AEMO

AUSTRALIAN ENERGY MARKET OPERATOR

ISP Methodology

June 2025

For the Integrated System Plan (ISP)

We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country, and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

AEMO publishes the ISP Methodology pursuant to National Electricity Rules (NER) 5.22.8(d). This report includes key information and context for the methodology used in AEMO's ISP.

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Version control

Version	Release date	Changes
1.0	30/7/2021	Initial release.
1.1	20/8/2021	Corrected description of how the firm capacity of scheduled generation is determined in capacity outlook modelling.
2.0	30/6/2023	Updates made to consider changes relating to transmission project lead time uncertainty, impact of fossil-fuelled generation on renewable energy zone (REZ) transmission limits, network losses between REZs and sub-regions, assumed renewable energy resource quality, value of carbon emissions, consumer risk preferences, and modelled duration of demand-side participation response.
3.0	25/06/2025	Updates made to consider changes relating to an expanded gas supply model, treatment of gas network operational capacity and limitations, implementing imperfect foresight for storage devices in time-sequential model, distribution network capabilities for consumer energy resources and other distributed resources, testing project actionability, modelling of hydrogen electrolysers, treatment of system security, representation of large dispatchable loads and diversity of potential wind resources in REZs, and other minor changes to clarify meaning and update terminologies.

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1 Modelling overview

AEMO's *Integrated System Plan* (ISP) is underpinned by an integrated approach to energy market modelling, combined with relevant power system analysis. The objective of the suite of models and analysis is to determine an Optimal Development Path (ODP) that optimises benefits to consumers and meets government energy and emissions targets between now and 2050.

Each individual process is important in the overall ISP process, however the linkages and interactions between the processes are also critical in ensuring the ISP delivers an integrated solution that is robust and operable.

This section focuses on describing the high-level process that is used in the modelling and assessment undertaken to prepare the ISP, including the key interactions between the various models and analytical processes. Each individual process is considered in more detail in later sections:

- Section 2 describes the models and methodologies using the capacity outlook modelling process.
- Section 3 details the approach that is used in more granular time-sequential modelling to inform and validate the capacity outlook modelling.
- Section 4 describes the gas supply modelling process and its application in the ISP.
- Section 5 documents the various power system assessments of system reliability, security, and operability.
- Section 6 steps through the cost-benefit analysis approach which is used to inform selection of the optimal development path.

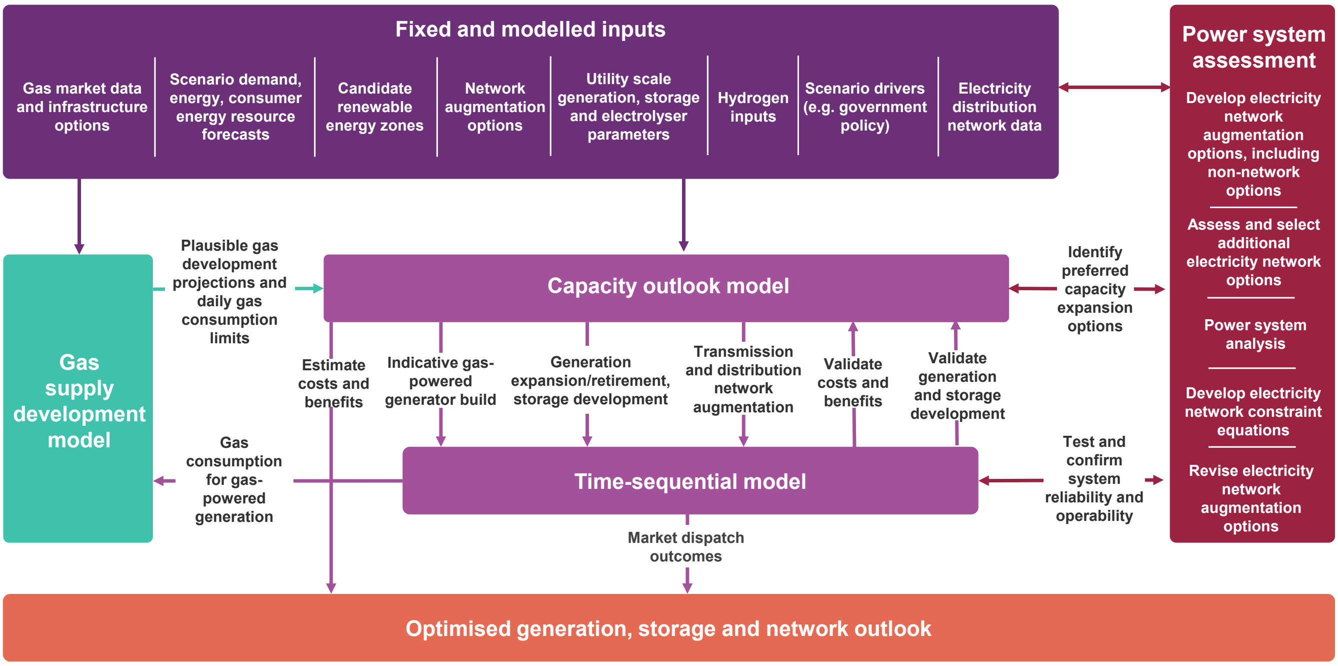
Figure 1 provides an overview of the integrated suite of models and assessments which are used to prepare the ISP. The overall ISP process is an iterative approach, where the outputs of each of the different models or analytical processes are used to determine or refine inputs into the other models and processes. Using the colours shown in Figure 1:

- The fixed and modelled inputs are the inputs, assumptions and scenarios published in the *Inputs, Assumptions and Scenarios Report* (IASR). These are influenced by earlier power system assessments used to describe the existing capability of the National Electricity Market (NEM) and to develop a set of network and non-network development options.
- The capacity outlook model (Section 2) uses all the available inputs to develop projected generation, transmission, distribution to increase opportunities for distributed resources, generation retirement, and dispatch outcomes in each of the ISP scenarios. The aim when doing so is to minimise capital expenditure and operational costs over the long-term outlook while achieving the objectives (social, political, and economic) within each scenario.
- The time-sequential model (Section 3) then optimises electricity dispatch for every hourly or half-hourly interval. In so doing, it validates the outcomes of the capacity outlook model and feeds information back into it.

The model is intended to reflect participant behaviour hour-by-hour, including generation outages, to reveal performance metrics for both generation and transmission.

- The gas supply development model (Section 4) identifies gas infrastructure limitations and gas development projections to be used in the capacity outlook and time-sequential models.
- The power system assessment (Section 5) tests the capability outlook and time-sequential outcomes against the technical requirements for the power system (power system limits and constraints, security, strength, inertia) as well as assessing future marginal loss factors (MLFs) to inform new grid connections. These assessments feed back into the two models to continually refine outcomes.
- Finally, the cost-benefit analyses (Section 6) test each individual scenario and development plan considered by the ISP to determine the ODP and test its robustness.

Figure 1 Overview of ISP modelling methodology



2 Capacity outlook modelling

Capacity outlook modelling is the core process to explore how the energy system would develop in each scenario, and to determine candidate development paths from which the optimal development path is selected.

The model reveals long-term outcomes for generation development and retirement, network development, storage, and dispatch options in all ISP scenarios. The objective is to minimise the costs incurred to operate the NEM over the long-term outlook, and to achieve the type of net zero transition outlined in each scenario.

The capacity outlook model takes all the relevant inputs through two modelling processes:

- The Single-Stage Long-Term model (SSLT) optimises over the entire modelling horizon.
- The Detailed Long-Term model (DLT) optimises over sequential, shorter time horizons.

In this section:

- Section 2.1 introduces the purpose and constraints of the capacity outlook modelling.
- Section 2.2 describes the SSLT and DLT models that make up the capacity outlook model.
- Section 2.3 explains how input assumptions are developed and used in the capacity outlook modelling.
- Section 2.4 focuses on specific applications of the modelling (for example, an early generation retirement or the demand or variable renewable energy [VRE] profile) and the methodologies for them.
- Section 2.4.8 explores the modelling of large-scale uptake of NEM-connected hydrogen.

2.1 Purpose and size of the modelling process

Purpose of the modelling

The capacity outlook modelling process seeks to minimise capital expenditure and generation production costs over the long-term outlook. In doing so, it must:

- Ensure there is sufficient supply to reliably meet demand at the current NEM reliability standard, allowing for inter-regional reserve sharing.
- Meet government policies which AEMO must or may consider under National Electricity Rules (NER) 5.22.3(b) in determining the power system needs to be met by the ISP and how the ISP contributes to achieving the national electricity objective (NEO).
- Observe physical limitations of relevant energy infrastructure affecting the investment needs of the NEM.
- Account for any energy constraints on resources.

- Perform checks on modelling outcomes, such as sensitivity analysis to explore uncertainties (for example, limitations on supply chains, or variations to meeting policies).

Simplification of inputs and assumptions required

The model applies a mathematical linear program to solve for the most cost-efficient generation and network development schedule (considering size, type, location, and commissioning and retirement date of generation and network assets)[1]. A single run of the capacity outlook model can take days to complete, and thousands of simulations are completed during an ISP process. The model must therefore focus on its most valuable uses, that is, the details most material to understanding potential investment needs.

For the modelling to remain computationally feasible through this complex task, some inputs and assumptions must be simplified. These simplifications include:

- Using multiple configurations of interacting capacity outlook models.
- Breaking the optimisation into smaller steps (optimisation windows).
- Aggregating demand and VRE profiles.
- Avoiding integer decision variables by linearising generation, network build, and retirement decisions (effectively allowing partial units or lines to be built if desired). Many of these key linear decisions are validated in subsequent models.
- Generally reducing the number of decision variables through limiting the number of generator and storage augmentations that are considered and aggregating inputs where appropriate.

2.2 The Single-Stage and Detailed Long-Term models

The capacity outlook process uses two interacting models to address different aspects of the long-term optimisation. Together, the SSLT and DLT represent detailed demand and VRE outcomes over the length of the planning horizon.

Figure 2 provides an overview, focusing on the decisions that are made at each stage.

[1] These options are outlined in the most recent version of the IASR, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

Figure 2 Overview of ISP capacity outlook model

Single-Stage Long-Term model (SSLT)

The SSLT optimises the entire modelling horizon in a single stage to allow consideration of aspects with long-term impacts such as:

- Emissions budgets across the entire horizon, including determining the pathway for electricity generation emissions given that cumulative budget. The emissions pathway is then split into segments and used as an input for each of the smaller optimisation windows in the DLT. Further detail on this approach is provided in Section 2.4.5.
- New high-utilisation fossil-fuelled generation (for example, combined-cycle gas turbines [CCGTs] or coal-fired generation) which would be subject to emission constraints.
- Generator retirements, taking into account future conditions, emission budgets, and potential replacements. This modelling may be supplemented by an economic assessment of coal closures through time-sequential modelling (see Section 3.1.2).
- Co-optimisation of generation and network developments. In this model, network augmentations are linearised due to computational limitations. The linear network build decisions from this model provide the first indication of potential network investments, and are used as a starting point for the development of development paths (see Section 6). The collection of development paths is then tested rigorously in the DLT.

This extended modelling horizon requires a coarser representation of demand and VRE variability to address computational limitations. To achieve this, the model applies a 'sampled chronology' setting, which maintains a representation of intermittency and chronology but potentially reduces the level of variation explored in the SSLT. Further information about the sampled chronology setting is covered in Section 2.4.2.

The key inputs used in the SSLT that are distinct from those used in the DLT are:

- A cumulative emissions budget across the entire horizon.
- Consideration of retirement candidates which are then able to be brought forward from their assumed closure year within the model.
- Linearised inter-regional, intra-regional, and REZ transmission augmentations. These are developed by averaging the assumed configurations and costs across the different distinct options. The options that are included in this averaging are adjusted iteratively throughout the ISP process to focus on those options which are most frequently assessed as potentially viable. This is to improve the consistency between the SSLT and the DLT.

Detailed Long-Term model (DLT)

The DLT divides the modelling horizon into multiple steps which are optimised sequentially. The shorter optimisation windows allow a chronological optimisation of each day of the modelling horizon that preserves the original chronology of the demand and renewable resource time series, ensuring a more detailed representation of demand and VRE variability than the SSLT. Demand and VRE profiles are represented using a 'fitted chronology' which is described in Section 2.4.2.

The DLT provides a granular representation of each day's demand and VRE availability while leveraging the outcomes of the SSLT such as the decomposition of the carbon budget, retirement decisions, and development of high-utilisation fossil-fuelled generation. The increased accuracy of variability and flexibility of the modelled power system provides a more in-depth assessment of dispatch and operability of the generation fleet, including the operation of storages (both daily and seasonally), providing a more accurate estimation of costs.

The DLT is primarily used to:

- Optimise the development, location, and operation of VRE, storage (battery and pumped hydro), electrolysers and other generation such as peaking gas generation.
- Evaluate the development paths[2]. Each development path is tested individually through the DLT. Testing of the network development paths is a key process in determining the ODP and performing cost-benefit analysis. This process is described in more detail in Section 6.

Iterative market modelling process

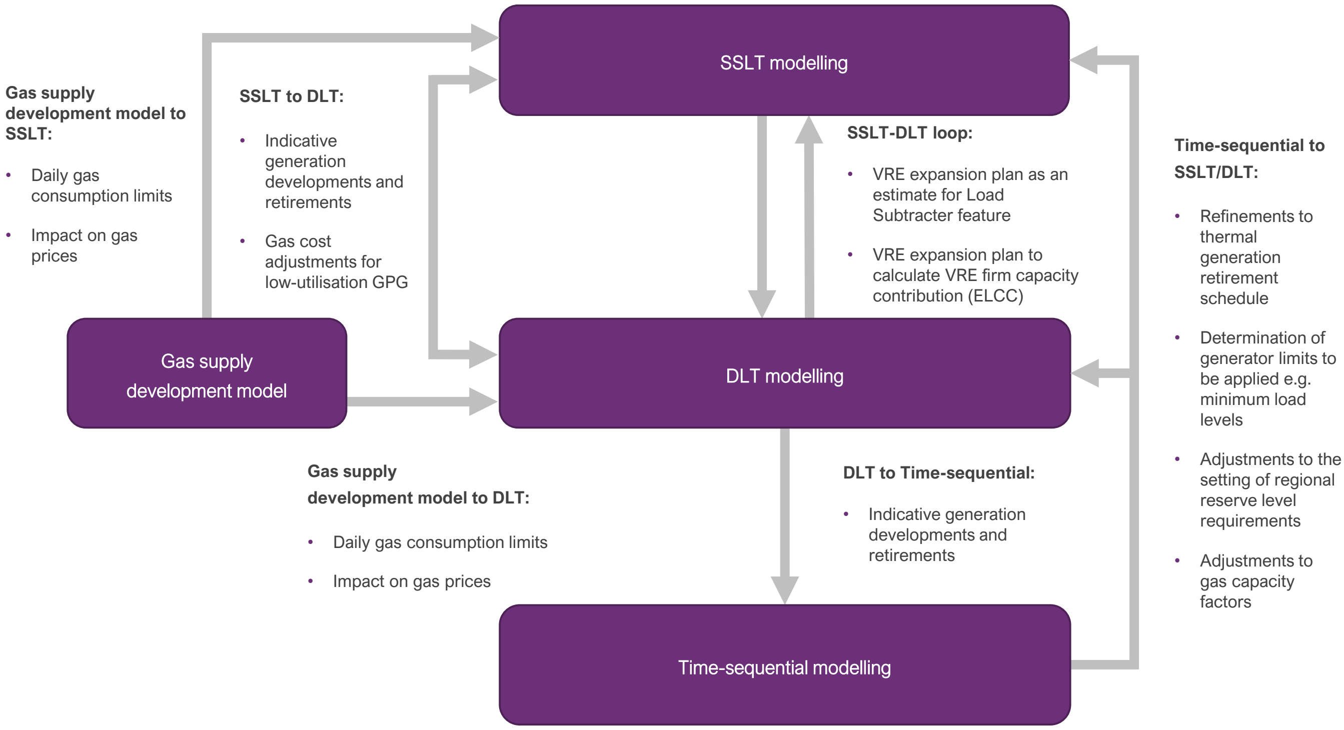
Figure 2 above focuses on the decisions and outcomes which are taken from the capacity outlook models. In addition to this process, the inputs to the capacity outlook models are refined using the outputs of each other, as

[2] Development paths refer to combinations of transmission and non-network augmentations. Section 6 has more detail on the use of development paths.

well as via linkages with the time-sequential modelling and the gas supply development model. The interactions between the models and the inputs and methodologies used in each are explored in detail throughout this section.

Figure 3 below illustrates the various interactions between the market models which are used to refine modelling outcomes; these are described in more detail in Section 2.4, Section 3 and Section 4.1.2.

Figure 3 Interactions between market models



Note: SSLT: Single-stage long-term; DLT: Detailed long-term; ELCC: Effective load carrying capacity.

2.3 Preparing inputs for the capacity outlook model

2.3.1 Market modelling topology

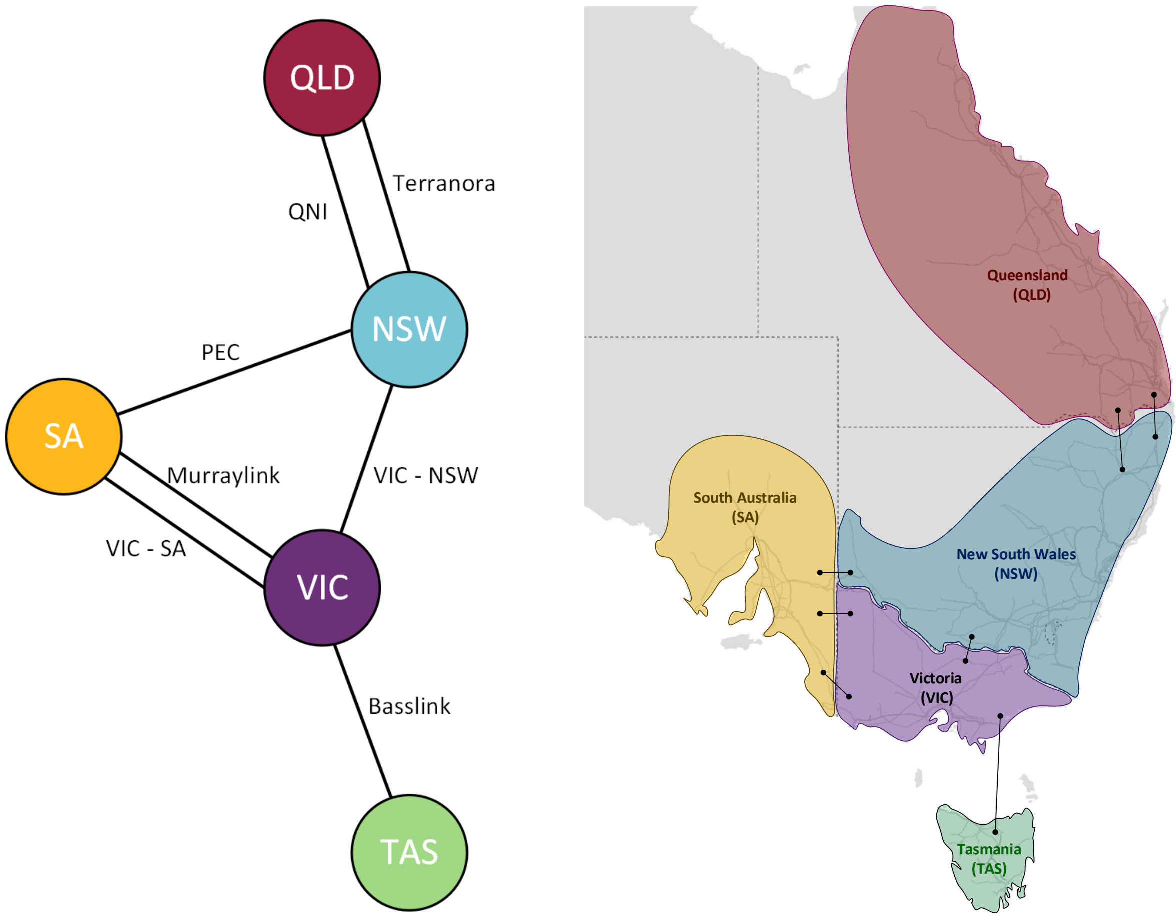
The NEM is comprised of the five regions of Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia, and Tasmania, referred to as regions. The capacity outlook model can apply two alternative approaches to this regional market topology:

- Regional representation – this approach replicates the classic NEM regions, representing the network as a system of five regional reference nodes, connected via existing and potential inter-regional flow paths.
- Sub-regional representation – this disaggregates some regions into sub-regions to better reflect current and emerging intra-regional transmission limitations.

Regional topology

The regional topology mirrors the operation and settlement of the NEM Dispatch Engine (NEMDE) which is responsible for directing generation dispatch in the NEM, and is shown in Figure 4.

Figure 4 Regional representation of the NEM, including existing and committed interconnection



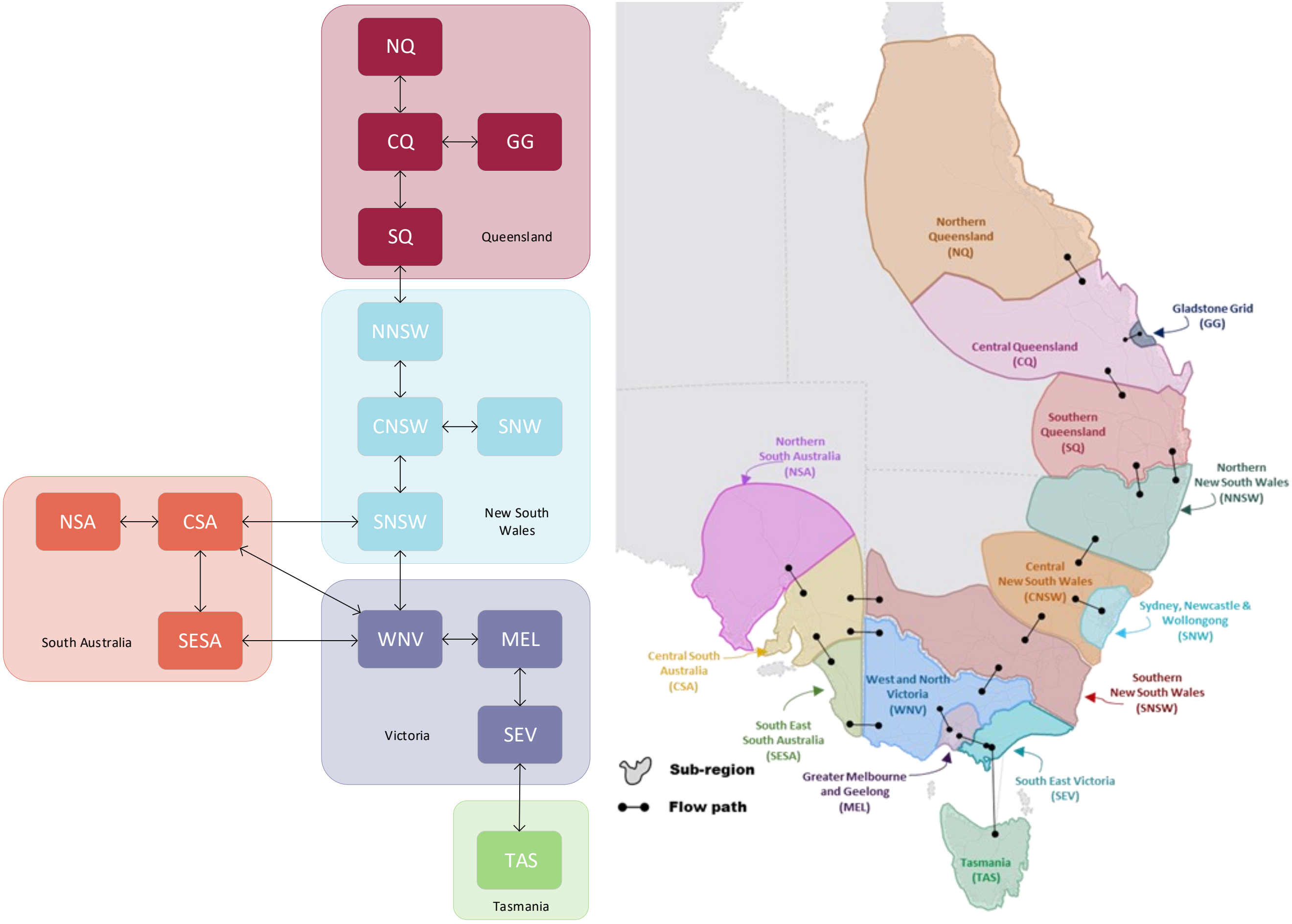
Sub-regional topology

AEMO uses a sub-regional topology in the capacity outlook models, because as more geographically diversified VRE generation develops, a regional representation limits the representation of intra-regional transmission constraints and intra-regional network losses, which in turn limits consideration of renewable energy zone (REZ) transmission augmentations, and AEMO's consideration of congestion between major load centres, given how it can be influenced by generation between regional reference nodes. Sub-regional representation also improves the ability for the model to consider diversity of load developments within a region, and the interactions this has with generation, storage and network development needs.

The approach disaggregates some regions into multiple sub-regions, configured to identify major electrical subsystems within the electricity transmission network that allow free-flowing energy through the transmission elements. Where key flow paths that may materially constrain the transmission system from delivering energy between locations are identified, this alternative sub-regional approach splits these areas from each other to better identify the capacity of the intra-regional transmission system and the value of potential augmentations.

An example of the sub-regional topology outlined in the Draft 2025 IASR is reproduced in Figure 5 below. AEMO may update the sub-regional topology to improve the speed or accuracy of modelling in consultation with stakeholders via the IASR development process.

Figure 5 NEM sub-regional topology



2.3.2 Allocation of electricity demands to sub-regions

Modelling the sub-regional network topology requires the capacity outlook model to use sub-regional inputs, including demand traces. These traces are generated at a sub-regional scale and to ensure alignment with the regional level, they are reconciled accordingly. The methodology is outlined in the *Electricity Demand Forecasting Methodology*[3].

More explicit accounting of consumer energy resources (CER) and their impact on distribution networks (see Section 2.4.7) requires the use of underlying demand instead of operational demand. In addition, AEMO models hydrogen loads (for export, domestic use, and green commodity manufacturing) as additional flexible demand that has to meet energy consumption targets over a specified time period. Hydrogen load projections are published as part of the IASR. Further detail on hydrogen modelling can be found in Section 2.4.8.

2.3.3 Transmission limits and augmentation options

Electricity networks have physical limits on their ability to transfer energy. Transfer capability across the transmission network is determined by assessments of thermal capacity, voltage stability, transient stability,

[3] Currently under consultation; further details are available at draft-electricity-demand-forecasting-methodology-clean.pdf.

oscillatory stability, and power system security/system strength. Transfer capability varies throughout the day with generation dispatch, load, and weather conditions. Other factors also play a part, such as status and availability of transmission equipment, operating conditions of the network, generator, or high voltage direct current (HVDC) runback schemes, and any special protection schemes (SPSs).

Transmission limits are included within the capacity outlook model to reflect the ability of the network to transfer electricity between sub-regions.

Representation of transmission limits in capacity outlook model

For capacity outlook modelling, a range of notional transfer limits between sub-regions is used. This approach is aligned with the approach for setting generator capabilities (see Section 2.3.7)[4] and broadly allows the transfer limits to reflect the impact of two major influences on transfer limits: ambient temperatures and demand.

AEMO first determines the transmission limits for reference temperatures listed in the *ESOO and Reliability Forecast Methodology Document*[5]. This gives three conditions – "Summer 10% Probability of Exceedance (POE) Demand", "Winter Reference" and "Summer Typical".

The approach to applying these ratings in the ISP is as follows:

- The winter reference capacity is used for all periods during winter.
- The summer 10% POE capacity is applied to the subset of hottest summer days, using the same approach outlined in the *ESOO and Reliability Forecasting Methodology Document*.
- For all other days in summer, the average of the summer typical capacity and the winter reference capacity is applied. This approach is different to that used in reliability forecasting, and better estimates the energy transfer capability of the network in summer, as opposed to focusing on the transfer capability during peak periods which is more critical for unserved energy assessments.

The following steps are applied to identify transfer limits for each seasonal condition:

1. AEMO gathers input data from asset owners, for example network ratings for various ambient temperature conditions, any runback schemes or SPSs. AEMO also gathers historical operational data for the network.
2. AEMO consults with the local transmission network service providers (TNSPs) to understand potential limiting factors.
3. Either AEMO or the TNSP undertakes power system analysis[6] to evaluate the impact of each of the limiting factors on the transfer capacity. This includes:
    a. A mixture of thermal capacity, voltage stability, transient stability, oscillatory stability, and power system security/system strength assessments, depending on the sub-region, and

[4] AEMO. *ESOO and Reliability Forecast Methodology Document*, page 8, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

[5] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

[6] AEMO. 2020 ISP Appendix 9 – ISP Methodology, Section A9.4.4 Power system analysis, at https://www.aemo.com.au/-/media/files/major-publications/isp/2020/appendix--9.pdf?la=en.

   b. testing worst-case conditions and typical conditions, and a selection of appropriate demand and generator dispatch conditions.

4. AEMO selects the most binding transfer limit. For example, if there is a transient stability issue which limits flow between sub-regions to a particular megawatt (MW) value, but that value is higher than the MW flow value for the voltage stability limit for that sub-region, the voltage stability limit will be used to set the transfer capability.

Augmentation options

This section describes the method and approach to developing credible augmentation options.

Generally, transmission corridors are still conceptual when modelling for the ISP. As such, specific details on route selection and easements are not yet identified, and the essential consultation with community, traditional owners, or property title holders has not yet commenced. It is vital that developers and TNSPs identify key stakeholders and commence engagement on land and access as early as possible.

In the IASR, AEMO starts this process by consulting on the broad geographic properties of augmentation options. This includes:

- The design of the sub-regional model.
- Transmission corridors for augmenting the backbone of the network – this includes interconnector upgrades and sub-regional upgrades.
- REZ geographic boundaries.

AEMO publishes GIS files showing REZ locations to support engagement on these broad geographic properties. Transmission corridors for sub-regional upgrades are provided within the IASR or via a separate consultation.

Example – establishing and refining an augmentation option

In the Draft IASR, AEMO seeks feedback on options to increase transfer capacity between two areas – for example, Central to Southern Queensland. Several options are proposed, including new high voltage alternating current (HVAC) or HVDC transmission lines, upgrades to the existing network, and non-network options (for example, virtual transmission lines or other alternatives). For each option, AEMO describes and seeks feedback on the approximate geographic and technical parameters. AEMO also seeks feedback on non-network technologies and the approach to costing non-network options.

AEMO then collaborates with TNSPs to develop the cost and capacity of each option – including options to stage projects and consideration of feedback that is received to the Draft IASR. AEMO then consults publicly on transmission costs via a Draft *Electricity Network Options Report*. Feedback to the Draft *Electricity Network Options Report*, and TNSP estimates from active Regulatory Investment Tests for Transmission (RIT-Ts) and Preparatory Activities, are included in the final *Electricity Network Options Report* which accompanies the IASR.

The augmentation options in the IASR are inputs which may be refined in response to modelling outcomes throughout the ISP modelling process (for example, optimisation with nearby projects, staging, and new information). AEMO will publish any changes to transmission costs in the Draft or final ISP.

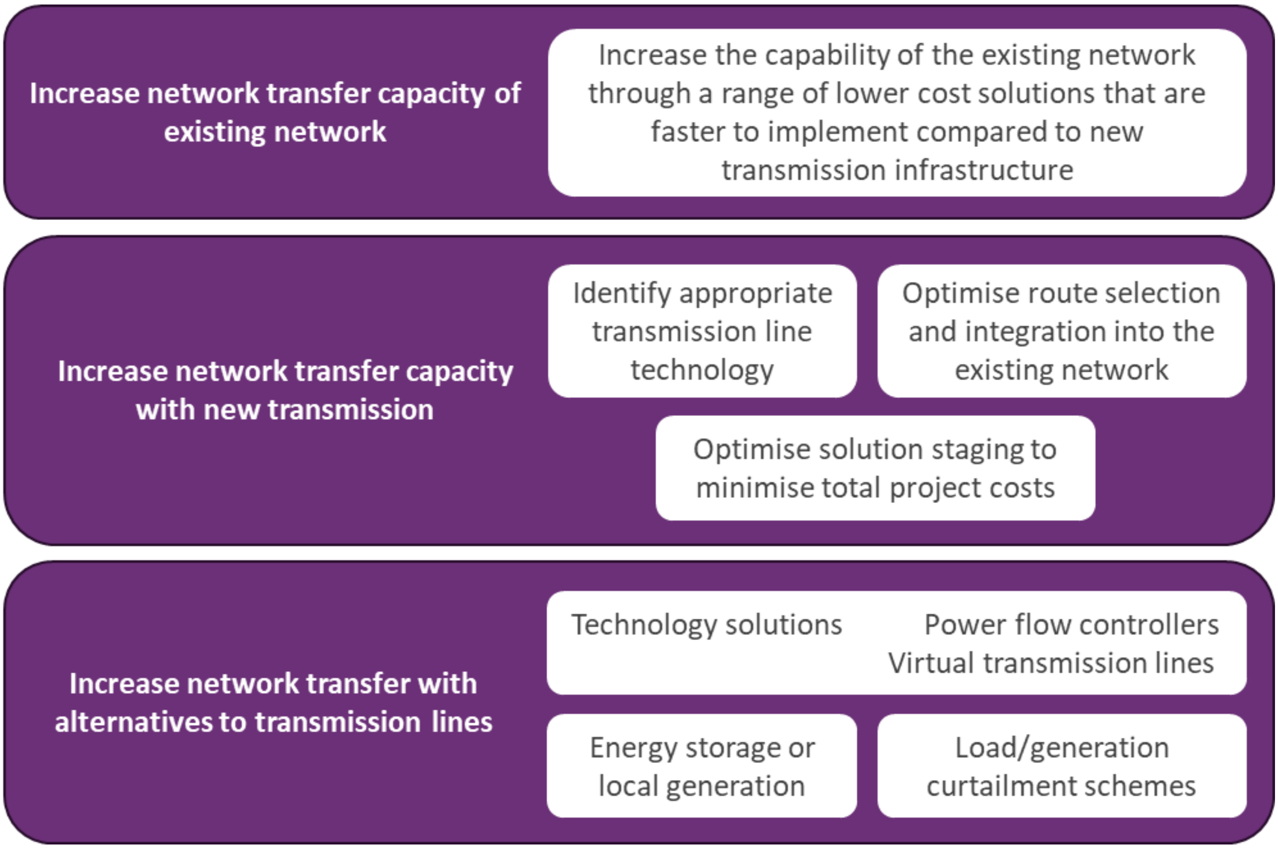
Once the broad geographic properties are defined, AEMO collaborates with TNSPs to create preliminary designs for augmentation options, and then proceeds to develop an initial estimate of the cost and transfer capability of each option.

Figure 6 summarises the parameters considered in developing each type of transmission option. Sub-regional network augmentation options, including interconnector options, typically fall into the following categories:

- Minor network upgrades and augmentations to the existing network (brown field augmentation).
- Additional new transmission lines (green field augmentation).
- Alternative technologies to minimise the requirement for new transmission lines, including non-network options.

When considering whether to upgrade existing network or build new transmission, AEMO also assesses alternative technologies to increase the transfer capacity of the existing network, including power flow controllers and other options that do not involve new or expanded transmission. Once the credible options have been identified, detailed power flow studies are undertaken to assess the capability of the resultant augmentation options. AEMO may revise options or add new augmentation options throughout the modelling process.

Figure 6 Developing credible transmission options to increase network transfer capacity in the ISP



Options to increase network transfer capacity of the existing network

Minor network upgrades and augmentations to the existing network can be relatively low cost and have a short lead time to implementation, with lower environmental and community impacts than those of major new transmission lines. They usually meet the needs for small capacity gains on the network.

The options considered to increase capability of the existing transmission network may include:

- Network reconfiguration to balance or reduce overloaded network elements.
- Application of dynamic line ratings for transmission lines for additional thermal capacity under favourable weather conditions.
- Control schemes to reduce generation and load immediately following a contingency.
- System Integrity Protection Schemes (SIPS) applied with a battery energy storage system (or another piece of power system equipment).
- Uprating of transmission lines for additional thermal capacity.
- Additional new transformers for additional thermal capacity.
- Additional new static and/or dynamic reactive plant.

New transmission line options

The configuration of new transmission lines to increase network capacity is assessed based on:

- Identification of appropriate transmission line technology with technical feasibility.
- Consideration of route selection factors and integration into the existing network, including cost effective access to renewable generation and consideration of energy losses.
- Identification of solution staging to minimise total project costs.

In the NEM at present, HVDC is currently used for point-to-point interconnection links between regions. When assessing new transmission line proposals, both HVAC and HVDC implementations are considered:

- HVDC can be more economic than HVAC for longer distance point to point applications, typically several hundred kilometres, or for applications under ground and under water, even when including the converter stations at each end of the transmission line.
- An exception to this is where multiple converter stations are required along the route, for example, when connecting multiple REZs along the line route. This is the case in the 2020 ISP, where most actionable ISP projects are related to connection of multiple REZs. As the costs of converter stations are material, the overall cost of a HVAC implementation can be cheaper than the overall cost of a HVDC implementation.
- For shorter transmission lines, the added cost of converter stations may make HVDC implementations more expensive than HVAC alternatives.

The benefits of each technology are assessed and verified through a technical feasibility study to determine the most appropriate technology to use, to design a new transmission line or network augmentation. This is followed by an economic analysis to determine the net market benefits.

In designing new transmission line options, AEMO assesses the possibility of solutions to be delivered in stages (see Section 6.4 for discussion on staging and option value).

Alternatives to transmission lines

Alternative technologies and non-network solutions are also considered in order to assess the most efficient approach to meet the identified need (see Section 5.9.2). Alternative technologies and non-network options can fulfil the need to increase power system capacity while still optimising economic benefit to all those who produce, consume and transport electricity in the market. Delivery of these alternative technologies and nonnetwork options is often a case-by-case regulatory treatment, depending on the nature of the identified need and the alternative option selected. Alternatives to transmission can include:

- Technology solutions such as power flow controllers and virtual transmission lines[7].
- Energy storage or local generation.
- Control schemes such as fast acting load curtailment schemes, or local generation run-back and curtailment schemes.

Modelling of non-network solutions can occur as bespoke options within the ISP or as alternatives to a network investment within the regulatory investment test for transmission (RIT-T) framework. The approach to assessing these options is similar to the assessments needed for transmission options. AEMO (or the RIT-T proponent) conducts a technical analysis to determine the system limits with the option in service. This is followed by an economic analysis to determine the net market benefits.

An accurate assessment of alternative technologies may require information which is only available in the late stages of project completion and is often commercially sensitive. AEMO receives non-network submissions throughout the ISP consultation process, and a TNSP may receive additional options within the RIT-T. AEMO's approach is to assess the technical capability of options with the available information and undertake economic analysis to consider each submission as an alternative to network options.

To ensure non-network options are considered appropriately, AEMO consults on non-network options for all actionable ISP projects[8].

Transmission costs

For actionable ISP projects that are proceeding under the current RIT-T process, AEMO works with the relevant TNSPs and incorporates the published costs and designs in its assessments.

[7] Virtual transmission lines use storage (or fast acting power response) at both ends of a particular transmission line which is expected to constrain power transfer. Immediately following a contingency event, the storage at the sending end of the transmission line absorbs power and the storage at the receiving end releases the same amount of power (less the transmission line losses). This avoids any thermal overloading on surrounding parallel transmission lines. This process of placing energy storage on a transmission line and operating it to inject or absorb real power, mimicking transmission line flows, is an alternative to uprating, replacing, or building new transmission lines to increase transmission capacity.

[8] AEMO will consult on non-network options in the Draft ISP or final ISP for all actionable projects in accordance with 5.22.12 and 5.22.14(c)(1) of the NER. AEMO will also consider non-network options prior to the Draft ISP via early engagement with non-network proponents and joint planning obligations in accordance with the AER's CBA Guidelines.

TNSPs also provide estimates of costs and initial designs for projects that are 'Future ISP projects with Preparatory Activities' or are undergoing the RIT-T process. Information provided by TNSPs is cross-checked by AEMO and included in the IASR.

Other transmission network augmentation options and costs are consulted on in the preparation of the IASR. Through that process, a Transmission Cost Database is developed in collaboration with the TNSPs and the Australian Energy Regulator (AER). The Transmission Cost Database is released for public visibility alongside an *Electricity Network Options Report* that demonstrates its use on ISP projects.

Because interconnector and REZ designs are inter-related, AEMO may update transmission designs and their costs using building blocks in the published Transmission Cost Database throughout the course of ISP modelling. This is done in the Power system Assessment model (see Section 4).

2.3.4 Renewable energy zones (REZs)

REZs are geographical areas in the NEM where clusters of large-scale renewable generation can potentially be developed. REZs may include offshore resources which sit outside the geographical boundaries of the NEM. The capacity outlook models include REZs to account for differences in energy resource yield and infrastructure limitations within each sub-region. The geographic boundaries for REZs are determined through the IASR consultation process.

This section covers methodologies relating to REZs:

- Resource and transmission limits.
- Network development.

REZ resource and transmission limits

For the purposes of capacity outlook modelling, REZ capabilities can be described using two key concepts:

- Resource limit – the assumed upper limit of generation supported by land availability and resource quality.
- Transmission limit – the amount of power that can be transferred from and into the REZ through the shared transmission network.

REZ transmission limits can be increased by augmenting the shared transmission network (modelled as a network development cost), and REZ resource limits can be increased by utilising a larger land area or converting more land within a REZ to be suitable to host generation (modelled as a land use penalty factor). By using a land-use penalty factor, AEMO can model a staged increase in land costs, reflecting more complicated arrangements required for planning approvals and social licence as more infrastructure is built within a REZ.

REZ resource limit

Land use reviews indicate that the development of REZs is likely to become constrained by social licence factors, as opposed to purely on land availability. In the ISP model, REZ resource limits reflect the total available land and offshore areas for renewable energy developments, expressed as installed capacity (MW). The availability is determined by:

- existing land use (for example, agriculture);

- environmental and cultural considerations (such as national parks);
- quality of wind or solar irradiance; and
- offshore areas with ocean depths that allow for fixed or floating structures to be used.

Resource limits can be exceeded if a land use penalty factor is incurred by the model, up to an assumed land use limit. This penalty factor reflects increasingly complex and costly arrangements required for planning approvals and engagement with community and traditional landowners as more renewable generation is developed in a REZ. If a REZ land use limit is lower than the resource limit, the land use limit is increased to match the resource limit – this reflects that some REZs have large areas with high-quality renewable resources. REZ resource limits, land use limits and penalty factors are determined through the IASR consultation process.

REZ transmission limit

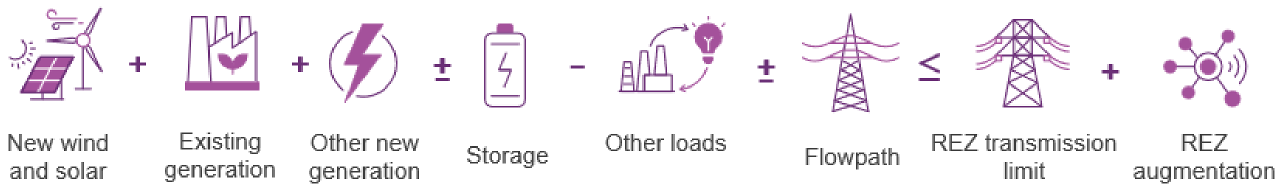
REZ transmission limits represent the maximum generation that can be dispatched at any point in time within a REZ, reflecting the transfer capability of the shared transmission network, and taking into account any local load. Network studies using PSS®E are undertaken to identify transmission limits for REZs.

These transmission limits are able to be increased through:

- Augmentation between sub-regions – these could pass through a REZ and improve its access to the shared transmission network (for example, a new interconnector that passes through a REZ).
- Augmentation from a REZ to the NEM shared transmission network.

The REZ transmission limit is expressed as a generation constraint in the capacity outlook model[9]. The purpose of the constraint is to limit the generation dispatch up to the REZ transmission limit which can be increased when it is economically optimal. The REZ transmission limit can be specified as a seasonal limit, consistent with how inter-regional limits are defined (see Section 2.3.3).

The generation constraint takes the following form:



$$Gen_{New,Solar} + Gen_{New,Wind} + Gen_{Existing} + Gen_{New,other} + Discharge_{Storage} - Charge_{Storage} - Load_{Other} + Flow_{Flowpath} \leq REZ\ transmission\ limit + REZ\ augmentation$$

where:

- $Gen_{New,Solar}$ is the generation from new entrant solar capacity (variable optimised within the capacity outlook model).

[9] In some cases, a more complicated REZ network topology might be expressed with the application of more than one limit in the model (a 'secondary' limit), to appropriately consider sub-sets of the generation within a REZ.

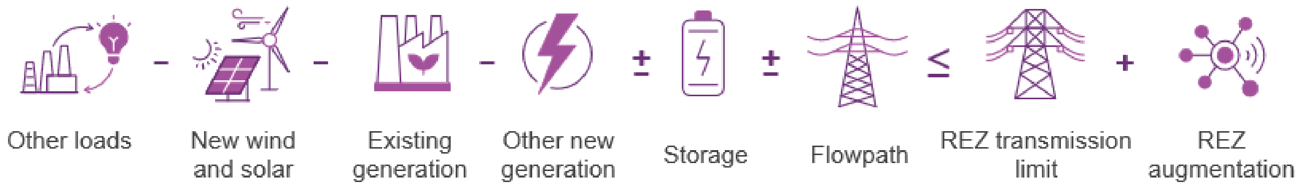
- $Gen_{New,Wind}$ is the generation from new entrant wind capacity (variable optimised within the capacity outlook model).
- $\text{Gen}_{Existing}$ is the generation from relevant existing VRE and fossil-fuelled generation and may be included if this generation would materially affect the use of the REZ transmission network and the need for augmentation.
- $\text{Gen}_{New,\ other}$ is the generation from relevant new, other generation (not new solar or wind capacity optimised within the capacity outlook model) and may be included if this generation would materially affect the use of the REZ transmission network and the need for augmentation.
- $Discharge_{Storage}$ and $Charge_{Storage}$ are the discharge/generation and charge/pumping of any battery storage and/or PHES that is located within the REZ respectively.
- $Load_{Other}$ represents loads (other than storage), for example potentially hydrogen electrolysers that are explicitly modelled, and located within the REZ. This term will be applied only if it will significantly improve the modelling of the REZ transmission limit.
- $Flow_{Flowpath}$ captures the impact of the instantaneous flow across any relevant major transmission flow path that would materially affect the use of the REZ transmission network and the need for augmentation.
- $REZ\ transmission\ limit$ reflects the limit of the existing network at the point(s) where the REZ meets the network. This value changes in cases where transmission developments improve access to the REZ.
- $REZ\ augmentation$ reflects the additional network capability available as a result of transmission developments between the NEM transmission network and the REZ.

Modelling the instantaneous transmission limit and generation dispatch captures the diversity of wind and solar generation and the potential for these technologies to effectively ‘share’ the transmission network. This enables the capacity outlook model to optimise network investment against generation curtailment, considering any load developments connected within a REZ.

Both battery and pumped hydro storage have the potential to help manage curtailment due to network limitations and therefore impact the potential value of REZ augmentations. While it may not be computationally tractable to model new storage options in all REZs, if a major REZ augmentation is expected to become an actionable project during the cost benefit analysis (CBA), storage options may be selectively added to the REZ constraints to assess the benefits of alternative solutions which incorporate storages. The storage projects would appear in the left-hand side of the equation above, with positive coefficients on generation/discharge and negative coefficients on pumping/charging. See Section 6 for further details on the CBA process.

AEMO also may model, for certain REZs, a separate REZ transmission constraint to accommodate the appropriate treatment of import limitations (the reverse direction) into the REZ and corresponding augmentation options. These REZ constraints may be applied to certain REZs with large dispatchable loads only, for example those candidate to hosting electrolyser loads.

The constraint formulation shown below links the degree of imports with the potential need to augment a REZ. Note that depending on network topology, some REZ network augmentation options may improve the REZ transmission capacity in both directions, in and out of the REZ.



$$Load_{Other} - (Gen_{New,Solar} + Gen_{New,Wind} + Gen_{Existing} + Gen_{New,other}) + (Charge_{Storage} - Discharge_{Storage}) - Flow_{Flowpath} \leq REZ\ transmission\ limit + REZ\ augmentation$$

AEMO may add a $Flow_{Flowpath}$ term to the REZ import constraint equation for some REZs with large dispatchable loads that may be fed by other sources in the network through a flow path.

Group constraints for transmission limits

"Group constraints" combine either the generation output from more than one REZ, or the generation within a REZ with the power flow along a flow path, to reflect network limits that apply to multiple areas of the power system. These are developed by considering the limits observed from power system analysis, and in consultation with TNSPs.

Group constraints also have network upgrade options developed, and specific development costs applied within the capacity outlook optimisation as per the normal REZ network development methodology.

The transmission limits for REZ group constraints are expressed in the same format as a single transmission limit, however the $Gen_{New,Solar} + Gen_{New,Wind}$ is the summation of the generation in all REZs to which the group constraint applies.

REZ network development

The capability to transfer power from the REZ to the load centres often needs to increase to support VRE development within a REZ. This is achieved by the development of network augmentation options to increase the REZ hosting capacity and REZ transmission limit.

There are two main steps to this:

- Development of network augmentation options that increase the REZ transmission limit.
- Linearisation of the network augmentation options for each REZ for input into the capacity outlook model.

Development of network augmentation options

Credible options to increase the transmission limit through REZ augmentation are developed through a technical assessment. The methodology to develop REZ network augmentation options is consistent with the sub-regional network augmentation options described in Section 2.3.3.

The REZ augmentation costs determined are specific to the network location of the REZ, and need to be designed to integrate with nearby network upgrades. In instances where nearby network upgrades are chosen by the capacity outlook model, REZ designs and augmentation costs may be revised.

Linearised representation of REZ network augmentation options

Having a series of discrete network augmentations as possible candidates to be selected in the capacity outlook modelling (similar to inter-sub-regional options) which represents all credible REZ augmentations is computationally intensive. Therefore, to represent the cost of expanding the network servicing a REZ, an incremental augmentation cost (measured in $/MW) is determined. This augmentation cost is a linearised value derived from the total cost ($) and REZ hosting capacity increase (MW) of a network augmentation option.

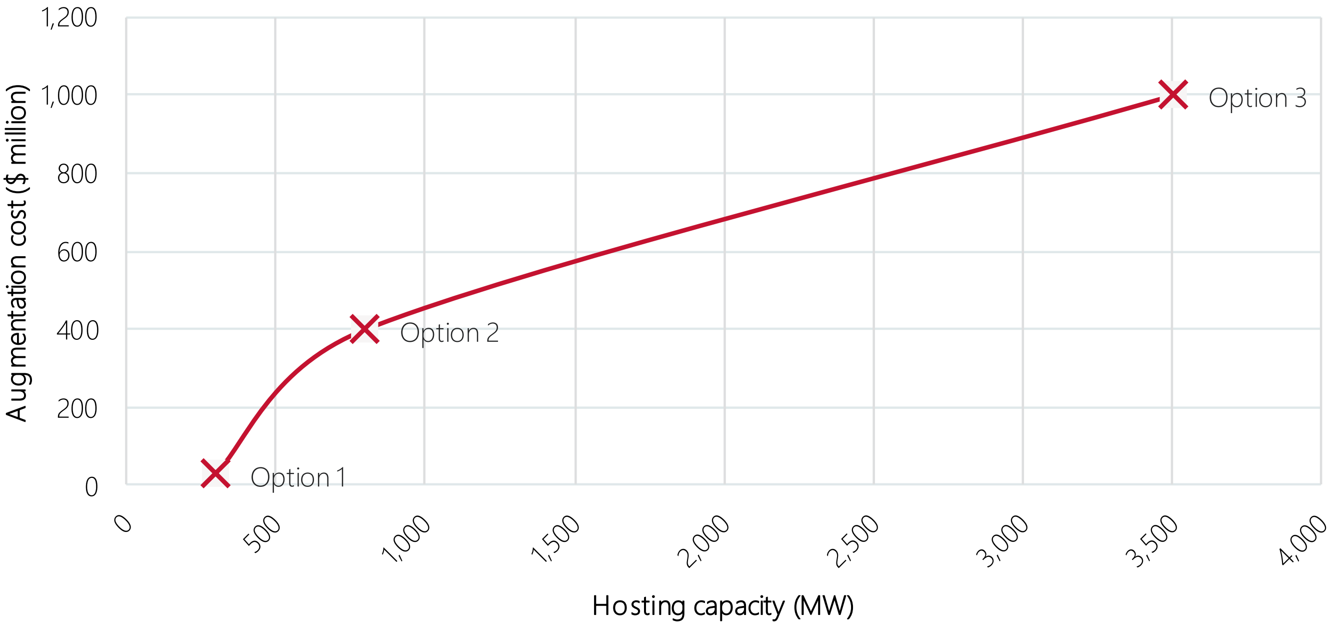
The cost-effectiveness of network options can vary significantly between small and large augmentation options – larger options will generally deliver economies of scale. It is therefore not appropriate to use a linearised value derived from a minor network augmentation to represent the cost-effectiveness of much larger options, or vice versa. AEMO must therefore select an appropriate linearised value from a set of possible network augmentations as a starting point. Table 1 outlines several hypothetical options to expand the hosting capacity of a REZ.

Table 1 REZ network augmentation options

Option	Description	Augmentation cost	Additional hosting capacity	Linearised value
Option 1	Uprating critical spans	$30 million	300 MW	$100,000/MW
Option 2	Rebuilding entire 220 kilovolt (kV) line at higher rating	$400 million	800 MW	$500,000/MW
Option 3	New 500 kV loop	$1,000 million	3,500 MW	$285,714/MW

The augmentation options outlined in Table 1 are illustrated in Figure 7. AEMO initially selects a point on the line which best represents the linearised cost of a particular network augmentation. This point will generally be the least-cost linearised value as a starting point (for example, Option 1). If the optimised model builds significantly more or less generation in the REZ compared to the chosen point, then the point can be revised (for example, Option 2 or 3). AEMO considers that approximately two to three network options per REZ provides a sufficiently broad range of options.

Figure 7 Cost and capacity of REZ network augmentation options



The range of credible network options may result in a function which is not necessarily monotonically increasing, and may have discontinuities that reflect the capability of discrete network options. Therefore, the linearised approach requires careful selection of the appropriate point on the function to reflect a realistic REZ augmentation in terms of size and cost. This is an iterative process that ensures the resulting REZ network augmentations and their costs are appropriate.

Interplay between sub-regional augmentations and REZ network capacity

Sub-regional augmentations are augmentations of any flow path between two sub-regions, whether inter- or intra-regional, and include interconnector augmentations or new lines. Within a sub-region, there may be a need to reflect the capability of the local network to export renewable generation from multiple REZs – this is done with group constraints that limit REZ output from a combination of REZs.

Sub-regional limits can therefore apply additional constraints on the maximum output from REZs, as well as any other generation or interconnector flow within a sub-region. Depending on the location of the REZs and definition of the sub-regional flow paths, this could impose limits on a REZ augmentation which are automatically increased if a sub-regional augmentation then occurs.

Sub-regional upgrades do not necessarily require REZ augmentations to show a need for upgrades to be implemented; it could be based on other factors, such as being able to supply demand under peak load conditions. An increase in a Group constraint limit is in effect the same as a REZ augmentation.

This interplay helps ensure the full network upgrade costs when a REZ augmentation is required are correctly captured, and assists in co-ordinating network upgrades that could be required for a number of different reasons.

REZ augmentation costs for load centres not at the Regional Reference Nodes (RRNs)

The REZ network augmentation costs have been determined by the need to increase network capacity to allow transfer of generation output from the REZs to the existing load centres. These load centres are usually the capital cities, or RRNs.

Depending on the specifics of the scenario, and timings of the upgrades required, high level transmission cost assumptions reflecting the distance from the REZ to each nearby emerging load centre may be utilised in lieu of full modelling of new nodes/sub-regions and load centres. Augmentation costs are initially calculated using an annualised cost per MW per km equivalent ($/MW/km), based on a generic large capacity upgrade (for example, 500 kilovolt [kV] double circuit) which applies to all REZs, although other cost options may be considered depending on the level of augmentation required.

Modelling renewable energy without REZ network augmentation

When determining the economic benefits of a development path, AEMO must compare system costs against a counterfactual where no transmission is built. In this counterfactual, new transmission to increase REZ transmission limits is generally not allowed.

To conduct this analysis, it is necessary to increase the allowance for renewable generation to connect to areas with network capacity, but which may also have low quality resources (these parts of the network are not already defined as REZs due to their lower resource quality). For this reason, resource limits, generator capacity factors, and network capacity are also determined for areas of the network that have existing capacity, or where generation retirement is expected resulting in additional network capacity being available. These lower quality resource areas are included in all scenarios, not just the counterfactual studies. This ensures the capacity outlook model can determine the optimal trade-off between development of high-quality renewable resources in REZs, with associated network build, compared to developing lower quality resources in other areas.

2.3.5 Representing weather variability

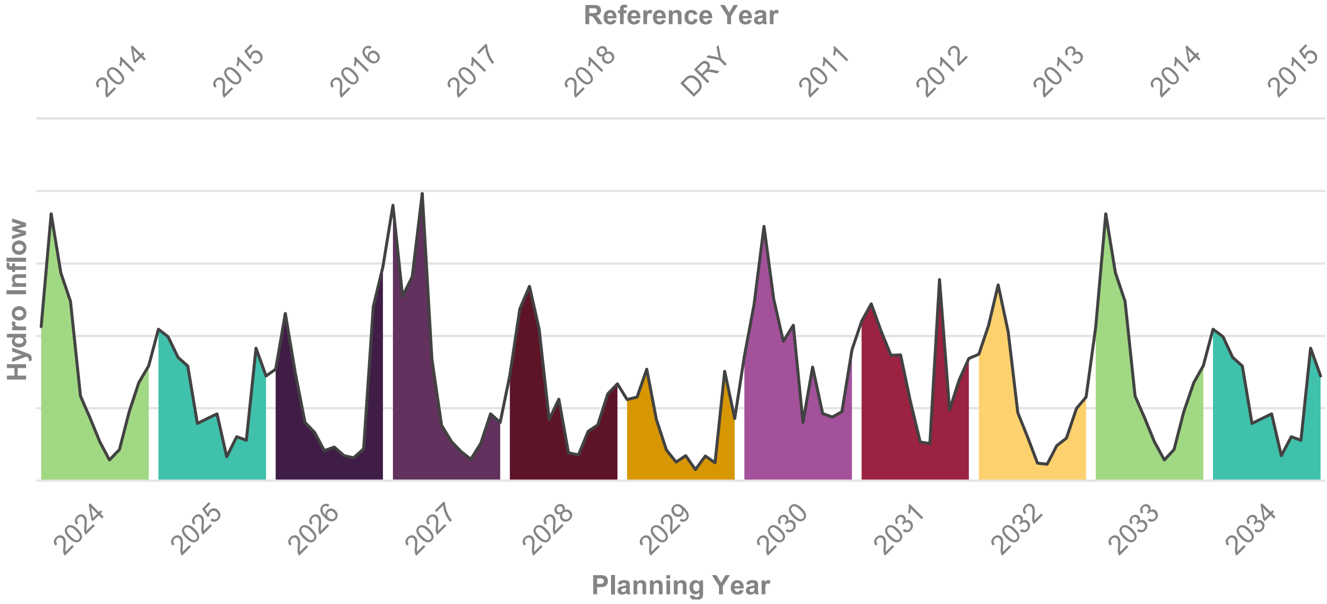
AEMO optimises augmentation decisions across multiple historical weather years known as “reference years” to account for short- and medium-term weather diversity. Where practical, these weather years also account for the variance around a long-term climate trend.

The use of multiple reference years allows the modelling to capture a broad range of weather patterns affecting the coincidence of customer demand, wind, solar and hydro generation outputs. This approach increases the robustness of AEMO’s development plans by inherently considering the risks of renewable energy or hydro ‘droughts’, representing extended periods of very low output from any particular renewable generation source, which may be observed across the NEM within or across multiple years.

To achieve this, AEMO uses a ’rolling reference years‘ approach in the capacity outlook models. This involves combining a number of demand and renewable historical profiles including hydro inflows to produce a time series that captures a diverse set of historical weather patterns throughout the planning horizon. To appreciate the effect of persistent drought and its potential impact on long-term hydro yield, AEMO also models water years representative of a severe water drought, and scales historical water inflows throughout the planning horizon in line with scenario definitions and projected trends in rainfall and hydro inflows.

In the capacity outlook models, reference years are assigned to the planning horizon by rolling through and repeating each of the input reference years. This approach results in a repeating sequence of reference years across the study period, as demonstrated in Figure 8.

Figure 8 Example of a rolling reference year sequence in capacity outlook modelling



AEMO tests a number of alternatives to determine the sequence and ensure results are not unduly influenced by the reference year mapping. The sequence that results in the most "typical" outcomes for key results such as the development of VRE and firm capacity is selected to ensure the sequence chosen is not resulting in an outlier outcome.

AEMO may test the resilience of the ODP in the capacity outlook model via sensitivity analysis, for example by the use of 'worst weather' sequence which reflects the most adverse weather conditions across the horizon.

Renewable resource quality

The resource quality for renewable generators (including potential REZs) is based on mesoscale wind flow modelling at turbine hub height for wind, while Global Horizontal Irradiance (GHI) and Direct Normal Irradiance (DNI) data derived from satellite imagery are used to assess solar resource quality. The methodology used to develop VRE resource profiles is detailed in the *ESOO and Reliability Forecast Methodology Document*[10].

In the ISP, VRE is identifiable at either a specific location (for existing, committed, or anticipated projects), or aggregated within a geographical area, such as a REZ. For REZ aggregation, AEMO applies the same resource profile development technique, but considers the aggregated resource across multiple sites in the REZ rather than one specific location. This is to reflect the fact that future generation development in a REZ is likely to occur across several different locations, and to better capture intra-REZ resource diversity.

As part of the site selection process, AEMO draws on a land use dataset to consider the viability of REZ locations for wind and solar farm development. This dataset considers constraints across a range of categories such as environment complexity, cultural heritage, land planning, and proximity to airports and residential areas. Locations deemed unsuitable for development (such as those that score poorly considering the above categories) are ruled out prior to resource quality analysis.

For wind profiles, given the variance that may exist in the wind resource across a small geographical area, the wind resource is split into two tranches based on wind resource quality, as outlined below. For solar profiles, AEMO estimates the solar resource by averaging the resource quality across a subset of locations within the REZ, considering existing and anticipated projects where appropriate. Unlike wind resource, the solar resource does not vary materially from site to site within a small geographic area.

This approach is commensurate with considering that not all available land will be developed for VRE generation purposes, considering competing land use and focusing only on developing above-average sites. Further detail on the REZ aggregation profile approach is provided below.

Aggregate REZ wind generation profiles

AEMO typically represents the wind resource available in each REZ in two tranches, to represent the resource quality differences that are observed in the mesoscale data:

- The first tranche represents the highest quality wind resource, and maximum build limits are applied given the land area identified through the mesoscale data.

[10] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/esoo-and-reliability-forecast-methodology-document-2022.pdf?la=en.

- The second tranche represents the remaining good quality resource – above the average of the REZ, assuming wind development would be targeted at only the better wind sites. Build limits also apply for this second tranche.

AEMO sets the tranches using a calibration process that aligns the wind resource quality with historical performance. This involves adjusting the settings of the first and second tranches, to align as best as possible with historical wind generation profiles seen in the NEM.

When appropriate and depending on the REZ, AEMO may model more than two sets of wind resources in some REZs, recognising that this assumption may be required to better represent resource diversity across a large geographical area.

2.3.6 Network losses

As electricity flows through the transmission and distribution networks, energy is lost due to electrical resistance and the heating of conductors. For HVAC, losses are generally equivalent to approximately 10% of the total electricity transported between power stations and market customers.

Energy losses on the network must be factored in at all stages of electricity production and transport, to ensure the delivery of adequate supply to meet prevailing demand and maintain the power system in balance. In practical terms, this means more electricity must be generated than indicated in demand forecasts to allow for this loss during transportation.

This section presents three complementary approaches to modelling different aspects of network losses:

- Inter-regional transmission losses.
- Intra-regional transmission losses.
- Generator marginal loss factors.

Inter-regional transmission losses

The capacity outlook model (described in Section 2.3.1) uses a topology which splits the five regions defined in the NEM into a number of sub-regions. Despite this, AEMO maintains a regional representation of losses for the transmission network; that is, inter-regional losses are the determined losses on a notional interconnector between two RRNs[11]. AEMO may model intra-regional loss equations in some instances to capture change in losses either when generation in developed remote to demand centres or when a sub-region is remotely located to the reference node of that region.

Augmentations of the network influence these losses. For the existing network configuration, and each network augmentation option between sub-regions that is explicitly modelled in the capacity outlook model, three types of inputs are required to represent physical and economic impacts of transmission losses:

- Inter-regional loss equations – used to determine the amount of losses on an interconnector (that is, between RRNs). These are used to determine net losses for different levels of transfer between regions to ensure the

[11] For an explanation of notional interconnectors, see AEMO, *Proportioning Inter-Regional Losses to Regions*, 2009, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/loss_factors_and_regional_boundaries/2009/0170-0003-pdf.pdf.

supply-demand balance includes losses between regions. Inter-regional loss equations are used for DC interconnectors.

- Interconnector MLF equations – describe how the losses change for an increase or decrease in transfer between regions and are essentially the derivative of inter-regional loss equations. These equations are necessary to cater for the large variations in loss factors that may occur between regions as a result of different power flow patterns on interconnectors, and incorporate the impact of regional demand. Interconnector MLF equations are used for AC interconnectors.
- Interconnector loss proportioning factors – used to separate the inter-regional losses into the amount belonging to each of the two regions.

Three different approaches are taken to calculate loss equations, depending on how complex the physical network is represented by notional interconnector is:

- Inter-regional loss equation scaling – used in instances where the proposed network option augments an exists transmission corridor.
- First principles – used in circumstances where the losses between regional reference nodes are dominated by one link (for example, HVDC connection connecting in the vicinity of RRNs).
- Case extrapolation and regression – used to build an inter-regional loss equation when the network augmentation option is for an entirely new and complex transmission corridor.

Inter-regional loss equation scaling for network augmentations

For existing interconnectors, the current inter-regional loss equations and MLF equations are available through the NEM's annual loss factor calculation process[12].

Using the power system modelling tool PSS®E (which contains a model of the network), the losses are calculated and plotted across a range of flows on each interconnector for a single PSS®E case. The augmentation is then applied, and the losses recalculated. Where there is a linear relationship between the two loss curves (which is generally the case, especially for incremental upgrades), the average scaling factor is used to scale the interregional loss equation for the existing interconnector, creating an inter-regional loss flow equation for the augmented interconnector.

The marginal losses are calculated by differentiating the inter-regional loss equation and using the same scaling approach to determine the new marginal loss equation.

Finally, the loss proportioning factor is determined by calculating network losses in either region as the interregional flows are scaled. This loss proportioning factor is again averaged and scaled against the existing proportioning factor to determine new loss proportioning factors.

[12] See AEMO's Loss factors and regional boundaries web page, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries.

First principles

This approach is most accurate for examples where one link dominates the losses between regions (that is, multiple parallel pathways do not increase the complexity of the calculation). In this instance, calculation of losses uses the traditional formula of current squared by resistance ($I^2 * R$).

Case-extrapolation and regression

In the absence of an existing inter-regional loss equation to use as a starting point, an entirely new loss equation must be calculated. To do this, losses, demand terms and interconnector flows are calculated using PSS®E. However, instead of a single PSS®E case, over 100 variations of load and generation are used to obtain data for losses, demand and interconnector flows for a wide variety of system conditions. Using this set of data:

- a linear regression is performed to determine an equation for losses, then
- a marginal loss factor equation is calculated by differentiating the inter-regional loss equation, and loss proportioning factors are based on the average regional split of losses across all cases.

Intra-regional transmission losses

Where a consideration of intra-regional losses is material to the assessment of a particular asset or where the potential actionable ISP project has marginal benefits, AEMO may undertake additional analysis to ensure that any consumer benefits that arise from lower transmission losses are considered. To do this analysis, AEMO can follow either of the following processes:

1. Post-processing.
   - Use the capacity outlook model or time-sequential model to report on the marginal electricity production cost in each time period – measured in $/megawatt hour (MWh).
   - Use load flow analysis to calculate the change in local network losses with and without the potential actionable ISP project for each time period modelled in the previous step – measured in MWh.
   - Estimate the cost or benefit of intra-regional losses by multiplying the change in losses by the marginal cost of losses.
2. Inclusion of loss equations on intra-regional flow paths.
   - This requires that the sub-regions and intra-regional flow paths are defined and setup in the model, and calculation of new loss equations from first principles as per the same process described previously for interconnectors. This has the advantage of allowing the capacity outlook model to consider the losses and additional costs associated when determining the optimal generation development.

Generator marginal loss factors

The NEM uses marginal costs as the basis for setting spot prices in line with the economic principle of marginal pricing. There are three components to a marginal price in the NEM: energy, losses, and congestion.

The spot price for electrical energy is determined, or is set, by the incremental cost of additional generation (or demand reduction) for each dispatch interval. Consistent with this, the marginal loss is the incremental change in total losses for each incremental unit of electricity. The MLF of a connection point represents the marginal losses to deliver electricity to that connection point from the RRN.

For input into the capacity outlook model, the latest calculated MLF values[13] are selected. For future generators, a MLF from an existing generator which is of similar technology and in a similar location is selected.

2.3.7 Generation and storage in the capacity outlook models

Seasonal ratings

AEMO applies the typical summer capacity, in combination with the 10% POE peak derated capacities across the seasons[14] in a manner that reflects expected generator capabilities in the capacity outlook models. The definitions of these seasonal ratings and the temperature specifications are consistent with the *Electricity Statement of Opportunities* (ESOO) and described in the *ESOO and Reliability Forecast Methodology Document*[15].

The approach to applying these ratings in the ISP is as follows:

- The winter capacity is used for all periods during winter.
- The 10% POE demand summer capacity is applied to the subset of hottest summer days, using the same approach outlined in the *ESOO and Reliability Forecasting Methodology Document*.
- For all other days in summer, the typical summer rating is applied.

Impact of Equivalent Forced Outage Rate (EFOR) and maintenance rates

The EFOR of generators in the capacity outlook models is represented by a percentage of the total hours of unavailability of the unit for each year. Since Monte Carlo simulations are not possible in the capacity outlook models, these values are accounted for by derating the available capacity of each generator.

This reflects that, on average, across many simulations, you would expect the generator's available capacity in any given period to be equal to (100% - EFOR). For example, a 100 MW generator with an EFOR of 5% is assumed to have an available capacity of 95 MW in all periods.

As for maintenance events, it is assumed that they are able to be distributed throughout the year such that they do not limit generating capacity at times when it is most required. Over time, as fossil-fuelled generation declines, this may be an optimistic assumption. As a result, the impacts of maintenance outages are not reflected in the capacity outlook models but are included in time-sequential modelling to ensure this assumption does not mask reliability or system security issues.

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[13] Generator MLFs for the most recent financial year are available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries.

[14] Seasonal definitions reflect those specified in the 2022 ESOO; that is, summer ratings are applied between November to March and winter ratings between April to October.

[15] The most recent *ESOO and Reliability Forecast Methodology Document* at time of publication of this ISP Methodology is at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/esoo-and-reliability-forecast-methodology-document-2022.pdf.

Storage optimisation

The operation of large-scale batteries is optimised within the capacity outlook models depending on the defined capacity, power, and charge/discharge efficiencies. Similarly, the optimisation of pumped hydro energy storage (PHES) technologies is based on the pumping efficiency and capacity of each plant.

The amount of firm capacity the capacity outlook model assumes can be provided by storage technologies is covered in Section 2.4.2.

Hydro optimisation

The NEM contains scheduled hydroelectric generators in Tasmania, Victoria, New South Wales, and Queensland. These schemes are typically modelled with their associated storages and water inflows. For each storage, the generating capacity, depth of storage, initial levels, and the timing and volume of expected inflows considering rainfall variability and climate change factors determine the availability of energy for hydroelectric generation.

Hydro generators are modelled using one of two methods:

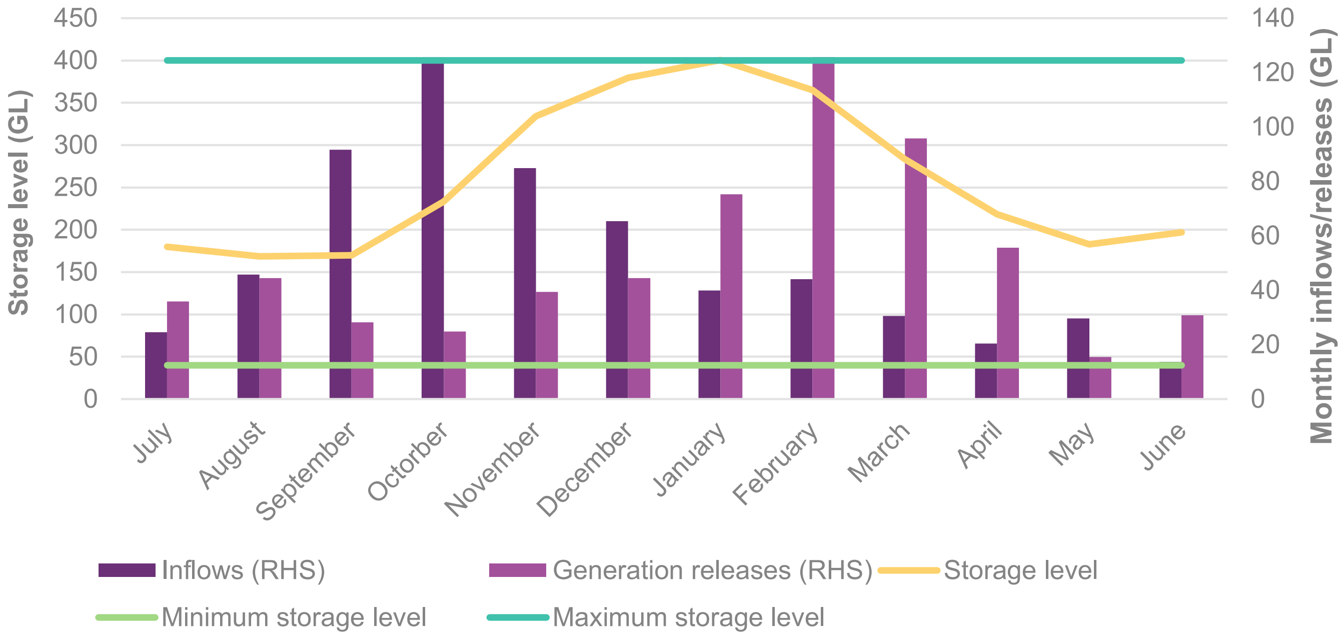
- Energy constraints – which place maximum annual, monthly or seasonal energy limits on individual generators which are then optimised to minimise total costs.
- Storage management – which is optimised to minimise total costs based on the management of water available in the storage, inflows, and the limitations of the storage and waterways. This also considers an optimisation of any pumping capability within the scheme.

Figure 9 shows a conceptual example of hydro storage management over the course of the year, showing the accumulation of water in storage after a period of high inflows which is then released during summer and autumn, with the final volume being maintained at the level of the initial volume each year. The capacity outlook model requires storages to end each year at their initial volume. This is considered appropriate for a number of reasons:

- Without this limitation, the model may draw down heavily on its storages in early years as this delivers great cost savings simply due to the discounting of costs in future years.
- The model has perfect foresight within each multi-year optimisation window, and without the limitation may use much more aggressive or conservative storage management over a year given the inflows in the next year are known with perfect certainty.

For the capacity outlook models, certain aggregations and simplifications of some hydro schemes may be used if this is deemed not material to the overall objective of the modelling and is found to sufficiently reduce the problem size.

Figure 9 Conceptual example of hydro storage management



Operating limits

In long-term planning studies, it is not always possible to capture all actual limits and constraints that would apply in real-time operations, because these can depend on a range of factors. Given the rapid transition currently underway, forecasting these operational limitations is increasingly complex, particularly as the underlying reasons are often opaque and may not be reasonable to assume long term. As a result, AEMO limits assumptions of this kind to focus on what is most material, including:

- Any limitations that are due to system security implications – the approach for developing these inputs is detailed in Section 4.
- Some element of must-run operation at coal generators – it is important that some element of coal inflexibility is captured as it significantly impacts outcomes such as the level of VRE curtailment and the potential value of storage.
- Setting maximum capacity factors on coal stations when generation levels well above historical levels are observed – important to ensure that dispatch is plausible and reflective of any upstream fuel constraints.

Even with granular time-sequential modelling, the forecasting of coal flexibility is a challenging exercise with significant uncertainty. It is not tractable to forecast any optimisation of this behaviour within the capacity outlook modelling and therefore some assumptions need to be made.

AEMO uses current observations, any market intelligence (such as company announcements), and insights from time-sequential modelling to inform a set of reasonable modelling parameters for coal units that reflect the likely operation of coal in the capacity outlook models. These assessments are informed by outcomes from time-sequential modelling such as the frequency at which stations are operating at minimum stable levels, or at low capacity factors, and of unit commitment decisions. These modelling parameters are then refined through an iterative process throughout the ISP.

Minimum stable levels are defined by the minimum of observed historical performance of generators over the past several years, generator performance standards, and any feedback from power station operators.

Gas operational constraints

The capacity outlook model incorporates a set of constraints aimed at reflecting gas system capacity constraints. Some constraints aim to reflect the maximum daily sub-regional gas supply limits on the delivery of natural gas to generators while other constraints reflect the impact of using secondary fuel for generation. Additional capital expenditure of on-site storage capacity for the secondary fuel is also reflected.

AEMO will use these gas network capabilities with outcomes from the gas supply development model described in Section 4.1.2.

Fuel cost adjustments

AEMO develops forecast gas prices for gas-powered generation (GPG) as a key input developed as part of the IASR development. As part of this forecasting process, GPG receives a gas price that is both reflective of current and known future contract positions as well as the evolving trend in gas pricing across each scenario, considering the influences of oil-price linkages, competition, supply and demand within the gas market.

For GPG, low utilisation plants such as open-cycle gas turbines (OCGTs) include in their pricing a premium reflecting the additional cost of sourcing gas at a short notice, typically reflecting delivery and storage costs. Gas prices also include a locational charge specific for each generator.

This approach considers the increased cost associated with servicing low-utilisation customers. OCGTs, like residential consumers, require gas to be available year-round, but are unlikely to use gas in a consistent manner. Gas prices for these customers therefore incorporate additional costs associated with the time or 'shape' of the expected gas consumption, as well as gas storage costs to ensure availability when required. This improves the capture of fixed costs associated with key gas-market infrastructure, within a simplified variable-cost structure (such as a $/gigajoule [GJ] gas price).

To reflect the possibility that existing high-utilisation gas plant may lower their production in future years, AEMO's methodology allows for an iterative refinement to the gas price that applies to GPG. Where annual capacity factors of CCGT plant are observed to reduce to below 20%, AEMO may adjust the gas price to reflect that of an OCGT, rather than the lower CCGT charge. This iterative assessment occurs between SSLT to DLT, and DLT to DLT model phases, as well as with ST to DLT phases of the modelling approach. While this increased cost is unlikely to materially affect overall dispatch outcomes (as limited alternatives are priced between the cost of CCGT at either a high or low-utilisation gas price), the overall system costs are expected to be more reflective of actual GPG costs if utilisation was reduced to low levels and gas contracts in these circumstances reflected greater prices to recover fixed costs.

GPG with dual or multi-fuel capabilities may switch from natural gas to diesel, hydrogen or other green gases (such as biomethane) based on emissions requirements, fuel cost or fuel availability.

AEMO may adjust fuel costs based on findings from the different gas development pathways identified by the gas supply development model described in Section 4.1.2.

Other technologies and alternatives

Distributed photovoltaics (PV)

Distributed PV is to be explicitly modelled at a sub-regional level with uptake reflective of the inputs consulted with stakeholders via the IASR.

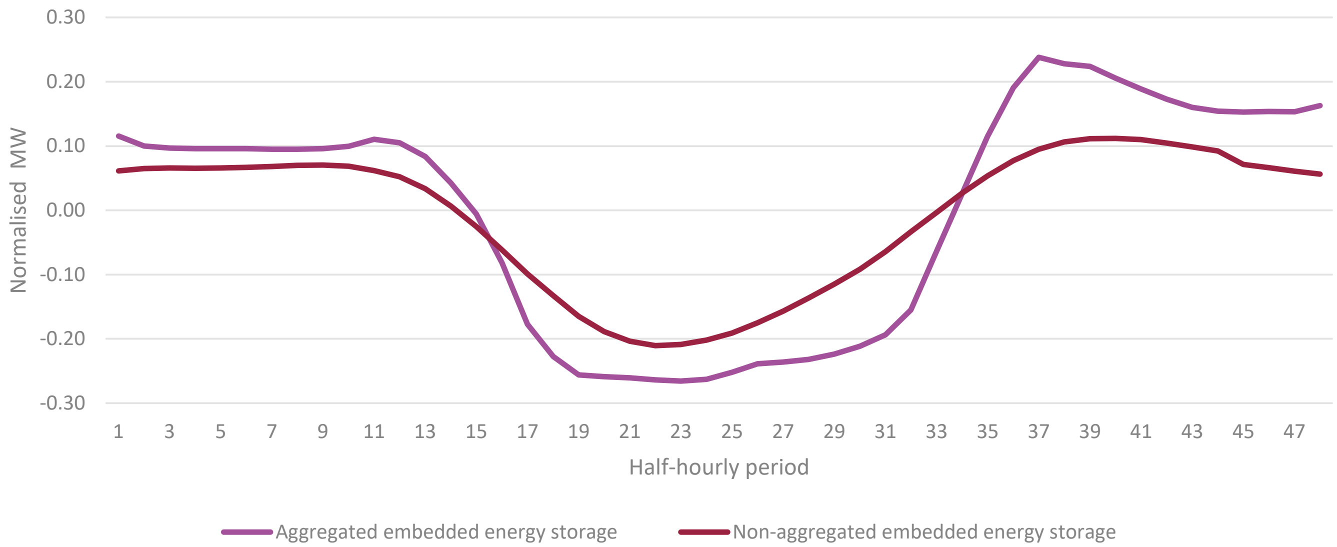
Non-aggregated embedded energy storage

Non-aggregated embedded energy storage will continue to be incorporated into the traces. This simplifying assumption implies that charging and discharging from these storage systems are unaffected by distribution network limitation.

Aggregated embedded energy storages

Aggregated embedded energy storages are modelled as virtual power plants (VPPs) in the capacity outlook models. VPPs are modelled similar to large-scale battery storage technologies with the maximum capacity (in MW) and storage duration (in MWh) being the two input parameters required. Similar to large-scale battery storage, the charge and discharge profiles are endogenously determined within the optimisation. As seen in Figure 10, this results in increased output in the morning and evening peaks. This outcome generally differs to the charge and discharge profile of non-aggregated embedded energy storage which, as detailed above, is not optimised but instead incorporated into the traces.

Figure 10 Example of charging and discharging patterns for aggregated and non-aggregated embedded energy storage



Electric vehicles (EVs) to grid

The potential discharging of EVs to the grid (when this is assumed to occur based on the scenario) is modelled as a form of controllable battery storage, similar to VPPs. The charge and discharge behaviour is optimised within the models, with a maximum load value used to reflect constraints on the ability to discharge, taking into account driving patterns.

Other distributed technologies

The ISP model incorporates build candidates reflecting other distributed technologies that may be deployed within distribution networks across sub-regions. The cost and technical parameters of these additional assets is discussed in the IASR. The uptake and operation of these assets will be influenced by the sub-regional constraints for other distributed resources.

Demand side participation

Demand side participation (DSP) assumptions are developed annually and forecast a certain level of DSP available at a range of price bands. The capacity available in each price band evolves over time depending on the scenario. For the capacity outlook models, DSP bands are at times aggregated to reduce computational complexity.

2.3.8 Treatment of committed and anticipated projects

AEMO includes all committed and anticipated generation and transmission projects in all future states of the world, in accordance with the AER's CBA Guidelines[16].

The CBA Guidelines (and the RIT-T Instrument[17]) define five criteria that must be used to assess the commitment status of generation (and transmission) projects. If the generation, storage, or transmission project has satisfied all five criteria, then it is defined in the glossary of the RIT-T Instrument as a committed project. If the project is in the process of meeting at least three of the criteria, it is defined as an anticipated project.

In classifying anticipated projects, AEMO needs to be reasonably confident that the project will proceed. If anticipated projects influence power system investment needs identified in the ISP but then do not proceed, consumers are at risk of paying more than necessary for reliable and secure power. Conversely, if anticipated projects are ignored in identifying power system needs and yet do proceed to plan, then inefficient levels of generation curtailment may occur that could similarly result in consumers paying more than necessary for reliable and secure power.

Committed and anticipated generation and storage projects

AEMO maintains a list of committed and anticipated generation projects using information on its Generation Information page[18]. This includes a list of generating units for which formal commitments have (and have not) been made for construction or installation, to the extent that it is reasonably practicable to do so, as well as key connection information (KCI) regarding connection enquiries and applications made to TNSPs.

Generating units are categorised by their stage of development, which is assessed quarterly through survey, using a series of questions (provided in Table 2) that help determine progress against the five commitment criteria: Land, Contracts, Planning, Finance, and Construction. For the Land, Contracts, and Planning criteria, if at least half of the questions related to a particular criteria are answered in the affirmative, the project may be considered to be "in the process of meeting" this criteria. For the Finance and Construction criteria, if at least one of the questions

[16] At https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

[17] See https://www.aer.gov.au/system/files/AER - Regulatory investment test for transmission - 25 August 2020.pdf.

[18] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

related to a particular criteria are answered in the affirmative, the project may be considered to be "in the process of meeting" this criteria. To ensure reasonable confidence that the project will proceed, AEMO may place more importance on particular questions being answered in the affirmative, or require particular questions to be mandatorily answered in the affirmative, for a project to be considered "in the process of meeting" this criteria. The series of questions (and the method for assessing them as "in the process of meeting" commitment criteria) may be modified over time to reflect technology and policy changes, to ensure ongoing reasonable confidence that projects classed as anticipated are likely to proceed.

Scheduled and semi-scheduled generation projects that are sufficiently progressed towards meeting at least three of the five commitment criteria are assigned a commitment status classification of anticipated for ISP purposes.

To maintain this commitment classification over time, AEMO seeks evidence that the project is continuing to make progress towards meeting the commitment criteria. If a generation information survey has not been submitted by the project proponent in the previous six months the project is no longer classified as anticipated.

If government-awarded funding is announced for a generation project, this will be considered in the assessment of whether a project is sufficiently progressed towards meeting the finance commitment criteria. For such a generation project to be considered as anticipated, it must be in the process of meeting at least two other commitment criteria. In the case where government-awarded funding provides long-term investment certainty and is awarded as part of a large-scale program, AEMO may have regard to the eligibility criteria for this funding when considering a project's progress against other (non-Finance) commitment criteria.

The anticipated project commitment status classification is included in the Generation Information publication.

The following table provides an example of questions that are asked of developers to demonstrate and classify project commitment. These may be changed when AEMO considers it appropriate to do so to increase the accuracy of the Generation Information dataset. As such, this indicative list should be considered a representation of the survey questions, rather than a definitive list of current survey questions.

Table 2 Project commitment criteria questions

Land	• Have the rights been secured for the land or sea that is required for construction of the generating unit(s)? • Have the rights been secured for the land or sea that is required for easements of new lines to connect the generating system to the transmission/distribution network?
Contracts	• Has the detailed design been completed to the extent required for a connection enquiry to be made to the relevant network service provider (NSP)? • Are contracts for the supply and construction of major plant or equipment finalised and executed (officially signed), including any provisions for cancellation payments? (Major plant and equipment include components such as generating units, turbines, boilers, transmission towers, conductors, and terminal station equipment, as relevant to the project.)
Planning	• Has an application to connect been made with a NSP? • Has a connection agreement with a NSP been signed? • Have you received AEMO's official letter of acceptance of the generator performance standards? (This is confirmed with AEMO Registrations.) • Have all relevant environmental approvals for construction and operation been obtained? • Have all relevant planning and licensing approvals, from local and state government authorities, been obtained?
Finance	• Does the project/project stage/generating unit(s) have an associated Power Purchase Agreement (PPA)? • Besides a PPA, are there other financing arrangements in place (such as merchant financing or long-term State or Federal Government funding)? • Has the Final investment Decision (FID) been reached (signed off), under the usual commercial definition of official Board financial approval regarding when, where and how much capital is being spent?

Construction	• Has a firm construction start date (or range) been set? Provide the earliest likely date, and the latest likely date, for commencement of construction or installation at the Site. • Has construction or installation commenced at the Site? If so, provide the actual date that construction commenced. • Has a Full Commercial Use Date (or range) been set, that is, the date from which the generating system is planned to have received official approval (sign-off) of all commissioning tests, from AEMO and the NSP? If so, provide the earliest likely date, and the latest likely date, for Full Commercial Use.

Anticipated transmission projects

Anticipated transmission projects are transmission augmentations that are not yet committed but are highly likely to proceed and could become committed soon. Such projects could be network or non-network augmentations and could be regulated or non-regulated assets. Because these projects are an input to ISP modelling, they cannot become actionable under the ISP framework. They are included in the ISP so their impact on other projects can be captured (their merit is not assessed).

AEMO consults on anticipated transmission projects through the IASR framework. If a developer intends to become licensed as a TNSP for the purpose of constructing, operating, and maintaining transmission network, AEMO applies the same rigor used to determine the project status as for any other generation or network project.

2.4 Methodologies used in capacity outlook modelling

The capacity outlook modelling uses a number of methodologies described in this section, including:

- Early generator retirements, for which AEMO uses both the SSLT and time-sequential modelling.
- How demand and VRE profiles are approximated within the capacity outlook models.
- Firm capacity requirements and their application to different technologies.
- How new entrant candidates are considered.
- The approach to modelling emission trajectories and targets.
- Build decisions for generators and interconnection.
- Consideration of distribution network capabilities, distributed resources and CER.

2.4.1 Early generator retirements

All generators are required to inform AEMO of their expected closure year[19] (in accordance with NER 2.2.1(e)(2A)) and their closure date once they seek to terminate their classification as a generating unit (in accordance with NER 2.10.1(c1)), which is used as an input to the ISP modelling. However, the potential for early retirements needs to be explored across all scenarios given the materiality of their impact on the needs of the power system.

AEMO uses both the SSLT and time-sequential modelling to determine and explore generator retirements. The consideration of retirements is limited to the period beyond any NEM or jurisdictional notice of closure

[19] AEMO publishes generator closure information as part of its regular Generation Information updates. See the *Generating Unit Expected Closure Year* spreadsheet, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

regulations[20]. Similarly, if a generator has reported its closure date (as opposed to its expected closure year) then earlier retirement of that unit is not considered.

Any new entrant generators that are built in the model are assumed to retire at the end of their technical life.

AEMO deploys a slightly different approach to generation retirements depending on the scenario:

- When an explicit emissions constraint is influencing generator retirements, Approach 1 is used, which initially determines a retirement trajectory through least-cost modelling which takes into account the impact on cumulative emissions. These outcomes are then validated in time-sequential modelling where only large negative profitability outcomes are sufficient to trigger further retirements.
- For potential scenarios which have periods that are not influenced by an explicit decarbonisation constraint in the electricity sector, Approach 2 would be used to reflect the primary driver of retirements being on the basis of wholesale prices.

The IASR specifies the approach used in each scenario.

Approach 1: Least-cost retirement approach

For the scenarios that use this approach, AEMO applies the following steps:

- Use expected closure years in AEMO's latest Generation Information page and from jurisdictional policy objectives or implementation details, and take into account any retirements that are brought forward in scenarios where Approach 1 was adopted.
- Apply those retirements in addition to the expected closure years/closure dates to generators through the capacity outlook modelling to determine representative generation and transmission developments. The SSLT model is able to bring forward generator retirements, provided they are not before any notice for closure restrictions (any retirements are integerised as described in Section 2.4.6).
- Apply the developments and retirements to time-sequential modelling to validate the retirements. This validation explores whether there are any remaining thermal power stations which are making considerable negative returns over multiple years. These stations may then be added to the retirement schedule.
- Any additional retirements are added to the retirement schedule and applied in the SSLT to determine a revised schedule, with is again validated in time-sequential modelling.

Approach 2: Price forecasting and least-cost retirement hybrid approach

For other scenarios, AEMO would use the following approach:

- Use expected closure years in AEMO's latest Generation Information page where possible, and from jurisdictional policy objectives or implementation details, as a starting point for a generator retirement trajectory.

[20] Under NER 2.10.1, generators are required to provide at least 42 months' notice of closure, while Latrobe Valley coal generators in Victoria are required to give five years' notice (see https://www.premier.vic.gov.au/certainty-workers-and-communities-latrobe-valley). In ISP modelling, these periods are implemented as minimum lead times for least-cost retirements for generators without a specific closure date.

- Apply any early generator retirements that are identified through the SSLT capacity outlook modelling (any retirements are integerised as described in Section 2.4.6), and adjusting the year they are retired in the DLT modelling as appropriate based on the SSLT model's application of relevant jurisdictional policies that may prevent its retirement or other modelled drivers.
- Apply the developments and retirements to time-sequential modelling to determine whether additional conditions are observed to bring forward a generator retirement or a mothballing decision:
  - A station is making a negative return which exceeds the cost of bringing forward retirement by a single year.
  - The station continues to be making a negative return over the period covered by any relevant jurisdictional policy, or until its expected closure year/closure date.
  - Retirements may be staged over two years for four-unit stations. In closure year submissions and observed generator retirements, retirements of units at a station are typically within a short period of time, and rarely over more than two years.
- Any further early retirements are then reapplied in the SSLT in the period up until the future year set based on relevant jurisdictional policies, and the process continues iteratively until no further retirements are identified in the time-sequential modelling.
- A final simulation through the SSLT determines the generator retirement schedule until the end of the modelling horizon.

2.4.2 Representation of demand and VRE profiles

In AEMO's time-sequential modelling that is used for reliability assessments such as the ESOO, a weighting of simulation results from 10%, 50% and sometimes 90% POE simulations are used, with many iterations performed in each set of POE simulations, varying supply availability due to forced outages. For the capacity outlook modelling, this approach is not possible given that the capacity outlook model requires a single demand trace and does not use any stochastic techniques, and instead uses a constant derating of capacity by the EFOR (as described in Section 2.3.7). Compared to stochastically modelling outages, a constant derating results in an optimistic representation in terms of reliability.

To balance the need to ensure that capacity is sufficient to meet high peak demands against the simpler representation of firm capacity due to the derating approach to forced outages, 10% POE demand profiles are used. The demand profiles are on a "sent out" basis (rather than "as generated"), and auxiliary loads are subtracted off the gross generation before balancing loads at the node. This allows the modelling to reflect the potential change in generation auxiliary loads resulting from a changing generation technology mix.

Load duration curve

Load duration curves (LDCs) are used to approximate half-hourly demand in longer-term models which span multiple years and make the problem computationally tractable. This involves aggregating a collection of demand intervals exhibiting similar characteristics and modelling them as a single load block. As much as practicable, seasonal and diurnal patterns are preserved. This aggregation of demand is then applied to VRE such that the same periods are aggregated (using averaging) to preserve correlation between demand and VRE availability.

The extent of aggregation is determined based on the final model settings and assumptions which affect the simulation time. The level of aggregation is minimised to preserve the maximum level of granularity available within a workable simulation time. Some scenarios may therefore need to apply a lower level of granularity as needed if those scenarios require more simulation complexity in other aspects of the model.

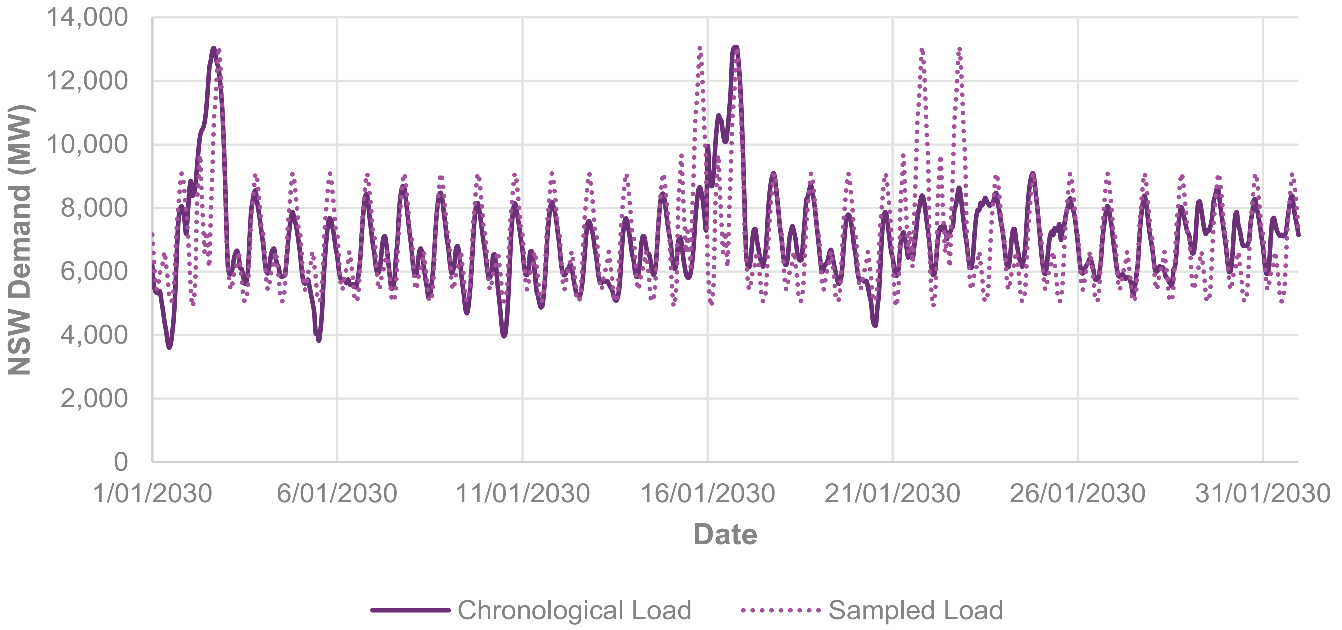
There are many different ways that half-hourly demands can be aggregated into load blocks. Some minimise variation in operational demand within a block, but if there was large variation in VRE availability across the loads within that block then this variability would be lost due to the averaging that takes place. Further, if chronology is completely ignored, daytime loads (and hence solar generation) could be included in every load block and the value of storage to complement solar generation would diminish significantly.

The techniques used by AEMO for capacity outlook modelling have therefore been chosen to strike a balance between the importance of capturing variability in load and VRE availability and the chronological nature of energy storage. 'Sampled' and 'fitted' chronology settings are used for the SSLT and DLT models, respectively, as discussed below.

Sampled chronology

The SSLT uses the "sampled" chronology setting which preserves a specified number of periods (typically day(s) per month or week(s) per year) for modelling. This is shown in Figure 11, which compares sampled load profile (two days per month) against the chronological load, for a forecast of January 2030 in New South Wales. The remaining periods (unsampled) are mapped to the samples to produce a full set of results. While this method preserves chronology and enables the evaluation of storage and inter-temporal constraints within the model, it has the drawback of assuming the same amount of VRE resource availability for the other 'unsampled' periods.

Figure 11 Example representation of a sampled load profile



VRE profiles are scaled within the modelling software to ensure that the capacity factor of each VRE generator is aligned between the sampled outputs and the underlying input data.

The “sampled” chronology setting, while not as comprehensive as the approach used in the DLT, allows the SSLT to solve within a reasonable timeframe (days) while still retaining an appropriate reflection of variability and chronology.

Fitted chronology

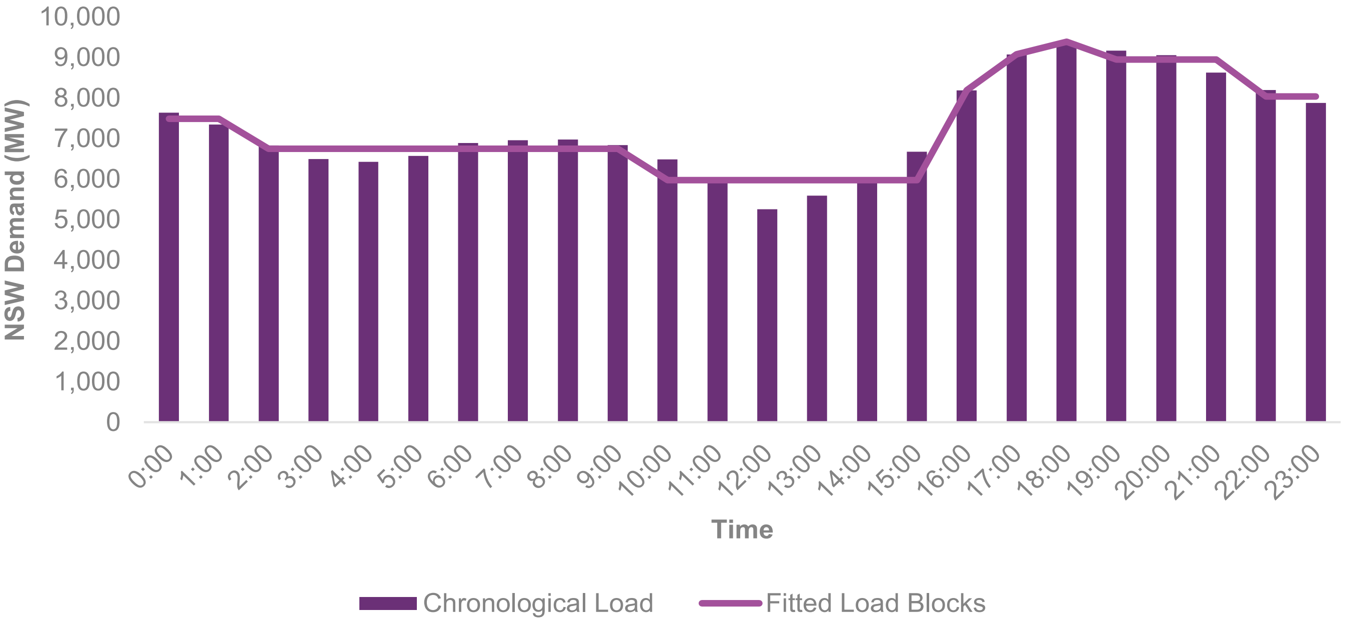
The DLT simulates with aggregations at a daily level in a chronological fashion, thus retaining granularity while covering all periods in the modelling horizon and preserving diurnal patterns. The regional demand time series fed into the DLT is fitted with a step function so the total number of simulation periods per day is reduced from 24 hours to a small, but still representative, number of load blocks (typically five to eight).

The load blocks are created using a weighted least-square fit method, which performs an optimisation that minimises the sum of squared errors (that is, the square of the difference between the hourly demand fed into the model and the step function approximation). The weighted least-square approach has the advantage of fitting the step function more tightly to the original demand time series – allocating more blocks to periods where demand is more variable, for example during the evening peak. The duration of each block can therefore vary depending on how the underlying intervals are grouped together.

Maximum and minimum demand in each day are not necessarily preserved through this approach, as the allocation of blocks may average over multiple periods at these times. However, the weighted least-square approach will generally result in more blocks during peak periods, particularly where peaks are much higher than surrounding periods.

Figure 12 provides an example of eight load blocks approximating the forecast hourly underlying demand of New South Wales for a sample forecast day in July 2029. The methodology produces a load block “trace” that varies to reasonably fit the hourly demand profile. Load blocks are reserved to shoulder and peak periods as a result of the weighted least-square approach, whereas off-peak hours are generally represented by fewer and thus longer blocks.

Figure 12 Example representation of fitted load blocks



Load subtracter – an improvement in the representation of intermittency

The process of aggregating chronological load profiles into fitted load blocks for the DLT model results in the blocks being aggregated into time periods in such a way that there is potentially misrepresentation of solar/wind generation, for example, solar generation late in the evening/at night.

This may happen in the DLT model if a load block is allocated to a time period from 5.00 pm to 11.00 pm, for example (which would include both solar and non-solar production time). To refine the model further, an estimate of the half-hourly regional VRE generation is subtracted from the chronological load, and the step function is built around this net load instead. The estimate of regional VRE generation is based on both existing generation and projections of VRE development from the previous modelling iteration. This is an iterative process which aims to improve the accuracy of the approximation of load and VRE output. This interaction is illustrated in Figure 3 in Section 2.2.

This approach results in greater variability in net load informed by VRE profiles, which is considered when fitting the load blocks, and therefore leads to a better load block representation around the shoulder periods and better reflects the remaining load which is needing to be served by other generation and storage available. It is important to note that this net load only impacts the initial 'slicing' of the chronological load blocks, and that in all modelling simulations, the original load is always considered.

This feature is also applicable for the SSLT, where the selection of the sample day/week/month is dependent on the net load (chronological load minus an estimate of VRE generation), hence resulting in a better representative day/week/month being used as a sample.

2.4.3 Firm capacity requirements

Reserve levels

The current reliability standard, set by the NER, specifies that a region's maximum expected unserved energy (USE) should not exceed 0.002% of energy consumption per year. When applicable, the Interim Reliability Measure further aims to reduce that to just 0.0006% unserved energy in each region per year.

In AEMO's reliability assessments for the ESOO, many Monte Carlo simulations of the time-sequential model are performed to forecast the average weighted USE. Due to the lack of granularity in the capacity outlook models, it is not possible to get an accurate, probabilistic assessment of the USE level in any given year. However, it is critical that these models are developing generation that is sufficient to achieve the reliability standard, valuing appropriately the reliability benefits provided by different generation, transmission, storage, and demand-side options.

The capacity outlook models therefore incorporate minimum capacity reserve levels for each region as a proxy for reliability, along with assumed contributions to these reserves from generation, transmission, storage, and demand-side technologies. These reserve levels are implemented as constraints in the model, targeting the achievement of the reliability standard[21], defining the minimum amount of firm capacity above load that must be either installed in each region or imported from neighbouring regions for all time periods. The regional minimum

[21] The reserve levels are specified to achieve the Reliability Standard, and not other interim or region-specific targets. As such, other targets, such as the Interim Reliability Measure or the New South Wales Energy Security Target (EST) are not applied over the long-term planning horizon deployed for the ISP. The IASR will specify if any exceptions to this approach will apply.

capacity reserve level is allocated regionally, and AEMO may complement the regional minimum capacity reserve level by considering sub-regional reserve levels based on the findings from the time-sequential simulation, as needed.

The amount of reserves that can be imported from other sub-regions at any given time depends on transmission limits between sub-regions, the coincidence of peak loads, and firm capacity in other sub-regions, which is given full consideration when optimising firm capacity developments in the capacity outlook models.

More detailed assessments of supply adequacy are then simulated in more granular time-sequential models, the results of which are used to refine the capacity reserve levels and firm contribution factors used in the capacity outlook models. Through the iterative process previously presented in Figure 3 in Section 2.2, the capacity outlook models ensure that sufficient firm capacity (including those imported from neighbouring regions) is installed and maintained within each region to meet the reliability standard.

AEMO may implement a firm capacity constraint defined not on peak demand but on winter and low VRE conditions if reliability issues during those periods are found in the time-sequential modelling, adjusting the level of the constraint to resolve any identified reliability issues as needed based on these more granular modelling outcomes.

If the time-sequential models show the reliability standard is being exceeded, then the reserve levels are increased. If the time-sequential modelling shows that capacity was added to the system as a result of the firm capacity requirements and a region is comfortably below the reliability standard, the reserve levels are reduced.

Key reserve modelling inputs to the capacity outlook models include:

- Minimum capacity reserve levels (in the first instance, set to the size of the largest generating unit in the region, or with minimum reserve levels calculated in the most recent ISP, and adjusted based on subsequent time-sequential modelling).
- Maximum inter-regional reserve sharing (based on an assessment of the transfer capability of interconnectors at times of maximum demand).
- Firm capacities for scheduled generators using seasonal ratings, adjusted for equivalent forced outage rate (see Section 2.3.7)
- Firm capacities for VRE generation and storage which are based on firm contribution factors. These factors are only used by the capacity outlook model to estimate the contribution of these technologies to meeting minimum reserve levels.

The capacity reserve level constraint is formulated, in simple terms[22], as:

$$\begin{aligned} &SUM(Scheduled\ generator\ firm\ capacity) + SUM(inter-regional\ reserve\ sharing + SUM(VRE\ firm\ capacity) \\ &\quad + SUM(\text{Storage firm capacit}y) \\ &\quad - \text{Regional } \mathit{Maximum\ Demand\ (10\%\ POE)\ \text{-}\ electrolyser\ load\ obligation} \geq \text{Regional reserve level} \end{aligned}$$

The following subsections discuss in more detail the method used to determine firm contribution of scheduled generators, VRE, storages, and transmission lines. The approach described for each component is only an approximation of the true contribution to reliability, however a simplified assumption must be made that can be

[22] The exact implementation of this equation within the model requires greater complexity regarding the dynamic capabilities of some terms, and considering the capabilities of intra-regional network limits within this regional constraint.

formulated as an input to the capacity outlook model. The more complete contributions to reliability and to the system more broadly are captured through the actual capacity outlook modelling which takes into account variability and chronology, and through the validation in time-sequential modelling.

Scheduled generators

Scheduled generators can typically provide power at near-full output at times of maximum demand for the purpose of meeting reserve requirements in the capacity outlook model.

The firm contribution from scheduled generators, used solely to assess adequacy of reserves, is based on their seasonal ratings as provided to AEMO via the Generation Information page[23]. In summer, firm capacity is assumed to be their 10% POE demand summer rating, while the winter rating is used for winter. These ratings are adjusted for EFOR, as a proxy for the impact of generator outages which are modelled stochastically in reliability assessments.

Firm contribution factors for VRE

For the purpose of reserve modelling, AEMO develops wind and solar contribution factors that represent the assumed equivalent firm capacity from these technologies that can be relied on during times of peak demand. By their nature, intermittent renewable generators cannot operate at any dispatch target at any time; rather the generation they provide depends on prevailing weather conditions. As such, while VRE generation often can be observed at high levels, the capacity that may be relied upon to operate during times of 10% POE maximum demand may be materially lower than the installed capacity, especially if weather conditions that typically produce high demand events (particularly hot conditions) are highly correlated with low VRE production periods (for example still/low wind conditions).

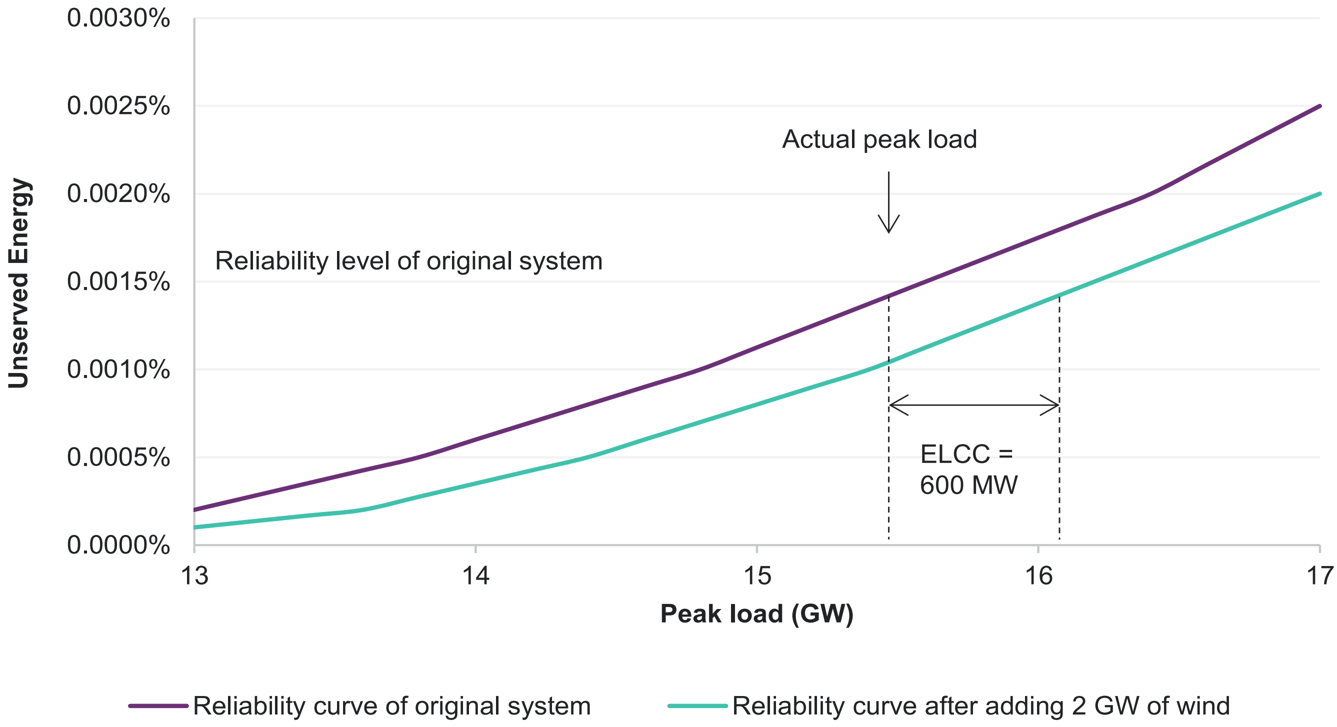
AEMO approximates the firm contribution factors of solar and wind by calculating the effective load carrying capacity (ELCC) of these technologies. The ELCC of a generator or technology represents the equivalent amount of perfectly reliable capacity[24] that would need to be added to the system to achieve the same level of system reliability if the peak load increased.

As demonstrated in Figure 13, this value can be calculated as the amount by which load can be increased with the generator or technology in the system, while maintaining the same level of reliability as is achieved without it. In this example, after 2 gigawatts (GW) of wind generation is added to the system, load can be increased by 600 MW before reaching the same level of reliability as the original system. This means the additional wind generation has an ELCC of 600 MW, or 600/2,000 = 30%.

[23] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[24] Perfectly reliable capacity refers to capacity that is 100% available and can be operated to meet any dispatch target with instantaneous ramping.

Figure 13 Example calculation of effective load carrying capability



ELCC values for solar and wind are computed endogenously within the iterative modelling process for both summer and winter for each region in the NEM, expressed as a percentage of installed capacity, and minimum across all reference years is selected. As ELCC depends on the resource mix of the system and generally declines as penetration of VRE increases, values are calculated in five-year increments for each scenario, based on an assumed resource mix equal to that observed for the given horizon year and scenario in previous simulations. This is necessarily an iterative process, as VRE penetration may subsequently be influenced by the assumed contribution to maximum 10% POE demand, as shown in Figure 3 in Section 2.2. The calculated ELCC values for wind and solar in each scenario is published in the assumptions workbook that accompanies the draft and final ISP.

If reliability issues are found in the time-sequential modelling, AEMO may augment the methodology that underpins the derivation of the ELCCs to account for the greater degree of variability that is present in the underlying weather conditions that underpin VRE. This includes the potential inclusion of an additional firm capacity constraint to reflect energy requirements in winter where there are low VRE conditions.

During the course of an ISP, AEMO may further modify the values iteratively to ensure the ELCCs appropriateness.

Firm contribution factors for storage

The challenges with modelling the firm contribution from storage technologies are different to those detailed for VRE, because the issue relates to the ability to run over a continuous period, rather than to reflect variability.

AEMO approximates firm contribution factors for storage by determining the average duration of peak demand events and adjusting the firmness of different storages to reflect their ability to provide generation across this period. For example, if the average duration of peak demands were determined to be approximately three hours, a 1 MW/2 MWh battery with an effective storage depth of two hours would be allocated a firm contribution of 2/3 = 66.7%.

Determination of the average duration of peak events initially involves analysing modelling outcomes from the most recent ESOO to calculate the average number of hours that instances of USE are expected to last, in regions and scenarios that are close to the reliability standard.

Firm contribution from other technologies

Distributed generators, including rooftop PV and non-scheduled solar generation

The firm capacities of CER and distributed resources (see Section 2.4.7 for more details) are derived similarly to those for large-scale VRE generators. This may result in a potential overestimation of the firm capacity contribution of rooftop PV if CER and distributed resource constraints are not significantly augmented, so AEMO may adjust their firm capacity factors based on observed modelling outcomes.

Hydrogen electrolysers

The fixed load component of electrolyser demands increases firm capacity requirements in the above-described constraint.

Aggregated embedded energy storages

As discussed in Section 2.3.7, aggregated embedded energy storages (including VPPs) are represented similarly to large-scale battery storages in the capacity outlook models. As such, the firm capacity contribution from these storages uses the same approach as outlined above for storage technologies, based on forecasts for maximum power and storage capacity in each region and scenario. If CER and distributed resource constraints are not significantly augmented, resulting in increased levels of curtailment of projected resources, AEMO may adjust the contribution of these technologies.

Electric vehicles to grid

The approach to determining firm capacity also based on the approach outlined for large-scale storages and takes into account any time-of-day limitations that reflect driving patterns.

Demand side participation

The contribution of DSP to reserve levels in each region is equal to the total quantity of DSP available. This quantity represents the amount by which demand can be reduced at times when the supply-demand balance is tight and USE might otherwise occur, and as such has an equivalent ability to maintain system reliability as firm generation of the same capacity.

2.4.4 New entrant candidates

Build limits and lead time

The capacity outlook models consider a wide range of build candidate options for generation and energy storage technologies listed in the IASR. Build limits associated with new investments are incorporated to reflect the maximum development of the different options at a regional and sub-regional level. Construction lead times for each technology type are reflected in the models by specifying the earliest build date for each candidate technologies.

Supply chain limits may be applied in scenario or sensitivity analysis to limit the rate at which infrastructure can be delivered in the NEM, a region, a sub-region or a REZ. This could be modelled with annual limits on:

- Transmission network – a total length or cost of network build.
- Generation – a total capacity or cost of generation per year (potentially split into generation technologies)
- Storage – a total capacity, cost or amount of energy (potentially split into storage technologies)

For renewable generators in REZs, the representation of resource potential and transmission limitations is developed separately, and described in Section 2.3.4.

Filtering approach

To manage the simulation scale of the capacity outlook models, AEMO uses filtering techniques to eliminate technology development options that are considered uneconomic or unlikely given the scenario drivers.

Filtering is applied to the DLT which involves a preliminary screening of the set of candidate options, including thermal, storage, and electrolyser options, by simulating snapshot years across the horizon to determine whether a technology is a part of the most economically efficient solution at any time across the planning horizon. For example, this might include simulations to determine the optimal generation mix in 2029-30, 2039-40, and 2049-50. Any technology option that is not developed in any of those smaller simulations can then be excluded from full horizon modelling.

Applying a snapshot year approach to filtering isolates the selected years, reducing the problem size significantly, and allowing greater technology development options to be included. Years are chosen based on the DLT's step size and policy setting requirements. For example, if a key policy needs to be met by 2034-35, 2034-35 will be considered a snapshot year. If needed to manage simulation complexity and solve times, a similar filtering process applying outcomes from snapshot year capacity outlook modelling may also be used before running the full-horizon SSLT model to reduce the number of REZ electrolyser candidates.

For storage candidates, options are selected considering the following conditions:

- Each sub-region or region should have at least one storage candidate of each technology type from the range of available storage depth options in the region. For example, if the available options in region A include depth storages of two hours, four hours, six hours, and eight hours, the filtered candidates will consist of at least one of these options across the sub-regions.
- Pumped hydro technology is selected based on available resource for suitable sites, allowing to reduce the number of options where no feasible sites can be developed.
- The filtering technique is carried out for each scenario and sensitivity.

2.4.5 Emission trajectory and targets

Modelling emission trajectories and targets

The degree of interdependency between energy sectors is projected to increase as Australia continues to decarbonise. In a low emissions economy, low or zero carbon energy fuels (such as renewable generation, green hydrogen, or bioenergy) will be required to meet an increasing share of energy demands. At the same time, not all sectors of the economy will decarbonise at the same rate, considering the varying degree of penetration and commercial viability of low carbon technologies across different sectors. Likewise, sectors that rapidly decarbonise may not find that full decarbonisation is economic relative to alternatives.

In recognition of this, AEMO is using multi-sectoral modelling to better understand the degree of nation-wide emission reductions that the electricity sector may support. This allows for consideration of the relationship between emission reductions and economy-wide electrification in the capacity outlook model. In effect, the multi-sectoral modelling allows AEMO to consider an economy-wide emission constraint or target consistent with its scenario ambitions and to determine emission pathways at a sectoral level, including for electricity and specifically the NEM. At the same time, the model considers individual technologies across all energy sectors to ascertain the degree of increased electrification (for example, of transport, heating, and for industrial applications) that is consistent with a certain level of final energy demand growth and economy-wide emission reduction ambitions.

The emission allowance (or carbon budget) obtained from multi-sectoral modelling is used as input in AEMO's capacity outlook models. A similar approach to the one discussed below is applied for jurisdictional carbon budgets.

For any given scenario, the jurisdictional carbon budgets are first imposed onto the SSLT where the carbon budget is met by changing the retirement timing of fossil-fuelled generation or out-of-merit-order dispatch. Annual emission trajectories that meet the cumulative carbon budgets for the NEM and for relevant jurisdictions are determined in the SSLT.

Annual emission trajectories derived from the SSLT for each scenario are then re-aggregated into cumulative emission constraints that span the length of each step in the DLT and are fixed for each scenario[25]. Once again, this allows the model to re-optimise emissions in each step of the DLT while respecting overall constraints derived from the SSLT and multi-sector models.

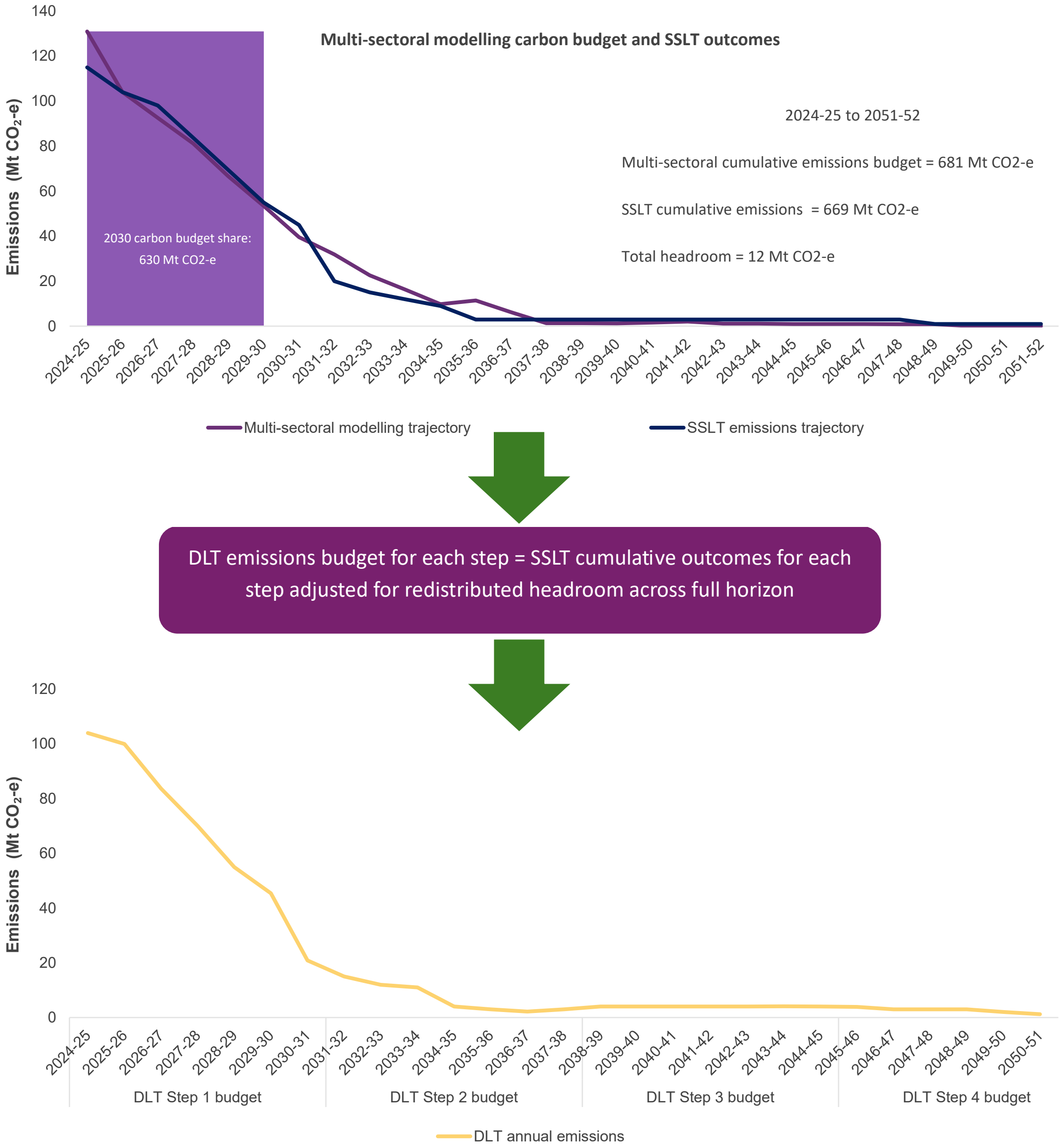
The SSLT and DLT impose hard emission constraints, which means emissions are not allowed to exceed the carbon budget. If the cumulative emissions in the SSLT are lower than the emission constraint (the constraint is not binding), then calculating each step's emission budgets imposed in the DLT will account for this headroom by distributing the difference between actual emissions in the SSLT and the carbon budget to each step's budget in the DLT. This approach is illustrated in Figure 14.

This prevents the DLT from being overly constrained beyond what the multisectoral model estimated was the carbon budget for the electricity sector over the period or the jurisdictions' emission reduction targets. This also

[25] An exception is a scenario counterfactual, which is underpinned by a different SSLT and therefore different carbon budget. More detail on counterfactuals can be found in section 6.6.1.

allows flexibility to account for minor differences in modelling outcomes attributable to using a sampled chronology to fit load blocks in the SSLT.

Figure 14 Decomposition of emissions constraint in the capacity outlook models



2.4.6 Build decisions for network, generation and storage

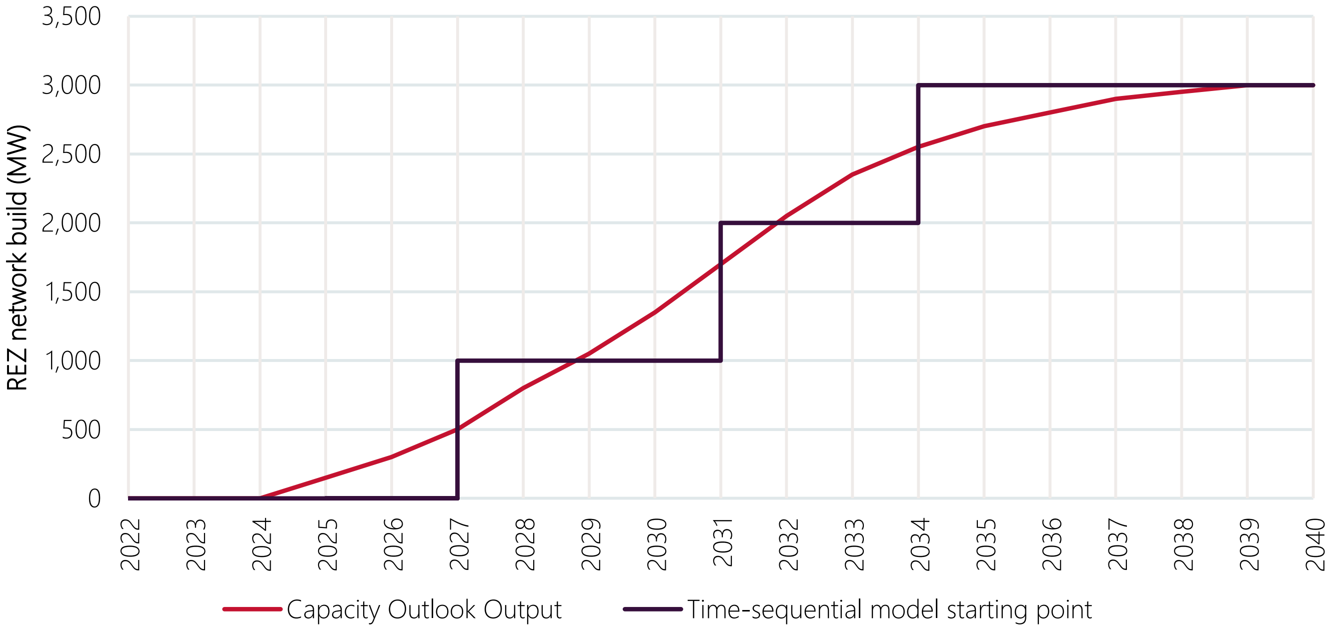
Decision variables in the capacity outlook models include the size and timing of new generation, storage, and network builds. To keep simulation times manageable, the models use linear programming rather than mixed integer programming, meaning that these discrete decision variables are linearised (for example, the model could choose to build 0.314 units of a 300 MW CCGT plant).

The approaches used for rounding linearised build decisions in the capacity outlook models are described below.

REZ network augmentations

The capacity outlook model uses linearised REZ augmentation costs to determine the approximate scale and timing of REZ network augmentations (see Section 2.3.4). This process results in a continuous build trajectory for the network augmentation of each REZ (see the "Capacity Outlook Output" in Figure 15). Because network investments are discrete (that is, they are typically large bespoke projects), the continuous trajectory from the capacity outlook model must be transformed into a step function that represents the delivery of individual network augmentation projects over time (see the "time-sequential model starting point" in Figure 15). The step function is used as a starting point to determine the optimal timing and scale of REZ network augmentations in the time-sequential model and for potential actionable ISP projects in the DLT model.

Figure 15 Conversion of linearised REZ augmentation to network upgrade options



Sub-regional flow path augmentations

In the SSLT, alternative options between the same regions are simplified to a MW capacity in each flow direction. The SSLT optimisation identifies whether an interconnector augmentation is developed. The size and timing of the developments identified in the SSLT provide a starting point for developing potential augmentation combinations. The combinations of sub-regional augmentations and REZ network augmentations are tested for each scenario in the DLT to determine candidate development paths (see Section 6 for further information on the ODP methodology).

Fossil-fuelled generation investments

For fossil-fuelled plants, such as coal-fired generators and CCGTs, the SSLT determines the linear build of these technologies. These continuous MW builds are then converted into discrete builds of standard turbine size for use in subsequent models through a simple rounding process. If at least 50% of the notional generator size is built in the SSLT, then it is considered committed in the DLT. For example, if 1.3 CCGTs were built in the SSLT model, only one CCGT would be modelled in the DLT model and subsequently in the time-sequential model.

The same approach is applied to any additional generation (for example, open-cycle gas turbines [OCGTs]) developed in the DLT for subsequent time-sequential modelling).

Thermal retirements

Thermal retirement decisions made in the SSLT are also linearised (see Section 2.4.1 for more details on the retirement approach). Due to the necessary coarseness and simplifications of the SSLT (see Section 2.2), the aggregate volume of thermal retirements determined each year is meaningful, but specifics related to choice of units to retire can be unintuitive. This is because often the differences in the input assumptions for power stations of the same type are marginal.

For example, the SSLT may retire parts of a number of coal-fired power stations within the same region without retiring an entire station. Alternatively, the sequence of retirements relative to the expected closure year information provided by participants might be completely jumbled, with the model choosing to retire plant with longer remaining technical lives ahead of plant currently expected to retire in the next decade.

To develop a more realistic schedule of retirements, AEMO applies the following approach for coal-fired generation:

1. Use the SSLT to determine the trajectory of coal retirement and aggregate the capacity retired within each region.
2. In each year, develop an order of coal-fired generation based on the expected closure year or closure date (whether its expected closure date, date informed from relevant government publications, or date determined in time-sequential modelling).
3. Depending on the cumulative coal capacity that is projected to be retired in that year (based on Step 1), determine the units that need to be retired based on the order developed in Step 2. This uses a similar approach described for generator investments, where a 50% threshold is required for a unit to be retired.

For example, assume that the two power stations closest to retirement are as follows:

- Power Station A: 2 x 300 MW power station that is six years from its retirement.
- Power Station B: 4 x 500 MW power station that is eight years from its retirement.

If the SSLT modelling determined that 800 MW of coal was to be retired in four years, this would involve retiring all of Power Station A, but no units of Power Station B (as the remaining 200 MW of retirement does not meet the 50% threshold). If 900 MW were retired, this would also then retire one unit of Power Station B.

This approach maintains the aggregate level of coal retirement within each region, but brings forward power stations which are closest to the end of their life.

A similar approach is generally followed for gas-fired and liquid-fuelled power stations, which are also assessed on a unit basis with the exception that the steam turbine of combined cycle gas power station is retired by the time the last gas turbine unit is retired.

Variable renewable energy, storage and hydrogen electrolyser builds

The development of new VRE, battery storage, pumped hydro is allowed to remain continuous as the sizes of these assets are less standardised than fossil-fuelled generation. These technologies can typically be scaled to any size by adding more turbines/panels/batteries (or for pumped hydro are more influenced by topographical features), and as such, no rounding is applied.

The development of hydrogen electrolysers is also allowed to remain continuous, given the technology is modular and scalable. Further details on the approach to modelling hydrogen electrolysers are described in Section 2.4.8.

2.4.7 Distribution network capabilities and opportunities for CER and other distributed resources

AEMO has prepared this approach on incorporating distribution network capabilities and opportunities for CER and other distributed resources in response to the 2024 Review of the ISP and a subsequent rule determination. AEMO will apply this approach for the 2026 ISP, and expects that the approach can be enhanced for future ISPs as modelling capabilities and data availability evolve.

AEMO's IASR formally defines CER and other distributed resources. However, for guidance when reading in this document:

- CER refers to embedded solar and battery systems owned by consumers, where PV systems are below 100 kW and battery systems are below 5 MW, as well as EVs.
- Other distributed resources include larger embedded generators and storage below utility scale, below 30 MW.

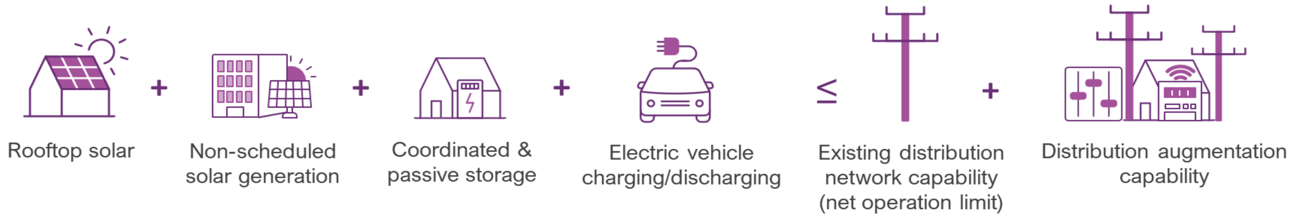
AEMO may apply two separate sets of constraints: one to represent distribution network limitations on the operation of CER, and another set to represent distribution network limitations on the uptake and operation of other distributed resources.

Modelling distribution network limitation impacting CER operational constraints

The ISP model is a sub-regional model with limited number of sub-regional reference nodes, which are necessary to reduce computational requirements. As such, the ISP is unable to include each individual distribution asset (distribution substation, feeder, zone substation, sub-transmission substation) in the model. Therefore, assumptions and simplifications of the downstream distribution network are necessary to reduce the number of distribution objects and constraints being modelled.

These distribution constraints aim to reflect the sub-regional volume of CER output to supply other loads (export capability), as well as the potential forecast curtailment associated with higher uptake levels of new CER.

AEMO will model for every sub-region the following constraint:



$$\begin{aligned} &\text{Gen}_{\text{Rooftop solar}} + \text{Gen}_{\text{Non-scheduled solar}} + \left(\text{Discharge}_{\text{Coordinated storage}} - \text{Charge}_{\text{Coordinated storage}}\right) \\ &\quad + \left(\text{Discharge}_{\text{Passive storage}} - \text{Charge}_{\text{Passive storage}}\right) + \left(\text{Discharge}_{\text{Passive EV}} - \text{Charge}_{\text{Passive EV}}\right) \\ &\quad + \left(\text{Discharge}_{\text{V2G}} - \text{Charge}_{\text{V2G}}\right) \\ &\quad \leq \text{Distribution network capability} + \textit{Distribution}\ \text{network a}\textit{ugmentation} \end{aligned}$$

where:

- $\text{Gen}_{\text{Rooftop solar}}$ and $\text{Gen}_{\text{Non-scheduled solar}}$ represents generation from rooftop solar and non-scheduled generation.
- $\text{Discharge}_{\text{Coordinated storage}}$, $\text{Discharge}_{\text{Passive storage}}$, $\text{Discharge}_{\text{Passive EV}}$, $\text{Discharge}_{\text{V2G}}$ represent the discharge of CER storages (both residential and commercial sized non-scheduled storage) and EVs associated with a sub-region.
- $\text{Charge}_{\text{Coordinated storage}}$, $\text{Charge}_{\text{Passive storage}}$, $\text{Charge}_{\text{Passive EV}}$, $\text{Charge}_{\text{V2G}}$ represent the charge of CER storages and EVs associated with a sub-region.
- Distribution network capability reflects the existing ability for the distribution network to support the operation of forecast CER for each sub-region. This is calculated as a net operation limit for aggregated CER output, where both the underlying demand and CER availability forecasts at the distribution transformer asset level are used to calculate CER output, before being aggregated to the sub-region. This captures the ability of the local network capacity to support local generation to meet consumer demand over a larger geographical area.
- Distribution network augmentation reflects the increase on the distribution network capability to support higher levels of operation of CER for each sub-region as a result of augmentations. The approach to identifying distribution network augmentation opportunities to facilitate CER and their indicative cost curves will be developed and presented in the *Electricity Network Options Report*.

Note that to support model tractability and simplicity, AEMO may include the charging and discharging of passive EVs and passive storage into the underlying demand traces. AEMO considers that the curtailment of CER will likely occur at times of peak rooftop solar export. In the case of passive EVs and storage, AEMO considers that export from passive EVs and storage is unlikely to contribute to curtailment, i.e. uncoordinated storage will not be discharging at times of peak rooftop PV export and instead will be charging or not operating. This implicitly assumes that charging and discharging of EV and passive storage are not subject to curtailment during high rooftop PV exports.

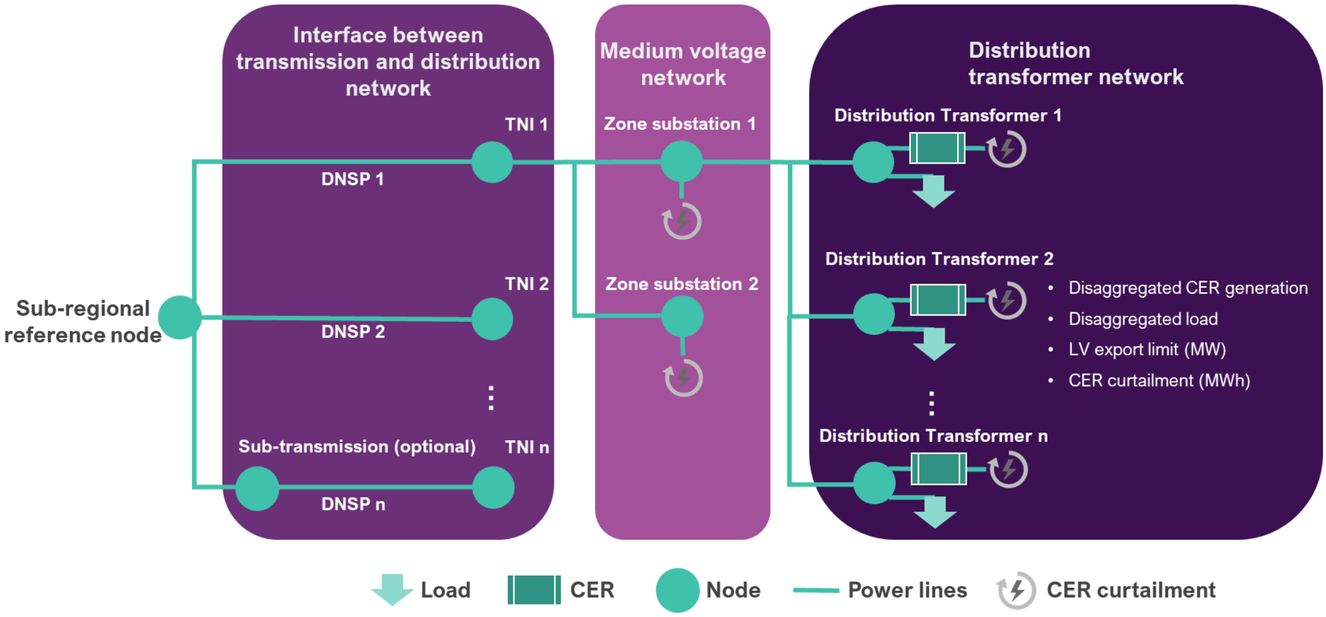
A unique sub-regional constraint will be applied at each sub-regional reference node in the capacity outlook model, with the aggregated distribution network capability derived from distribution network service provider (DNSP) data. These constraints are proposed to be developed in two ways with DNSPs:

- Data asset approach – the volume of CER output being enabled for each distribution data asset is calculated, using DNSP-provided network limits and disaggregated AEMO forecasts for CER uptake and consumer load, before being aggregated back up to the sub-regional reference node. This is the default approach.

- Detailed modelling approach – the volume of CER output being enabled for each Transmission Node Identifier (TNI) is calculated by DNSPs, using AEMO's forecasts for CER and consumer load, before being aggregated back up to the sub-regional reference node. This allows for DNSPs that have the modelling capability to provide more accurate results over the data asset approach.

Figure 16 describes the data asset approach process of disaggregating AEMO sub-regional demand forecasts and CER uptake projections at the distribution transformer level, and then re-aggregating to the sub-regional reference node level.

Figure 16 Data asset design approach for implementing distribution network capabilities in the capacity outlook model



Under the data asset approach, the volume of CER curtailment and output is calculated at each of these disaggregated distribution assets, at a half-hourly level for each scenario. These outcomes are then reflected in the overall constraint at the sub-region when these CER capabilities are aggregated back together. Under the detailed modelling approach, this analysis is performed by the DNSP using AEMO's forecasts up to the TNI.

For both approaches, DNSPs will provide indicative cost curves for distribution augmentation (costs and associated augmentation capacities to enable higher levels of CER operation), that the capacity outlook model uses to choose to build to allow further output of CER to reduce curtailment.

The treatment of CER uptake

AEMO treats CER uptake as an exogenous input to the capacity outlook model as it is driven by consumer investment decisions that focus on their specific circumstances, rather than system impacts or benefits. Many households and businesses are investing in CER, and AEMO considers that those individual investment decisions are being driven by both financial and non-financial factors. CER is already, and will continue to be, an important part of the NEM energy transition. The IASR contains more information regarding the development of the CER projections and their underlying drivers.

Modelling distribution network limitations impacting other distributed resources

Another potential set of constraints aims to reflect the limitation on the uptake and operation of other distributed resources, which may be developed at the distribution level – upstream from CER – beyond those exogenously forecast. The cost and technical parameters of these additional assets is discussed in the IASR. The implementation of these constraints for other distributed resources are separate to the constraints for CER above.

The capacity outlook model will optimise the build of other distributed resources as well as the necessary distribution network augmentations to support them. These sub-regional constraints could take the form of:

$$\text{Gen}_{\text{Distributed PV without CER}} + \left(\text{Discharge}_{\text{Distributed storage}} - \text{Charge}_{\text{Distributed storage}}\right) \leq \text{Distribution network capability} + \textit{Distribution}\ \text{network a}\textit{ugmentation}$$

where:

- $\text{Gen}_{\text{Distributed PV without CER}}$ represents generation from distribution-connected solar resources, excluding rooftop and utility-scale solar.
- $\text{Discharge}_{\text{Distributed storage}}$ and $\text{Charge}_{\text{Distributed storage}}$ represent the discharge and charge of distributed storage build candidates.
- $\text{Distribution network capability}$ reflects the existing ability for the distribution network to support these distributed resources for each sub-region. This may be modelled as a net operation limit similar to CER, or be defined by medium voltage distribution limit information provided by DNSPs, subject to data availability.
- $\text{Distribution network augmentation}$ reflects the increase on the distribution network capability to support these distributed resources.

The cost and other technical parameters of these distributed resources and storage assets are published in the *Electricity Network Options Report* and IASR. The existing distribution network capability and the cost and size of the distribution network augmentations will also be published, subject to the availability of data.

2.4.8 Modelling hydrogen in the capacity outlook model

With growing global interest in hydrogen-based energy systems, the potential for Australia to export clean hydrogen is substantial. Beyond Australia's export potential, there is also a range of potential domestic hydrogen opportunities. However, the technical progression and commerciality of the resource is not yet proven and there remains substantial uncertainty.

For ISP purposes, the scale and location of hydrogen production in Australia is scenario-specific and largely assumption driven, informed by stakeholder engagement and reviews of targeted hydrogen development forecasts[26]. For details of scenario-specific hydrogen assumptions, refer to the latest IASR.

The inclusion of hydrogen requires a number of considerations in the capacity outlook modelling process, including:

- The degree of flexibility of electrolysers, which consume electricity to produce hydrogen for domestic use and/or export.
- The potential for inflexible electricity consumption to support hydrogen consumers, including domestic manufacturing, green commodity production, and/or ammonia production.
- The location and electrical connection of electrolysers, including consideration of potential embedded generation supply that may reduce the electricity supply needed from the electricity grid.
- The potential for hydrogen to be used by electricity generators, as an additional firming generation technology for the NEM.

This section details the approach that is applied when modelling scenarios with NEM-connected electrolysis.

Overview of hydrogen modelling

For the ISP, AEMO considers the electrolysis of water powered by electricity as the hydrogen production technology. The commercial-scale production of hydrogen from grid-connected electrolysers would increase electricity demand on the NEM. That would require a significant development of generation, and hence it has the potential to have a significant impact on Australia's electricity system. There is also potential for development of off-grid hydrogen projects, which may complement grid-connected facilities – the development uncertainty is a key driver for alternative hydrogen futures considered with AEMO's scenario collection. The capacity outlook model covers all REZ-based electrolysers, but excludes those geographically located outside of REZs. Further information is included in the IASR.

Green commodity production and other new industrial advancements may contribute to expanded export opportunities with the potential advent of a hydrogen sector in Australia. These industrial sector advancements would complement any export hydrogen production centres. Where relevant, AEMO's input assumptions identify quantities of both hydrogen and electricity consumption for green commodities production.

In modelling the interactions of hydrogen in the NEM, AEMO uses the capacity outlook model to:

- Determine the location and size of electrolysers to meet regional hydrogen demand for export and green commodities, as well as sub-regional hydrogen demand for domestic use.
- AEMO assumes the electrolysers will be located within REZs, meaning that the electrolyser load may be effectively co-located within the capacity outlook model's network topology with renewable generation developments, influencing the requirements for network developments as appropriate. The cost of hydrogen transportation assets from the REZ will be incorporated into the electrolyser capex.

[26] For example, the National Hydrogen Strategy and its companion modelling reports, at https://www.industry.gov.au/data-and-publications/australias-national-hydrogen-strategy and https://energyministers.gov.au/publications/reports-support-national-hydrogen-strategy respectively.

- Determine the flexible operation of electrolysers to meet hydrogen demands while minimising costs for the NEM.

Given the uncertainties around how hydrogen production may evolve in Australia, and acknowledging that the key focus of the ISP is to understand the future power system needs for the NEM, a number of simplifying assumptions are made when modelling hydrogen in the capacity outlook model:

- The magnitude of NEM hydrogen export demand, and sub-regional domestic demand and green commodities production, are all considered exogenous, provided in the IASR, and not optimised by the model.
- Potential electrolyser locations are assumed to be allocated to REZs based on resource quality and distance to hydrogen consumers such as ports and hubs. If AEMO considers that it is necessary to shortlist candidate REZs due to computational limitations, the selection of REZs may be pre-filtered using the snapshot-year capacity outlook modelling process described in Section 2.4.4. Alternatively, AEMO may outline an assumed shortlist of REZ locations for electrolysers within the IASR and its relevant data workbook(s), as appropriate. For committed and anticipated hydrogen production projects, these will be located in the most geographically appropriate REZ or at a sub-regional reference node.
- Desalinated water is assumed to be piped from the coast to the REZs for hydrogen. The cost of water pipelines is included in the ISP as a premium on the electrolyser costs, and cost of water treatment will be included as opex. Water costs are included in the IASR.

Electrolyser location

In the Australian context, two primary hydrogen supply pathways exist to support large-scale hydrogen hub developments connected to the grid. Firstly, electrolysers may locate close to coastal locations ('Coastal electrolyser'), providing close proximity to water supply and customer loads and potential export infrastructure, but typically necessitating the transportation of electrical supplies longer distances via transmission lines to power the hydrogen facilities.

Secondly, electrolysers may locate with greater proximity to sources of renewable energy generators, reducing proximity to existing manufacturing and industrial facilities, as well as export infrastructure (if relevant) and likely distant from water supplies. Such a location would likely require lesser electricity infrastructure and greater water and hydrogen transportation capacity to facilitate appropriate access to end customers.

Following stakeholder feedback, AEMO has reviewed external studies[27] on the optimal choice of pathway. The majority of studies found that it is cheaper to transport molecules, although this can be project dependent. There are many factors influencing optimal electrolyser location, including distance from the VRE source to the hydrogen user, planning considerations and community expectations.

For all supply pathways, it is likely that hydrogen hubs located close to cities and ports would distribute hydrogen for green commodity manufacturing, general industrial use, and potentially for further distribution for local domestic use. If electrolysers are based in the REZs, hydrogen pipelines would be used to transport hydrogen to

[27] DeSantis et al, 2021, Cost of long-distance energy transmission by different carriers, https://doi.org/10.1016/j.isci.2021.103495; Patonia et al, 2023, Hydrogen pipelines vs. HVDC lines: Should we transfer green molecules or electrons? https://www.oxfordenergy.org/publications/hydrogen-pipelines-vs-hvdc-lines-should-we-transfer-green-molecules-or-electrons/; DCCEEW, 2023, National Hydrogen Infrastructure Assessment, https://www.dcceew.gov.au/energy/publications/national-hydrogen-infrastructure-assessment; Net Zero Australia, 2023, https://www.netzeroaustralia.net.au/final-modelling-results/.

hubs. If electrolysers are located near the ports and hubs, electricity transmission would be required to bring the power to the electrolyser load.

AEMO considers that given the scale of hydrogen export development, hydrogen production for domestic consumption, green commodities and export should be modelled at the REZ level. A pre-selection of suitable REZ locations for hydrogen production may be implemented ahead of modelling based on considerations such as proximity to hydrogen consumer location (for example, export ports and hydrogen hubs), resource quality, and availability of variable renewable energy in those REZs.

Modelling hydrogen in capacity outlook models

The main objective of hydrogen modelling in the capacity outlook models is to determine the optimal electrolyser size and operation, and the corresponding impact on the development of generation and network that minimises total costs. To this end, AEMO uses the capacity outlook models to identify the location and size of the electrolyser plants required to meet hydrogen demand at REZ locations.

The assumed domestic and export hydrogen demands are modelled as separate flexible loads, with minimum production requirements on a weekly timeframe[28]. Export facilities that incorporate hydrogen conversion facilities (such as to ammonia) and green commodity manufacturing facilities operate with an allowance for inflexible baseloads.

Electrolysers built in REZs incorporate a component for the cost of building associated hydrogen pipelines and may include the assumed necessary hydrogen storage. The electrolyser capacity determined by the model balances capital cost and operational flexibility in a way that minimises total costs.

Hydrogen operation is flexible to minimise total costs while meeting production targets over a period of time, but it is subject to an inflexible baseload component and minimum annual utilisation factors. More electrolyser capacity can increase operational flexibility and lower operating costs but comes at a higher capital cost. Electrolyser builds are linearised as with other generation, storage, and network build decisions in the SSLT and DLT (Section 2.4.6).

Within the model, the choice of electrolyser locations for hydrogen export and green commodities is based on minimising the development cost of powering the electrolysers, considering the cost and availability of resources (such as VRE and transmission). The cost of network augmentations to deliver the VRE to the electrolysers is determined based on the approach discussed in Section 2.3.4.

The capacity outlook model determines the REZ location and size of electrolysers to meet total export hydrogen demand, regional domestic hydrogen demand, and hydrogen demand for green commodities.

The IASR provides the sub-regional hydrogen demands as well as candidate hydrogen consumption centres. The list of candidates may be further refined via filtering techniques to reduce computational complexity during the capacity outlook modelling phase.

[28] This assumption is based on an analysis made by stakeholders in response to the results of the 2024 ISP (which assumed a monthly balancing timeframe). The stakeholders' response suggests that there is only a need for storages capable of storing five to 12 days worth of hydrogen or an average of approximately eight days. At andrew-fletcher-and-huyen-nguyen.pdf, Figure 14.

Details of hydrogen modelling within the capacity outlook model

There are a number of elements factored in the implementation of hydrogen in the capacity outlook models, including:

- Electrolysers as electricity loads connected to the NEM.
- The weekly hydrogen demand and additional demand from associated plant.
- Electrolyser capital and operating costs, which may include a component for assumed hydrogen storage and pipeline costs where relevant. As the locations of electrolysers will be determined in the pre-selection process that may involve iterations of the capacity outlook models but ultimately determined in the SSLT, the associated capital and operating costs of electrolysers will be similar to all CDPs (see Section 6), and will therefore not impact on the CBA results.
- Utilisation of hydrogen for electricity production, if selected as a generation technology.
- Green commodities production as both additional hydrogen demand and associated inflexible electricity demand.

3 Time-sequential modelling

The time-sequential model optimises electricity dispatch for every hourly or half-hourly interval, rather than aggregating outcomes for the whole outlook period. In so doing, it validates the outcomes of the capacity outlook model, and feeds information back into it.

The time-sequential model is intended to reflect participant behaviour, including generation outages, to reveal performance metrics for both generation and transmission. These outputs can in turn provide further refinements to the models and modelling inputs.

In this section:

- Section 3.1 provides an overview of the time-sequential modelling process.
- Section 3.2 outlines the modelling inputs which are specific to the purpose of time-sequential modelling.
- Section 3.3 provides further detail on specific methodologies used.

3.1 Overview of time-sequential modelling process

The time-sequential modelling used in the ISP has numerous purposes and requires a number of alternative configurations which are targeted at best meeting each purpose.

Compared to the capacity outlook modelling, the time-sequential modelling focuses more strongly on participants' behaviour. This requires AEMO to overlay strictly technical assumptions with views on portfolio dynamics and strategic decisions. AEMO applies detailed analytics to inform these considerations, although there are limitations to the extent to which these behaviour drivers can be accurately forecast and reflected in the modelling, given the dynamic nature of operational decisions applied by generation portfolios.

The generation and transmission outlook developed by the capacity outlook model is validated using a time-sequential model that mimics the dispatch process used by NEMDE.

The time-sequential model considers the modelled time horizon at a higher resolution than the capacity outlook model. It optimises electricity dispatch for every hourly or half-hourly interval in the modelled horizon using the PLEXOS modelling software, and includes Monte Carlo simulation of generation outages, allowing the development of metrics of performance of generation (by location, technology, fuel type, or other aggregation) and transmission (flow, binding constraint equations).

The time-sequential model is used to provide insights on:

- Possible exceedance of the reliability standard and the Interim Reliability Measure.
- Potential economic drivers of generator retirements.
- The feasibility of the generation and transmission outlook when operating conditions and more detailed intra-regional network limitations are modelled.

- An indication of where possible congestions points may exist and how network augmentations would be beneficial in alleviating network issues.
- A more accurate forecast of the annual generation dispatch and fuel offtake.
- More precise cost benefit analysis/network augmentation benefits for specific projects.
- Impacts of weather variability on dispatch outcomes.
- Impacts of unplanned generation outages.
- The number of synchronous generators online.
- Assessment of system strength, inertia, and plant ramping characteristics.

The validation and analysis done in the time-sequential models may result in modification of inputs in the capacity outlook model (as shown in Figure 3 in Section 2.2), or power system assessments (as described in Section 4).

Complexity and time required for the time-sequential modelling simulations

Much of the work involved in the ISP, particularly related to the determination of the ODP, relates to comparing modelling outcomes over an extended period for differences in the transmission and generation system.

One of the key limitations in the use of time-sequential modelling is the complexity of detailed network constraint equations which are critical in being able to represent the differences in the transmission system. This process can take significant time to develop (in some circumstances this can be a number of weeks) and the constraints are customised to a given capacity expansion determined by the capacity outlook models. As discussed in Section 2.1, the capacity outlook modelling can involve many hundreds of distinct simulations leading to an impracticable number of distinct constraint equations that would need to be developed. As such, the use of time-sequential modelling needs to be targeted in areas where its benefits over capacity outlook modelling are most valuable (such as to confirm that the proposed ODP is in the best interest of consumers).

3.1.1 Time-sequential model settings

Simulation phases

The time-sequential model comprises three interdependent phases that operate in sequence. Designed to better model medium-term to short-term market and power system operation, these phases are:

- Projected assessment of system adequacy (PASA) – this phase determines the generator units' maintenance schedule while optimising capacity reserves across an outlook period. The resulting maintenance outage schedule is passed on to both the medium-term schedule and short-term schedule.
- Medium-term schedule – this schedules generation for energy-limited plants (hydroelectric power stations or emission-constrained plants) over a year. A resulting daily energy target or an implicit cost of generation is then passed on to the short-term schedule to guide the hourly dispatch.
- Short-term schedule – this solves for the hourly or half-hourly generation dispatch to meet consumption while observing power system constraints and chronology of demand and variable generation. This phase can use a Monte Carlo mathematical approach to capture the impact of generator forced outages on market outcomes.

Resolution and optimisation window

For the ISP, time-sequential models are generally simulated at a half-hourly level of granularity, although at times hourly simulations are performed to increase simulation speed in large simulations (for example, in reliability assessments).

Generator planned and unplanned outages

The time-sequential model uses the same inputs for forced outage and maintenance as the capacity outlook models. However, rather than applying as a static derating, full and partial outages are modelled stochastically.

Time-sequential modelling is generally performed across multiple reference years and/or demand POE levels and uses Monte Carlo simulations to model multiple generator outage patterns. Maintenance is modelled as discrete outage events and planned through the PASA phase, as described above.

Types of time-sequential models used

AEMO may use any of the following time-sequential models, or a combination of them, throughout the outlook period, depending on the purpose of the modelling:

- Short Run Marginal Cost (SRMC) model – the simplest dispatch model, which represents perfect competition. This model assumes that all available generation capacities are bid in at each unit's SRMC. Depending on the type of assessment carried out, this model features different degrees of complexity. AEMO distinguishes between two types of SRMC models:
  - SRMC with no unit commitment – this model uses a linear solve and therefore captures the technical envelope of each generator broadly within the limits of linear programming. Only ramp rates, simple heat rates, and other continuous variables are modelled. This model is primarily used to validate network constraints and for reliability assessments.
  - SRMC with unit commitment – this model overlays the pure SRMC algorithm with additional technical limitations at unit level as well as system security constraints, thus requiring a mixed integer solve. This model is used to carry out cost-benefit analysis and to produce insights on the future operability and security of the system.
- Bidding behaviour model – this model uses historical analysis of actual bidding data and back-cast approaches for the purposes of calibrating generator bids, rather than costs, that determine the generator dispatch outcomes. The historical bidding analysis reflects current market dynamics – such as contract and retail positions of portfolios – by ensuring that modelled generator bids broadly replicate dispatch preferences of generators and portfolios submitted in each generator's actual historical bids. Portfolio outage management (by adjusting bids at times of generator outages to maintain portfolio positions) is considered for some large generation portfolios. New entrant generators are assumed to bid in at similar price points to existing generators of the same technology, given the uncertainty around their ownership and operating strategy.

Large-scale Generation Certificates (LGCs) will cease to operate beyond 2030 and VRE generators might alter their bidding strategies to ensure long-term cost recovery. To account for this, AEMO may calibrate VRE bids at certain time intervals after 2030 to include revenue adequacy considerations for new VRE generators. A similar long-term cost recovery approach might be adopted for new GPG by introducing multiple price bands that are calibrated based on the historic bidding behaviour of the independently operated GPGs in the NEM. The bidding model is used to forecast one of a number of possible future bidding outcomes. This model is used for price forecasting and revenue sufficiency assessments that may be used to inform retirement decisions in the model and to produce insights on the future operability and security of the system.

3.1.2 Use of time-sequential models in the ISP

Determination of generator retirements

The determination of generator retirements (outlined in Section 2.4.1) is based on projected wholesale net revenue from the bidding model. This provides the best estimate of the financial viability of each generator within the limits of the information available to AEMO.

AEMO acknowledges that the approach simplifies the complex array of considerations which are taken into account for any individual station's retirement, including areas such as contracting positions, fuel supply arrangements, and portfolio value. As these considerations are difficult to quantify and are often opaque, AEMO is not in a position to incorporate this level of detail but does consider the potential for strategies to avoid negative price exposure such as seasonal decommitment, changing minimum continuous operating levels or two-shifting (the ability for coal generation to shut down and restart quickly).

It is critical that AEMO does consider the potential for early generator retirements and understand their implications for system security and operability and the potential impact on benefits of other investments, including the overall ODP. Therefore, AEMO has outlined an approach to determine an indicative retirement schedule which balances complexity, the availability of information, and the need to develop indicative retirement schedules for each scenario.

The general approach for identifying risk of potential early retirements relies on a number of considerations and metrics. The primary criterion is least-cost retirement as described in Section 2.4.1.

Wholesale price forecasts

Time-sequential modelling is used to produce wholesale price forecasts which may be used for a number of purposes. These forecasts inform retail price forecasts, which are used for forecasting demand and CER uptake, and also used to explore the distributional effects of the ODP. This is described in Section 6.10.

Cost-benefit analysis

Time-sequential modelling may be used to support and validate the take-one-out-at-a-time (TOOT) analysis which is carried out as part of the cost-benefit analysis approach. This uses the SRMC model, which, compared to the capacity outlook models, includes increased granularity and detail in the representation of both the inter- and intra-regional transmission limitations addressed by the ISP project. Further details on the TOOT approach are provided in Section 6.9.3.

Capacity expansion

There are a number of inputs to the capacity outlook modelling that are informed by the time-sequential modelling. These include the following (illustrated in Figure 3 in Section 2.2):

- Generator limitations to be applied such as units to operate with a minimum load and approximations of the impact of any system security constraints.
- Adjustments to the setting of regional reserve level requirements to approximate the capacity that will be needed to maintain the Reliability Standard.
- Short-term operating levels of GPG to improve alignment between historical and expected forecast in the capacity outlook model.

This creates a feedback loop between the capacity expansion model and the time-sequential model.

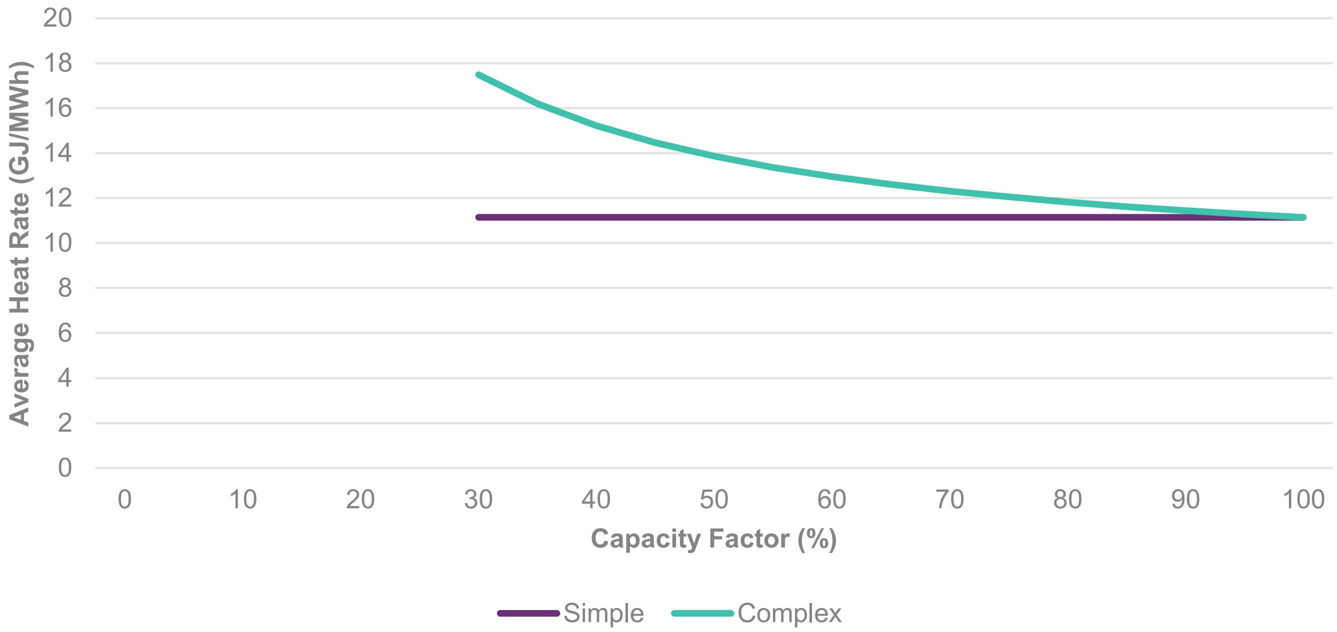
3.2 Inputs to the time-sequential models

The time-sequential modelling uses the same inputs as the capacity outlook modelling but increases the level of detail used for some assumptions such as using a complete set of network constraints. The time-sequential modelling also employs additional methodologies particularly related to unit commitment.

3.2.1 Fuel consumption and heat rate modelling

Generators consume fuel according to their heat rate function, expressed in units of GJ/MWh. Simple heat rates apply a constant average heat rate and can be modelled without the use of integer variables. However, in applying the heat rate at maximum output to the entire range of output, they overestimate efficiency at low operation level. This affects dispatch and fuel offtake projections, particularly for CCGTs and gas-fired steam turbines (GFSTs). To improve its modelling, AEMO has implemented affine-linear marginal heat rates referred to as 'complex heat rates' (see Figure 17).

Figure 17 Example of heat rates – simple versus complex



Detailed representation of the efficiency curves is computationally expensive and only applied to the SRMC models with unit commitment, which are used to inform costs benefits analysis and specific operational insights. Other time-sequential models focusing on competition dynamics and or reliability assessments, where fuel consumption is not a key variable, employ simple heat rates for computational reasons.

3.2.2 Configuration of combined cycle gas turbines

AEMO's time-sequential models consider CCGTs in greater operational detail, and capture explicitly heat output/input dynamics between the gas turbine (GT) units and the steam turbines (STs). To render realistic operation regimes and correctly consider the relative inflexibility of CCGTs, AEMO enforces constraints, where applicable, to ensure that the GTs and ST unit commitment decisions are linked together as appropriate. In instances where the CCGTs are by design equipped with a bypass stack upstream of the ST (for example, Darling Downs Power Station), these constraints are omitted so the model has the option to run the asset more flexibly in open-cycle mode.

3.2.3 Network limits

In cases where detailed network modelling is required to inform the time-sequential study, detailed transmission constraint equations are applied to a regional network topology (see Section 2.3.1), consistent with the approach used in NEMDE. These transmission constraint equations represent the network configuration following the REZ network augmentations and sub-regional augmentations identified from the capacity outlook modelling.

AEMO develops constraint equations to represent five types of limits in the time-sequential model. This section describes how the five constraint types are determined, and the process to develop the constraint equations.

Types of network limits

The ISP defines these operating limits in terms of five network limits:

- Thermal capability.
- Voltage stability.
- Transient stability.
- Oscillatory stability.
- Additional power system security/system strength.

Thermal capability

The power flow through a transmission element is limited to its maximum thermal capacity. TNSPs provide transmission line and transformer ratings for different ambient temperatures, seasons, months, and times of day. The following thermal ratings are applied in the network capability assessment:

- Normal ratings for pre-contingent conditions.
- Contingency ratings for post-contingent conditions.
- Short-term ratings for post-contingency conditions, if an operational solution is available to bring the line loading below the normal rating within the allowed time.

The determination of maximum transfer levels is carried out using PSS®E studies.

Voltage stability

Voltage stability refers to maintaining stable voltage control following the most severe credible contingency event or any protected event. Assessment of voltage stability limits is undertaken as per requirements in Chapter 5 of the NER. The determination of voltage stability limits is carried out using PSS®E studies.

Transient stability

Transient stability refers to maintaining the power system in synchronism and remaining stable following any credible contingency event or protected event. Assessment of transient stability limits is undertaken as per requirements in Chapter 5 of the NER. The determination of transient stability limits is carried out using PSS®E studies.

Oscillatory stability

Oscillatory stability refers to maintaining the power system in synchronism and remaining stable in the absence of any contingency event, for any level of inter-regional or intra-regional power transfer up to the applicable operational limit; or following any credible contingency event or protected event. Assessment of oscillatory stability limit is undertaken as per requirements in Chapter 5 of the NER. The determination of oscillatory stability limits is carried out using PSS®E and Mudpack[29] studies.

Additional power system security/system strength

The modelling of a system strength or security requirement ensures that the projected generation outlook can withstand a credible fault (for example the loss of a synchronous unit), at different non-synchronous generation levels.

The time-sequential model implements these constraints where applicable by ensuring that a certain number of synchronous thermal units are online at any time within a region – as directed by the system strength requirements. The modelled formulation of unit combinations may be based on planning assumptions, or developed from operational advice if available.

System strength constraints are explicitly modelled for the South Australian region to address the identified system strength gap[30]. The time-sequential model applies unit commitment constraints to a number of South Australian synchronous plants to ensure that the system strength requirements are met. These requirements are adjusted as the operational environment in South Australia evolves.

Development of constraint equations

Depending on consumer demand, dispatch of generation, and availability of network and non-network assets, transmission elements can become congested. To manage network flows, AEMO uses constraint equations as a

[29] Mudpack is an oscillatory stability simulation software used by AEMO.

[30] AEMO. *System strength requirements methodology. System strength requirements and fault level shortfalls*, July 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

mathematical way to represent the physical limitations (network limits) of the power system within the time-sequential model.

There are two specific sets of constraint equations considered in the determination of optimal market dispatch outcomes from the time-sequential model:

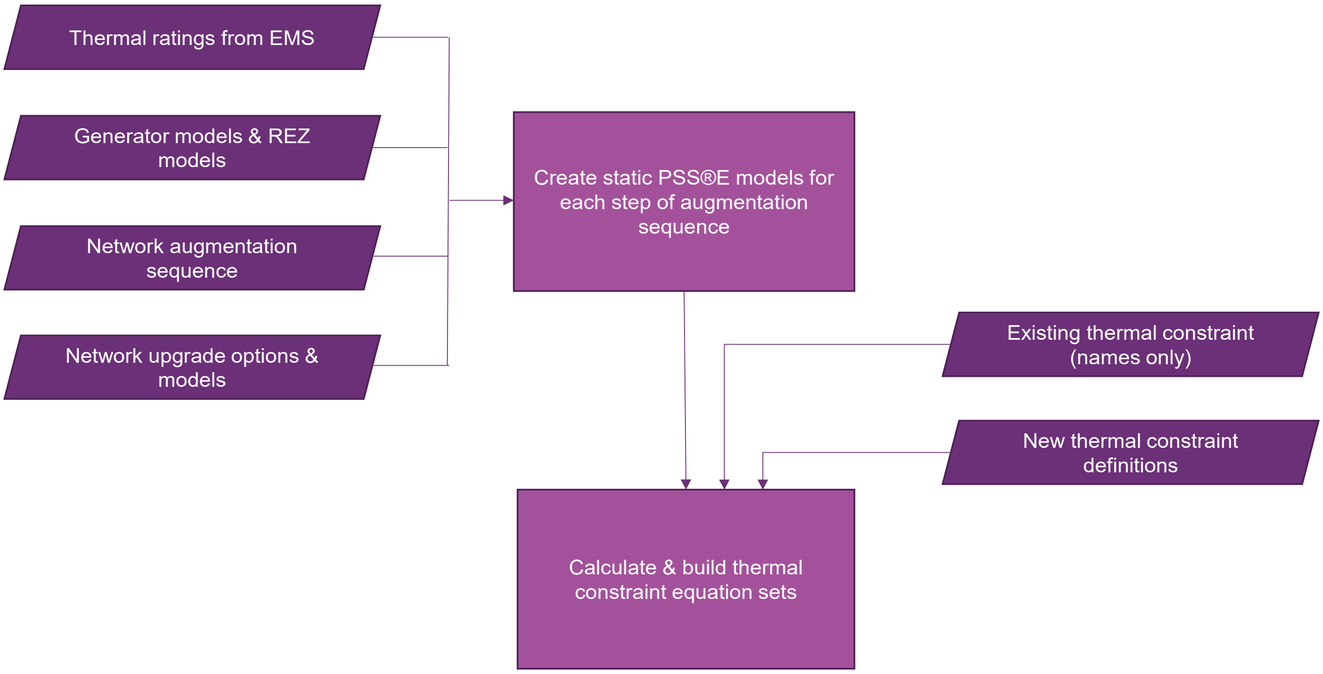
- Thermal constraint equations.
- Stability constraint equations (including voltage, transient and oscillatory limits).

These are discussed in more detail in the following sections.

Thermal constraint equations

Thermal constraint equations are built from PSS®E load flow cases for a given network configuration. Thermal ratings of the transmission network are applied as per the latest information in the IASR. The process of developing thermal constraint equations is illustrated in Figure 18.

Figure 18 Thermal constraint equation process



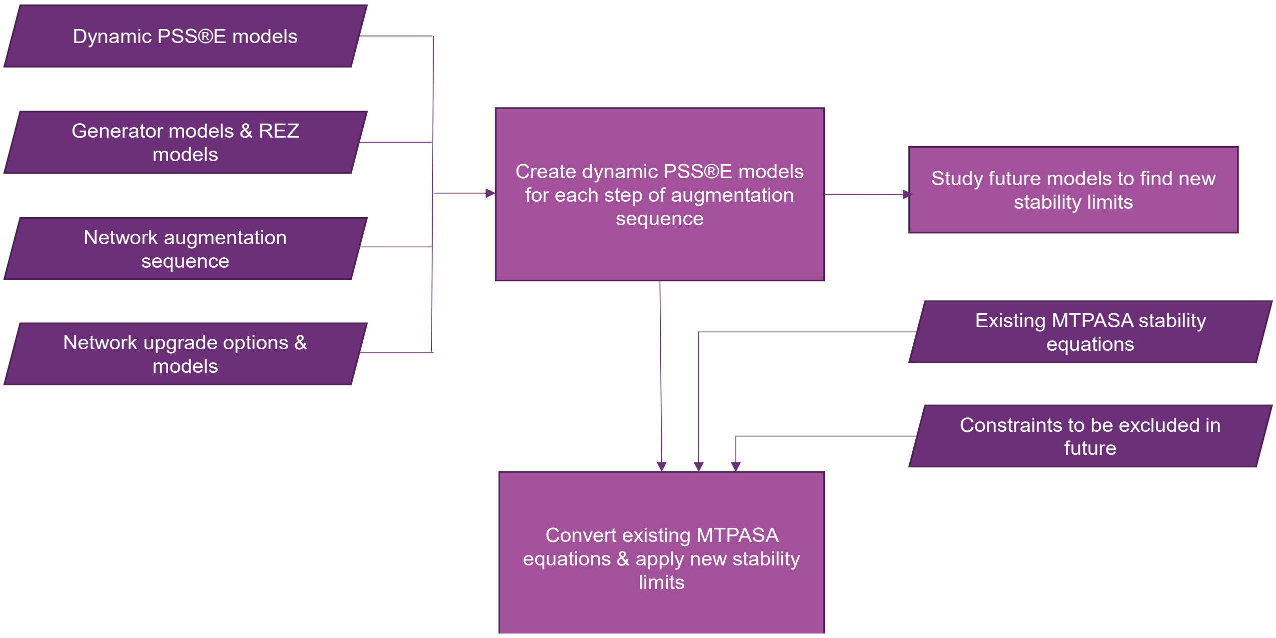
Note: EMS – Energy Management System.

Stability constraint equations (voltage, transient and oscillatory)

Stability constraint equations for the existing network are developed and validated by the relevant TNSP. AEMO conducts due diligence on these constraints before applying them in dispatch. Development of these stability constraint equations is time-consuming. For modelling the existing network, dispatch stability constraint equations are converted into a format that can be interpreted by the time-sequential model. These stability equations include transfer levels determined by voltage, transient, oscillatory, rate of change of frequency (RoCoF) and system strength limits.

For the future network, dynamic network models are created with future upgrades and then studied to determine the difference in stability limits from the existing network. For some upgrades, the TNSPs have already completed these studies, so their results are used wherever possible. From these studies, an offset to the right-hand-side of the existing Pre-Dispatch, Short-Term or Medium-Term Projected Assessment of System Adequacy (ST PASA or MT PASA) constraint equation is determined and applied in the stability constraint equations. This process is detailed in Figure 19.

Figure 19 Stability constraint equation process



Additional constraints for power system security/system strength

These are developed on a case-by-case basis. Where an existing constraint is in MT PASA, ST PASA, or Pre-dispatch PASA, these are utilised and modified as appropriate. Additionally, where there are future constraints not currently in NEMDE, these are developed on a first principles basis. Where these constraints have terms related to operational measures that are taken that are able to alleviate the constraint, such as putting on a capacitor or putting a unit in synchronous condenser mode, it is assumed that these measures are taken within the formulation of the constraint.

Constraints within the market modelling are also required to represent known operational measures, such as directions that force generation on and therefore impact on dispatch. An example of these is how the system strength generator combinations in South Australia are represented. While the limit advice for the system strength combinations contain a large number of permutations, only a reduced set of combinations needs to be modelled. This is to allow for the least-cost directions outcome, but also allows for sufficient gas units to be included in other combinations to allow for maintenance and forced outages of some of these units.

3.3 Methodologies used in time-sequential modelling

3.3.1 Unit commitment

Solving a unit commitment problem involves determining which generating units to switch on/off, and for how long, over a given horizon.

Apart from the marginal cost of generation, optimal constrained unit commitment problems also include technical limitations such as minimum stable levels for operation, and minimum up-times and down-times. Start-up and shut-down cost profiles may also be considered to solve for an economically optimal and feasible dispatch.

Unit commitment problems are computationally complex, as they involve making integer/binary decisions subject to intertemporal constraints. AEMO only considers the inclusion of integer-optimal unit commitment modelling where it is deemed important to understand a potential emerging trend or issue. At other times, unit commitment is rounded from a linear solve, or assumed (for plant that typically operate base load).

When optimised unit commitment modelling is used, the complexity is balanced by solving the study period in multiple chronological steps. AEMO's approach involves optimising decisions over an outlook of 24 hours. To ensure optimality, an additional forward-looking period with a less granular resolution is modelled to inform unit commitment decisions towards the end of each step. This way the optimisation is able to 'look ahead' and know it might be better to keep a unit online overnight at low generation levels, even when making a loss, to avoid the cost of restarting it the next day and to be available during high price periods that might occur in the first hours of the morning.

It should be noted that unit commitment optimisation and minimum stable levels are not strictly modelled for peaking plant when using an hourly or 30-minute model resolution and are therefore not typically included in the time-sequential model. These units can typically start up to operate in minutes rather than hours, and it would not be appropriate to impose a constraint in the model that forces them to remain operating at their technical minimum stable level for an entire hour if dispatched.

Therefore, to maximise the efficiency of the market model and to ease computational burden, unit commitment decisions are only imposed in the time-sequential modelling on generators that:

- Are required to be online for system security purposes.
- Are involved in unit commitment constraints to emulate a known network requirement.
- Are likely to materially impact the level of annual gas consumption.
- Have limited flexibility to start up and shut down (such as coal-fired generation, CCGTs, and GFSTs).

3.3.2 Optimisation of large-scale storage operation

Large-scale storage operation (battery, hydro, pumped hydro, or any other dispatchable storage) is expected to generate opportunistically based on price and the efficiency loss associated with charging and discharging the storage, effectively arbitraging between periods of high and low price. For example, in a future energy mix with high renewable penetration, VRE may be smoothed by effectively charging storages when high renewable energy volumes are available, for later discharge when renewable energy is low.

The second phase of the time-sequential model (medium-term schedule) completes an energy management study across a year to schedule energy consumption and generation from large-scale reservoirs. This is further refined by the third phase of the time-sequential simulation (short-term schedule), where network limitations are included on a more granular time scale. This phase has limited foresight, ranging from one day to a week depending on the model configuration, and optimises operation of most storage systems, including batteries and closed pumped hydro. The latest assumptions can be found in the IASR and in AEMO's current planning and forecasting inputs, assumptions, and methodologies data set.

3.3.3 Limitations on storage devices

AEMO will apply constraints that reduce the perfect management of stored energy, by limiting charge and discharge behaviours near the maximum and minimum state of charge (introducing headroom and footroom energy reserves) and may apply operating strategies with imperfect visibility of upcoming weather patterns in the time-sequential model. The modelling approach will validate that the reliability and operability outcomes are achieved with imperfect foresight of future system conditions. This approach does not attempt to reflect revenue maximisation behaviours that may be promoted by energy arbitrage opportunities, however the effect of these opportunities may lead to greater frequency of imperfect operation by storage operators, of which this approach is a reasonable proxy.

These additional features are:

- Headroom and footroom capacity reserves set aside a margin of energy at the upper and lower states of charge that is accessible to the system only during conditions that would otherwise result in unserved energy (effectively reducing the storage depth of typical operating conditions). This approach is applied in all ISP time-sequential modelling.
- Deliberate energy planning error through the creation of imperfect charge targets, by developing a charge profile based on alternative generator outage, renewable energy availability and demand conditions to the short-term energy plan, and then applying this charge profile to other market conditions. Storage devices in the modelling will then try to operate in accordance with the operating strategies developed with these alternative system conditions, leading to a suboptimal dispatch outcome. This approach will be only used as a validation step, and will not be included in all time-sequential modelling.

This methodology does not apply to the capacity outlook model; however, insights from this method may inform adjustments to the capacity outlook model such as through reserve capacity constraints and firm contribution factors of storage technologies.

3.3.4 Gas network interactions

The time-sequential model applies constraints on certain gas generators or aggregations of generators that are in congested parts of the gas network or have limited on-site fuel storage. These constraints are informed by modelling and analysis of the East Coast Gas Market. Insights from the gas model may inform generator build or retirement decisions or appropriate locations for new gas generation. See Section 4 for more information on gas supply modelling.

3.3.5 Hydrological constraints on hydroelectric generation

In addition to the detailed reservoir topology, the time-sequential model applies various constraints that reflect hydrological limits. Examples of such limits are seasonal minimum flow out of deep storages for agricultural purposes or environmental releases of water.

3.3.6 Energy limits on demand-side participation

AEMO applies limits to the daily energy contribution from DSP in the time-sequential model within the reliability-response band of DSP, to reflect expected DSP utilisation.

4 Gas supply modelling

Gas supply modelling evaluates the reserves, production, and transportation capacity of Australia's East Coast Gas Market to calculate the availability of gas supply to gas consumers, including gas-powered generators.

Two models may be deployed to analyse gas supply – the *gas supply* model, which assesses physical infrastructure adequacy of existing, committed and anticipated gas developments, and the *gas supply development model* which introduces the capacity to assess various gas supply solutions in addition to the infrastructure assessment of the gas supply model. These two models are highly related, and use equivalent assumptions and model configurations where appropriate.

In this section:

- Section 4.1 provides an overview of the gas supply modelling process.
- Section 4.2 outlines the gas supply model configuration.

4.1 Overview of the gas supply modelling process

The gas supply development model is built on top of the gas supply model used for the *Gas Statement of Opportunities* (GSOO).

4.1.1 The gas supply model used for the GSOO

The gas supply model simulates daily gas supply and demand balances over a 20-year timeframe. The model computes energy balances at all levels of a gas system from reservoirs, basins or liquefied natural gas (LNG) facilities to the demand centres, in each gas network node and time period, and supplies gas at minimum cost subject to the infrastructure's technical capabilities.

The model considers:

- *adequacy of existing, committed and anticipated gas projects and infrastructure to meet the future gas needs of consumers*; and
- *capability of the* East Coast Gas Market *to deliver gas for electricity generation purposes*. This is implemented within the capacity outlook model, as constraints on gas generators whose operations may be impacted by gas network congestion.

4.1.2 The gas supply development model

AEMO has prepared this approach on expanding its consideration of gas market conditions in the ISP in response to the 2024 Review of the ISP and a subsequent rule determination. AEMO will apply this approach for the 2026 ISP, and expects that the approach can be enhanced for future ISPs as modelling capabilities and data availability evolve.

The gas supply development model uses the same inputs and network configuration as the gas supply model and incorporates gas development options including but not limited to transport, gas storage, regasification terminal, and/or production augmentations. The gas supply development model would test a suite of potential gas development options informed by the GSOO and industry engagement to determine where supply, storage and infrastructure options or augmentations could be located to meet ISP development pathways using gas development projections under different scenarios and to maintain appropriate adequacy of gas supplies in the East Coast Gas Market. Gas development projections will provide insight into the availability and limitations for gas to supply GPG in the NEM, improving consideration of fuel availability when determining electricity investments.

The gas supply development model is used to:

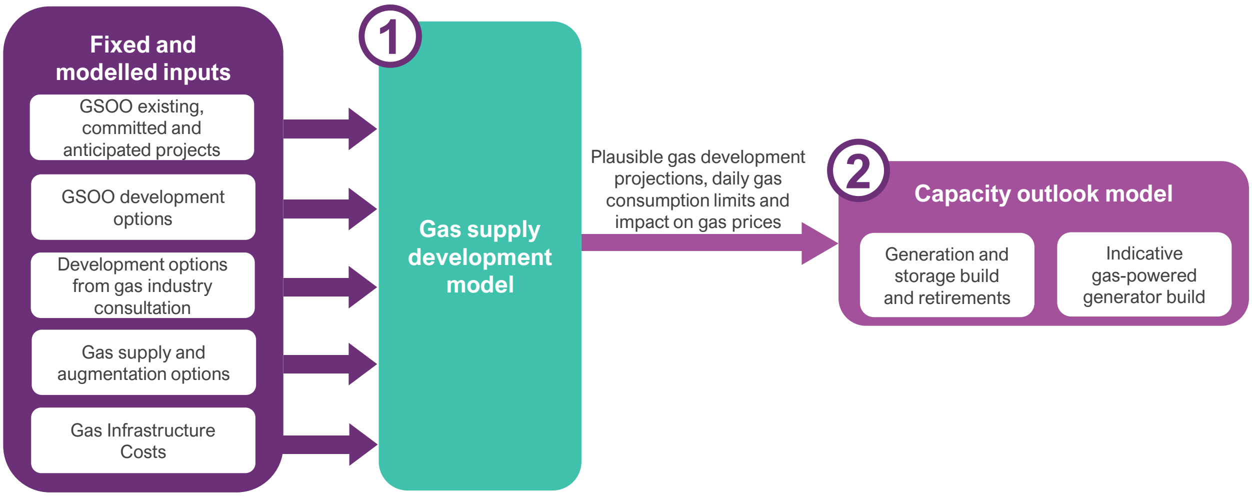
- Consider cost-efficient gas supply, storage and transportation development options to meet forecast gas consumption for electricity generation from the time-sequential model.
- Establish at least one gas development projection per ISP scenario.

The *Gas Infrastructure Options Report*, published as part of the collection of materials developed for the IASR, outlines key inputs that will inform the gas development projections in the ISP. These inputs include various gas infrastructure options and their associated cost components. The report also explains how these options and costs will be used to develop gas development projections and provide limitations for fuel availability for GPG.

Interaction with the capacity outlook model

Figure 20 illustrates the interaction between the gas and electricity models.

Figure 20 Interaction between the electricity and gas supply development models



It has the following steps:

1. The gas supply development model will iteratively analyse gas supply, storage and pipeline augmentations based on a suite of options. For a medium-term view of the gas system conditions, the model will incorporate existing, committed and anticipated gas infrastructure from the GSOO, as well as uncertain development

options[31] as pre-defined options. Additional projects identified during the engagement with gas industry process may also be included as pre-defined options. For the long term, the gas supply development model will optimise gas infrastructure requirements considering a set of augmentation options. AEMO is also exploring how the model could assess hydrogen and biomethane developments to meet forecast demand for renewable gases.

2. Outputs from the gas supply development model would inform a set of potential gas development projections that define the capabilities of the gas infrastructure to supply GPG in the NEM. These gas network capabilities would be taken as an input and ultimately mapped to the capacity outlook model. The gas development projections would be represented as a maximum daily gas zone limit that summarise the gas infrastructure that delivers to, produces in, or stores gas within each gas zone. These limits may impact the gas available for GPG fuel on a daily basis, influencing the electricity investments for firm capacity (including GPG and electricity storage devices, for example). If insufficient gas is available due to these limits, the capacity outlook model would optimise firm capacity requirements and operation by considering alternatives, including secondary fuels or non-molecular firming capacity. AEMO may also explore impacts on gas prices as a result of different gas development projections and their inclusion in the capacity outlook model.

The above process is completed at least once for each scenario to facilitate greater consideration of gas sector capabilities and influence on electricity investments. To demonstrate resilience of the ODP to different levels of gas infrastructure availability, AEMO may consider alternative gas development projections as part of the analysis. Ultimately, a single gas development projection will be selected for each scenario, which will form the basis of subsequently optimising electricity sector investments and deriving the ODP. This selection will consider trade-offs between electricity and gas sector investments, and will be subject to stakeholder feedback between the draft and final ISP.

The projected gas consumption for GPG used in the gas supply development model is derived from the other models (for example, the time-sequential model). During ISP development, AEMO will assess the impact of variations in GPG gas consumption as a result of different generation and electrical storage developments. The capacity outlook model and/or time-sequential model may be used during the validation process to assess the feasibility of the GPG builds. Insights from the time-sequential model could inform adjustments to the inputs used in the capacity outlook model.

When assessing the benefits of electricity transmission, only the costs and benefits which are within the scope of the electricity sector will be included in the transmission cost-benefit analysis[32]. However, at this stage in the modelling, the process to select a plausible gas development projection in each scenario has already included some consideration of the potential trade-offs between gas and electricity sector investments. Further, sensitivity analysis may be used to inform the selection of the ODP or evaluate its robustness (for example, using decision tree of regret analysis of electricity investments with alternate sensitivities of gas development projections). Finally, any gas sector costs that were considered in developing the gas development projections can be used in the reporting of infrastructure costs in the ISP.

[31] Options currently under consideration by market participants which include transportation developments, LNG regasification terminals, new domestic gas supply sources (including renewable gases), and gas storages.

[32] This approach is consistent with the requirement in the AER's CBA Guidelines that in estimating classes of costs under the ISP analysis only costs that can be measured as a cost to generators, DNSPs, TNSPs and consumers of electricity can be included. It is also consistent with the definition of *net economic benefit* in the NER.

Application of gas development projections in the ISP

The gas development projections are included in the capacity outlook model to inform electricity investments in generation, (electrical) storage and network developments. At least one plausible gas development projection is developed per scenario to inform the assessment of electricity investment, and AEMO intends to consult with gas industry stakeholders to support the development of these projections.

These gas development projections will influence the operability of gas generators, with more explicit consideration of the daily gas that will be available from gas production, transportation and gas storage facilities. Where secondary fuels are appropriate (for example diesel or hydrogen), the approach will also consider the cost and operational impact of on-site secondary fuel storage and the secondary fuel costs. In assessing the needs of the gas system, AEMO has considered it important to capture the level of gas usage consistent with outcomes observed in the East Coast Gas Market. That is, if the capacity outlook models do not reflect similar consumption levels to those observed in the market, due to the cost-reflective approach to dispatching generation technologies, then AEMO may adapt the operation of existing gas generators in the capacity outlook model to improve alignment between modelled and actual outcomes.

When developing the counterfactual (where no new electricity transmission is developed), AEMO will consider the appropriateness of the gas development projection. AEMO may identify that an alternate gas development projection for the counterfactual development path of each scenario may be beneficial if the counterfactual development path identifies reasonably different GPG requirements without investment in transmission augmentations (other than committed and anticipated projects). This alternate gas development projection, if identified, would be similarly considered to other plausible gas development projections, where relevant, when considering the ODP selection process.

4.2 Gas supply development model configuration

The gas supply development model incorporates major gas transmission pipelines, demand centres and production facilities. The model computes energy balances at all levels of a gas system from reservoirs, basins or LNG regasification terminals to the demand centres, in each gas network node and time period, and supplies gas at minimum cost. For the gas supply development model, there is an additional consideration of potential gas supply, storage and transportation augmentations options based on cost-efficiency.

The gas supply development model contains the following components:

- Gas network, which considers the capacity from existing transmission and processing infrastructure, as well as publicly announced infrastructure augmentations (committed or anticipated).
- Gas fields and basins, which represent gas supply connected at a specific location.
- Storage facilities.
- Daily forecasts of gas demand.
- Gas development options from the GSOO, which may include potential LNG regasification terminals, pipeline developments, new storage and/or new supply.

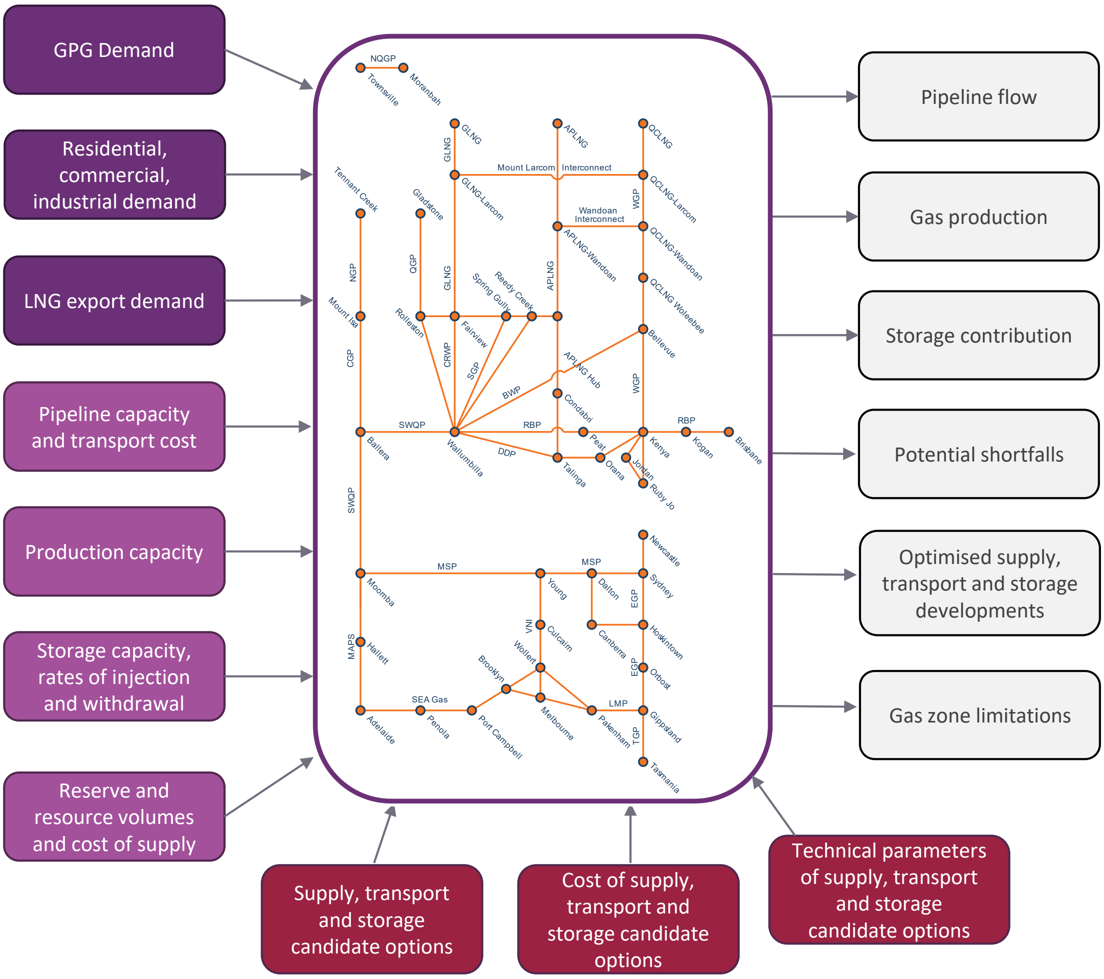
- Gas supply and transportation candidate build options, including but not limited to gas pipelines, processing facilities, compression facilities, storage facilities, LNG regasification infrastructure. Associated capital costs, operational costs and operational constraints are considered as part of the model.

More information on the detailed gas supply and demand methodologies is available in AEMO's GSOO publication materials[33].

The gas supply and augmentation options for inclusion in the gas supply development model would be developed and consulted on as part of the IASR and the Gas Infrastructure Options Report processes.

A representation of the gas model with inputs and outputs is shown in Figure 21.

Figure 21 Gas supply development model inputs and outputs



[33] At https://www.aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

5 Power system assessment

The power system assessment is the final stage of the linear modelling process. It tests the capacity outlook and time-sequential outcomes against the technical requirements for the power system (security, strength, inertia) as well as assessing MLFs to inform new grid connections.

The power system assessments feed back into the two models to continually refine outcomes towards the ODP. They ensure the capacity outlook and time-sequential outlook are robust and credible from a technical perspective, before considering the financial or commercial viability of the option.

This section sets out the methodology that AEMO uses to:

- Verify that capacity outlook outcomes are technically feasible – including revision to inputs such as network augmentation options (see Section 5.1).
- Evaluate power system security services (see Section 5.2).
- Assess MLF robustness to help inform risks for new generators connecting to the grid (see Section 5.3).

These assessments feed into the continuing iterative process to refine to the outcomes from the capacity outlook and time-sequential models.

Throughout the power system assessment process, the cost-effectiveness of alternative network and non-network options are considered, to maximise their economic benefit.

Iteration of power system assessment and market modelling

Throughout the power system assessment, there are refinements to inputs to the other stages of the ISP process. The most technically viable and economic options for generation, storage, and transmission and distribution augmentation identified in the power system analysis can be input back into the capacity outlook model, and then further refined using the PSS®E platform. Because interconnector and REZ designs are inter-related, AEMO may update transmission and non-network designs and their costs using building blocks in the published Transmission Cost Database.

The process is repeated until the outputs from both stages are aligned.

A similar iterative process occurs between the power system assessment and time-sequential model. The time-sequential model results in optimal generator dispatch outcomes and options to ensure transmission is adequate over the ISP horizon. If the power system assessment suggests network changes, the inputs into the time-sequential model are adjusted and the process is repeated. Iterations continue until the optimised generation, storage, and network outlook has met the system reliability and operability needs and the overall costs and benefits have been determined.

5.1 Verifying capacity outlook outcomes

Once the capacity outlook and time-sequential modelling has been completed, it is important to verify outcomes to see if they are robust and to understand if any additional investment is required to ensure power system security and reliability.

This step is essential; the previous stages of the modelling do not directly model the electrical characteristics of the power system because doing so would result in an unworkably complex model. Instead, the power system limits in these models are represented through constraint equations, and AEMO must verify that these constraint equations are correctly representing the entirety of power system limits and the process is not missing any power system limitations. If a limit is not represented, a new constraint is formulated to do so. This ensures a technically robust ISP.

To verify the capacity outlook, AEMO uses outcomes from the time-sequential modelling. These include generation dispatch, operation of network constraints, and frequency of binding constraints.

Power system analysis

AEMO carries out power system analysis using PSS®E to investigate the performance of the network and to identify any additional network augmentation to ensure system security and reliability. The analysis is performed on generation dispatch at selected intervals to verify:

- Network design under regional maximum and minimum demand conditions.
- Network design under regional maximum and minimum variable renewable energy generation conditions.
- An augmentation under selected conditions of interest, for example high interconnector flow plus inclusion of REZ generation.

The analysis typically includes investigating whether:

- Network equipment remains within its thermal ratings.
- Voltages can be managed within specified operating ranges.
- Voltage stability and transient stability of the network can be maintained.

If the analysis uncovers any issues, then AEMO revises the scope of relevant network designs and the implementation of those designs in the capacity outlook model and time-sequential model.

Example – refining the scope of an augmentation option

The power system assessment will test the feasibility of optimal augmentation options, such as a Queensland – New South Wales Interconnector upgrade. In doing this, AEMO conducts power system analysis to investigate key operating conditions, applying snapshots of the future system to test operability – such as high transfer levels and high demand conditions.

If AEMO's analysis determines, for example, that voltage stability cannot be maintained, then the design of the augmentation option will be revised. In this instance, AEMO adds additional dynamic reactive plant to the scope of the HVAC augmentation option – an additional synchronous condenser (or a static Var compensator [SVC]) might enable voltage stability to be maintained. This design change would result in a change to the cost and performance of the augmentation option. AEMO will use the Transmission Cost Database to determine the cost associated with the design change. The technical and economic characteristics of the revised augmentation option are updated and fed into the capacity outlook model to test whether the option remains optimal.

This process ensures that the capacity outlook model and the time-sequential model are evaluating an option that is appropriately costed and capable of delivering the benefits modelled.

Constraint equations

Statistics on constraints that bind in the time-sequential model are analysed. This analysis involves investigating the type, timing, and frequency of the constraints which are binding, that is, affecting the generation dispatch, as well as the marginal value of the constraint[34].

Constraint equations that bind frequently or have a high marginal value are considered critical. The presence of critical constraints indicate that network limits are causing congestion. AEMO may need to add new network or non-network augmentations so that the models can assess whether these are economic to address critical constraints. For example, if a thermal constraint on an interconnector is projected to be critical, it is important that there are options in the models to alleviate that constraint where economic. Within the power system assessment, AEMO will review the performance of the capacity outlook model and the time-sequential model in assessing options to alleviate these critical limits. Outcomes of this assessment could involve refinements to those models or modifications to the augmentation options.

5.2 Evaluation of power system security services

The adequacy of system security services is of critical importance as the power system transitions to a greater reliance on distributed and renewable energy resources. The ISP power system assessment evaluates current and emerging system security needs as follows:

- Iteratively – given the dependence on outcomes such as synchronous generation retirements, the size and location of inverter-based resource (IBR) builds, new storage builds, and transmission network builds.
- Holistically – considering all system security services together, not in isolation; for example, a synchronous condenser could provide system strength, reactive compensation, and inertia.
- With broad planning assumptions – to capture a reasonable cost impact. The planning assumptions used in the ISP are drawn from other work undertaken by AEMO, such as the Network Support and Control Ancillary Services (NSCAS) and system strength assessments.

The power system assessment considers the system security services, outlined in Table 3. These services are described in more detail in AEMO's *Power System Requirements* paper[35], setting out the fundamental technical

[34] See AEMO's *congestion information resource* for more details, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource.

[35] AEMO, July 2020, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf.

attributes necessary for secure and reliable system operation. This section outlines how the ISP studies evaluate the need for different system security services.

Table 3 Summary of system security services and references

System security service	This document	Power System Requirements Paper reference
Frequency control	Section 4.2.1	Section 3.2
System inertia	Section 5.2.2	Section 3.2.1
Voltage control	Section 5.2.3	Section 3.3
System strength	Section 5.2.4	Section 3.3.3
System restoration	Section 5.2.5	Section 3.4
System flexibility	Section 5.2.6	Section 3.1.3 (operating reserves)

5.2.1 Frequency control

The power system must have the ability to set and maintain frequency within a tight range to continue to operate securely. Power system frequency is controlled by the constant balancing of electricity supply and demand. If electricity supply exceeds demand at an instant in time, power system frequency will increase. If electricity demand exceeds supply at an instant in time, power system frequency will decrease.

The power system uses frequency control services to maintain this balance: primary frequency control is used to hold frequency close to 50 hertz (Hz), and secondary frequency control services are triggered and act to inject active power to remedy a frequency excursion. The services which maintain frequency must collectively provide a continuous response to arrest any deviation in frequency, and then return it to desired levels.

The ISP assumes the current NER in respect of primary frequency control together with contingency and regulation frequency control ancillary services (FCAS). It is assumed that the FCAS market will ensure sufficient headroom is available on generation or batteries, as well as provide signals for investment if needed. Given the wide range of potential sources of global FCAS providers, this is not seen to influence the ODP.

5.2.2 Inertia

In relation to the power system, inertia is an inherent electromechanical response provided by large synchronous generators as a by-product of energy production. It arises because the rotating parts of synchronous generating units (such as the turbine and rotor) connected to an AC power system spin in lockstep with the system frequency. The response is provided by the physical properties of the machine, and does not require control system interaction.

AEMO is required to plan and operate the power system to meet the frequency operating standards using inertia services provided by the local TNSP. AEMO determines three levels of inertia for each NEM region[36] required to be available:

[36] AEMO, *Inertia Requirements Methodology.* Nov 2024, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/inertia-requirements-methodology-v2-0.pdf.

- The Minimum Threshold Level of Inertia is the minimum level of inertia required to operate an islanded region in a satisfactory operating state when a region is islanded[37] or at credible risk of islanding.
- The Secure Operating Level of Inertia is the minimum level of inertia required to operate the islanded region in a secure operating state when a region is islanded.
- An apportionment of the system-wide inertia requirement, which must be maintained within each mainland region at all times, including during normal interconnected operation.

AEMO can agree to adjust these requirements if inertia support activities (such as Fast Frequency Response [FFR]) will reduce the levels of synchronous inertia needed to meet system security requirements.

There are a number of trials underway in Australia which aim to provide an inertia-like response using IBR. AEMO's approach for determining inertia requirements is consistent with the current inertia framework in the NER, which includes allowance for inertia to be provided by synchronous rotating machines or synthetic inertia services, and which can be offset by FFR.

The *Inertia Requirements Methodology*[38] details the inertia calculation methods to be used, identifies relevant inertia sub-networks, and describes the methodology by which synthetic inertia services will be quantified and approved for use in meeting inertia requirements. The most recent inertia requirements are utilised when assessing inertia across the NEM, and are available via AEMO's website[39].

Method used to assess inertia requirements

Projected online inertia is determined from time-sequential market modelling generation dispatch outcomes. These are post-processed to also include inertia from synchronous condensers, as well as consideration for FFR from new batteries[40]. This is compared to the local regional inertia requirements[41] prior to assessing any need for additional inertia services. If new interconnectors are built between regions, AEMO considers the impact of this change on the likelihood of regional separation when determining if local inertia service requirements remain in effect.

Projected online inertia for each region is determined in the ISP as follows:

1. The status of all synchronous units (on/off) is extracted from the market modelling outputs[42] for each half-hour interval.
2. The corresponding inertia constants for all online generation are then obtained.

[37] Islanding means the physical separation of the NEM region from other regions, through disconnection of all interconnection.

[38] AEMO, *Inertia Requirements Methodology.* Nov 2024, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/inertia-requirements-methodology-v2-0.pdf.

[39] AEMO, System Security Planning, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

[40] When sufficient local experience from trials is available to support the use of synthetic inertia and inertia response from batteries, these services could be included.

[41] AEMO, *Inertia Requirements Methodology.* Nov 2024, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/inertia-requirements-methodology-v2-0.pdf, and as updated from time to time in other AEMO documents available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

[42] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

  - The model assumes typical parameters for projected new synchronous plant such as gas peaking, CCGT, and pumped hydro.
  - The inertia constants for future TNSP synchronous condensers and adjustments for sources of FFR and very fast frequency control ancillary service (VF FCAS) are also added into the calculations for the time periods they expected to be in service, for example the high inertia synchronous condensers in South Australia or the potential for FFR and VF FCAS from battery energy storage systems (BESS) as relevant.
3. The total inertia is then calculated for each region by summating all the inertia constants and adjustments.
4. The process is repeated for each half-hour market modelling interval to produce annual inertia duration curves.

Consistent with the NSCAS Description and Quantity procedure[43], inertia investments are identified when the projected regional inertia cannot be maintained above the regional secure operating level of inertia for more than 99.87% of a year, and the risk of the region needing to be operated either as an island, or while at credible risk of islanding, is deemed to be sufficiently likely.

5.2.3 Voltage control

Voltage control in the power system acts to maintain voltages at different points in the network within acceptable ranges during normal operation, and to enable recovery to acceptable levels following a disturbance. Acceptable voltage ranges are defined in the NER[44].

Voltage control is managed through balancing the production or absorption of reactive power[45]. Reactive power does not 'travel' far, meaning it is generally more effective to address reactive power imbalances locally, close to where it is required. Adequate reactive power reserves are maintained to ensure the security of the transmission system in the event of a credible contingency.

The costs for new reactive compensation are included as part of network augmentation costs. Network augmentations are designed to include reactive compensation that meets the NER standards. AEMO may revise the scope of network augmentations throughout the ISP modelling process to ensure these standards are met.

5.2.4 System strength

Methods used to assess system strength

System strength requirements are calculated through fault level studies that take into account network developments and generation dispatch. AEMO's ISP modelling evaluates system strength requirements through two different fault level metrics as follows:

- System strength needed to feasibly operate the network – assessed by calculating the synchronous three phase fault level at key network locations during each simulated dispatch interval.

[43] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0.pdf.

[44] AEMC. Schedule 5.1a of the NER, at http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/Current-Rules.

[45] The rate at which reactive energy is transferred. Reactive power, which is different to active power, is a necessary component of AC electricity. Management of reactive power is necessary to ensure network voltage levels remains within required limits, which is in turn essential for maintaining power system security and reliability.

- System strength needed to connect and operate IBR – assessed by calculating an equivalent system strength impact using an available fault level (AFL) calculation consistent with the *System Strength Impact Assessment Guidelines*[46].

The ISP modelling will be prepared consistent with the current system strength framework.

The system strength needed to operate the network

The synchronous three phase fault level is used to determine the system strength needed to operate the network. This is measured in megavolt-amperes (MVA) and includes fault level contribution from synchronous machines. It is calculated under system normal conditions, and also under credible contingencies.

It is a helpful measure for system strength because it can be used to assess:

- the correct operation of protection systems,
- the size of voltage deviations due to static voltage control devices, such as switched inductors or capacitors, and
- the stable operation of existing generation.

AEMO's *System Strength Requirements Methodology*[47] details the fault level calculation method to be used, and defines the system strength nodes and requirements for key locations within each region. The ISP uses the most up-to-date minimum fault level requirements for each location, and any corresponding investment underway by the regional TNSP to maintain these minimum requirements . The fault level requirements themselves are derived through electromagnetic transient (EMT) studies that leverage the minimum synchronous generator combinations required to be online in each NEM region to provide adequate network stability[48].

AEMO calculates the synchronous three phase fault level in the ISP as follows:

1. The status of all synchronous units (on/off) is extracted from the market modelling outputs[49] for each half-hour interval.
2. The synchronous unit status is applied to the PSS®E network model.
   - The model assumes generic parameters for projected new synchronous plant such as gas peaking, CCGTs, and pumped hydro.
   - The model includes committed synchronous condensers and network upgrades.
   - The model does not assume any system strength mitigation with future IBR.
3. All IBR are switched off.
4. The fault level is then calculated at each fault level node using PSS®E.

[46] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/system-strength-impact-assessment-guidelines.

[47] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf?la=enf.

[48] AEMO. *Transfer Limit Advice – System Strength*, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf.

[49] Information about the market modelling methodology is at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

5. The network model used in the calculations is updated in a time-sequential manner to account for future ISP network upgrades.
6. The process is repeated for each half-hour market modelling interval to produce annual fault level node duration curves.

Consistent with the NSCAS Description and Quantities Procedure[50], system strength investments can be identified when the synchronous three phase fault level cannot be maintained above the minimum fault level requirements for at least 99.87% of the period.

The system strength needed to connect and operate IBR

AFL is used as a method to determine the system strength needed. This is measured in MVA and defined as the actual synchronous three phase fault level minus the required synchronous three phase fault level specified by the manufacturer of IBR. It is a helpful measure for system strength because it assesses whether the control systems of IBR will operate correctly. It is considered superior to a weighted short circuit ratio (SCR)[51], because the calculation includes the impact of surrounding IBR and also their relative electrical distances.

The *System Strength Impact Assessment Guidelines*[46] describe the assessment process and the methodology for determining AFL.

AEMO calculates the AFL in the ISP as follows:

1. The status of all synchronous units (on/off) is extracted from the market modelling outputs[52] for each half-hour interval.
2. The status is applied to the PSS®E network model.
   - The model assumes typical parameters for projected new synchronous plant such as gas peaking, CCGTs, and pumped hydro (that is, generic power system models).
   - The model is adjusted to ensure the minimum fault levels are met, and includes future TNSP synchronous condensers and network upgrades.
   - The model starts by not assuming any system strength mitigation with future IBR.
   - The impedance of IBR is modified according to minimum required SCR and unit MW capacity.
   - Two fault levels for each node are calculated using PSS®E:
     - Three phase synchronous fault level (contributed by synchronous resources only), and then
     - Total three phase fault level required for IBR to operate in a stable manner, based on the previous SCR assumptions.
   - AFL is then calculated for each node by subtracting the total required fault level from the actual synchronous fault level. A negative outcome indicates a need for additional synchronous fault level at the

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[50] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0.pdf.

[51] AEMO. *System Strength Impact Assessment Guidelines*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Impact_Assessment_Guidelines_PUBLISHED.pdf.

[52] Information about the market modelling methodology is at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

location. This reduced equation provides an indication of the positive contribution from synchronous resources, and the current understanding of interplay between synchronous resources and inverter-based resources with relation to system strength. It is important to note that this is an area of evolving understanding and technical innovation.

- The network model used in the calculations is updated in a time-sequential manner to account for the proposed ISP network upgrades.
- The process is repeated for each half-hour market modelling interval to produce annual fault level node duration curves.

Investment needs for system strength can be identified when the AFL becomes negative.

How system strength costs are approximated

AEMO's approach for estimating costs includes technologies that are commercial or have been demonstrated at a large scale. For this reason, synchronous condensers will in some cases be used as a proxy for estimating system strength costs. While AEMO expects that alternative technologies, such as grid-forming inverters, are likely to improve system strength in future, their performance and costs are still developing. This provides a robust approach to assessing the need for future network investment, as alternative technologies would only be considered when more optimal than the proxy.

The system strength needed to feasibly operate the network

As synchronous generating units reduce operation and exit the market, system strength solutions will be required to feasibly operate the electricity network. To take into account the anticipated lead time for system strength remediation, AEMO takes a different approach depending on the timing of a system strength need.

In early projections (in the first five years – or a period stated in the IASR), the time-sequential model ensures a minimum dispatch of synchronous generation (consistent with existing operational requirements).

For longer timeframes (beyond five years – or a period stated in the IASR), the costs of installing replacement fault current sources to meet the system strength requirements are applied as an additional retirement cost to existing thermal generation. This allows the model to optimise retirement decisions with an understanding of the likely system strength remediation costs. These cost assumptions and trajectories are consulted on through the IASR process.

The system strength needed to connect and operate IBR

The ISP model will reflect the implications of the current system strength framework in place in the NEM. The cost of system strength services may be incorporated in the ISP model via connection costs and REZ augmentation costs and as part of network upgrades. The cost of system strength services may be approximated using a combination of different system strength technology costs – including appropriately sized synchronous condensers, grid-forming technologies, and the incremental cost associated with fitting clutches or retrofitting generating units to run as synchronous condensers when not required for energy. These cost assumptions and trajectories are consulted on through the IASR process.

5.2.5 System restoration

The ISP model typically projects a significant amount of resources that can provide system restart services – primarily hydroelectric generation, pumped storage, battery storage[53], and GPG. As AEMO anticipates system restart ancillary services (SRAS) requirements to be met and costs to not significantly vary between network development outcomes, SRAS requirements are not independently assessed as part of the ISP.

5.2.6 System flexibility

Large generators and demand response can require many hours' notice before they can start generating or provide an initial response. To ensure the system operates in real time with high technical integrity, it is necessary to ensure the system is able to cope with unexpected variations in supply and demand.

As the penetration of VRE increases, the system needs to operate more flexibly to accommodate increases in variability and uncertainty. AEMO's Renewable Integration Study Appendix C (Section C5)[54] showed that a range of flexible resources must be utilised and planned ahead of time, so the right mix of system resources is available when needed to maintain the supply-demand balance across different time scales. It also showed that the supply of flexibility is specific to the rate of change, region, market behaviour, and other operational or system events.

The time-sequential model captures variability to an extent; however some aspects are not captured, due to:

- The use of a 30-minute simulation timestep (high ramps that can occur over shorter periods like 5-15 minutes may be missed).
- The difficulty in accurately modelling fast start generator start-up times (if offline when high ramping period occurs).
- The difficulty in accurately modelling slow start-up/ramp rates for fossil-fuelled generators if offline (start-up time can be dependent on time previously offline).

There are ongoing reviews and studies regarding ramping and operational reserve requirements, so where ramping limits or headroom requirements are identified[55] they will be incorporated into ISP studies.

System flexibility can be sourced from interconnection, existing online generation, BESS, VRE (if pre-curtailed), VPPs, CER, wholesale demand response, flexible loads, or fast-start generation.

5.3 Marginal loss factor robustness

Once the generation and transmission outcomes are verified in the power system assessment, AEMO investigates how sensitive MLFs (see Section 2.3.6) are to additional generation being added within a REZ. Even though the analysis does not affect projections of generation in the ISP, the outcome is provided because it has a commercial impact on the NEM, and consequently is highly valued by many stakeholders.

[53] Not proven for large scale regional restart to date, only smaller isolated networks.

[54] AEMO, *Renewable Integration Study*, Appendix C, April 2020, at https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-c.pdf?la=en.

[55] For example, as outcomes of the Engineering Framework studies, at https://aemo.com.au/en/initiatives/major-programs/engineering-framework.

The MLF robustness is the sensitivity of current and future MLFs to increased generation capacity within each REZ. AEMO has defined a grading for MLF robustness as indicated in Table 4. This system shows the amount of additional generation capacity (MW) that can be installed before the MLF changes by -0.05.

Transmission models are first created for each stage of the ODP. The models include any future augmentations and installed capacity at REZs. The flows through each line and transformer for each 30minute interval in a year are calculated with a direct current approximation using the power system modelling tool PSS®E (which contains a model of the network) and the market modelling results.

Then for each candidate REZ:

- A base case volume-weighted MLF for the year of interest is calculated with the flows through each line and transformer.
- The generator outputs from the market modelling results are modified by scaling up the active power output of candidate REZ, then scaling down the region's remaining generation by the same amount.
- The line and transformer flows are re-calculated with the modified generator outputs.
- The new volume-weighted MLF is calculated with the new line and transformer flows.
- The robustness is found by comparing the base MLF with the new MLF as further active power is added.

Table 4 Added installed capacity before marginal loss factor changes by -0.05 and robustness score allocated

Added REZ capacity	≥1,000 MW	≥800 MW	≥600 MW	≥400 MW	≥200 MW	<200 MW
MLF robustness score	A	B	C	D	E	F

Note: For reporting purposes, AEMO may use different thresholds in subsequent publications.

Effect of energy storage on MLFs

The effect of energy storage on a MLF depends on how well its charging and discharging profiles correlate with the generation profile and load profile. The MLF of a site will improve if the energy storage is charging at times when the generation of the REZ is high and the local area load is low. For example, co-locating a battery with a solar farm could not only assist in shifting the output to times when needed, but could also improve the MLF for the site.

6 Cost benefit analysis methodology

The cost benefit analysis (CBA) is the approach AEMO uses to develop and test alternative development paths, and ultimately determine the ODP.

The market modelling and power system analysis documented in the sections above explores how the energy sector may develop across a set of scenarios. This modelling and analysis are also a critical input into the determination of the ODP.

The ODP is the suite of actionable projects which best serves the long-term interests of consumers of electricity by balancing the net market benefits and the risk of over- and under-investment given all the uncertainties in the energy future. It also delivers positive net market benefits in the most likely scenario.

The appropriate test for that investment is a transparent CBA approach that considers the costs and benefits of alternative development paths, and the robustness of those paths under different futures.

In this section, Section 6.1 provides an overview of the objectives and principles that govern AEMO's approach to the CBA. Section 6.2 then details the approach to quantifying the cost of each development path.

The steps AEMO uses to determine and to test the resilience of the ODP are:

- Section 6.3: Determine the least-cost development path for each scenario.
- Section 6.4: Build candidate development paths.
- Section 6.5: Assess each candidate development path across all scenarios.
- Section 6.6: Evaluate net market benefits.
- Section 6.7: Rank candidate development paths.
- Section 6.8: Finalise the draft ODP selection through sensitivity analysis.
- Section 6.9: Key information for actionable ISP projects.
- Section 6.10: Transparency around decision-making criteria, further testing, and analysis of the ODP.

6.1 Principles that govern the cost benefit analysis

The CBA outlined in this methodology comprises numerous steps which are used to determine the ODP based on the AER's CBA Guidelines. Throughout the process, a number of principles are pursued including:

- Positive net market benefit in the most likely scenario.
- Ensuring flexibility to respond to the conditions in each scenario is appropriately valued, including the consideration of any option value provided by early works and other forms of project staging or timing.
- A consideration of the concept of regret as a measure of risk to consumers when considering the merits of any decision to invest or not invest in an ISP project.
- The need to ensure that the determination of the ODP is robust across changes in input assumptions.

This section also outlines some of the terminology that is used throughout the section.

Flexibility

The ISP identifies the future need for broad electricity system investments in generation, storage and network, including identifying actionable transmission projects that need to be actioned by TNSPs within an ISP cycle (every two years). However, to minimise risk to consumers of over- or under-investment, any actionable ISP project must consider future developments of generation, network, and storage investment, and the evolving needs of consumers over the life of the project.

Projects that are more capable of adapting to different future market conditions and drivers are inherently valuable. A need must be demonstrated for actionable ISP projects to progress now such that the benefits of investing now outweigh the potential value in delaying investment until more information is available given the inherent uncertainties that may impact decision-making.

The ISP can add optionality to actionable ISP projects, adding flexibility to projects with more uncertain benefits. This includes options such as staging the overall size or timing of the project (splitting a project into smaller sizes, and retaining the flexibility to deliver subsequent stages if and when needed), using non-network options that manage the immediate need (and enable ISP projects to be delivered if and when needed in future), and undertaking early works (to enable rapid delivery in future if required). Decision rules may also be introduced to assist in identifying the ongoing need of staged or delayed projects.

By incorporating these options, the ISP considers the risks of both under-investment (not being prepared) and over-investment (the costs of building projects that are not needed).

Regrets

In the ISP context, regrets are associated with investment decisions that are later shown to be in excess of, or short of, future needs, given the future conditions that may be present subsequent to an investment decision. For example, consumers may regret over-investing in infrastructure if conditions no longer require these assets and benefits are therefore not realised, or consumers may regret under-investment if changes occur faster than anticipated and the asset is needed sooner than what is possible when improved visibility of future conditions are apparent.

Recognising potential regrets is important in the ISP because uncertainty and consumers' risk tolerance need to be understood and considered. In some future circumstances, the risk of high future costs may be significant for a particular investment combination and outweigh the potential benefits of these investments if these circumstances eventuate.

Where investments are identified as having high risks, the cost-benefit analysis must consider the risk tolerance of consumers to these events occurring, which may not be adequately captured by simply averaging across scenarios.

These risks can occur for both under- and over-investment – often, the lack of investment can have higher risks associated with reliability than over-investment.

AEMO applies a 'Least-Worst Weighted Regrets' (LWWR) approach as one approach to inform the determination of the ODP. This helps understand potential regrets for consumers and the cost of building robustness into the plan to help minimise the likelihood for regret. In such an approach, regret is defined as the reduction in net market benefits that result from making sub-optimal investment decisions under a future scenario.

It is not reasonable to assume that perfect foresight is available for investment decision-making, nor is it reasonable to assume that all investments can be deferred until scenario likelihoods are more certain. The LWWR approach to inform determination of the ODP seeks to minimise the potential regret across all reasonably likely scenarios by testing the regrets (that is, cost of adapting and impact on benefits) associated with various alternative investment options across the range of scenarios. If a development path which was desirable in one or many future market conditions was highly regretful in another, the LWWR approach provides a means for highlighting that potential risk even if the investments were valuable in other future market conditions.

Robustness

A desired feature of the ODP is its robustness to changes in key assumptions. Scenario analysis provides an inherent opportunity to test the benefits to consumers of alternative development options under different future conditions. However, as the scenarios reflect a number of differing inputs and assumptions between them, using scenario analysis alone may not identify the impact of specific, significant variables. The use of sensitivity analysis provides a more appropriate vehicle to test whether the ranking of candidate development paths changes with a change in one (or more, if considered appropriate) single inputs.

The ODP selection approach should retain the flexibility to factor the additional benefits and lesser regrets that may exist in development paths under a plausible range of inputs.

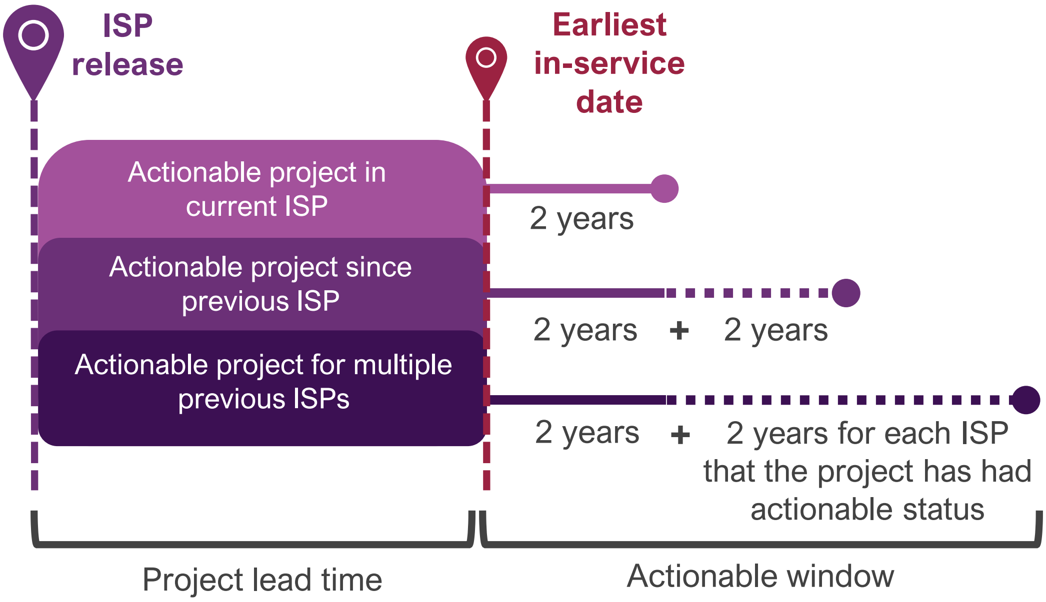
Terminology

This section uses key terms, many of which have not been referred to in this Methodology to this point. Some terms used are defined by the NER, or the accompanying AER Guidelines, in which case those definitions apply, and the terminology here provides an appropriate interpretation of those definitions. For reference, these terms are defined as follows:

- The earliest in-service date (EISD) of a project is the earliest date the project can be completed. AEMO will take advice on the EISD for a project from relevant parties through extensive joint planning with TNSPs and any relevant jurisdictional bodies. Where timelines permit, AEMO will endeavour to consult publicly on EISDs before their application in the ISP modelling.
- Proponent’s timing is the delivery date advised by transmission project proponents for projects that have previously been found actionable. This delivery date falls within a project’s actionable window and is informed by the project development activities undertaken to progress the project.
- Actionable ISP projects are projects that require a Project Assessment Draft Report (PADR) to be completed within 24 months of the ISP that identifies it as actionable.
  - A project that was not actionable in the previous ISP is identified as actionable where the CBA has concluded that the project should proceed before “EISD + 2”. If the project’s optimal timing is two or more years after the EISD, it can be actioned in a subsequent ISP – recognising that the subsequent ISP is typically published two years later than the current assessment.

   - A project that was actionable in the previous ISP is identified as actionable where the CBA has concluded that the project should proceed at the proponent's timing, compared to after the end of the actionable window (see below).
- An actionable window is set such that the CBA can identify that a project should be actioned now rather than being actioned in a future ISP. Because regulatory approval for large transmission projects can take more than four years, the actionable window is used to assess whether a project that was previously actionable should retain its actionable status from one ISP to the next. Figure 22 describes how the actionable window is calculated for a transmission project in the ISP.

Figure 22 Calculating actionable window for a transmission project in the ISP



   - For a new actionable project, the actionable window is two years (if the project is not required until two years after the EISD, then it can wait two years to be actioned if still required in the next ISP).
   - For a project that was first made actionable in the previous ISP, the actionable window is increased by two years to a total of four years (the project has been advancing for two years already, and if it does not maintain its actionability, the EISD would slip by two years because regulatory approvals, early works or preparatory activities may need to be repeated or renewed if it is subsequently actioned in future).
   - For a project that has been actionable for multiple ISPs, the actionable window is two years (to wait for the next ISP) plus two years for each ISP that it maintained its actionable status (excluding ISP updates).
- Future ISP projects are defined in the NER as those projects that address an identified need, form part of the ODP, and may be actionable ISP projects in the future. As such, a future ISP project is identified where the CBA has concluded that the project should proceed at EISD + Actionable Window or beyond.
- Potential actionable and future ISP projects share the definitions outlined above, except these concepts appear before the determination of the ODP.
- Development Paths (DPs) are defined in the NER as a set of projects (actionable projects, future projects, and development opportunities) that together address power system needs. For the purposes of assessing the

CBA, DPs refer to a combination of ISP projects that enable development opportunities. DPs are not scenario-specific, as they can be imposed and modelled across more than one scenario. DPs are not necessarily optimal in any scenario – many DPs are generally required to be tested to determine which is optimal in any given scenario.

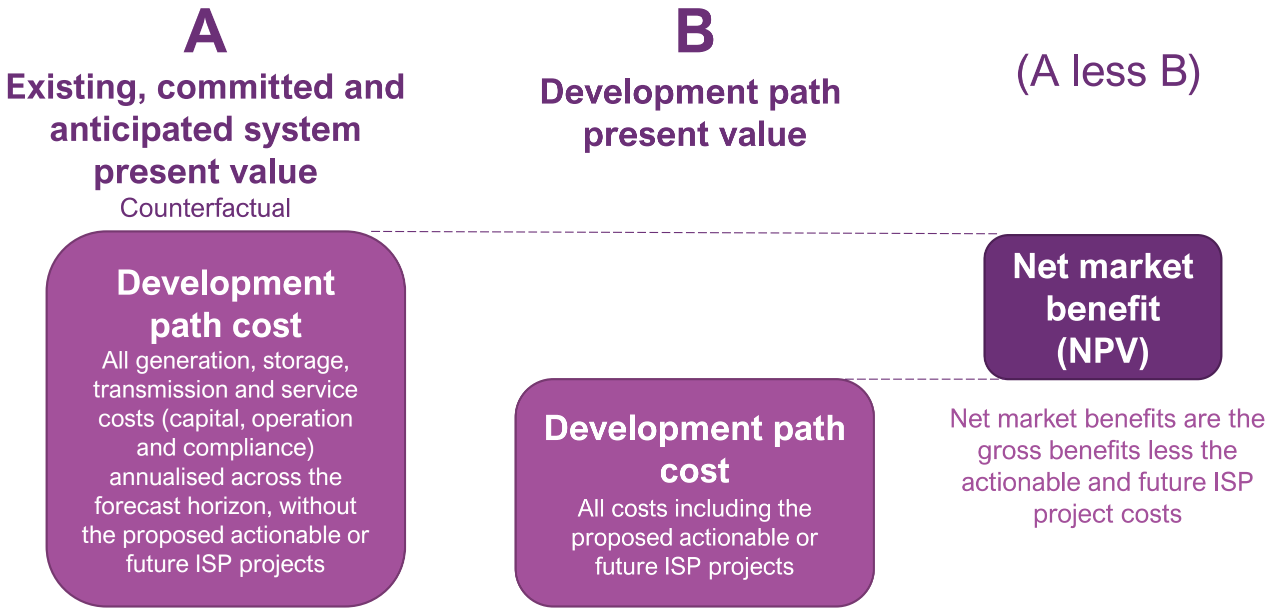
- A Candidate Development Path (CDP) represents a collection of DPs which share a set of potential actionable projects. The timings of potential future ISP projects are then allowed to vary across scenarios depending on the needs of a given scenario.
- The Optimal Development Path (ODP) is chosen from the set of CDPs as the suite of actionable and future ISP projects which optimises benefits to consumers given the uncertainties in the future outlook.
- The counterfactual DP (CFDP) represents a DP with no future network augmentation other than committed and anticipated projects, or small intra-regional augmentations and replacement expenditure projects. It forms the basis on which all other DPs are compared within each scenario.
- An ISP development opportunity means a development identified in an ISP that does not relate to a transmission asset or non-network option and may include distribution assets, generation, storage projects or demand side developments that are consistent with the efficient development of the power system.
- Present Value is the discounted sum of all costs and is used to determine the discounted cost of each DP.
- Net Present Value (NPV) is the discounted sum of all costs and benefits. It reflects the discounted net market benefits of a given DP in comparison with the counterfactual DP.

6.2 Quantification of costs and market benefits

To enable development paths to be compared, AEMO is required to determine the NPV of their net market benefit which requires the calculation of the discounted total cost of each DP compared against a counterfactual.

Figure 23 presents the calculation of net market benefits for development paths.

Figure 23 Cost-benefit analysis calculation of net market benefits of development paths



This section:

- identifies the relevant categories of market benefits that are assessed for each development path, then
- details how AEMO considers the cost of investments which have economic lives which extend beyond the modelling horizon, including both the approach to annuitising capital costs and the considerations of terminal value.

Classes of market benefits included in the CBA

The AER's CBA Guidelines set out the classes of market benefits that are considered in the ISP. The classes of market benefits included in AEMO's CBA assessment include:

- Benefits related to the development and operational costs of generation and storage assets:
  - Changes in fuel consumption arising through different patterns of generation dispatch.
  - Changes in costs for parties due to the timing of new plant, differences in capital costs, and differences in operating and maintenance costs.
- Development and operational costs of transmission assets:
  - Differences in the timing of expenditure.
  - Differences in operating and maintenance costs.
- Costs associated with demand reduction:
  - Changes in voluntary load curtailment (through DSP).
  - Changes in involuntary load shedding costs, valued at the value of customer reliability (VCR).
- Emissions reduction benefits.

Several classes of market benefits within the CBA Guidelines are not explicitly accounted for above, and AEMO's approach to accounting for these classes of benefit is as follows:

- Changes in network losses:
  - To some extent, differences in losses attributable to differences in interconnector flows and interconnector loss equations are accounted for in the changes to the fuel and operating costs of generation assets, because interconnector losses are calculated dynamically as a function of interconnector flow and allocated between regions as additional demand within the model.
  - In a similar manner, changes in intra-regional losses that may arise in alternative DPs are accounted for with intra-regional loss equations.
  - Where a consideration of other losses is material to the assessment of a particular asset, and where the potential actionable ISP project has marginal benefits, AEMO may undertake additional analysis to ensure any consumer benefits that arise from lower transmission losses are considered.
- Additional option value:
  - AEMO's scenario analysis already includes considerations of option value through the assessment of flexibility in DPs, the approach to identifying the ODP, and through the other classes of market benefits.
- Changes in ancillary service costs:
  - AEMO does not consider changes in ancillary costs as part of its CBA analysis, because they are challenging to quantify and are generally not influential to the determination of the optimal development path.
  - Where material, changes in ancillary service costs may be considered by TNSPs as part of subsequent RIT-T analysis on any actionable projects.
- Competition benefits:
  - Competition benefits refer to the increased economic efficiency that may occur from improved competition in the market as a result of investments.
  - Quantification of competition benefits is a challenging task even when considering a single investment. Including competition benefits throughout the consideration of alternative DPs on a whole-of-system plan would not be possible, nor would the benefits be expected to be.
  - AEMO does not by default include competition benefits in the CBA analysis, but they could be included by TNSPs as part of subsequent RIT-T analysis on any actionable projects.

Annuitisation and discounting of costs

For the ISP, capital investment in generation, storage and transmission infrastructure is converted into an equivalent annual annuity to allow like-for-like comparison on assets with different economic lives and different commissioning dates. It also avoids the need to explicitly model benefits well into the second half of this century.

The capital investment is spread over the economic life of the asset as a stream of equal annual payments using the following formula:

$$P = \frac{C \times r}{1 - (1 + r)^{-t}}$$

where P is the annualised cost of the asset applied during the CBA process, C is the capital cost of the asset, r is its weighted average cost of capital (WACC), and t is its economic life.

For example, suppose a new generator is developed in the capacity outlook model in 2029-30 with a capital cost of $100 million (real), and an assumed WACC of 5% and economic life of 25 years. Using the above formula, the capital cost of the generator is converted to an annual payment of $7.1 million and applied for the duration of its economic life that lies within the modelling horizon, starting from its first year of operation.

In the ISP, the discounted total cost of a development path represents the present value of annual costs accrued during the modelling horizon, and is determined using the following formula for present value:

$$Present\ Value = \sum_{i=1}^{n} \frac{A_i}{(1 + r)^i}$$

where A_i is the total annual system cost (in real terms) in year i of the modelling horizon, n is the length of the modelling horizon in years, and r is the discount rate for that scenario.

This approach inherently makes an assumption that costs and benefits are neutral for the remaining economic lives of assets beyond the modelling horizon.

6.3 Step 1: Determining least-cost Development Paths for each scenario

The first step in determining the ODP is to determine the least-cost DP for each scenario. These least-cost DPs maximise non-competition net market benefits for consumers for a given scenario assuming perfect foresight.

This forms a starting point for exploring potential DPs that best serve the long-term interests of consumers of electricity by optimising market benefits and taking into account risks given all the uncertainties reflected in the scenarios and sensitivities.

In this first step, a significant number of DPs are simulated in each scenario to determine which DP is least-cost in that scenario. As outlined in Section 2.1, the results of the SSLT are used to inform the development of DPs in each scenario, but many combinations of projects and timings are tested.

This process includes a consideration of physical staging through the potential projects which are tested – for example, building a single-circuit transmission line on double-circuit towers and stringing the second circuit at a later date. This approach adds option value, but also cost compared to building the double-circuit option from the outset.

For projects previously identified as actionable, AEMO only tests at the proponent’s timing and at the end of the actionable window or after, to determine the optimal timing of projects in the least-cost development path. The remainder of this section considers a complete example of the CBA process based on four scenarios and testing four potential augmentation options.

Table 5 presents the timings of projects in four illustrative least-cost DPs for hypothetical scenarios A, B, C, and D and projects 1, 2, 3, and 4. For the purposes of this example, consider that Project 4 represents a smaller version of the augmentation provided in Project 3. Project 1 was also found actionable in a previous ISP, so it has a longer actionable window that recognises the progress that has been made to-date on the project.

Each DP has been assigned a four-digit identifier denoting each unique combination of projects and timings. Only the DP that was identified as least-cost is shown in this table for simplicity, although potentially many other DPs (hundreds) were simulated with different timings and options to determine these optimal combinations for each scenario.

Table 5 Scenario least-cost Development Paths

	DP	Project 1	Project 2	Project 3	Project 4	Total cost ($m)
EISD	-	N/A	2030-31	2032-33	2030-31	-
Proponent's timing		2029-30	N/A	N/A	N/A	
Actionable window	-	4 years†	2 years	2 years	2 years	-
Scenario A least-cost	0012	2029-30	2030-31	2035-36	-	212
Scenario B least-cost	0022	2029-30	2030-31	2032-33	-	535
Scenario C least-cost	0045	2029-30	–	2032-33	-	111
Scenario D least cost	0061	2029-30	2030-31	-	2033-34	141

† Note in this example that Project 1 was actionable in the previous ISP, so its actionable window is 4 years. If a decision is made to remove its actionable status, then the EISD would be delayed by 2 years to wait for the next ISP and a further 2 years to repeat the regulatory approval steps which progressed since the previous ISP.

Table 5 also presents the Proponent's timing for Project 1 (given it is a previously actionable project) and EISD for Project 2, 3 and 4 and which projects in a given DP would be considered as potential actionable ISP projects based on their timing under each scenario.

For previously actionable projects, the CBA will be used to ascertain whether a project remains actionable, assessing the proponent's timing against a future timing after the actionable window (either as soon as possible after the actionable window or at a later time, to be determined by the model). For newly potential actionable projects the CBA will first assess their optimal timing, which may be at any point during the EISD + actionable window or a future timing.

In the above example, Project 1 would be considered a potentially actionable ISP project in DP 0012 given it is found in the least-cost at the proponent's timing. Project 2 would be considered a potential actionable ISP projects based on DP 0012 as the projects' optimal date is within the EISD + Actionable Window. On the other hand, this DP has development of Project 3 at an optimal timing of 2035-36 – beyond its actionable window. Considering this DP in isolation, Project 3 would not be classified as a potential actionable ISP project and would instead be classified as a potential future ISP project.

Potential actionable ISP projects under each of the DPs are present in bold in the table above. Potential actionable ISP projects would include those projects that are developed within their Actionable Windows.

6.4 Step 2: Building candidate development paths

The determination of least-cost DPs in each scenario is an important first step in the CBA process. These DPs are used as the basis for identifying a set of CDPs which are then assessed across all scenarios.

CDPs consolidate the identified DPs, creating a shortlist of varying investment decisions that may need to be made in the future, separately or in combination, to optimise benefits for consumers. The development of a set of CDPs is important for testing the risks and benefits of alternative combinations of potential actionable ISP projects. Beyond the initial investment in potential actionable ISP projects, the CDPs may feature future ISP projects or stop progressing any subsequent stages of a potential actionable ISP project.

The set of CDPs developed using this approach is designed to provide the ability to determine whether to invest now, to defer an investment until there is greater certainty, or to stage the investment to retain flexibility to hedge against uncertainty.

Initial formation of CDPs based on least-cost DPs from each scenario

The least-cost DPs in Step 1 form the basis of the initial set of CDPs. Each least-cost DP with a unique set of initial investments (potential actionable ISP projects) is used to form a CDP by fixing only the potential actionable ISP projects from that DP, with other projects classified as potential future ISP projects. Table 6 presents an example of the first set of CDPs that would be formed based on the least-cost DPs presented earlier in Table 5.

Table 6 Candidate Development Paths based on least-cost Development Paths

Candidate Development Path	Description	Potential actionable projects		
CDP1	Based on Scenario A and D's least-cost DP	Project 1	Project 2	
CDP2	Based on Scenario B's least-cost DP	Project 1	Project 2	Project 3
CDP3	Based on Scenario C's least-cost DP	Project 1	Project 3	

Note in the example above that although Scenario A and Scenario D had different least-cost DPs (see Table 5), they shared the same combination of potential actionable projects and therefore are consolidated into a single CDP.

Refining the set of Candidate Development Paths to include early works

As described earlier in this section, early works are pre-construction activities that can be taken now, while keeping open the option to either continue, defer, or cancel the project as new information becomes available. Some projects may have capacity to undertake early works, maintaining momentum on the project to still enable delivery at or shortly after the EISD if the future unfolds in a way that makes this project beneficial, without committing to the full development.

The inclusion of early works is therefore one of the means of capturing the option value that is attributable to the ability to stage a project delivery, or at least to delay the full approval of the entire project without materially compromising the project delivery schedule. Other forms of staging, such as building a large project in stages in such a way that each individual stage provides distinct value and enables a subsequent stage to be built more cheaply or quickly if subsequently needed, are captured through the testing of development paths – these staged projects can be specified as separate projects (for example, building a single-circuit transmission line on double-circuit towers and stringing the second circuit at a later date).

A potential actionable ISP project that could be staged (through early works) may warrant an additional CDP or CDPs that investigate the option value of the early works. These projects fall into two categories:

- Those that are potential actionable ISP projects in all scenarios – in this instance early works would never present any benefit, given the consistent timing preference across scenarios to deliver the project as early as the project's EISD (or at least before EISD + Actionable Window). The CBA would therefore not consider early works as a valuable first stage. These projects are classified as 'minimum regret projects' but are subject to final confirmation in the ODP (see Section 6.8).
- Those that are potential actionable ISP projects in only some scenarios – in this instance the timing uncertainty of the project suggests that early works may provide option value to retain delivery flexibility.

In the example above, assume that Project 1 and Project 3 have the option of early works[56]:

- Project 1 is a potential actionable project in all scenarios and is therefore considered a minimum regret project, without any need to consider early works.
- Project 3 is only a potential actionable project in Scenario C's least-cost DP. From this point on, an additional CDP (CDP4) is created with only the early works component of Project 3 fixed across scenarios so that the option value of early works can be assessed.
  - In all scenarios, a CDP incorporating early works on a project may be slightly more expensive than a CDP with the project developed as a single stage due to:
    - rework costs associated with delays if the project does not progress immediately to construction on completion of early works in the scenario, or
    - cost increases that are associated with a slightly longer planning timeline that follows from considering early works ahead of the full project.
  - The difference between CDP2 and CDP4 is that the decision to progress through from early works to construction could be deferred, potentially indefinitely, under certain scenarios, whereas CDP2 does not have this flexibility.

The decision to proceed with early works should therefore consider the breadth of outcomes modelled across the scenario/sensitivity analyses. If the benefits of early works exceeded the cost only under highly unlikely conditions, then it may be appropriate to dismiss the early works staging option. If, however, there is a higher likelihood that conditions arise that would provide greater benefits of project delivery flexibility, then AEMO may exercise its professional judgement discretion in preferring CDPs with early works. In so doing, AEMO will develop a decision tree that identifies the circumstances and value provided by the staging (physical or early works).

These conditions may be identifiable within the scenarios or sensitivity analyses that AEMO conducts.

[56] Project 2 and Project 4 are assumed to not have early works available for the purpose of this conceptual example. This could be because both projects have already completed early works in a prior ISP (for example).

Table 7 Candidate Development Paths adjusted for early works

Candidate Development Path	Description	Minimum regret projects	Potential actionable projects	
CDP1	Based on Scenario A and D's least-cost DP	Project 1	Project 2	
CDP2	Based on Scenario B's least-cost DP	Project 1	Project 2	Project 3
CDP3	Based on Scenario C's least-cost DP	Project 1	Project 3	
CDP4	Based on Scenario B's least-cost DP (updated for early works)	Project 1	Project 2	Project 3 – early works only

Augmenting the set of Candidate Development Paths to consider project deferrals

At this stage, the CDP collection is based on the least-cost DP in each scenario. However, the determination of the ODP is based on the value of projects when considered across all scenarios, and the CDP collection may be augmented with additional CDPs that represent DPs that may be near-optimal in all or some scenarios.

In addition, to better understand the potential costs or benefits of deferring projects, additional CDPs that feature the removal of combinations of potential actionable ISP projects from each CDP are added. This would result in a set of additional CDPs in the example which are shown in Table 8.

Table 8 Additional Candidate Development Paths with project deferrals

Candidate Development Path	Description	Minimum regret projects	Potential actionable projects
CDP5	Based on CDP1, removing Project 2	Project 1	
CDP6	Based on CDP4, removing Project 2	Project 1	Project 3 – early works only

Note that only two additional CDPs are required at this stage as there would be significant overlap if, for example, Project 3 is removed from CDP3, resulting in only Project 1 since this is already covered by CDP5.

It should also be noted that although Project 2 has been removed as a potential actionable ISP project in CDP6, Project 2 may be developed as a potential future ISP project when assessed across scenarios. In this circumstance, its EISD is delayed by two years, reflecting the ISP cycle.

This testing and analysis of the removal of potential actionable ISP projects from the set of CDPs is an important part of the process. The comparison of CDPs with and without a potential actionable project indicates the benefits of progressing a project immediately. The CDP that does not feature that project at its EISD considers one of two potential responses in each scenario:

- Proceeding with the project at a later date. If the CDP with the project as actionable optimises consumer benefits more than the CDP which delays that project, all else being equal, then it means that the analysis has determined that the value of immediately progressing with the project exceeds any value from deferring the decision on the project.
- Not proceeding with the project at all, either by proceeding with an alternative network or non-network investment or by not investing in network and instead using other alternatives such as more localised generation development. A comparison between network and more localised generation and storage solutions is considered throughout the entire CBA process.

Augmenting the set of Candidate Development Paths by adding other combinations

At this point, other CDPs may be added which could be considered potentially optimal.

For example, in considering Table 5, Project 4 is identified as a potential future ISP project in Scenario D. Although not potentially actionable in any of the least-cost DPs, this smaller and cheaper alternative to Project 3 is assumed close to being in the least cost development plan across a number of scenarios. Therefore, there may be value in testing this as an alternative CDP, as seen below in Table 9. Assuming that Project 4 could be built upon over time to match the capability of Project 3, this additional option effectively represents another form of project staging. Even if Project 3 and Project 4 were mutually exclusive, Project 4 may deliver a more consistent set of market benefits across scenarios and therefore may prove to have lower regret cost than Project 3.

Table 9 Additional Candidate Development Paths to explore other alternatives

Candidate Development Path	Description	minimum regret projects	Potential actionable projects	
CDP7	Based on both CDP1 and CDP2	Project 1	Project 2	Project 4

6.5 Step 3: Assessing each Candidate Development Path across all scenarios

Once the collection of CDPs has been determined, they are tested across all scenarios so their volume-weighted net market benefits can be quantified.

CDPs lock in various combinations of potential actionable ISP projects across all scenarios. All further investment in future ISP projects (including the potential to complete projects that have advanced through early works) is then co-optimised with generation and storage development opportunities considering the investment drivers that exist for each scenario.

Timings for any subsequent network investment are re-assessed, informed incrementally by each simulation. These potential future ISP projects are modelled after their EISD plus their Actionable Window (two years for projects that were not previously actionable), as by definition if they are not progressing within the next two years in that CDP, and may only become actionable after the following ISP, which will add a two-year development delay (or more than two years if they were previously actionable).

Table 10 highlights a conceptual result for the application of each CDP across the four scenarios. Focusing on CDP1, which is built off the Scenario A least-cost DP (0012), Project 1 and Project 2 are fixed as potential actionable ISP projects across all scenarios. The timings of Project 3 and Project 4, which are potential future ISP projects in this CDP, are allowed to vary to meet the needs of each scenario at lowest cost, as long as that timing is beyond the EISD plus their Actionable Window (two years for projects that were not previously actionable).

For example, in Table 5 it is identified that the least-cost DP for Scenario B (0022) has Project 1, Project 2, and Project 3 all at their respective Proponent's timing/EISDs. In CDP1, however, Project 3 is classified as a potential future ISP project, and therefore cannot be developed for 2032-33. In the example below, an alternative DP (0028) has been found where Project 3 is introduced in 2034-35 which is the earliest possible timing if the project is not declared actionable within the current ISP[57] given its actionable window.

Similarly, if the decision is made to invest in Project 1 and Project 2 immediately (CDP1), and Scenario C eventuates, then it is no longer optimal for Project 3 to progress under that scenario. Given that Project 1 and Project 2 have been developed, developing Project 3 by 2033-34 now provides greater cost savings for consumers than the earliest possible non-actionable timing of 2031-32. On the other hand, in Scenario D, the potential actionable projects in CDP1 are consistent with the least-cost DP in this scenario, and therefore the cost is unchanged from that shown in Table 5.

CDP4 is an example which includes early works (for Project 3). In Scenario A's least-cost DP (CDP1), Project 3 is not required until 2035-36. Under CDP4, early works are delivered for the project to ensure it is ready when needed under some scenarios, but in Scenario A the completion of the project remains in 2035-36. If, in two years' time when the next ISP is prepared, this scenario is still plausible and reasonably likely and other scenarios less likely, it would be in consumers best interests to delay development of Project 3 rather than progress with a costly investment that is not yet needed[58]. The difference in total cost between the least-cost DP (CDP1) and CDP4 for Scenario A therefore reflects the proportion of early works on Project 3 which will need to be reworked at a later date as a result of the delayed delivery ($8 million in this example).

Table 10 Development Paths for each scenario in CDP1 to CDP6 (based on scenario least-cost Development Paths)

	DP	Project 1	Project 2	Project 3 early works	Project 3 completion	Project 3	Project 4	Total cost ($m)
EISD		N/A	2030-31			2032-33	2030-31	
Proponent's timing		2029-30	N/A			N/A	N/A	
Actionable window		4 years	2 years			2 years	2 years	
CDP1	-	Minimum regrets	Potential actionable	-	-	Potential future	Potential future	-
Scenario A	0012	2029-30	2030-31	N/A	N/A	2035-36	-	212
Scenario B	0028	2029-30	2030-31	N/A	N/A	*2034-35*	-	575
Scenario C	0057	2029-30	2030-31	N/A	N/A	*2034-35*	-	181
Scenario D	0061	2029-30	2030-31	N/A	N/A	-	2033-34	141
CDP2	-	Minimum regrets	Potential actionable	-	-	Potential actionable	Potential future	-
Scenario A	0074	2029-30	2030-31	N/A	N/A	2033-34	-	248
Scenario B	0022	2029-30	2030-31	N/A	N/A	2032-33	-	535
Scenario C	0078	2029-30	2030-31	N/A	N/A	2032-33	-	147
Scenario D	0081	2029-30	2030-31	N/A	N/A	2033-34	-	191

[57] All projects which are not potential actionable ISP projects but which are developed at their earliest date as potential future ISP projects are italicised.

[58] In reality, if early works had proceeded, in two years' time a decision would need to be made as to whether construction should commence on Project 3 and this decision would need to consider risks of over- and under- investment across the range of plausible scenarios explored at that time. This decision would still need to be made based on imperfect information but would benefit from knowledge of how the future has unfolded in the past two years.

	DP	Project 1	Project 2	Project 3 early works	Project 3 completion	Project 3	Project 4	Total cost ($m)
CDP3	-	Minimum regrets	Potential future	-	-	Potential actionable	Potential future	-
Scenario A	0129	2029-30	*2032-33*	N/A	N/A	2033-34	-	290
Scenario B	0135	2029-30	*2032-33*	N/A	N/A	2032-33	-	570
Scenario C	0045	2029-30	-	N/A	N/A	2032-33	-	111
Scenario D	0164	2029-30	*2032-33*	N/A	N/A	2033-34	-	169
CDP4	-	Minimum regrets	Potential actionable	Potential actionable	Potential future	-	Potential future	-
Scenario A	0012	2029-30	2030-31	TRUE*	2035-36	N/A	-	220
Scenario B	0022	2029-30	2030-31	TRUE	2032-33	N/A	-	535
Scenario C	0078	2029-30	2030-31	TRUE	2032-33	N/A	-	147
Scenario D	0061	2029-30	2030-31	TRUE	-	N/A	2033-34	149
CDP5	-	Minimum regrets	Potential future	-	-	Potential future	Potential future	-
Scenario A	0098	2029-30	*2032-33*	N/A	N/A	2035-36	-	241
Scenario B	0105	2029-30	*2032-33*	N/A	N/A	*2034-35*	-	672
Scenario C	0109	2029-30	-	N/A	N/A	*2034-35*	-	156
Scenario D	0118	2029-30	*2032-33*	N/A	N/A	-	2033-34	150
CDP6	-	Minimum regrets	Potential future	Potential actionable	Potential future	-	Potential future	-
Scenario A	0098	2029-30	*2032-33*	TRUE	2035-36	N/A	-	249
Scenario B	0135	2029-30	*2032-33*	TRUE	2032-33	N/A	-	570
Scenario C	0149	2029-30	-	TRUE	2032-33	N/A	-	111
Scenario D	0118	2029-30	*2032-33*	TRUE	-	N/A	2033-34	158
CDP7	-	Minimum regrets	Potential actionable	-	-	-	Potential actionable	-
Scenario A	0172	2029-30	2030-31	N/A	N/A	-	2030-31	230
Scenario B	0175	2029-30	2030-31	N/A	N/A	-	2030-31	552
Scenario C	0181	2029-30	2030-31	N/A	N/A	-	2030-31	137
Scenario D	0185	2029-30	2030-31	N/A	N/A	-	2031-32	148

* The value TRUE here for early works here refers to early works commencing as a potential actionable project.

6.6 Step 4: Evaluation of net market benefits

The next step in the process is to determine the estimated market benefits by comparing the discounted total cost of each CDP in each scenario against the discounted total cost of the counterfactual DP (CFDP) for the same scenario.

6.6.1 Defining the counterfactual Development Path

The CBA assesses the benefits of ISP projects against a status quo where no ISP projects are built. This requires the development of a CFDP to be modelled for each scenario. This counterfactual case considers the development of the system without any actionable or future ISP projects (although ISP development opportunities may be included) and is used to identify the market benefits of the set of ISP projects included in each DP. These benefits are the differences between the discounted total cost of the CFDP and the discounted total cost of each DP (see Figure 23 in Section 6.2).

Consistent with the AER's CBA Guidelines, the CFDP considers the costs of meeting the needs of consumers within each scenario without the continued development of transmission infrastructure but instead having to rely on large-scale generation, storage, CER, and small intra-regional augmentation and replacement expenditure projects[59]. This means the CFDP does not include any inter-regional or intra-regional augmentation projects that are not already committed or anticipated. This restricts the ability to expand the transmission system beyond transmission limits that result from existing, committed, and anticipated projects, even if this leads to significant generation curtailment in REZs.

For the purpose of the example in this section, the CFDP has been denoted as "0000", as shown in Table 11.

Table 11 Counterfactual Development Path timings by scenario

Counterfactual	DP	Project 1	Project 2	Project 3	Project 4	Total cost ($m)
Scenario A	0000	-	-	-	-	356
Scenario B	0000	-	-	-	-	903
Scenario C	0000	-	-	-	-	278
Scenario D	0000	-	-	-	-	342

6.6.2 Calculation of net market benefits

Once discounted total costs have been calculated for the CFDP and the CDPs in each scenario, the net market benefits of each CDP are determined by subtracting the CDP's discounted total cost from the discounted cost of the CFDP for each scenario. This results in a measure of the NPV of net market benefits of each CDP under each scenario.

Table 12 highlights this process for the examples presented above. For example, for Scenario A – CDP 1, the cost of the least-cost DP (0012, $212 million) is subtracted from the cost of the Scenario A CFDP ($356 million). The reduction in costs of meeting system requirements in Scenario A arising from project investment (a $144 million reduction) can then be interpreted as the net benefits (cost savings) of that CDP under that scenario.

[59] See Section 3.2.2. of the AER's CBA Guidelines, at https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

Table 12 Calculating the net market benefits ($m) for each scenario – counterfactual Development Path combination

	Scenario A	Scenario B	Scenario C	Scenario D
CDP1	356 - 212 = 144	903 - 575 = 328	278 - 181 = 97	342 - 141 = 201
CDP2	356 - 248 = 108	903 - 535 = 368	278 - 147 = 131	342 - 191 = 151
CDP3	356 - 290 = 66	903 - 570 = 333	278 - 111 = 167	342 - 169 = 173
CDP4	356 - 220= 136	903 - 535 = 368	278 - 147 = 131	342 - 149 = 193
CDP5	356 - 241 = 115	903 - 672 = 231	278 - 156 = 122	342 - 150 = 192
CDP6	356 - 249 = 107	903 - 570 = 333	278 - 111 = 167	342 - 158 = 184
CDP7	356 - 230 = 126	903 - 552 = 351	278 - 137 = 141	342 - 148 = 194

6.7 Step 5: Ranking the candidate development paths

Once the net market benefits of each CDP are calculated, the final step is to apply appropriate methodologies to rank the CDPs and select the ODP.

The AER's CBA Guidelines describe the framework used to select the ODP. According to these guidelines, the ODP must:

- promote the efficient development of the power system,
- be based on quantitative assessment of costs and benefits across a range of scenarios, and
- have a positive net benefit in the most likely scenario.

The robustness of the ODP is tested through the use of sensitivities, as discussed in Section 6.8.

Consistent with this framework, AEMO ranks the CDPs using three approaches, with each exploring the relative benefits of different CDPs in a different manner to help inform the selection of an ODP that considers the risks and uncertainties reflected in the scenarios and delivers positive net market benefits in the most likely scenario.

This section:

- Describes the alternative approaches which AEMO uses to inform the selection of the draft ODP.
- Compares and contrasts the approaches.
- Details the approach AEMO uses to determine scenario weights through stakeholder consultation.

Section 6.8 provides further detail on how the robustness of high ranking CDPs is assessed using a risk assessment approach based on further sensitivity analysis.

6.7.1 Approaches for selecting the draft ODP

Under the CBA Guidelines, at a minimum, AEMO is required to use a scenario-weighted average approach to rank the CDPs against each other. AEMO is also allowed to use professional judgement in balancing the outcomes of the scenario-weighted approach with alternative approaches.

The mandatory scenario-weighted average approach

The scenario-weighted approach calculates the weighted average net market benefits of each CDP by applying likelihoods to each net market benefit. This approach relies on the determination of weights for each scenario (see Section 6.7.2). The methodology with this approach is as follows:

1. Ascribe probabilities to each of the scenarios ($, \ldots, Pn$, where n is the number of scenarios) considered for the CBA.
2. Calculate the net market benefits for each of the CDPs (1, 2,…i where i is the total number of CDPs) in each of the scenarios: B1,1,B1,2,…,Bi,n. (described in the previous steps).
3. Eliminate from further consideration any CDP that does not deliver positive net market benefits in the most likely scenario.
4. Calculate the scenario-weighted net market benefit A of all CDP not eliminated in Step 3 by applying the weights to the net market benefits: $\mathrm{Ai} = (\mathrm{Bi,1} * \mathrm{P1} + \mathrm{Bi,2} * \mathrm{P2} + \ldots. + \mathrm{Bi,n} * \mathrm{Pn})$.
5. Rank the CDPs in order from highest to lowest weighted-average net market benefit.

For example, in Table 13, CDP4 would be ranked highest using this approach and with the scenario weights specified.

Table 13 Ranking Candidate Development Paths via weighted net market benefits

	Net market benefits				Weighted average net market benefits ($m)	Ranking
	Scenario A	Scenario B	Scenario C	Scenario D		
Weight	40%	25%	25%	10%		
CDP1	144	328	97	201	184	4
CDP2	108	368	131	151	183	5
CDP3	66	333	167	173	169	6
CDP4	136	368	131	193	198	1
CDP5	115	231	122	192	153	7
CDP6	107	333	167	184	186	3
CDP7	126	351	141	194	193	2

The Least-Worst Weighted Regrets (LWWR) approach

An alternative approach is the LWWR approach, which aims to identify the CDP that would cause the least regret associated with under- or over-investment considering the uncertainties reflected across the scenarios. The approach accounts for scenario weights in determining the scale of regrets, therefore, explicitly reduces the potential impact of unlikely scenarios.

AEMO applies the LWWR approaches as alternatives for ranking CDPs as part of the process for determining the ODP. In these approaches, AEMO first identifies, for each scenario, the CDP that results in the largest net market benefit. The (negative) difference in net market benefits between all other CDPs and this identified CDP is calculated for each scenario and defined as the ‘regret’ of developing a sub-optimal pathway in that scenario. This results in a series of regrets (lower net market benefits relative to a scenario's best case) for each CDP in each scenario.

Generally, the more the CDP varies from the least-cost DP for that scenario, the greater the regret associated with either under- or over-investment. To the extent that projects can be staged, with access to recourse at a later point in time, the regret cost may be relatively small, but this is not always the case.

For the LWWR, the 'regret' calculated for each CDP in each scenario is then weighted by the scenario's probability. This has the effect of reducing the impact of high levels of regret in unlikely scenarios, and similarly placing greater emphasis on regrets in more likely scenarios.

The approach is described as follows:

1. Calculate the net market benefits for each of the CDPs (1, 2,…i where i is the total number of CDPs) in each of the scenarios: $B1{,}1, B1{,}2, \ldots, Bi, \mathrm{n}$. (described in the previous steps).
2. For each scenario, identify the least-cost DP and determine the net market benefit through comparison with the counterfactual (LB1,LB2,…,LBn).
3. Calculate the regret cost for Ri,n of a CDP/scenario pairing by subtracting the net market benefits from the net market benefit of each scenario's least-cost DP: $R\mathrm{i},\mathrm{n} = (LB1 - B\mathrm{i},1, LB2 - B\mathrm{i},2, \ldots, LB\mathrm{n} - B\mathrm{i},\mathrm{n})$.
4. Weight each of these regret costs Ri,n by the scenario probabilities (for LWWR) (, …,, where n is the number of scenarios) in the CBA, to calculate a series of weighted regrets.
5. Identify, for each CDP, the greatest of the possible weighted regret costs across all scenarios: W1,W2,…,Wi and rank from lowest to highest. For the standard LWR approach, the CDPs are ranked according to their unweighted regrets (potentially excluding unlikely scenarios).

Table 14 shows the determination of the LWWR. For each scenario, the CDP with the maximum net market benefits is identified (this is equivalent to the least-cost DP).

For Scenario A below it is CDP1, with $144 million. The net market benefit of each CDP (for each scenario) is then subtracted from the maximum net market benefit under that scenario to calculate its regret cost which is then weighted by the scenario probabilities to calculate their weighted regrets. The worst of these across the scenarios is recorded for the purpose of determining the least-worst weighted regret amongst all CDPs. Ranking CDPs to determine the LWWR shows that CDP7, which made Project 4 a potential actionable project (rather than its more expensive and larger alternative, Project 3), results in the lowest maximum regret across all scenarios.

Table 14 Calculating the weighted regret cost ($m) and ranking of Candidate Development Paths via Least-Worst Weighted Regrets

	Weighted regrets				Worst weighted regret ($m)	Ranking
	Scenario A	Scenario B	Scenario C	Scenario D		
Weighting	40%	25%	25%	10%		
CDP1	(144 - 144) * 40% = 0	(368 - 328) * 25% = 10	(167 - 97) * 25% = 18	(201 - 201) * 10% = 0	18	5
CDP2	(144 - 108) * 40% = 14	(368 - 368) * 25% = 0	(167 - 131) * 25% = 9	(201 - 151) * 10% = 5	14	3
CDP3	(144 - 66) * 40% = 31	(368 - 333) * 25% = 9	(167 - 167) * 25% = 0	(201 - 173) * 10% = 3	31	6
CDP4	(144 - 136) * 40% = 3	(368 - 368) * 25% = 0	(167 - 131) * 25% = 9	(201 - 193) * 10% = 1	9	2

	Weighted regrets				Worst weighted regret ($m)	Ranking
	Scenario A	Scenario B	Scenario C	Scenario D		
Weighting	40%	25%	25%	10%		
CDP5	(144 - 115) * 40% = 12	(368 - 231) * 25% = 34	(167 - 122) * 25% = 11	(201 - 192) * 10% = 1	34	7
CDP6	(144 - 107) * 40% = 15	(368 - 333) * 25% = 9	(167 - 167) * 25% = 0	(201 - 184) * 10% = 2	15	4
CDP7	(144 - 126) * 40% = 7	(368 - 351) * 25% = 4	(167 - 141) * 25% = 7	(201 - 194) * 10% = 1	7	1

Comparison of the scenario weighted average and the LWWR approaches

The mandatory scenario-weighted approach seeks to maximise net market benefits and make the best decision on the balance of probabilities. However, the scenario-weighted approach focuses on expected outcomes and may obscure significant risks that may be apparent in some scenarios, especially if these are considered unlikely (akin to high impact, low probability events).

The alternative LWWR approach chooses the option which minimises the worst 'regret' across all scenarios being considered. The LWWR approach provides a robust decision against the range of uncertainties examined, clearly demonstrates risks, and minimises the chance of particularly adverse outcomes impacting consumers. Compared to the scenario-weighted approach, it may rank more highly a CDP that has less upside benefit for consumers but limits the downside risk, while still delivering positive net market benefits in the most likely scenario. The calculation of benefits using this approach provides information that increases transparency around the risks and rewards of alternative CDPs.

By comparing the weighted net market benefits of the potential ODP against the highest ranked CDP under the scenario-weighted approach, the cost associated with selecting a CDP that helps mitigate risks to consumers can be determined. In this example, CDP7 delivers $5 million fewer net market benefits to consumers compared to CDP4 but minimises the risk of over-investment if Scenario C were to eventuate.

The AER's CBA Guidelines require AEMO to rank the CDPs based on the scenario-weighted approach but allow AEMO to use an alternative approach (such as LWWR) and professional judgement to select the ODP provided the choice is explained fully and reasonably reflects consumers' level of risk neutrality or aversion. AEMO involves its ISP Consumer Panel to understand consumers' level of risk neutrality or risk aversion.

AEMO considers that each of the assessment approaches provides value in understanding the merits of alternative CDPs and, in combination, provide transparency to help inform decision-making. The ranking of CDPs under each approach, as well as their performance in sensitivity testing (outlined in Section 6.8) is all considered in the selection of the ODP.

6.7.2 Allocating weights to scenarios

The use of a scenario-weighted average approach requires AEMO to determine a weight for each scenario. The scenario weights must add to 100% and AEMO must identify a most likely scenario that takes the most probable value for each input variable or parameter, provided that together they form an internally consistent and plausible scenario[60].

[60] See Section 3.2.2. of the AER's CBA Guidelines, at https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

Scenario weights are developed through an appropriate form of stakeholder engagement that enables AEMO to demonstrate that the weightings reflect appropriate collaborative decision-making from across the stakeholder cohort (for example, the use of a Delphi technique). The following section sets out an example process AEMO could use in determining scenario weights. This example approach may be replaced with another suitable methodology, if AEMO considers it more appropriate.

Example approach – the Delphi technique

The Delphi technique draws on an anonymous panel of subject matter experts to rank the relative likelihood of each scenario using a questionnaire and provide reasoning for their selection. Responses are collected, analysed, common and conflicting views identified, and shared with the Delphi panel. Panel members then have the opportunity to modify their original views based on varying positions of other panel experts, with the goal of reaching consensus where possible. Considering the insights provided by the Delphi process, AEMO may subsequently apply the weightings informed by the panel's responses, or adapt them, with justification, as appropriate.

AEMO has applied the Delphi approach to determine scenario weights in previous ISPs. For the 2026 ISP, AEMO is considering the appropriate approach or technique to determine scenario weights, prior to application. AEMO typically develops these weights as late as practical to ensure the weights reflect as up-to-date considerations as available, prior to application in the draft and final ISP.

6.8 Step 6: Finalising the draft Optimal Development Path

Once the CDPs have been ranked under the ODP selection approaches outlined above, AEMO applies further scrutiny to explore the robustness of high ranking CDPs to changes in some key assumptions through sensitivity analysis, and through any other applications of AEMO's professional judgement provided the choice is explained fully and reasonably reflects consumers' level of risk neutrality or aversion.

In the scenario analysis described above, there may be CDPs that are not ranked at the top of any approach but perform strongly in each approach and are much more robust than other CDPs to variations in assumptions. These more robust CDPs may, in AEMO's professional judgement, better balance risk and benefit for consumers and ultimately influence selection of the ODP.

Application of sensitivity analysis

This section lays out the framework for how AEMO conducts sensitivity analysis and how this analysis is considered in selecting the ODP. The use of sensitivity analysis provides an opportunity for AEMO to test the robustness of the CDP rankings, the magnitude of net market benefits, and the importance that should be placed on accuracy of particular assumptions to strengthen the validity of the analysis. Sensitivities are deviations from a scenario that adjusts a single assumption, or at most a single combination of related assumptions.

For example, Section 4.1.2 describe the process of producing gas development projections, and how AEMO will assign a gas development projection to each scenario. As part of this phase to test the resilience of the ODP to assumption changes via sensitivity analysis, AEMO will conduct sensitivity analysis to examine the impact of alternate gas development projections to the costs and benefits of the CDPs, to determine the resilience of the ODP selection to uncertainties associated with gas developments.

More generally, sensitivities are applied to one or more of the scenarios and effectively substituted for that scenario or set of scenarios in the CBA analysis.

In conducting sensitivity analysis, AEMO may need to limit the breadth of analysis that is conducted, given the complexity and time required to re-optimise each stage of this process. AEMO therefore uses an approach that considers the trade-off of complexity versus breadth, such as:

- When testing sensitivities, the CDPs assessed do not re-optimise future ISP projects, rather adopting the transmission augmentations used in the primary simulations to identify the impact of the sensitivity to the net market benefits.
- When testing sensitivities, the analysis may be limited to a subset of scenarios, for example, the scenario or scenarios considered most likely according to their weight. For example, if a project in the ODP is suspected of being sensitive to minor variations in a key input variable and the project's presence in the ODP is heavily influenced by the outcomes of a given scenario, the sensitivity may only be applied to that scenario.
- Not all sensitivities may be logical to apply to all scenarios or may represent an outcome that is already reflected in that scenario's inputs or outputs. The consideration of what scenario a sensitivity will apply to will consider the same principles that underpin scenario development discussed in the IASR (that they should remain broad, distinct, internally consistency that would exist between the scenario and uncertainty to be explored, and the impact that the uncertainty would have in delivering informative insights to the system's overall development, and the potential selection of the ISP's optimal development path.
- Sensitivities may only be applied for CDPs that were highly ranked in the alternative methodologies applied.

An example is provided in Table 15, where a sensitivity has been applied to Scenario B which results in lower net market benefits in all CDPs. However, the reduction in market benefits for CDP4 is much more significant than the reduction in CDP7, and – as shown in the final column – this results in a significant revision in the rankings of the CDPs, with CDP7 being optimal in this sensitivity. For simplicity, this example focuses only on scenario weighted-average net market benefits.

Table 15 Impact of a sensitivity analysis on Scenario B

	Net market benefits					Weighted average net market benefit – original (ranking)	Weighted average net market benefit – sensitivity (ranking)
	Scenario A	Scenario B	Scenario B (sensitivity)	Scenario C	Scenario D		
Weight	40%	25%	25%*	25%	10%		
CDP1	144	328	302	97	201	184 (4)	177 (2)
CDP2	108	368	306	131	151	183 (5)	168 (5)
CDP3	66	333	268	167	173	169 (6)	152 (6)
CDP4	136	368	278	131	193	198 (1)	176 (3)
CDP5	115	231	189	122	192	153 (7)	143 (7)
CDP6	107	333	264	167	184	186 (3)	169 (4)
CDP7	126	351	326	141	194	193 (2)	187 (1)

* Scenario B (sensitivity) replaces Scenario B, rather than exist alongside it in the CBA. Both Scenario B and its sensitivity are presented side by side here to aid readers in their understanding of the consideration of sensitivities.

Table 16 expands the sensitivity analysis above and shows how the net benefits and relative ranking of the top four CDPs compares across four additional sensitivities to that presented above. From this example, it is clear that although CDP4 performs relatively poorly across the sensitivities examined, CDP1 and CDP7 perform relatively strongly.

Table 16 Summary of conceptual sensitivity analysis

Net market benefits ($M)	Original	Sensitivity 1	Sensitivity 2	Sensitivity 3	Sensitivity 4	Sensitivity 5
CDP1	184	177	175	188	168	90
CDP4	198	176	168	192	143	83
CDP6	186	169	162	168	140	85
CDP7	193	187	183	204	145	87

Note: For each sensitivity in the above figure, weighted net market benefits have been graded from white (lowest net market benefit) to dark (highest net market benefit).

Given the above result, it is likely that CDP7 may ultimately represent a preferred choice as the ODP, given its relative robustness to the additional uncertainties examined through sensitivity analysis, and its strong performance under the base settings.

In applying its professional judgement in finalising the ODP, AEMO must identify whether the sensitivity analysis it chooses to perform provides any influence on the ODP selection. If a higher-ranking CDP under one or both of the CDP ranking approaches is a poor performer in the sensitivity analysis conducted, it may be more appropriate to prefer another CDP that performed well in both the scenario and sensitivity analyses.

Even if the sensitivity analysis is not influential in the choice of the ODP, the presentation of the results of the sensitivity analysis will be valuable in demonstrating the level of robustness of the ODP, and the relative importance of various inputs.

Application of professional judgement to reflect consumers' risk preferences

The ISP determines an ODP which represents a major infrastructure investment on behalf of current and future consumers. The ODP optimises transmission, generation and storage to meet consumers' future energy requirements. Ultimately, the selection of an ODP relies on the use of professional judgment in balancing the outcomes of the above decision-making approaches to select a path that has a positive net economic benefit in the most likely scenario.

When applying this professional judgement, AEMO may choose to apply an assessment of consumer risk preferences to the ultimate determination of the ODP. For example, consumer risk preferences may be considered in the following ways:

- An evidence-based metric which puts stronger preference and therefore higher ranking on CDPs where risks of project timeline slippage are mitigated. This would reflect consumer preferences for early investment in infrastructure that is expected to mitigate risk of later price volatility.
- An evidence-based metric which puts stronger preference and therefore higher ranking on CDPs which present the highest net benefits and where price volatility is not mitigated with earlier infrastructure investment. This would reflect consumer risk neutrality in the face of price volatility.

- An evidence-based metric which puts stronger preference and therefore higher ranking on CDPs where investments are deferred and where price volatility is not mitigated with early or timely infrastructure investment. This would reflect a preference for consumers to actively seek risks of price volatility in preference to incurring known fixed costs.

This approach could apply to the selection of the ODP or the selection of which projects in the ODP are actionable. For example, if the benefit to consumers of a REZ augmentation is uncertain, AEMO may decide not to action that project, noting that it could still progress as a designated network asset – which is funded by connecting parties rather than consumers.

Regardless of whether the approach taken aligns with an example above or is entirely different, AEMO must transparently explain why the level of risk chosen as part of the application of professional judgement is a reasonable reflection of consumers' level of risk neutrality or risk aversion[61].

6.9 Key information for actionable ISP projects

This section outlines the approach to preparing key information relevant to actionable ISP projects including:

- The approach to applying decision rules.
- An overview of how AEMO assigns an identified need.
- The approach to estimating transmission cost thresholds.

6.9.1 Application of decision rules

AEMO in its professional judgement may identify circumstances where it is appropriate to qualify the actionability of projects given the outcomes identified within the ISP's CBA.

Two options exist for this purpose:

- Staging – as described previously, staging can provide protection to consumers from under- or over-investment by enabling progression of investments to achieve early investment milestones without committing to the development of the complete project, where sufficient uncertainty exists.
- Decision rules – these can provide protection to consumers from over-investment, by identifying conditions that must exist in order for actionable projects to proceed from one stage to the next. This is important where actionable projects rely heavily on future market conditions or events that may have identifiable signposts, such that decisions to proceed do not need to wait to the next ISP before moving forward if it becomes clear that they would now deliver benefits to consumers. The following principles would apply for defining and applying decision rules to projects:
  - The circumstances for the decision rules are identifiable and measurable.
  - The timing of this identification and measurement must be reasonably expected between the current and next ISP, or prior to the completion of the stage currently being progressed.

[61] Consistent with the AER's CBA Guidelines, at https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

– There is a need to provide clear investment direction ahead of the next ISP, rather than waiting for a re-assessment at the next ISP.

6.9.2 Determining the identified need

The AER's CBA Guidelines[62] describe the identified need as "the reason why an investment in the network is needed." AEMO is required to specify at least one identified need for each actionable ISP project. The identified need(s) must be described as an objective(s) to be achieved by investing in the network and can be addressed by either network or non-network options (or a combination of the two).

Informing the identified need

For an actionable ISP project, AEMO evaluates the benefits of the project that led to it being part of the ODP. The identified need for an actionable ISP project is therefore informed by the ISP modelling process. This process begins with the capacity outlook modelling (see Section 2), is informed by the time-sequential model and power system assessment (see sections 3 and 4) and is finalised through the CBA (see Section 6).

Consideration of benefits from the capacity outlook model

The capacity outlook model makes build decisions in order to minimise capital expenditure and operational costs of the entire NEM over the long-term outlook. It has an extensive set of options to choose from when making decisions – including renewable generation, GPG, storage, network, and non-network options[63].

Often, the capacity outlook model makes build decisions which increase the transfer capability of the network. This can be for a variety of reasons, including:

- Enabling generation to be developed in areas with high quality energy resources (for example, building new network into a REZ).
- Increasing network transfer capability across the NEM (for example, an interconnector upgrade).
- Increasing the capability to supply major load centres (such as supply to a major city).

Consideration of the power system assessment and the time-sequential model

The power system assessment and the time-sequential model verify that outcomes of the capacity outlook model can meet the power system needs[64] – including the reliability standard, power system security, system standards, technical requirements in the NER, other applicable regulatory instruments, and environmental or energy policy. This consideration may also include outcomes of the Power System Frequency Risk Review or its successor[65].

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[62] AER. *Cost Benefit Analysis Guidelines*, at https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

[63] See the IASR for further details, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[64] The power system needs are defined in NER 5.22.3.

[65] AEMC. *Implementing a general power system risk review*, at https://www.aemc.gov.au/rule-changes/implementing-general-power-system-risk-review.

Consideration of benefits from the cost benefit analysis

Additional value identified through the CBA could relate to:

- Option value – the inclusion of early works (see Section 6.1) or the ability to adapt or stage an option to cater to uncertainty.
- Risk mitigation – the ability for an option to provide benefit across a range of scenarios to mitigate risks relating to the future being uncertain.

As outlined in previous sections, scenario analysis may identify the option value of investments while future uncertainty exists. Alternatively, sensitivity analysis on the most likely scenario may identify risks that may be avoidable with the actionable investment, and decision-tree analysis may be deployed to assess the value in the actionable investment that assists in avoiding this risk.

To determine the option value of an actionable early works project, the ODP is compared with a CDP that shares the same actionable projects except for the early works for scenarios that exclude the most likely scenario. The difference in the weighted benefits between these two CDPs across the remaining scenarios provides an estimate of the option value attributable to the early works.

Describing the identified need

After considering benefits from the capacity outlook model, time-sequential model, power system assessment, and CBA, AEMO describes the identified need in a written statement. When describing an identified need, AEMO:

- Supports the long-term interests of electricity consumers by including an increase in market benefits into the statement (unless reliability corrective action is required). This could include specific reference to categories of market benefits or power system needs that are fundamental to the actionable project, or the risks that a project may assist in minimising.
- Considers related elements in the ODP and any approach used to incorporate risk into the selection of the actionable project as a part of the ODP.
- Provides sufficient specificity such that options can be narrowed without pre-supposing a particular outcome.
- Considers opportunities to realise option value by enabling staged investments and aligning with decision rules.
- Includes a reference to reliability corrective action[66] if it is required.

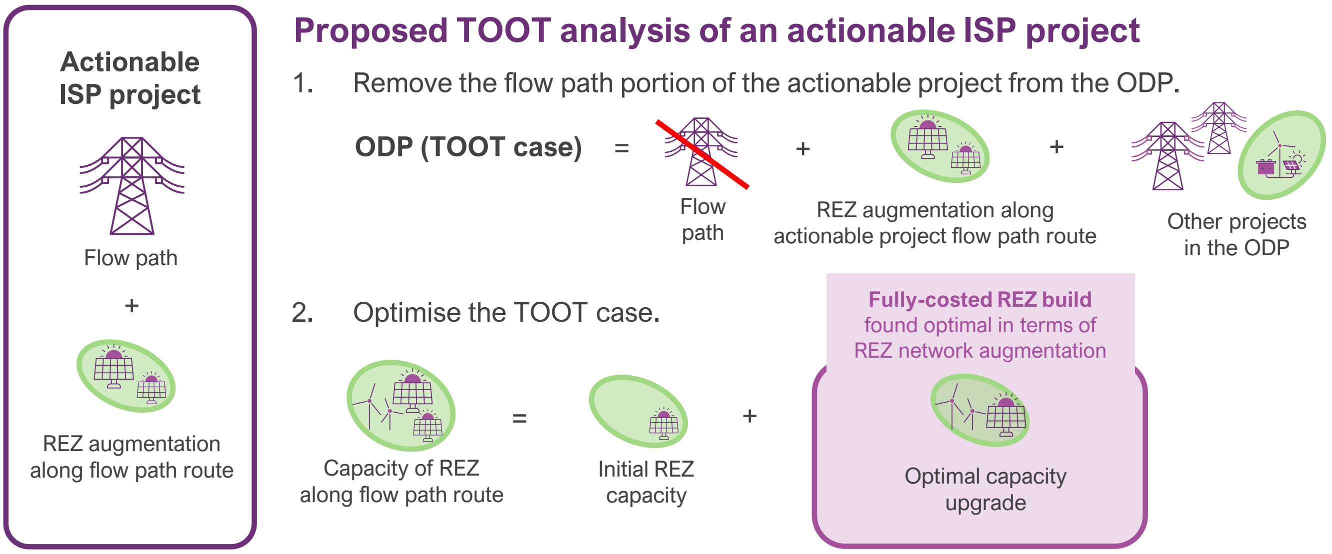
6.9.3 TOOT analysis

For each actionable ISP project in the ODP, AEMO performs TOOT analysis to provide a guide as to the individual contribution of each project to the ODP net market benefits. The TOOT approach removes the actionable ISP project from the draft ODP, along with any augmentations along the project route, for example, augmentations in the capacity available in REZs along the project route. The TOOT analysis is generally limited to the most likely scenario but may extend to other scenarios if appropriate and material to the ODP selection or to the specification of scenarios for RIT-T analysis. Figure 24 describes the process for TOOT analysis. The TOOT assessment includes the following steps:

[66] Reliability corrective action is defined in NER 5.10.2.

1. Identify the development plan of the ODP and calculate the total cost (already covered in earlier steps, and with validation through time-sequential modelling if possible).
2. For the 'base case', remove the actionable ISP project and dependent REZ network augmentations from the ODP.
3. Allow the model to optimise the capacity build and timing of any REZ network augmentations, even if the flow path itself is not built, including the full cost of the REZ network augmentations in the CBA. AEMO applies this approach to those REZ network augmentation that provide economic benefits independent of the related flow path augmentation.

Figure 24 Process for take-one-out-at-a-time (TOOT) analysis



Other aspects for the TOOT case include:

- All other major transmission augmentations (whether committed, anticipated, actionable, or future ISP projects) such as interconnector developments remain as stated by the ODP.
- No other major transmission developments are allowed.

The TOOT analysis therefore focuses on a comparison against a case without the actionable project such that it demonstrates that the actionable project delivers relative market benefits. The size of these incremental benefits is an indicator of the transmission cost threshold which, if exceeded, would lead to this project no longer being beneficial, all other inputs remaining unchanged. The relative market benefits that the TOOT analysis provides are for each project and do not consider overlapping benefits with other projects nor the synergies that could exist for multiple projects. Therefore the arithmetic sum of the relative market benefits do not necessarily add up to the net market benefits of the ODP.

Further analysis in the TOOT

For REZ developments which are determined to be actionable projects, AEMO may extend the TOOT analysis to consider the potential for reducing the scale of REZ augmentation through the co-location of storage. This is not intended to be a complete replacement of the consideration of non-network options in the RIT-T process. The inclusion of storage in REZs where there are likely actionable projects may also be considered, as discussed in Section 2.3.4.

6.10 Transparency around decision-making criteria, further testing and analysis of Optimal Development Path

AEMO considers that in optimising consumer benefits, a multi-criteria decision-making approach is required to deliver:

- Market benefits through cost savings, particularly in the most likely scenario.
- Resilience to events that can adversely impact future costs to consumers (low regret cost).
- Reliable and secure power supply.
- Robust solutions that are relatively insensitive to changes in input assumptions.

The preceding sections outline AEMO's approach to assessing the performance of CDPs, which may include any project staging or investments in early works of projects, and the draft ODP against these criteria or decision rules that need to be achieved in order to progress ISP projects. The AER Guidelines provide AEMO with the flexibility to rely fully, partly, or not at all on the results from any decision-making process it uses, however AEMO needs to justify and explain its choice.

AEMO provides additional analysis to increase the transparency around the choice of the ODP. The following information is provided in the ISP, along with the ODP for consultation:

- The reasons and justifications of the choice of the ODP, particularly where the ODP differs from the highest ranked CDP in the scenario-weighted approach.
- Quantification of the difference in costs (if any) between the ODP and the highest-ranked CDP in the scenario-weighted approach.
- The resulting net market benefits across the CDPs in all scenarios, and where relevant in the sensitivity analysis. This allows the value of each project (including minimum regret projects) to be clearly demonstrated through comparison with CDPs that do not have that project or feature smaller or other alternative projects.

Beyond the determination of the ODP, further analysis is also undertaken to explore a range of issues. Potential areas of analysis include:

- Distributional effects such as the impact of the ODP on consumer bills, including wholesale costs and transmission network charges, through detailed time-sequential modelling as outlined in Section 3.
- The resilience of the ODP against major climate risks, through time-sequential modelling (Section 3) using extreme weather case studies that have been co-designed with climate scientists[67].

This additional analysis is provided for information purposes only; it will not influence the determination of the ODP.

[67] AEMO formally collaborates with the Bureau of Meteorology and CSIRO through the Electricity Sector Climate Information (ESCI) project, which is funded by the Department of Industry, Science and Resources. Through this project, AEMO has access to extensive climate data and advice for long-term climate risk planning in the electricity sector. For more information on the project see https://www.climatechangeinaustralia.gov.au/en/projects/esci/.

Abbreviations

Term	Definition
AER	Australian Energy Regulator
AFL	Available fault level
BESS	Battery energy storage system
CBA	Cost benefit analysis
CER	Consumer energy resources
CCGT	Closed-cycle gas turbine
CDP	Candidate development path
CFDP	Counterfactual development path
DLT	Detailed long-term (model)
DNI	Direct Normal Irradiance
DP	Development path
DSP	Demand side participation
EFOR	Equivalent forced outage rate
EISD	Earliest in-service date
ELCC	Effective Load Carrying Capability
EMT	Electromagnetic transient
ESCI	Electricity Sector Climate Information (project)
ESOO	Electricity Statement of Opportunities
EV	Electric vehicle
FCAS	Frequency control ancillary services
FFR	Fast frequency response
GFST	Gas-fired steam turbine
GHI	Global Horizontal Irradiance
GPG	Gas-powered generation
GSOO	Gas Statement of Opportunities
GT	Gas turbine
GW	Gigawatt/s
HVAC	High voltage alternating current
HVDC	High voltage direct current
Hz	Hertz
IASR	*Inputs, Assumptions and Scenarios Report*
IBR	Inverter-based resources
ISP	*Integrated System Plan*
KCI	Key connection information
kV	Kilovolt/s
LDC	Load duration curve
LIL	Large industrial load

Term	Definition
LWWR	Least-worst weighted regrets
MLF	Marginal loss factor
MT PASA	Medium-Term Projected Assessment of System Adequacy
MVA	Megavolt-amperes
MW	Megawatt/s
MWh	Megawatt hour/s
NEM	National Electricity Market
NEMDE	NEM Dispatch Engine
NER	National Electricity Rules
NPV	Net present value
NSP	Network service provider
NSCAS	Network Support and Control Ancillary Services
OCGT	Open-cycle gas turbine
ODP	Optimal development path
PADR	Project Assessment Draft Report
PASA	Projected Assessment of System Adequacy
PHES	Pumped hydro energy storage
POE	Probability of exceedance
PV	Photovoltaic
REZ	Renewable energy zone
RIT-T	Regulatory Investment Test for Transmission
RoCoF	Rate of change of frequency
RRN	Regional Reference Node
SCR	Short circuit ratio
SPS	Special Protection Scheme
SRAS	System restart ancillary services
SRMC	Short Run Marginal Cost
SSLT	Single-stage long-term (model)
ST	Steam turbine
ST PASA	Short-Term Projected Assessment of System Adequacy
SVC	Static Var compensator
TNSP	Transmission network service provider
TOOT	Take-one-out-at-a-time (analysis)
USE	Unserved energy
VCR	Value of customer reliability
VPP	Virtual power plant
VRE	Variable renewable energy
WACC	Weighted average cost of capital