,000/MWh) to reflect the cost of restarting, plus incremental proportions of its capacity at positive prices to reflect their expected short-run marginal costs[53] that can vary based on their operating state and fuel costs.

In each forward-looking year in the Study Period, the bids for each generator are adjusted according to computed changes in their SRMC, which is based on the assumed annual applicable fuel price (and emissions costs, if relevant). These adjustments are only made to bid prices in a profile that are a function of the SRMC (i.e., this would not apply to bids near the market floor price). In the case that the most expensive SRMC of all generators increases due to the assumed fuel and/or emission costs for a given simulated year, EY increases the maximum energy price limits accordingly.

Since the operating conditions for most generators are confidential, EY determines suitable bidding profiles for each generator using a benchmarking process. This involves simulating the half-hourly dispatch and prices for a historical year with 2-4-C®, and adjusting the bidding profiles for each generator with an iterative process to reproduce actual dispatch and pricing outcomes as close as possible.

As part of this Project, EY is conducting a benchmarking process. This is being conducted on the 2016-17 historical year with the bidding profiles used in all the forward-looking market simulations

52 https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Price-limits
EY's market modelling incorporates these settings into generator bidding as well as in modelled price outcomes.
53 The WEM Market Rules requires that all Market Participants offer capacity at or below the reasonable expectation of that generator's SRMC.

for this Project as base values adjusted to account for scenario assumptions in the Study Period. Key outcomes of the benchmarking process will be made available and published as an appendix in the final report.

Note that Synergy currently bids its Balancing Portfolio[54] into the market as a single set of price-quantity pairs. In EY's modelling, each generator unit is modelled explicitly including each generator in Synergy's Balancing Portfolio. Modelling individual generator units is also a requirement for modelling constraint equations, which are typically derived with respect to generator unit terms. It is noted that the PUO considers that facility bidding is an essential reform to the WEM[55] to facilitate constrained network access and to improve transparency around market dispatch decisions. As per the approach described above, EY's forecast modelling will be consistent with individual facility bidding rather than the present regime where a single set of bids in submitted for the collective Synergy portfolio.

6.1.5 Demand side management

Electricity consumption in the WEM has some inherent non-disclosed price response where some market-exposed consumers tend to use less power when prices are high. The impact of this is captured in AEMO's energy and peak demand forecasts modelled by EY. However, AEMO also publishes an amount of demand that is responsive to market prices, and these loads bid into the market[56]. The explicitly bidding demand side management (DSM) loads are incorporated into 2-4-C® as it would in the actual market dispatch engine. Providers of DSM are also eligible for capacity credits. This is incorporated as an input into modelling the RCP based on the capacity credits assigned for DSM in AEMO's 2017 WEM ESOO.

6.1.6 Transmission network constraints

Partially and Fully Constrained Access in the WEM are both proposed to be taken into account in the dispatch process with network constraint equations. Constraint equations define the power transfer limits on transmission network assets and have been prepared by Western Power consistent with AEMO's pre-dispatch formulation guidelines.

For this Project, Western Power has formulated network constraint equations based on the existing network infrastructure in the SWIS, in addition to committed[57] network augmentation projects. Network constraint equations define the system normal network capability only as it is understood that existing unconstrained access entitlements only apply under these conditions[58].

Constraint equations are derived from power flow studies undertaken by Western Power and are based on power system thermal limitations identified on its network. No sensitivity studies are being performed to account for constraints that may apply for other network conditions involving planned or unplanned outages. The PUO have advised that the current unconstrained access framework only applies for system normal conditions.

Voltage, transient and other constraints related to the dynamic stability of the network have not been included in this assessment[59]. EY has been informed that to date, Western Power has not yet

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[54] Synergy's Balancing Portfolio consists of all Synergy's registered facilities other than what is defined in the Market Rules.

[55] Improving access to Western Power's network – Consultation Paper

[56] https://aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2017/2017-Electricity-Statement-of-Opportunities-for-the-WEM.pdf

[57] Committed network augmentation projects as per Western Power's Annual Planning Report 2017. EY has been informed that although not yet committed, Western Power is currently at advanced planning stages for a long term solution to relieve limitations associated with the APJ-PNJ line and expects to commit to a project in the near term. To account for the impact of this project the network constraints associated with this limitation have been removed from the constraint set.

[58] As advised by the PUO.

[59] With one exception: an upper limit has been modelled for new entrant generation connected to the single 330 kV transmission line between Neerabup Terminal and Three Springs Terminal.

identified any network limitations that set lower power transfer limits and that are likely to cause congestion above what would be determined by the thermal limits used in this study.

Existing generation runback schemes and special protection schemes that are currently operational on the SWIS have been taken into account by Western Power when formulating network constraint equations.

For each transmission constraint equation, Western Power also provides EY with summer and winter transmission line ratings to reflect the change in transmission line capacity due to ambient temperature conditions. In this context, summer is defined as November, December, January, February and March. Winter is defined as the other seven months.

Western Power provided network constraint equations based on the Base Scenario for the Partially Constrained case only and they do not reflect the impact of potential new entrant generation beyond 2022. The PUO has modified these equations to introduce terms on new entrant generator candidates in EY's modelling. It has also reformulated the network constraint equations to produce a second set suitable for the Fully Constrained Case. For both the Partially Constrained and Fully Constrained Cases it is assumed that any intermittent generator less than 10 MW will not be impacted by the constrained access reform (i.e., not subject to central dispatch). Some small generators are not reflected in the Western Power network constraint equations as their impact on transmission network power flows is considered immaterial.

In this Project, EY uses 2-4-C® to model least-cost dispatch in the WEM, with respect to all constraints, including the market price limits, network constraint equations and generator limits.

6.1.7 Treatment of intermittent loads

EY understands that proposed reforms to the WEM include consideration of how intermittent loads may impact the formulation of constraint equations. It is understood that the intermittent load registration class will be retained upon implementation of Fully Constrained Access.

These intermittent loads are typically larger industrial loads that may be serviced by a generator connected behind the same connection point. The generation behind the connection may also participate directly in the central dispatch process in the WEM, but with a dispatchable capacity (as opposed to a nameplate capacity) that takes into account the intermittent load.

This requires specific consideration in the formulation of network constraint equations as generator dispatch targets are based on a sent-out basis measured at the connection point. The intermittent load is therefore required to be taken into account when assessing constraints. This is modelled by representing the connection point with a generator and a constant load profile. Constraint equations are formulated to take the above into account.

Appendix A Modelling assumptions

An overview of modelling assumptions is provided in this Appendix. A supporting Excel assumptions workbook detailing primary data sets from the public domain is also available.

A.1 Electricity consumption and peak demand

One of the primary considerations when forecasting the electricity market is the future electricity consumption and peak demand. EY has used the data based on the WEM 2017 ESOO as the source of electricity demand and energy projections. Figure 11 shows this expected trajectory in annual operational energy consumption (to be met by large-scale Registered Facilities). Figure 12 shows the regional peak demand in the WEM for the 10% POE projection.

Figure 11: WEM 2017 ESOO annual operational energy forecast in the WEM

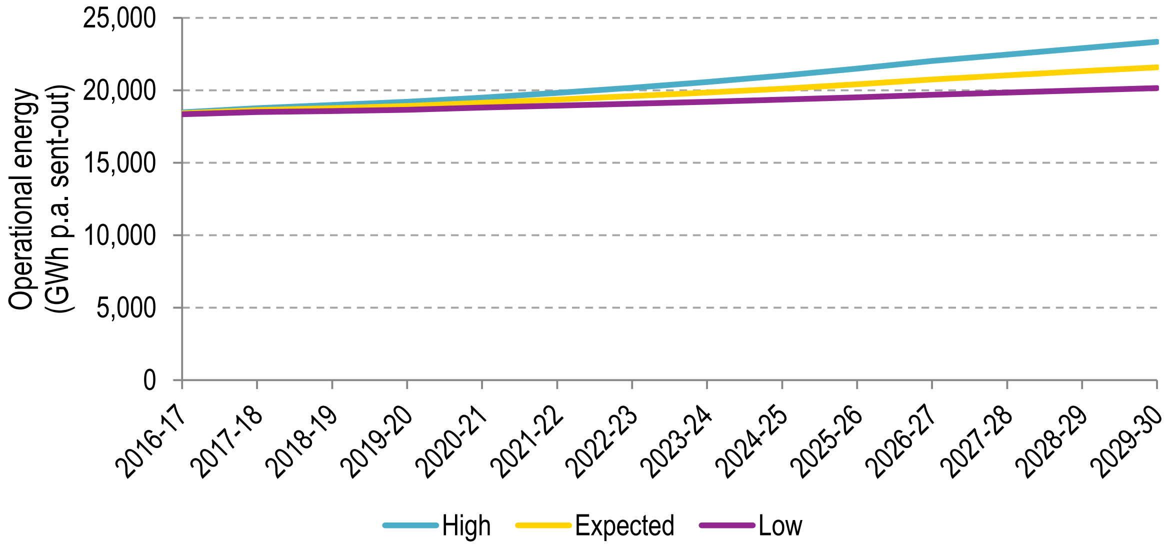
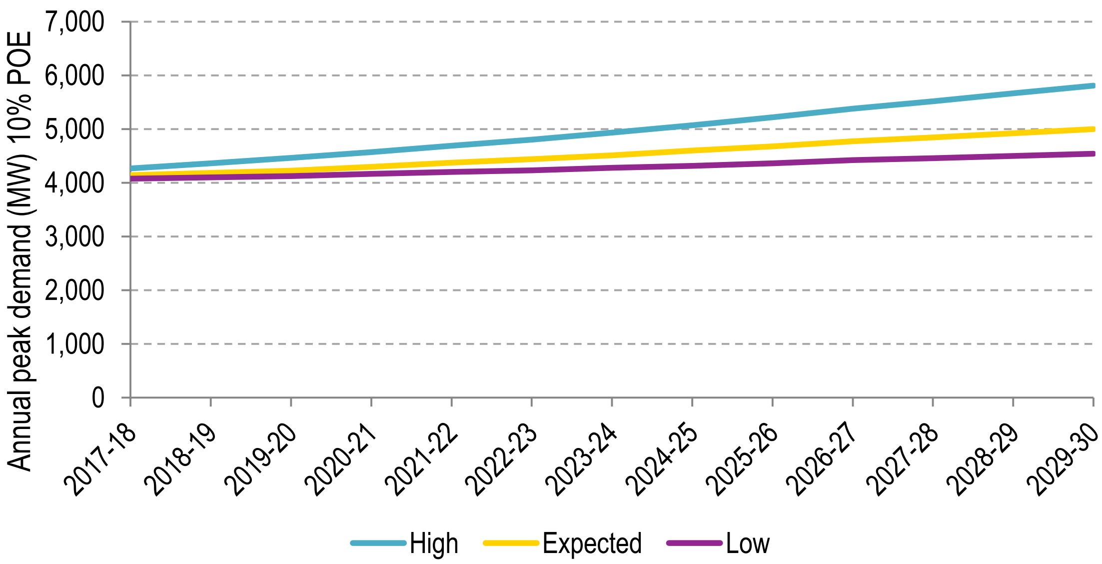


Figure 12: WEM 2017 ESOO annual 10% POE regional peak demand forecast in the WEM

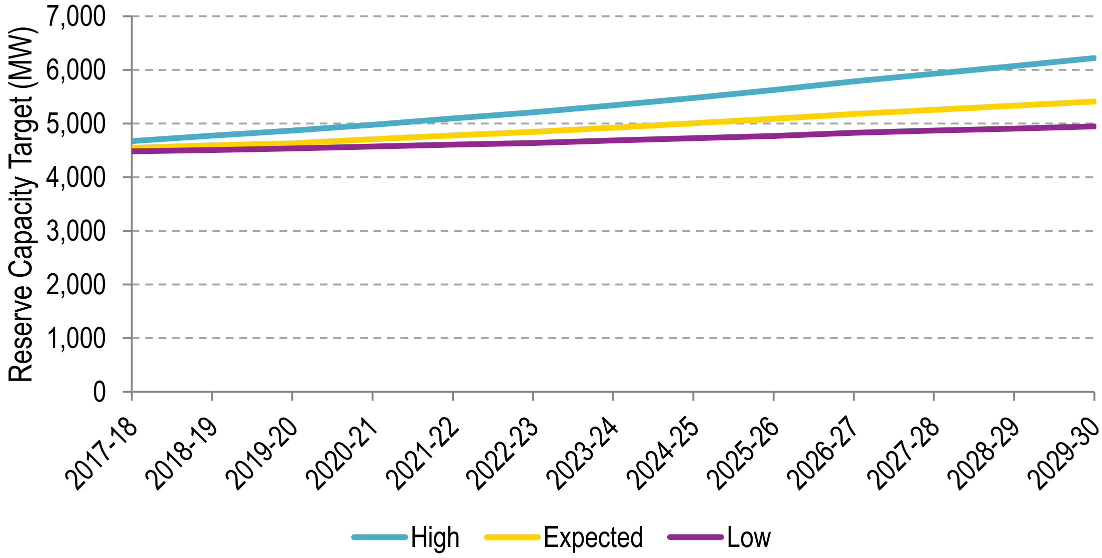


Peak demands are materially influenced by weather conditions, particularly hot temperatures in summer and cold temperatures in winter, driving cooling and heating air conditioning loads, respectively. The peak demand (and near-peak demand conditions) increases the risk of price volatility, and therefore the magnitude of the peak demand in any given year is a material factor in determining overall wholesale market pricing trends. Peak demand periods are also typically periods where network constraint equations bind. The 10% POE and 50% POE peak demand levels forecast by AEMO is modelled based on the WEM 2017 ESOO. The 50% POE peak represents a typical year, with a one in two chance of the peak demand being exceeded in at least one half hour of the year. The 10% POE peak demand represents a one in ten chance of being exceeded in at least one half hour of the year.

A.2 Reserve capacity target

Figure 13 shows the forecast RCT under the Expected, Low and High 10% POE peak demand trajectories for the WEM based on the WEM 2017 ESOO. It has been assumed that the contribution to the RCT requirement from intermittent loads, reserve margins and load following remains constant under the each of the scenarios. The RCT sets the RCR for the relevant Capacity Year.

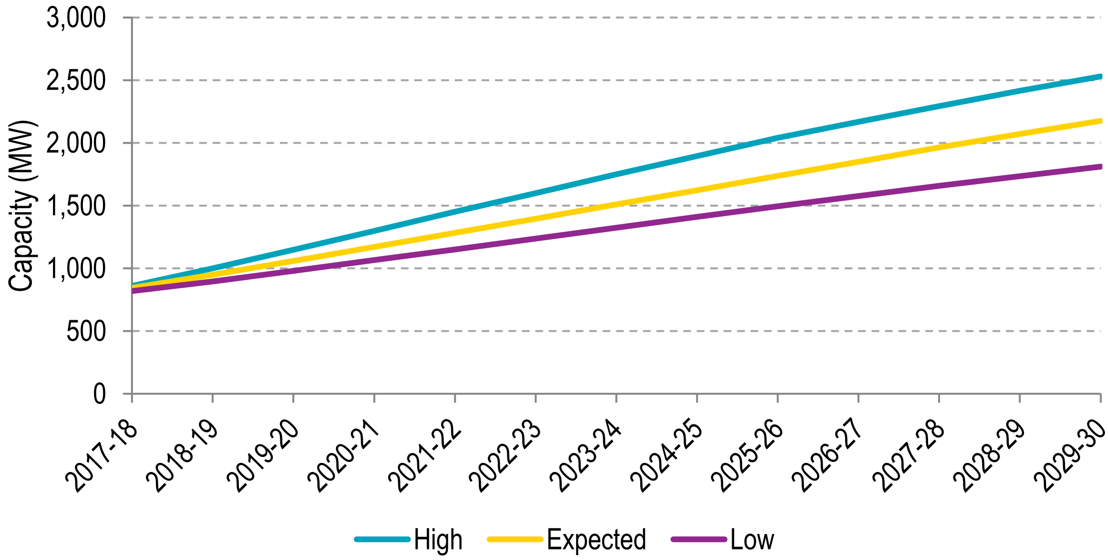
Figure 13: Calculated Reserve Capacity Targets for each WEM 2017 ESOO scenario



A.3 Commercial and residential rooftop PV systems

The uptake in rooftop PV systems has been rapid in the WEM, driven by favourable government policies and attractive payback periods. While many of the supportive government policies have now been removed (or significantly scaled back), AEMO still expects significant growth in rooftop PV uptake due to decreasing costs of PV systems and increasing (real or customer perceived) retail energy costs. Figure 14 shows the rooftop PV trajectory for the Expected, High and Low scenarios.

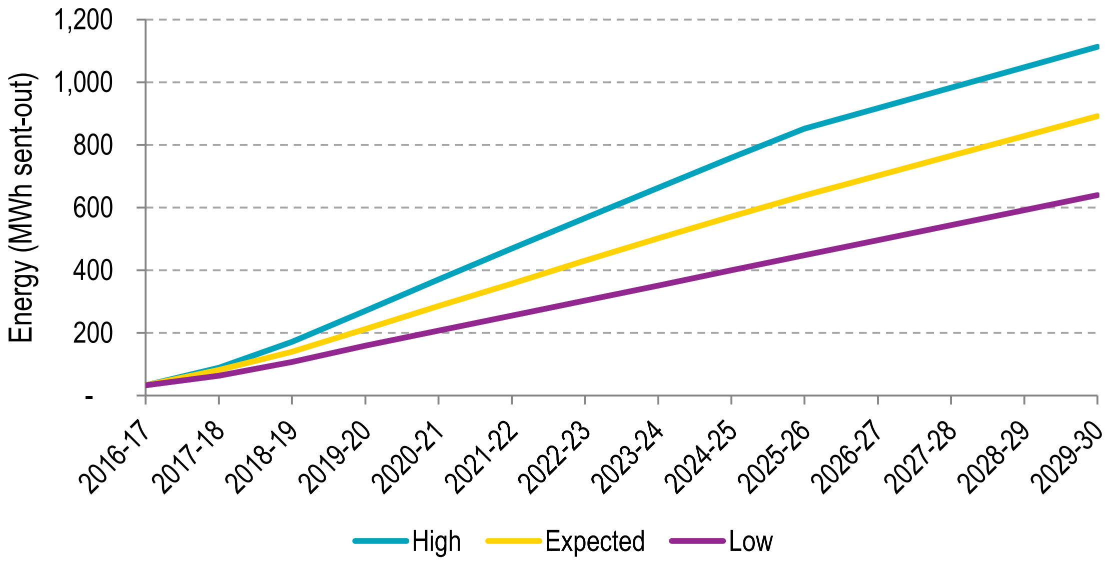
Figure 14: Projections for installed rooftop PV capacity forecast for the WEM for each WEM 2017 ESOO scenario



A.4 Behind-the-meter storage uptake

AEMO's behind-the-meter battery storage uptake from the WEM 2017 AEMO ESOO. These batteries are assumed to be installed in households and in the commercial sector, in most cases in conjunction with a rooftop PV systems. Large-scale storage would be in addition to these installations. Figure 15 shows the uptake of behind-the-meter battery storage from each WEM 2017 ESOO scenario.

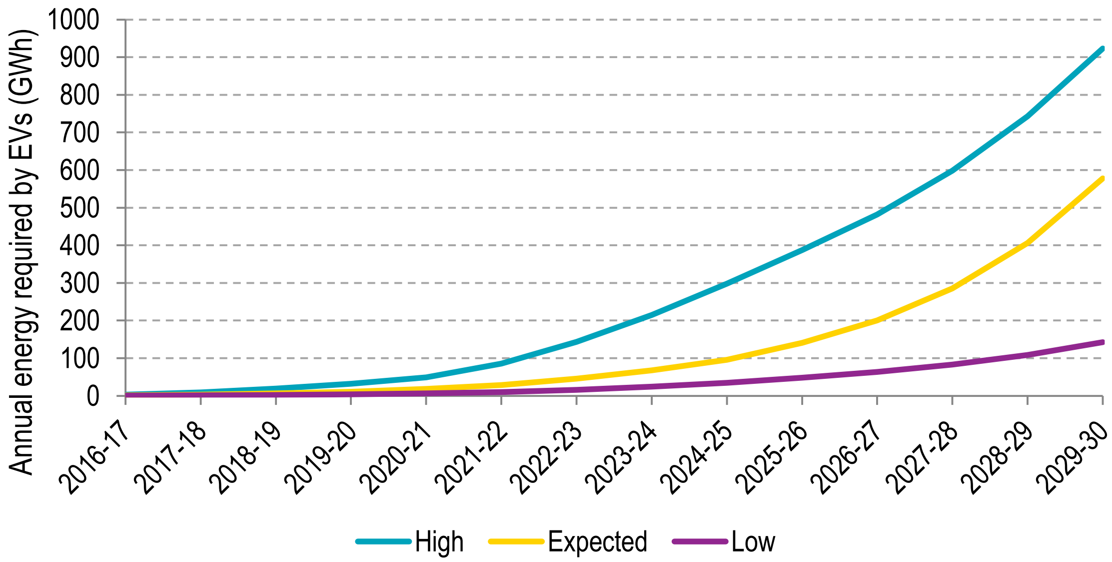
Figure 15: Behind the meter storage uptake for the WEM in each WEM 2017 ESOO scenario



A.5 Impact of electric vehicles

All scenarios consider an uptake of EVs providing a new source of electrical load as consumers switch from petrol-based vehicles to those that rely on charging from the grid as part of the decarbonisation effort. Figure 16 shows the assumed annual energy assumed to be required by EVs in each of the WEM 2017 ESOO scenarios.

Figure 16: EV energy demand trajectories for each WEM 2017 ESOO scenario



A.6 Thermal generation developments

In accordance with the Energy Minister's directive for the retirement of generation capacity in the WEM, the units listed in Table 8 are assumed to be retired in all scenarios as part of Synergy's 380 MW retirement schedule[60].

Table 8: Synergy retirements

Power station	Capacity (MW)	Fuel type	Retirement date
Kwinana Gas Turbine 1	21	Gas	30 September 2018
Muja A (G1, G2)	120	Black coal	Retired
Muja B (G3, G4)	120	Black coal	Out of service
Mungarra Gas Turbine 1, 2, 3	113	Gas	30 September 2018
West Kalgoorlie Gas Turbine 2, 3	62	Gas	30 September 2018

A.7 Large-scale renewable energy target

In June 2015 the Commonwealth Government legislated the revised LRET, ending a protracted review of the policy. The current legislated targets require 33,000 GWh per annum of eligible renewable energy from 2020 to 2030. Additional voluntary certificate surrenders are also expected, due to several state or territory policies, as well as consumer choice schemes such as the GreenPower program.

The WEM's assumed contribution to the LRET in the scenarios is as per the new entrant renewable capacity developments listed in Appendix A.7. Notwithstanding the discussion on the alternative

[60] Synergy 380 MW announcement

scenario on an emissions reduction policy in Section 4.3.1 and recognising that the LRET is a national policy, it has been assumed that the LRET is met largely by generation development projects in the NEM as is the current market expectation. No specific requirement is placed on WA's contribution to the RET.

A.8 Renewable capacity developments

Each scenario assumes the same list of new entrant renewable generators will be commissioned in the WEM as driven by the LRET by the commencement of the Study Period on 1 July 2022. The assumed new entrant renewable capacity development schedule for connection in the WEM is listed in Table 9.

Table 9: Assumed new entrant renewable capacity projects commissioned prior to 2022

Commissioning date	Project name	Type	Capacity (MW)	Capacity factor	Reasoning
In service by 1 July 2022	Byford Solar	Solar PV	30	30%	10-year off-take agreement signed with Kleenheat.
	Greenough River 2	Solar PV	30	30%	Project in Synergy's renewable project development.
	Emu Downs Solar Farm	Solar PV	20	30%	Off-take agreement signed to sell LGCs to Synergy up to 2030. Portion of funding from Arena.
	Northam Solar Project	Solar PV	9.9	30%	Part merchant/part PPA. Debt financing secured. Public confirmation of grid connection.
	Badgingarra Wind Farm	Wind	130	44%	12-year off-take agreement signed with Alinta Energy for bundled energy/LGC.
	Warradarge Stage 1	Wind	180	44%	Project in Synergy's renewable project development.
	Cunderdin Solar Farm	Solar PV	100	30%	Developed on a merchant basis. Public confirmation of grid connection.

A.9 Generator forced and planned outage rates

Table 10 shows the outage rate statistics assumed in the modelling, based on an IMO review of the Planning Criterion[61] and a review of historical data.

Table 10: Forced outage rates statistics from the IMO planning criterion review

Technology	Full forced outage rate (%)	Planned outage rate (%)
Coal	1.65	7.8
Gas (including cogeneration)	1.64	7.3
Gas/liquid fuel	1.3	8
Biomass (assumed same as gas liquid)	1.3	8
Wind and solar PV	Included in modelled capacity factor	

EY conducts a number of Monte Carlo iterations in the market modelling to capture the impact of forced (unplanned) generator outages. Each Monte Carlo iteration assigns random outages to each generating unit, based on assumed outage statistics. As shown in the table, the same outage statistics are applied for generators with the same fuel type.

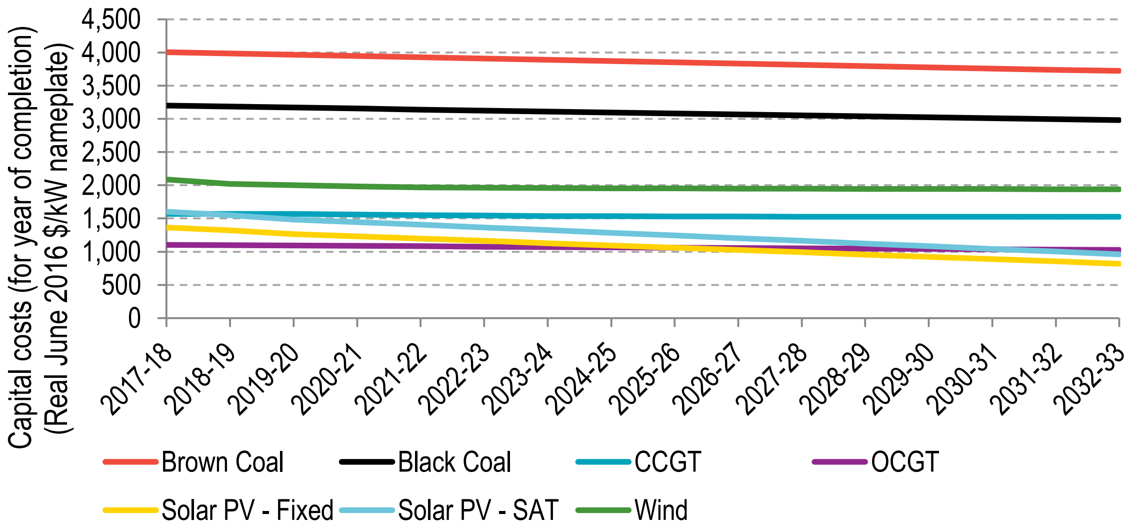
The nature of outages for wind and solar generators is different to large thermal generating units due to the modular nature of wind turbines or solar panels within a power station.

The capacity factors modelled for wind and solar farms are based on observed and expected output of the wind and solar farms modelled, and as such implicitly include the impact of outages.

A.10 New entrant parameters and capital costs

The technology costs are based on projections published in the 2016 NTNDP report. However, solar PV and wind capital costs have been reduced, in line with views developed from industry consultation. The capital costs for other technologies have remained unchanged. Figure 17 shows the capital costs projections for the main technologies of interest for the Study Period. Table 11 provides a summary of other new entrant parameters

Figure 17: New entrant capital costs assumed for different technologies



61 IMO 5 Yearly Review of Planning Criterion

Table 11: New entrant parameters

Technology	FOM ($/MW)	VOM ($/MWh sent-out)	Economic life (years)
Black Coal	42073	3	30
CCGT	43359	10	30
OCGT	10000	7	30
Solar PV – Fixed	30941	12	30
Solar PV – SAT	4000	10	30
Solar PV – DAT	25000	0	25
CST central receiver – (6 hour storage)	30000	0	25
Wind	40000	0	25
Large-scale storage (4 hours)	65000	4	30

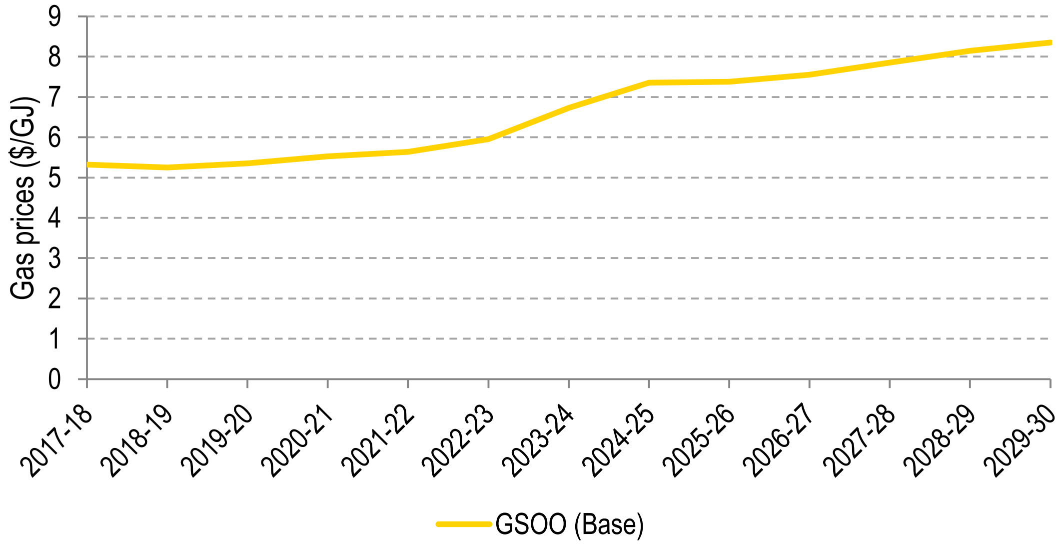
A.11 Coal prices

For this Project, EY has assumed that coal prices remain constant at $2.60/GJ in the Study Period.

A.12 New entrant gas prices

EY does not consider the impacts of short-term gas contracts in our modelling, rather considering the pricing effect of long-term gas contracts for gas powered generators. Figure 18 below shows the assumed gas price trajectory for the SWIS for uncontracted gas supplies, based on AEMO's 2017 Gas Statement of Opportunities (GSOO) base scenario[62]. As existing gas generators' current gas contracts roll off, EY expects that these generators will be forced to adopt this price trajectory for their future gas contracts.

Figure 18: Forecast gas prices for the SWIS (from the AEMO 2017 GSOO)



[62] https://www.aemo.com.au/Gas/National-planning-and-forecasting/WA-Gas-Statement-of-Opportunities

A.13 Marginal Loss Factors

Refer to Excel assumptions workbook.

Appendix B Weighting 50% POE and 10% POE

The potential for any particular outcome in the electricity market is probabilistic. Various combinations of prevailing customer demand, availability and costs of conventional and intermittent generation, energy storage devices, demand side participation, transmission network capability and availability will influence market outcomes.

In the absence of time constraints and data availability considerations the modelling would ideally apply a very wide range of key factors such as atmospheric conditions and peak demand and simply weight each event equally. Monte Carlo iterations of unplanned outage events on generation and transmission elements are each considered to be equally likely. The sample of two reference years for atmospheric conditions and 'load shape' are also considered to be equally likely for the purpose of the modelling. Ideally we would model a large number of POE peak demand conditions but the computation time would be intractable. To manage the problem size, we limit POE peak demand samples to 10% and 50% POE scenarios.

In order to establish the expected outcome for unserved energy from these samples we assume that the probability density function of the demand POE samples are normally distributed. We then seek to find the quantum of the cumulative distribution function exceeding the 90th, 50th and 10th percentile. It is found that 30.4% of the cumulative distribution is contained above the 10th percentile, 30.4% is below the 90th percentile and 39.2% between the 10th and 90th percentile. As peak demand expectation reduces the chance of unserved energy also reduces. We therefore make a conservative approximation that the unserved energy expectation is similar for all POEs below the 50% POE peak demand forecast. It then follows that we establish the expected unserved energy from the Monte Carlo simulations as follows in equation (1).

$$\begin{aligned} Expected\ USE = {} & 0.304 \times Avg\ of\ 10\%\ POE\ USE\ (2\ Ref\ Years \times 25\ Monte\ Carlo\ simulations) \\ & + 0.696 \times Avg\ of\ 50\%\ POE\ USE\ (2\ Ref\ Years \times 25\ Monte\ Carlo\ simulations) \end{aligned} \tag{1}$$

EY applies a rounded 0.3 weighting on all 10% POE outcomes and 0.7 weighting on 50% POE outcomes. While the above analysis is for USE specifically, EY applies the weightings to all outcomes (such as generator revenues and prices) for simplicity.

Appendix C Glossary and acronyms

Defined terms

Benchmarking	The process of iteratively comparing simulated outcomes from a model with observed outcomes from actual data to test the accuracy. Usually involves iterative adjustments to input parameters and/or the methodology
Benchmark Reserve Capacity Price	As defined within the Market Rules, in respect of a Reserve Capacity Cycle, the price in clause 4.16.2 as revised in accordance with section 4.16 of the rules
Capex	Capital expenditure
Capacity Credit	A unit of Reserve Capacity assigned to a Facility during a Capacity Year where each Capacity Credit is equivalent to 1 MW of Reserve Capacity
Capacity Year	A 12–month period commencing on 1 October.
Constrained network access	Where generators are dispatched taking into account defined transmission network limitations and power system security limits
Expected unserved energy	As defined within the Market Rules, an estimate, expressed in MWh, of energy demanded, but not supplied, as a result of involuntary load shedding in the SWIS
Fully constrained network access	A term used to describe a network access regime for the WEM where all existing generators and any new entrant generators connecting to the electricity network are subject to generation curtailment in response to network congestion identified within the market operators central dispatch engine
Long Term Planning Criterion (or Planning Criterion)	As defined within clause 4.5.9 of the Market Rules
Long Term Planning Horizon	The 10-year period commencing on 1 October of Year 1 of the Reserve Capacity Cycle
Market Rules	The Wholesale Electricity Market Rules made under the Regulations and contemplated by section 123 of the Electricity Industry Act 2004
Partially constrained network access	A term used to describe a network access regime in the WEM where some new entrant generators connecting to the electricity network are subject to generation curtailment in response to network congestion identified within the market operators central dispatch engine. All incumbent generators are not subject to dispatch curtailment.
Reserve Capacity Cycle	A four year period covering the events defined within Chapter 4.1 of the Market Rules
Reserve Capacity Price	As defined within the Market Rules and in respect of the Reserve Capacity Cycle, the price for Reserve Capacity expressed in $ per MW per year
Reserve Capacity Target	As defined within the Market Rules and in respect of a Capacity Year, an estimate of the total amount of generation or Demand Side Management capacity required in the SWIS to satisfy the Planning Criterion for that Capacity Year

Acronyms

2-4-C®	EY's in-house wholesale electricity market dispatch modelling software suite
AEMO	Australian Energy Market Operator
BOM	Bureau of Meteorology
BRCP	The Benchmark Reserve Capacity Price, as defined in the Market Rules
CF	Capacity factor
CPI	Consumer price index
DSM	Demand-side management
EV	Electric vehicle
FOM	Fixed operation and maintenance
FOR	Forced outage rate
GIA	Generator Interim Access
GWh	Gigawatt-hour
GSOO	Gas Statement of Opportunities, as published by the Australian Energy Market Operator annually.
LCOE	Levelised cost of energy ($/MWh). Equivalent to the long-run marginal cost (LRMC).
LGC	Large-scale generation certificates
LRET	Large-scale renewable energy target
MLF	Marginal loss factor
MWh	Megawatt-hour
NEG	National Energy Guarantee
NEM	National Electricity Market
NEM ESOO	Electricity Statement of Opportunities for the NEM, as published annually by AEMO
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
POE	Probability of exceedance
PUO	The Public Utilities Office
RCM	Reserve Capacity Mechanism
RCC	Reserve Capacity Cycle
RCP	Reserve Capacity Price
RCT	Reserve Capacity Target
RRN	Regional reference node
SAM	System Advisory Model, from the National Renewable Energy Laboratory for developing locational solar PV generation profiles
SAT	Single-axis tracking
SEST	EY's in-house solar energy simulation tool

SWIS	South-West Interconnected System, which comprises the entire interconnected power system in south-west Western Australia
USE	Unserved energy, expressed as percentage of a region's energy demand
VOM	Variable operation and maintenance
WA	Western Australia
WACC	Weighted-Average Cost of Capital
WEM	Wholesale Electricity Market, which comprises the electricity market operating in south-west Western Australia
WEM 2017 ESOO	Electricity Statement of Opportunities for the WEM, as published annual by AEMO
WEST	EY's in-house wind energy simulation tool

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