ISP Methodology Issues Paper

February 2021

Issues Paper

For the Integrated System Plan (ISP)

Important notice

PURPOSE

AEMO publishes this Issues Paper on 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.

DISCLAIMER

VERSION CONTROL

Version	Release date	Changes
1.0	1/2/2021	Initial Release

Executive summary

AEMO is currently developing the 2022 Integrated System Plan (ISP). Publication of this Issues Paper commences formal consultation on the Methodology proposed for use in the 2022 ISP. This paper provides detail on proposed enhancements to the existing modelling and cost benefit analysis methodologies, and invites stakeholders to provide suggestions for amendments to these to ensure AEMO can produce a robust methodology.

2022 ISP process thus far

This Issues Paper is the third major publication in the process to develop the 2022 ISP. AEMO published:

- The 2022 ISP Timetable in October 2020, providing a high-level overview of the key milestones related to the 2022 ISP, and allowing stakeholders to understand and engage in the ISP consultation process.
- The draft Inputs, Assumptions and Scenarios Report (IASR) in December 2020, proposing the scenarios to be used, as well as detailing current inputs and assumptions in relation to a variety of considerations, for use in the 2022 ISP, including the approach for updating current assumptions for use in the proposed scenarios. Before the draft IASR was published, multiple stakeholder engagements had taken place to inform the content, including workshops and webinars. The publication of the draft IASR began a consultation process with stakeholders, which is currently in progress, on these scenarios and their inputs.

The publication of this Issues Paper commences consultation on modelling methods that utilise the inputs and assumptions being consulted in the draft IASR. These methods, and proposed refinements and improvements, are not reliant on individual assumptions or the scenario definitions.

Notice of Consultation: Invitation for written submissions

All stakeholders are invited to provide a written submission to the questions outlined in this Issues Paper, and on any other matter related to the methodologies discussed to be used in the preparation of the 2022 ISP. Submissions need not address every question posed and are not limited to the specific consultation questions contained in each chapter.

Submissions should be sent via email to ISP@aemo.com.au and are required to be submitted by Monday 1 March 2021. All submissions should be provided in PDF format. Please identify any parts of your submission that you wish to remain confidential, and explain why.

AEMO requests that, where possible, submissions should provide evidence and information to support any views or claims that are put forward.

Modelling methodology

Section 2 of this Issues Paper provides a high level outline of AEMO's suite of ISP modelling tools, which consist of four mutually-interacting models (the three market models and an engineering assessment model). These models incorporate the assumptions about future development described by the scenarios (as outlined in the draft IASR) and simulate the operation of energy networks to determine a reasonable view as to how those gas and electricity systems may develop under different demand, technology, policy, and environmental conditions.

Section 2 also discusses proposed areas for enhancement in the outlined methodologies.

Cost Benefit Analysis methodology

Section 3 of this Issues Paper discusses the proposed approach to undertaking a cost benefit analysis for the 2022 ISP, and the key principles based on the information provided in the AER's Cost Benefit Analysis (CBA) guidelines.

This includes the selection of development paths, defining the counterfactual development path, the identification and quantification of costs/market benefits, and selecting the Optimal Development Path (ODP).

Next steps

The two-stage consultation process begins upon the release of this Issues Paper. Key milestones in this process are summarised below:

- 1 March 2021 – submissions to this Issues Paper are due.
- 21 April 2021 – AEMO will publish the draft ISP Methodology.
- 19 May 2021 – submissions to the draft ISP Methodology are due.
- 30 June 2021 – AEMO will publish the final ISP Methodology.

Section 4 describes this process in more detail, including more detail on how stakeholders can engage throughout.

Contents

Tables

Figures

1. Introduction

The Integrated System Plan (ISP) is a whole-of-system plan that provides an integrated roadmap for the efficient development of the National Electricity Market (NEM) over the next 20 years.

Leveraging expertise from across the industry is pivotal in developing a robust plan that supports the long-term interests of energy consumers. AEMO is committed to facilitating a stakeholder engagement process that ensures a collaborative approach to developing the 2022 ISP.

In developing the ISP Methodology, AEMO will follow the requirements of the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines[1] and Cost Benefit Analysis Guidelines[2] . This includes providing a transparent process, supporting and working with stakeholders in their understanding of AEMO's methodologies, and providing additional information to complement the formal documentation. This Issues Paper is the first part of this process.

1.1 Purpose

This Issues Paper aims to provide stakeholders with information about the methodologies AEMO proposes to use in the 2022 ISP, so a meaningful two-stage consultation process can be undertaken. By engaging on the proposed methodologies to be used, AEMO is ensuring stakeholders have the opportunity to provide their views on the proposed approach and help to shape the final methodologies.

Specifically, this Issues Paper aims to provide:

- An overview of existing methodologies (used in the 2020 ISP), and information on where these are discussed elsewhere (if applicable).
- Areas where AEMO is looking to enhance existing methodologies (used in the 2020 ISP) or introduce new methodologies to keep pace with emerging industry developments or align with the CBA.

The ISP Methodology developed for the 2022 ISP may also be used in the 2024 ISP and other ISP updates. A material change in circumstances could justify a review prior to the 2024 ISP[3].

1.2 Outline of this paper

The ISP Methodology Issues Paper sets out the proposed methodologies for:

- **Modelling** (Section 2) – the existing methodologies for the capacity outlook models, time-sequential model, engineering assessment and gas supply model. Particular focus is given where AEMO has proposed enhancements to existing methodologies, or where AEMO is proposing to implement new methodologies.
- **Cost Benefit Analysis (**CBA, Section 3) – provides an overview of AEMO's proposed approach to applying the steps outlined in Section 3.3 of the AER's CBA Guidelines. This section also discusses the proposed

[1] AER. Guidelines to make the integrated system plan actionable, at https://www.aer.gov.au/system/files/AER%20-%20Forecasting%20best%20practice%20guidelines%20-%2025%20August%202020.pdf.

[2] AER. Cost benefit analysis guidelines. Guidelines to make the integrated system plan actionable, at https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

[3] AER. Guidelines to make the integrated system plan actionable, at https://www.aer.gov.au/system/files/AER%20-%20Forecasting%20best%20practice%20guidelines%20-%2025%20August%202020.pdf.

approach to Take-one-out-at-a-time (TOOT) analysis, which is intended to form part of the approach to undertaking CBA.

1.3 Concepts and background

The two-stage consultation process for the ISP Methodology is an integral part of the broader process for developing the ISP. This section highlights other existing documents that are useful to understand when reading this Issues Paper, and explains how this consultation process fits into the 2022 ISP process.

Related documents

Table 1 below outlines related methodologies and procedures that will be used in preparing the 2022 ISP. Whilst the first two documents are related to this consultation, whereas the third is a link to the open consultation page for the Inputs, Assumptions and Scenarios. Stakeholders are invited to refer to these documents for further background and context.

Table 1 Related methodologies and procedures

Methodology/procedure	Description	Location
2020 ISP Methodology	The 2020 ISP Methodology provides an overview of the engineering assessment applied to develop the 2020 ISP. It is supplemented with the market modelling methodology report (see below).	https://aemo.com.au/-/media/files/major-publications/isp/2020/appendix--9.pdf
Market modelling methodology report	The market modelling methodology report contains descriptions of AEMO's various methodologies for simulating integrated energy supply developments for the electricity and gas systems.	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/market-modelling-methodology-paper-jul-20.pdf?la=en
2020-21 Planning and Forecasting Consultation on Inputs, Assumptions and Scenarios	AEMO is currently consulting on the scenarios, inputs and assumptions proposed for use in AEMO's 2021-22 forecasting and planning activities, including the 2022 ISP	https://aemo.com.au/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios

2022 ISP development process

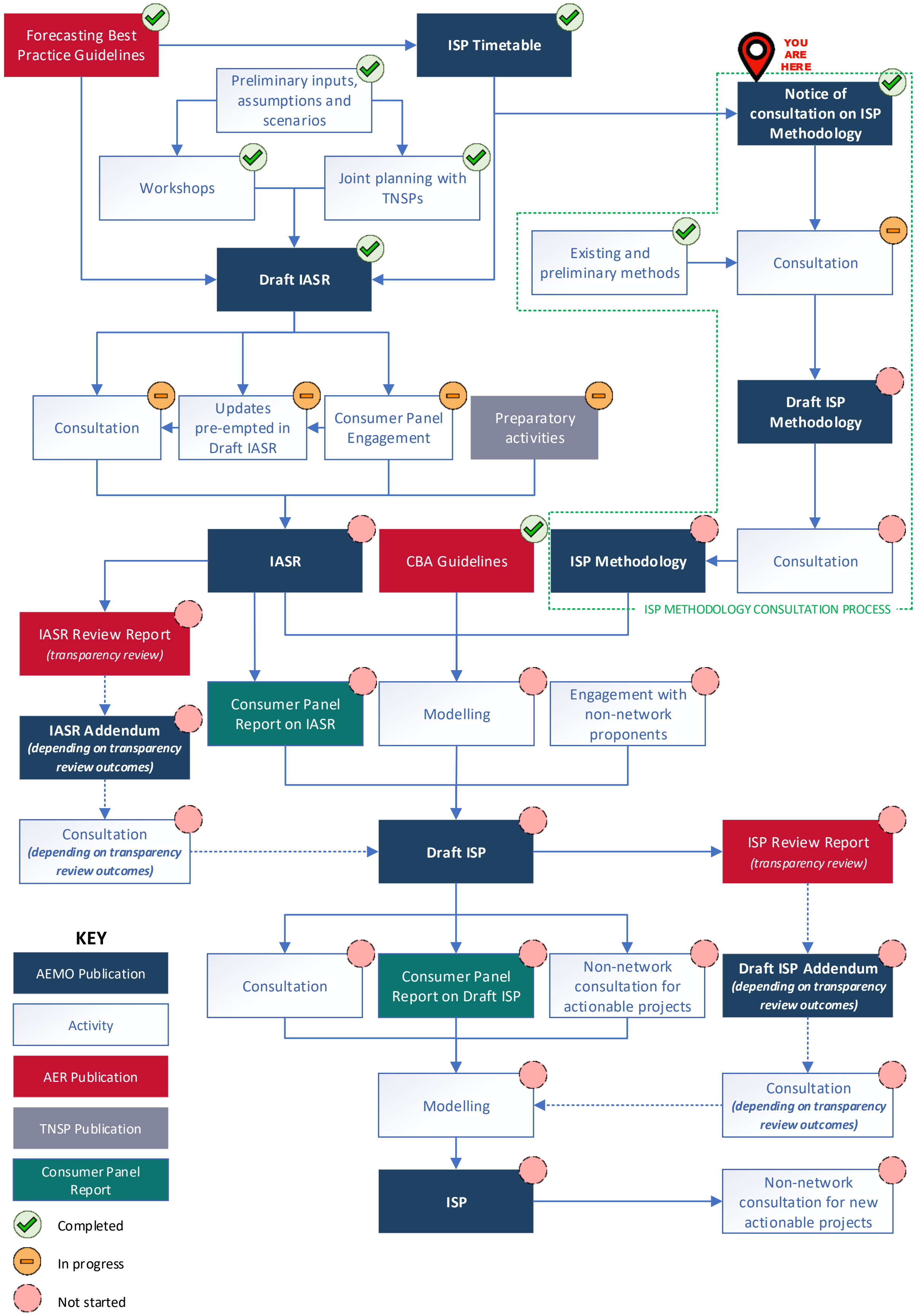
Figure 1 below shows the ISP process as a whole, noting current progress on all elements. The ISP Methodology consultation process is also highlighted within the overall process.

This Issues Paper commences the consultation on ISP Methodology, which is highlighted in Figure 1 by the dotted green line.

Transmission costs will be consulted on via a Transmission Cost consultation prior to being included in the final IASR. The development and finalisation of a Transmission Cost Report will include a draft report, public workshops, and a written consultation[4].

[4] AEMO. 2022 ISP – Opportunities for engagement, available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/opportunities-for-engagement.

Figure 1 Navigating the ISP process



† Note: The diagram above has been amended from the version published in the ISP Timetable by removing a box containing "Workshops and Meetings" before "Draft ISP Methodology". There will be meetings and a workshop at this point in the process, but this is captured in the "Consultation" box in the diagram.

2. Modelling methodology

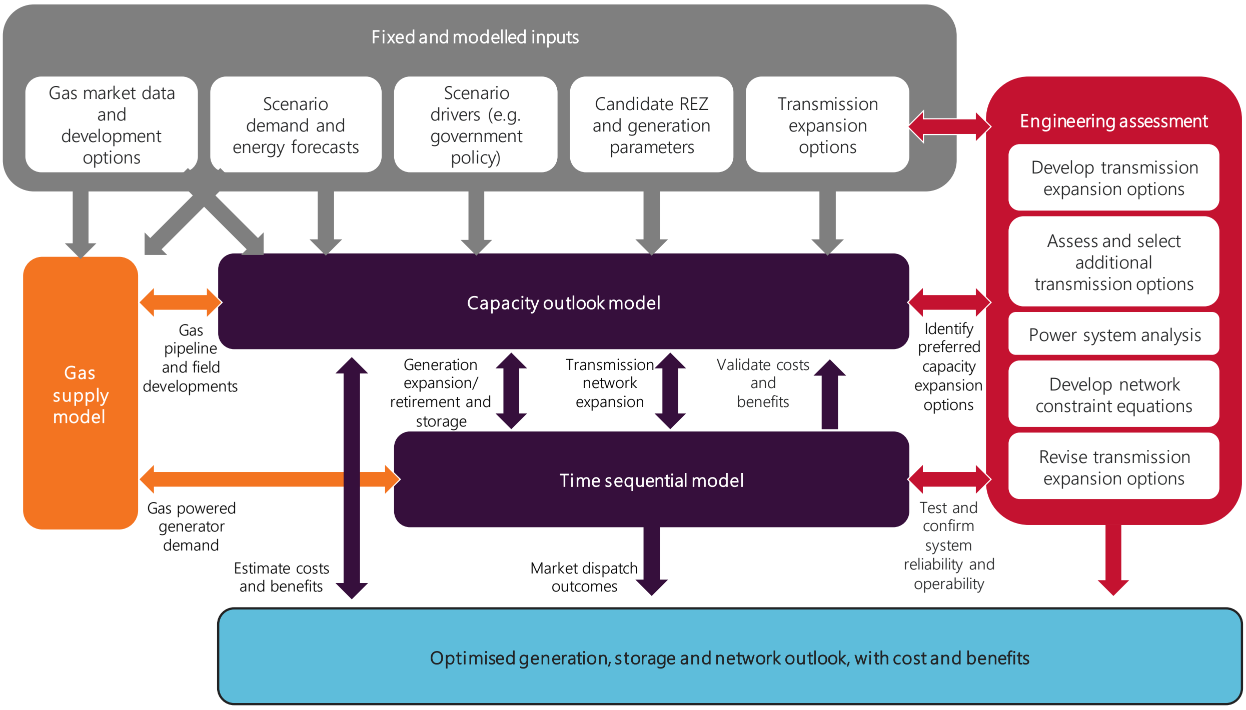
AEMO's long-term planning begins with the development of a series of global economic and technological development scenarios[5]. These scenarios are designed to cover a wide range of potential and credible futures and describe the environment in which Australia's energy networks may operate in the long term.

2.1 Modelling overview

AEMO uses a suite of interacting forecasting and planning models (the three market models and an engineering assessment model), shown in Figure 2, to assess the future development and operational requirements of Australia's energy system.

These models incorporate assumptions about possible states of the energy environment described by the scenarios and simulate the operation of energy networks to determine a reasonable view as to how those gas and electricity systems may develop under different demand, technology, policy, and environmental conditions.

Figure 2 Overview of ISP modelling methodology



The key elements of Figure 2 are summarised below, and the remainder of Section 2 follows the same structure as this summary:

[5] Details on the consultation on inputs, assumptions and scenarios are available at https://aemo.com.au/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios.

- **Capacity outlook model** – determines the most cost-efficient long-term trajectory of generator, storage and transmission investments and retirements to meet power system needs.
- **Time-sequential model** – a suite of models that carry out half-hourly and/or hourly simulation while considering various power system limitations, generator forced outages, variable generation's availability, and (optionally) bidding models. This model validates insights on power system reliability, available generation reserves, emerging network limitations, and other operational concerns, and is also used for TOOT analysis in the CBA (see Section 3).
- **Gas supply model** – used primarily to assess gas reserves, gas production, and gas transmission capacity adequacy. The model performs gas network production and pipeline optimisation at daily time intervals.
- **Engineering assessment** – examines and investigates possible engineering and operational solutions to emerging transmission network limitations identified by the capacity outlook model and time-sequential model. This assessment has three main steps:
  - Development of transmission options.
  - Assessment and selection of transmission options.
  - Power system analysis.

This Issues Paper identifies where AEMO is:

- Seeking specific feedback on the current methodology, and
- Proposing to implement new or improved methodologies.

2.2 Capacity outlook modelling

Capacity outlook modelling is used to:

- Determine the most cost-efficient trajectory for electricity generation, storage and network investments and retirements.
- Develop forecasts of the evolution of the energy system over the long term.

2.2.1 Overview of capacity outlook modelling

Capacity outlook modelling necessarily requires the use of simplifications to remain computationally feasible while being able to optimise long-term developments. For the ISP, AEMO uses a suite of capacity outlook models which make various simplifications that reflect the particular purpose of each model. The primary trade-off being made is between model granularity (spatial and/or temporal) and the optimisation horizon.

AEMO proposes to use the following variants of the capacity outlook model:

- Single-stage optimisation – a capacity outlook model which optimises the entire modelling horizon (out to 2050) in a single stage, but that necessarily requires a coarser representation of demand and variable renewable energy (VRE) variability. Inter- and intra-regional transmission augmentations are linearised for the purpose of this modelling.
  - The key purpose of this modelling is to determine the appropriate disaggregation of any carbon budget, and to determine the development of high-utilisation thermal generation (for example new combined-cycle gas turbines [CCGTs] or new coal-fired generation) which require a longer look-ahead and consideration of any carbon constraints.
- An extended multi-step optimisation – a capacity outlook model which divides the full modelling horizon into two steps while maintaining some overlap and adds additional detail in the representation of demand and VRE. Inter- and intra-regional transmission augmentations are linearised for the purpose of this modelling.

- The key purpose of this modelling is to determine whether generator retirements could be brought forward from expected closure years. The configuration of this modelling ensures that these retirement decisions take into account the impact of variability and flexibility, while also maintaining sufficient look-ahead such that the decisions take into account long-term drivers such as carbon constraints.
- This modelling would use the decomposed carbon constraint and the development of high-utilisation thermal generation from the single-stage optimisation.

- Multi-step optimisation – the final stage of capacity outlook modelling which divides the modelling horizon into three steps and applies the most detailed representation of demand and VRE variability that is computationally feasible. Transmission augmentations development paths for various interconnector and major intra-regional augmentations are developed for this modelling, informed by the outcomes of the previous optimisation steps.
  - This modelling would use the carbon constraint, retirement, and development of high-utilisation thermal generation outcomes from the previous capacity outlook optimisation steps. This modelling forecasts the development of VRE, storage, and other generation such as peaking gas generation. This modelling is also the key process by which alternative network development paths are tested.

2.2.2 Key modelling approaches used in capacity outlook models

Existing approach

Details of the modelling approaches applied in the capacity outlook models are documented in detail in Section 2.3 of the Market Modelling Methodology Paper that forms part of this consultation.

AEMO does not intend to change the approach to the following in the 2022 ISP:

- The use of rolling reference years to account for weather diversity.
  - AEMO uses a "rolling reference years" approach which involves combining a number of demand and renewable historical profiles including hydro inflows to produce a time series that would capture a variety of weather patterns throughout the planning horizon. AEMO applies this method to increase the input diversity, increasing the robustness of the expansion developments and increase the consideration of key input variance, particularly affecting weather-driven impacts on peak demands and available VRE resources.
- The application of the physical impacts of climate change.
  - Temperature rise and rainfall impacts of climate change are captured within the demand and resource availability to increase the internal consistency of the scenario narratives, and the resources affecting electricity supplies in each model. This climate adjustment is captured in the modelling by applying a linearised indexation of reference years across the capacity outlook and time-sequential models.
- The approach to load block approximations of time-sequential data.
  - Capacity outlook modelling requires simplifications in the representation of time-sequential data (demand, VRE resources, distributed energy resources [DER]) to manage computational complexity. Depending on the purpose, the various types of capacity outlook models may require the use of 'load blocks', using the load duration curve (LDC) approach which tends to smooth the intermittency of other chronological data sets, or using a chronological representation which better represents intermittency but is more computationally challenging.
- The approach to rounding from linearised build decisions in subsequent modelling processes.
  - The capacity outlook models may involve development of incremental generation developments to meet the power system needs. For many generation technologies, particularly VRE generators, no single generator sizing standard exists – a wind and solar farm can be incrementally developed with any number of turbines or panels. However, for other technologies, such as traditional thermal developments, standard turbine sizes are more appropriate, and these developments may require iterative validation of decisions within the capacity outlook models.

- Application of operational limits in the capacity outlook models to reflect technical constraints or likely gas consumption, which are informed by time-sequential models.
  - AEMO applies reasonable assumptions to reflect the operational limits of the power system, although in real-time operations these limits will depend on a range of factors to match real-world conditions. In the capacity outlook stage, the models require that some limitations are applied using simpler representations, in keeping with the operational expectations of each generation technology. This could include for example applying minimum capacity factors on CCGT generators.
- Approach to modelling build limits and lead times.
  - Build limits and development lead times ensure capacity developments reflect the real-world limitations that may impact development opportunities. Minimum development timeframes apply for each generation technology and transmission option, and maximum development levels for generation technologies on a geographic basis – regional or sub-regional as appropriate – considering resource and transmission access.

Amendments considered

- Categorising **anticipated generation projects**.
- Modelling temperature-dependent **seasonal generator ratings**.
- The approach to **reserve modelling**, including refining the method for determining the firm capacity contribution provided by VRE and storage.
- Assessing the risk of **early generation closures**.
- Adopting a **sub-regional topology** to better represent intra-regional transmission limitations.
- Representing **interconnector losses**.
- Including NEM-connected **hydrogen** electrolysis.
- Modelling **hybrid renewable energy-battery storage systems**.

Anticipated projects

For a project to be classified as committed, the CBA Guidelines[6] (and the Regulatory Investment Test for Transmission [RIT-T] Instrument[7]) define five commitment criteria that must each be satisfied:

- **Land** – the proponent has purchased/settled/acquired land (or commenced legal proceedings to acquire land) for the purposes of construction.
- **Contracts** – contracts for supply and construction of the major components of the necessary plant and equipment (such as generators, turbines, boilers, transmission towers, conductors, terminal station equipment) have been finalised and executed, including any provisions for cancellation payments.
- **Planning** – the proponent has obtained all required planning consents, construction approvals and licenses.
- **Finance** – the necessary financing arrangements, including any debt plans, have been finalised and contracts executed.
- **Construction** – construction has either commenced or a firm commencement date has been set.

Anticipated generation and transmission projects are not committed against all five criteria, but are in the process of meeting at least three commitment criteria.

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

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

Anticipated generation projects

For ISP purposes, AEMO develops a list of Anticipated generation projects using information gathered for its Generation Information publication[8].

In the Generation Information publication, generation projects are categorised by their stage of development, which is assessed using the five commitment criteria. Generation projects are assigned a commitment status classification – *Committed*, *Committed**, *Advanced*, *Maturing*, *Emerging* or *Publicly Announced*.

Advanced and Maturing projects were regarded as Anticipated projects for the 2020 ISP, broadly aligned with the RIT-T commitment criteria for anticipated projects.

AEMO intends to improve the alignment between Generation Information publications and the Cost Benefit Analysis Guidelines by addressing identified issues in the existing approach:

- The specificity of commitment status for Advanced and Maturing projects restricting the number of projects being classified as Anticipated for ISP purposes; and
- The regularity by which a project's status is updated, driven by low engagement from project proponents in terms of submitting status updates (via the Generation Information survey process) when a project is either progressed or discontinued.

AEMO is reviewing the way it assesses whether a project is *in the process of meeting* commitment criteria, to address the aforementioned limitations of the current classification process, and also to consider the influence of government-awarded contracts on a project's commitment status.

AEMO is proposing:

- To simplify the project commitment status categories:
  - AEMO is proposing to add an *Anticipated* category, and to consolidate the Advanced and Maturing categories.
  - This is intended to simplify the interpretation of project development progression, improving the usability of the information provided by the Generation Information publication, and directly meeting the needs of the 2022 ISP.
- A review of Generation Information survey questions to ascertain progress against each commitment criteria – see Table 2.
- That in the case where a project is categorised as Anticipated, but a survey has not been submitted by the project proponent in the previous 6 months, this project is no longer included in the list of Anticipated projects to be used for ISP purposes.
- To consider the role of government-awarded funding in the commitment criteria, in particular:
  - whether the announcement of government-awarded funding is sufficient to regard a generation project as Anticipated, on the assumption that a project must be viable and progressing towards at least two other commitment criteria (besides Finance) for it to qualify for government funding; or alternatively
  - that the Finance commitment status is assessed as "in progress" if any form of government-awarded funding is announced, but would only be categorised as Anticipated, and therefore included in all ISP modelling (including counterfactuals), if also progressing towards satisfying two other criteria.

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

Table 2 Project commitment criteria questions

Land

- Have the rights been secured for the land that is required for construction of the generating unit(s)?
- Have the rights been secured for the land 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 officially approved?
- 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)?
- If no PPA, are there other financing arrangements in place (such as merchant financing)?
- 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.
- Has Full Commercial Use commenced, that is, has the generating system received official approval (sign-off) of all commissioning tests, from AEMO and the NSP? If so, provide the actual date that the generating system received official approval (sign-off) of all commissioning tests, from AEMO and the NSP.

Matters for consultation

- Do you agree with the above proposal to simplify the Advanced and Maturing categories currently in Generation Information publication into a single Anticipated category?
- What is your view on the appropriateness of the current Generation Information survey questions? Please provide any suggestions for other questions that would better determine a project's progress towards meeting the commitment criteria.
- What is your view on how the announcement and/or commitment of government-awarded funding should influence the commitment status?
- Do you agree with the proposal that Anticipated projects must have provided project information within the past 6 months in order to be "progressing" and therefore included in the ISP? Alternatively, in what ways could AEMO improve the regularity by which a project's status is updated by project proponents to be satisfied that the project is progressing?

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).

As outlined in the Draft Inputs, Assumptions and Scenarios Report (IASR), AEMO sources the list of anticipated transmission projects from transmission network service providers (TNSPs) as information becomes available. If a developer intended to become licensed as a TNSP for the purpose of constructing, operating, and maintaining transmission network, AEMO intends to apply the same rigor used to determine the project status as for any other generation or network project.

Section 4.1 of the Draft 2021 IASR notes public policies that can directly influence the delivery of transmission projects (including the *National Electricity Victoria Act* and New South Wales Electricity Infrastructure Roadmap). AEMO's IASR consultation will determine which policies are included against each scenario.

Matters for consultation

- Do you agree with AEMO's approach to determining anticipated network projects for the ISP?

Seasonal ratings

In the 2020 ISP, AEMO used seasonal generator ratings that were defined based on 10% probability of exceedance (POE) conditions for summer and winter (called "10% POE demand summer capacity" and "winter capacity" respectively). The summer ratings therefore reflected expected generating capacity during periods of very high temperature, and applied these deratings throughout summer, irrespective of actual temperature.

In the 2020 Electricity Statement of Opportunities (ESOO), AEMO implemented a new approach which included the use of ratings based on typical summer conditions ("typical summer capacity"). This was applied in all but a small number of the hottest days during the summer period, where the 10% POE demand summer capacity continued to apply. This approach was implemented to better reflect the nature of temperature deratings which for many units only occur during extreme temperatures, and therefore often occur on only a few days during the summer period.

For the 2022 ISP, AEMO is proposing to also apply the typical summer capacity, in combination with the 10% POE peak derated capacities across the seasons, in a manner that will better reflect expected generator capabilities.

The proposed approach is as follows:

- The winter capacity will be used for all periods during winter.
- The 10% POE demand summer capacity will be used as the firm capacity at time of peak demand for all dispatchable generation (see the next section on reserve modelling for more on the definition and implementation of firm capacity).
- The 10% POE demand summer capacity will be applied to the subset of hottest summer days[9].
- For all other days in summer, the typical summer capacity is applied.

The proposed methodology better reflects the availability of generation while maintaining an appropriate assessment of the contribution from generation to meeting summer peak demand. The addition of temperature ratings does add complexity to the modelling process. AEMO considers that the proposed method provides an appropriate balance between modelling complexity and reflecting the expected contribution from generation at times of extreme peak conditions and during more typical summer conditions.

Matters for consultation

- Do you agree that the proposed approach represents an appropriate balance between modelling complexity and the expected contribution from generators during peak and typical conditions?

Reserve modelling

The reliability standard, set by the National Electricity Rules (NER)[10], specifies that a region's maximum expected unserved energy (USE) should not exceed 0.002% of energy consumption 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 lesser granularity in the ISP, it is not possible to get an accurate, probabilistic assessment of the USE level in any given year in the capacity outlook models. However, it is critical that the capacity outlook models are developing generation that is sufficient to achieve the reliability standard, valuing appropriately the reliability benefits provided by different generation, transmission, and demand-side options.

The capacity outlook models therefore incorporate minimum capacity reserve levels for each region which are used as a proxy for reliability; more detailed assessments of supply adequacy can then be simulated in future modelling stages with the more granular time-sequential models to refine the capacity reserve level used in the capacity outlook model. Through this iterative process, the capacity outlook models ensure that sufficient firm capacity is installed/maintained within each region, or imported from neighbouring regions, to meet these minimum capacity reserve levels.

The minimum capacity reserve levels are generally set equal to the size of the largest generating unit (although may be adjusted over time as the generation mix evolves and if the time-sequential modelling indicates that more (or less) firm capacity needs to be built in a region to avoid exceeding the reliability standard). These adjustments are made based on an iterative process which ensures that the setting of the

[9] For a detailed explanation of how this subset of days was determined, see the ESOO and Reliability Forecast methodology document, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

[10] In NER cl 3.9.3C(a), at https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules/current.

reserve levels is not too low, resulting in the addition of firm capacity which is insufficient to meet the reliability standard, or is it too high, therefore resulting in more firm capacity than is required.

Key reserve modelling inputs include:

- Minimum capacity reserve levels (in the first instance, set to the size of the largest generating unit in the region, 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 peak demand).
- Firm capacities for firm generation technologies using the 10% POE demand summer capacity, adjusted for the effective full forced outage rate. This is used as a proxy for the impact of full and partial outages which are modelled stochastically in reliability assessments.
- Firm capacities for VRE generation and storage which are based on firm contribution factors (further details below).

AEMO proposes keeping this approach largely unchanged, but is proposing several adjustments to improve the representation of some of the components described above. The following subsections discuss in more detail how amendments could better represent the firm contribution of VRE and storage.

Firm contribution factors for VRE

Intermittent renewable generators cannot operate at any dispatch target at any time; rather they are reliant on the variability of the 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 peak 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 the purpose of reserve modelling, some assumption needs to be made about the equivalent firm capacity that is provided by VRE generation.

Other forms of generation, such as traditional thermal generators, do not suffer from operational limitations that limit the availability of dispatch, beyond the seasonal temperature deratings that are described in the previous section, as well as forced outages. As such, these generators have a firm contribution factor at or near to 100% of their 10% POE seasonal peak rating, adjusted for expected forced outage rates.

AEMO currently develops wind and solar contribution factors that specify the amount of wind and solar generation that can be relied on during times of maximum demand. In this approach, AEMO computes the wind and solar contribution to peak demand to be the 85th percentile level of expected wind and solar generation across summer or winter peak periods (being the top 10% of 30-minute trading intervals in each season). These contribution factors are defined for each region in the NEM, and are finalised by taking the average of all reference years. AEMO calculates these factors for both existing generators and new entrant wind and solar farms, using historical generation (existing) and forecast renewable generation resources across each region.

For Queensland and Tasmania, AEMO considers that there is currently insufficient existing VRE for an existing technology contribution to peak factor to be determined with sufficient rigour. AEMO applies the new entrant contribution to peak factor for both existing and new entrant generators in these regions.

For solar generation, a contribution to peak of zero may result if the timing of the top 10% of demand intervals sufficiently is observed after sunset, such that the 85th percentile generation would observe periods of zero generation after dark.

These contribution factors are only used by the capacity outlook model to estimate the renewable generation contribution to meeting the minimum reserve margins. However, the approach described is based on thresholds and percentiles that may over- or under-state the true contribution from VRE.

AEMO is currently of the view that determining the Effective Load Carrying Capacity (ELCC)[11] for the penetration of wind and solar in aggregate in each region, averaged across all available reference years in five year increments, provides the best representation of the contribution to peak. This will necessarily be an iterative process within each scenario, as the penetration may be influenced by the assumed contribution to peak.

Firm contribution factors for storage

In the 2020 ISP, all storage was assumed to have a firm capacity contribution that was equal to its maximum capacity. This likely overestimates the reliability benefits of these technologies in many situations, particularly short-term storages such as batteries with one or two hours of energy storage, if the peak demand event can extend beyond the storage depth.

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

AEMO is proposing to explore new methodologies which generalise the reliability benefits of different storage configurations. One possible method is to determine a reasonable approximation of the duration of peak demand events and to adjust the firmness to reflect the contribution that could be provided across this period; for example, if the average duration of peak demands was determined to be approximately three hours, a 1 megawatt (MW)/2 megawatt hours (MWh) battery would be allocated a firm contribution of 66.7%.

Matters for consultation

- Do you have any alternative suggestions for methodologies or assumptions that better reflect the contribution to peak demand from VRE, in particular how this contribution evolves as the penetration of VRE increases?
- Do you agree with AEMO's proposed approach to determining firm contribution factors for storage by approximating the duration of peak demand events? Do you have any proposals for how AEMO may otherwise account for the contribution to firm capacity provided by storage technologies?

Sub-regional topology for the capacity outlook model

AEMO is proposing to move from a regional topology to a sub-regional topology for the capacity outlook model in the ISP. The proposed sub-regional model splits the existing Queensland and New South Wales regions into a number of sub-regions[12]. The reasoning for this change and the selection of individual sub-regions is outlined in the following sections.

In the regional topology, each of the five NEM regions are represented by a single reference node, and all regional loads are placed at the regional reference nodes, with new REZ generation limited by the REZ transmission limits.

For the proposed sub-regional topology, the regional load and generation resources are appropriately split between the different sub-regions. From this point, it would be similar to the regional model, with all sub-regional loads placed at the new sub-regional reference nodes, and generation represented across the power system considering the REZs. See the Draft 2021 IASR for more detail on topology[13].

---

[11] The ELCC of a generator or technology is the amount of capacity added which is equivalent to the addition of perfectly reliable capacity on system reliability.

[12] See AEMO's Draft 2021 IASR, Section 4.11.1, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/draft-2021-inputs-assumptions-and-scenarios-report.pdf?la=en.

[13] See AEMO's Draft 2021 IASR, Section 4.9.3, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/draft-2021-inputs-assumptions-and-scenarios-report.pdf?la=en.

Reasons for moving to a sub-regional model

The proposed sub-regional structure will enable better information for projects where AEMO triggered preparatory activities in the 2020 ISP, providing more granular information on key intra-regional transmission limitations and augmentations that are not well approximated by REZ limits alone.

There is a trade-off when adding sub-regions to this model. While additional sub-regions provide more information, they increase the computational complexity of the capacity outlook models. AEMO considers the proposed topology an appropriate balance of that complexity and accuracy trade-off. Further information on the approach for sub-region definition is provided in the following sections.

Considerations for the selection of sub-regions

Sub-regions were selected to better reflect a number of network characteristics, such as:

- Where there is a need to assess a potential actionable ISP project in the optimal development path (ODP) – for example, "Reinforcing, Sydney, Newcastle and Wollongong supply"[14].
- Removal of REZ 'group constraints' – the previous ISP had a number of REZ group constraints which were used to reflect situations where multiple REZs were restricted by the same transmission limit.
- Reflect significant transmission cutsets – the network has some key network segments, such as Central Queensland to Southern Queensland, which are suited to being modelled in the sub-regional approach.

There is potential for future expansion with additional sub-regions, such as breaking down Victoria or South Australia into multiple sub-regions. AEMO considers it prudent to not introduce further sub-regions initially, for considerations including the following:

- Some projects are reasonably captured through existing mechanisms within the capacity outlook model. These include the representation of REZ network expansion penalty factors, or through the existing regional boundary definitions, such as Victoria – New South Wales Interconnector (VNI) West.
- Managing computational complexity – the larger the number of sub-regions, the more computationally complex the model becomes. As computational complexity increases, the time required to solve the model also increases, or the problem may become unsolvable. It is therefore critical that computational complexity be managed such that the model can be run in a reasonable amount of time.
- Uncertainty around loops – the introduction of loops in the capacity expansion model can introduce unforeseen behaviour in the model, which may not be a reasonable representation of actual flows. These flows depend on network parameters such as impedance and voltage which are not captured in the sub-regional capacity outlook model stage.
- In the case of Victoria and South Australia, the existing regional topology, and the methods for capturing REZ dynamics through existing means, are considered reasonable given the high likelihood of loop creation with a more granular representation.

Matters for consultation

- Can you identify any issues with AEMO's proposal to move from a regional topology to a sub-regional topology for the capacity outlook model?
- Do you agree that the considerations listed above used to determine sub-regions are appropriate? Are there other considerations in the selection of sub-regions AEMO should be looking at?

[14] See AEMO, 2020 ISP, Section E2, at https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en.

How REZs and sub-regions relate to each other

The introduction of the sub-regional topology introduces some potential confusion with the sub-regions and the REZs. These are two different things; the REZs largely fall within the newly defined sub-regions, and the REZ definitions, and associated modelling characteristics, are largely unaffected by the introduction of the sub-regional model. AEMO proposes maintaining this separate treatment of REZs and the sub-regional model, as the existing REZ approach continues to be an effective representation of the considerations for renewable energy generation development. No REZ's cross sub-regional boundaries.

Forecasting demand at a sub-regional level

AEMO is in the process of developing a methodology to develop demand traces at the sub-regional level. Rather than building the sub-regional traces from the bottom up by aggregating demand traces at a connection point level, AEMO is pursuing an approach that disaggregates regional demand traces to the sub-regions.

The methodology being explored is broadly as follows:

- Determine sub-regional factors for components (such as distributed photovoltaic [PV] generation, electric vehicle [EV] uptake, and residential and commercial demand) based on historical data analysis and projected trends from AEMO's DER forecasts, which consider postcode level granularity.
- For large industrial loads, continue to forecast at a facility level which are allocated to sub-regions.
- Apply the factors to the regional forecasts of each component to determine sub-regional forecasts by component. In this context, the components[15] include business (industrial and commercial loads) and residential forecasts, considering the influence of DER on business and residential forecasts.
- Aggregate components at the sub-regional level, resulting in a sub-regional demand forecast.
- The sum of the sub-regional forecasts will reconcile with the regional demand forecast by virtue of the method described above.

AEMO believes that this methodology appropriately balances the level of complexity and detail with its materiality to the purpose of the ISP. The development of sub-regional traces from the regional demand forecasts is not part of the concurrent consultation on demand forecasting methodologies, but will be specified through the ISP methodology.

Matters for consultation

- Does the methodology described above to forecast demand at a sub-regional level seem appropriate for the sub-regional model?

New entrant candidates at a sub-regional level

A wide range of available generation technologies are considered as new entrant candidates. With the sub-regional representation, AEMO is proposing to consider thermal and storage development options on a sub-regional basis instead of including them at a purely regional level, as was the case in the 2020 ISP. Due to computational complexity, not all thermal and storage development options may be able to be considered in each sub-region. AEMO therefore proposes limiting the appropriate technology options that are available in each sub-region based on the availability of resources in sub-regions (for example gas infrastructure in the case of new gas generation, availability of suitable sites in the case of pumped hydro) and the potential value

[15] For more information on AEMO's existing forecasting approach, see https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach.

of locating different technologies in particular sub-regions (for example ensuring that long-duration battery storage can be located in the same zone as likely VRE development).

Renewable generation options will continue to be included for each REZ, based on resource potential, to represent variation due to geographical location.

Matters for consultation

- AEMO welcomes consultation on what matters should be considered in determining the location of storage and traditional thermal generators in the power system.

Representation of transfer between sub-regions in the sub-regional capacity model

In the actual power system, transfer capability across the transmission network is determined by a variety of power system phenomena including thermal capacity, voltage stability, transient stability, small signal stability, and system strength. It varies throughout the day with generation dispatch, load, network outages and weather conditions.

For capacity outlook modelling, notional transfer limits between the sub-regions are currently represented as a 'worst case' at the time of maximum demand in the importing sub-region. Previously this was seen as appropriate to reflect the conditions which historically drove need for network augmentations. AEMO now proposes modelling transfer limits that represent a number of system conditions to ensure the value of the existing network is fully captured while also understanding conditions that could lead to significant congestion. This approach could be based on demand (i.e. peak demand or typical demand), season (i.e. summer or not-summer), or time-of-day (i.e. day or night).

Matters for consultation

- AEMO proposes to model transfer limits that represent a number of system conditions. Please provide feedback on the types of system conditions that should be represented, and why.

Interconnector losses in the capacity outlook model

Losses between regions are a key input to the capacity outlook model, and inter-regional losses change as a result of network augmentations being built (among other things). How these losses are represented and modified remains an important consideration for the capacity outlook model.

The introduction of the sub-regional capacity outlook model raises the question of whether the representation of losses should be retained as inter-regional losses (losses between regional reference nodes) in line with existing NEM operation, or loss modelling should be modified to an inter-sub-regional approach (losses between sub-regions).

Modelling approach

Interconnector losses are presently modelled based on interconnector loss functions. For existing interconnectors, these parameters are sourced from the most recent loss factor calculations[16] using the methodology described therein.

For future inter-regional augmentations, these loss equations have been modified in one of three ways:

[16] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries.

- **Existing inter-regional loss flow equation scaling** – used in instances where the proposed upgrade augments an existing transmission corridor.
- **First principles** – used in circumstances where the losses between regional reference nodes are dominated by one link (such as a high voltage direct current [HVDC] connection connecting in the vicinity of regional reference nodes).
- **Case extrapolation and regression** – used to build an inter-regional loss flow equation for an entirely new and complex transmission corridor.

Matters for consultation

- AEMO is interested to understand perspectives on how to approximate future inter-regional losses as the network is modified.
- AEMO welcomes feedback on other matters related to losses not covered in the above.

Hydrogen

The 2022 ISP will include the impact of hydrogen for the first time. The proposed Export Superpower scenario includes the development of large amounts of NEM-connected electrolysis to supply domestic and international hydrogen demand (recognising that there may also be significant development of off-grid hydrogen production in that scenario, and other scenarios). AEMO has been exploring a range of methodologies to model the impact of the electrolysis load on the NEM.

Proposed modelling approach

Real-time operation of hydrogen plant will be affected by commercial arrangements. While hydrogen producers are operating for commercial reasons, the proposed approach assumes their electricity supply contracts will reflect the value of their flexibility to the NEM (there may be clauses that allow the electricity suppliers to turn down supply at times when the supply-demand balance is tight in return for lower prices). Actual contractual outcomes may of course vary from the optimal.

In modelling the interactions of hydrogen in the power system, the capacity outlook models must determine where to locate and use electrolysers to maximise system efficiency, and understand the impact on the development of generation and transmission. Given the complexity of broader international energy markets' influence on domestic hydrogen developments, the scale of hydrogen demand for NEM export and sub-regional domestic consumption are proposed to be exogenous inputs, rather than optimised within the modelling.

AEMO is proposing to use the capacity outlook modelling to determine the location and size of the electrolyser plants that are required to meet hydrogen demand at a sub-regional level. At a high level, using least-cost optimisation, the capacity outlook modelling would:

- Determine the sub-regional allocation of the NEM hydrogen production for export.
- Determine whether domestic hydrogen supply at a sub-regional level will be produced within that sub-region, or produced in another sub-region and transferred (at a cost). This would determine the allocation of the electrolysers for domestic hydrogen to each sub-region.

Within the capacity outlook modelling the location of electrolyser loads within each sub-region would be co-optimised with corresponding REZ generation expansion and the development of associated network.

Hydrogen storage

Hydrogen is a molecular energy source rather than electricity, and does not transfer energy instantaneously – it does not operate as a pure supply-on-demand system – so it is recognised that hydrogen will not be consumed at exactly the time of supply, and some level of storage will be needed.

For domestic-driven electrolysers, AEMO proposes assuming that there would be sufficient storage in the distribution pipelines and the new electrolyser plant to manage daily variances in demand, similar to the way in which linepack is currently managed by gas and pipeline operators. AEMO is exploring the ability to incorporate hydrogen storage into the capacity outlook modelling.

For export-driven electrolysers, AEMO proposes assuming that the export terminals have sufficient onsite storage to manage hydrogen production between shipments.

It is recognised that some simplifications will need to be made to the approach to hydrogen storage, particularly in terms of varying seasonal demand. If hydrogen developments continue to progress, and nearer timelines for major developments justify the additional model development, it may be an area for future improvements.

Limitations in the proposed implementation

The interaction of hydrogen in the electricity and gas systems introduces complexity. At this stage, some simplifications are proposed to manage the computational demands and also address uncertainties that are yet to be resolved. AEMO recognises these limitations, but considers the modelling will provide important insights that can be built upon for later ISPs.

The limitations of implementing hydrogen in the capacity outlook models as proposed include:

- Domestic and export hydrogen demand are exogenous and not optimised by the model.
  - Endogenous export consumption would require global modelling and the ability to model alternative hydrogen production sources and costs.
- If the magnitude of the export volumes is sufficient to supply domestic consumption from spot market hydrogen cargoes, the assumption about managing seasonal demand is reasonable – this has yet to be tested.
- The assumption of suitable storage to manage export cargoes would simply become part of the cost of the exported commodity, but the assumption of sufficient storage to manage daily supply variance is simplistic.
- The choice of electrolysis location is relatively coarse and assumed to be at either ports or near to reference nodes. This means that the model does not consider the trade-off between pipeline expansions or transmission expansion. AEMO's approach applies this simplification to manage the overall complexity of modelling the interactions of transmission, generation, pipelines, storage requirements, and water availability. Increasing the granularity of locating electrolysers would require simplifications in other parts of the model, which AEMO does not consider appropriate at this time.
- There is no consideration of what might make ports different from each other (for example, development costs, proximity to export markets, surrounding land use/easements).
- There is relatively limited consideration of water limitations/costs at this stage.

REZ expansion for hydrogen production

Because hydrogen electrolysers are expected in different locations (that is, major ports) to the existing load centres, expanding the capacity of REZs to supply those electrolysers will require a different approach. The methodology for REZ expansion to meet the increased demand from electrolysers is discussed in Section 2.5.

Matters for consultation

- Considering the limitations in the proposed implementation, are there prudent amendments to the proposed method that you consider would increase the effectiveness of the modelling approach?
- What approach, if any, should AEMO consider in capturing the potential different characteristics between hydrogen export ports?
- What additional considerations should be considered in the hydrogen methodology? Is the complexity of the approach appropriate, or should AEMO reduce the granularity (and therefore accuracy) of other parts of the capacity outlook models in order to increase the sophistication of this component?

Hybrid renewable-battery energy systems

The Draft IASR documented alternative cost assumptions for all large-scale battery storage options for hybrid generation projects (that is, wind and solar paired with battery storage as part of a single project). However, to include hybrid projects, AEMO would need to consider the various hybrid storage options in each individual REZ, which would add significant computational complexity in AEMO's models.

AEMO therefore proposes to not model hybrid battery storage projects in the capacity outlook models of the ISP. However, in the time-sequential modelling, AEMO does consider the benefits of co-locating battery storage with REZ development when allocating generation and storage developments to connection points. Analysis of the time-sequential modelling then informs refinements to the specification of REZ augmentation costs to reflect the impact of co-located storage on the scale of investment required.

For REZ augmentations that are determined to be actionable ISP projects, AEMO will examine through the TOOT process the interaction between network and non-network developments, particularly through the co-location of battery storage.

Matters for consultation

- What other options could AEMO consider to better reflect the potential benefits of the co-location of storage and VRE?

2.3 Time-sequential model

Time-sequential modelling is used to validate the outcomes of the capacity outlook modelling. In particular, the outputs of the time-sequential modelling:

- Validate the costs and benefits of key development paths.
- Confirm that the system is reliable and operable.
- Provide inputs for further engineering assessments (see Section 2.5).

Existing approach

The current approaches used in the time-sequential modelling in the ISP is documented in the Market Modelling Methodologies document[17].

[17] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/market-modelling-methodology-paper-jul-20.pdf?la=en.

Amendments considered

No amendments to current methodologies in the time-sequential model are being considered.

2.4 Gas supply model

The gas supply model assesses reserves, production, and transmission capacity adequacy for the Gas Statement of Opportunities (GSOO) for eastern and south-eastern Australia. The model performs gas network production and pipeline optimisation at daily time intervals that minimises the total cost of production and transmission, subject to capacity constraints.

Existing approach

Assessment of reserves requires the gas supply model to consider the sufficiency of gas production, storage, and pipeline solutions to supply any shortfall.

An augmentation of production near supply shortfall may draw on a different reserve to a pipeline augmentation solution, leading to different reserve depletion projections. For example, a supply shortfall in Melbourne may be addressed by increasing production from the Gippsland Basin, increasing production from the Otway Basin, or increasing transmission capacity on various pipelines or even via a liquified natural gas (LNG) receipt terminal, ultimately sourcing additional gas from north-eastern South Australia or Queensland.

The gas supply model does not presently contain cost-related information in sufficient detail to form a reliable view on pipeline and production augmentation based on cost-efficiency alone. It therefore does not co-optimise pipeline expansion from a number of options like the capacity outlook model does. Instead, when a supply shortfall is reported that may be alleviated with a transmission project, the model can be used to perform sensitivity analysis to test the ability of an augmentation or suite of augmentations to restore supply sufficiency.

More information on the detailed gas supply and demand methodologies is available in AEMO's GSOO publication materials[18].

Amendments considered

No amendments to current methodologies in the gas supply model are being considered.

2.5 Engineering assessment

The engineering assessment determines a number of technical parameters for use by the time-sequential and capacity outlook models. It is also used to refine and validate their outcomes – ensuring they are credible from an engineering perspective.

There are four main components to the engineering analysis:

- **Development of transmission and non-network options** for use as inter-regional, inter-sub-regional and REZ network expansion.
- **Assessment and selection of candidate options** to be used in the capacity outlook model.
- **Power system analysis** such as thermal and system strength assessments to account for power system requirements.
- **Consideration of the cost of transmission** to ensure the cost estimates for network expansion are as accurate as possible.

[18] AEMO, Gas Statement of Opportunities methodology – supply adequacy, at https://www.aemo.com.au/Gas/National-planning-and-forecasting/GasStatement-of-Opportunities.

The engineering assessment enables critical feedback loops between engineering assessment and market modelling, before stepping through each of the engineering assessment components in detail. AEMO conducts joint planning with TNSPs to ensure rigour in the engineering assessment.

Existing approach

The existing approach to the engineering assessment is described in Appendix 9 of the 2020 ISP, Section A9.4 Engineering Assessment[19].

Amendments considered

AEMO proposes three key amendments or considerations for the engineering assessment:

- **REZs** – formalise the development of REZ transmission network limits and better represent actual power system behaviour.
- **Power system security limitations** – improved consideration of system strength mitigation costs, and wider consideration of system security planning assumptions.
- **Infrastructure delivery** – consideration of labour and material limitations that could affect infrastructure delivery.
- **Distribution network** – consideration of the need to align inputs, assumptions and scenarios between distribution network plans and the ISP so that long-term network plans are on a consistent basis.

Renewable Energy Zones

REZ resource capacities, existing network limits, and likely expansion costs are key inputs into the long-term ODP for the ISP. This section gives an overview of how these aspects are proposed to be modelled, including:

- Factors influencing the derivation of **REZ resource limits**.
- The approach used to determine the **REZ transmission network limits**.
- Modelling limitations that need to be considered when determining linearised **REZ network expansion costs**.
- How AEMO proposes to model the **transmission expansion requirements for the Export Superpower scenario**.

REZ resource limits

In past ISPs, each REZ had a defined maximum resource limit (for wind and for solar), calculated based on a number of factors including a maximum percentage of land area used for VRE development.

AEMO is proposing to move to a 'soft' REZ resource limit for the 2022 ISP. This means the resource limit can exceed the previously defined limit, provided a penalty cost is incurred. This penalty cost is intended to reflect the increasing complexity and costs as the preferred sites for renewable generation development are used.

The need to relax the previous 'hard' limits is driven by the potential for some ISP scenarios to see a significant increase in REZ generation development. The additional REZ land use penalty factor is most likely to be utilised for the Export Superpower scenario, although it will be applied consistently to all scenarios. More detail specific to the modelling of demand for the production of hydrogen is provided in Section 2.2.2. By using the REZ land-use penalty factor, AEMO can model a staged increase in land costs, reflecting more complicated arrangements required for planning approvals and engagement with community and traditional landowners as more renewable generation goes into a REZ.

It is vital that developers and TNSPs identify key stakeholders and commence engagement on land and access as early as possible for AEMO's assessments of future REZ potential. This includes engagement with communities, title holders, and traditional owners. Early indications of sensitivities in proposed future REZ

[19] AEMO, 2020 ISP Appendix 9 .ISP methodology, at https://aemo.com.au/-/media/files/major-publications/isp/2020/appendix--9.pdf?la=en.

areas will assist in the assessment of potential expansion opportunities or limits, thereby improving the projections of future potential ISP candidate paths.

AEMO has undertaken a desktop analysis to estimate the theoretical maximum land use limit for VRE in each REZ based on individual known characteristics across the NEM. It is unlikely this upper bound will be reached or materially affect the outcomes.

Matters for consultation

- Are there other factors which need to be considered for the REZ resource limit?
- Is the penalty factor approach with soft land use limits appropriate?

REZ transmission network limits

The capacity outlook model also uses a single value to represent the network hosting capacity of a REZ. This value is intended to represent what level of renewable generation can be placed within that REZ while maintaining 'acceptable' levels of curtailment. What is considered acceptable for the purpose of ISP modelling has not been formally quantified, however, the level of renewable energy curtailment due to network congestion in the 2020 ISP Central scenario was modelled to be less than 0.5% from 2024 onwards[20]. The capacity outlook model may build generation in excess of the network hosting capacity by paying a penalty cost that represents the cost to increase network hosting capacity in that area.

Furthermore, the REZ transmission network limits do not explicitly consider the diversity of wind and solar. These factors were considered using heuristics. Storage which offsets network build is considered by placing the storage built as part of the capacity outlook and locating these in the optimal locations.

AEMO intends to formalise the development of REZ transmission network limits and better represent actual power system behaviour.

Matters for consultation

- AEMO welcomes ideas on what factors should be considered in the REZ network hosting capacity for the capacity outlook modelling, including whether an acceptable level of curtailment should be used, and if so, what level should be used.

REZ network expansion costing

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 expansions is computationally intensive. Therefore, to represent the cost of expanding the network servicing a REZ, the ISP uses an incremental expansion cost (measured in $/MW). This expansion cost is a linearised value derived from the total cost ($) and capability 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

[20] See AEMO, 2020 ISP, Appendix 6, Section A6.3.2, at https://aemo.com.au/-/media/files/major-publications/isp/2020/appendix--6.pdf?la=en.

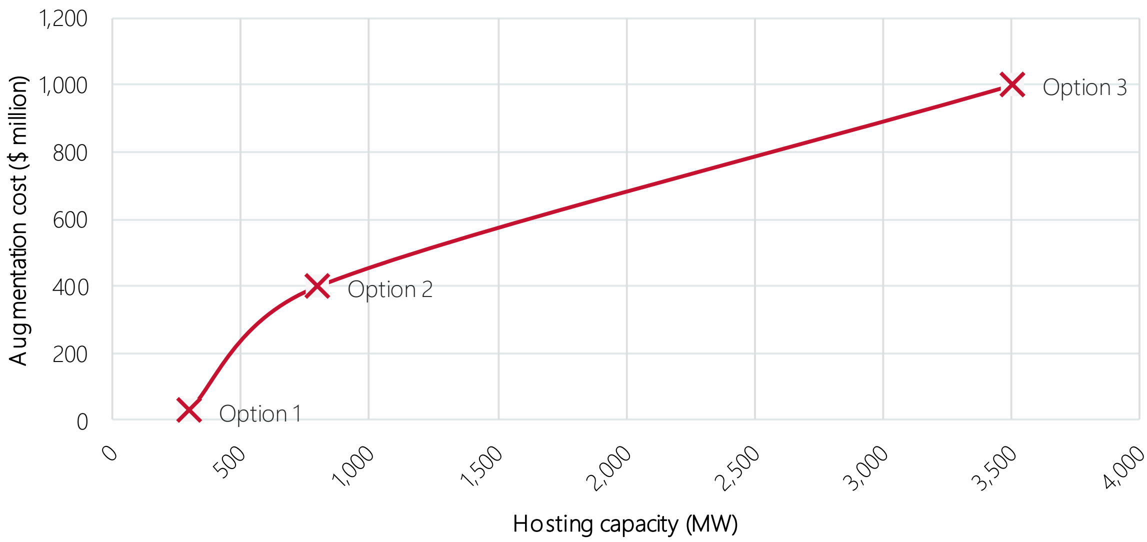
possible network augmentations as a starting point. Table 3 outlines several hypothetical options to expand the hosting capacity of a REZ.

Table 3 REZ network expansion 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 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 3 are illustrated in Figure 3. AEMO initially selects a point on the line which best represents the linearised cost of a particular network expansion. 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 will provide a sufficiently broad range of options.

Figure 3 Cost and capacity of REZ network expansion 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 expansion in terms of size and cost. This is an iterative process that ensures the resulting REZ network expansions and their costs are appropriate.

Matters for consultation

- Without care, this approach of linearising REZ expansion costs can over or understate the true cost of network expansion required for a given amount of REZ generation development. AEMO welcomes feedback on any possible improvements or refinements.

Transmission expansion for export superpower scenario

Significant expansion of REZ generation and network will be needed to supply electrolysers for hydrogen production in the Export Superpower scenario, likely well beyond the levels in the other scenarios. Consequently, simplifying assumptions will therefore be required to model this scenario as described below.

For hydrogen export, power will be assumed to be delivered to nearest port (from the list of nominated ports per state as outlined in the IASR) for each REZ, via a new dedicated transmission line; only a small amount of inter-connectivity with existing NEM assets will be assumed to minimise the overall cost. Augmentation cost for the REZ expansion to ports will assume 500 kV transmission and associated substation equipment and will be calculated as a single $/MW/km factor to be applied to each REZ/port combination.

Approximately 25-30% of hydrogen production is assumed to be for domestic usage (for transport, heating, and industrial use), as documented in the IASR. The electrolysers for domestic demand are assumed to be located near major load centres (approximated by the sub-regional reference nodes).

AEMO is expecting to consider the impact of increasing domestic electricity demand on transmission within the conventional framework[21] where possible. There may, however, be a need to use similar simplifying assumptions to the export supply, with $/MW/km values used to reflect new transmission lines being built from one or more REZs to each major load centre. This may be needed if the scale of the domestic supply goes beyond the existing interconnector and intra-regional expansion options.

Matters for consultation

- Are there any important factors that need to be considered when making assumptions to simplify the transmission expansion costs for the Export Superpower scenario?
- Do you agree with the direction being explored for simplifying assumptions for the Export Superpower Scenario?

Power system security costs

As part of the engineering assessments, AEMO also takes into consideration the requirements for and modelling of power system security services. As well as being required to understand the technical requirements of operating the power system, these outcomes also need to feed into the cost-benefit analysis (see Section 3), either as stand-alone costs or by introducing new constraints on generation or interconnector flow in the market modelling.

As the CBA guidelines outline[22], these costs of these services across scenarios and optimal development outcomes should be incorporated unless it can be demonstrated that either:

- A particular class of market benefit is likely not to materially affect the outcome of the assessment of the development path; or
- The estimated cost of undertaking the analysis to quantify the market benefit is likely to be disproportionate given the level of uncertainty regarding future outcomes.

Undertaking detailed design level studies to determine the requirements for these services for the longer-term study timeframes would be considered disproportionate, so broader planning assumptions need to be used to capture a reasonable cost impact.

[21] Described in AEMO, 2020 ISP Appendix 9 ISP methodology, at https://aemo.com.au/-/media/files/major-publications/isp/2020/appendix--9.pdf?la=en.

[22] AER, 2020 Cost Benefit Analysis Guidelines, at https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

Due to the changing nature of the power system, the ISP needs to assess both the existing power system services, and potential new power system services. The assessment of costs, and the potential impact on the CBA due to these services, varies case by case, as described in this section.

Existing power system services potentially requiring assessment include, but are not limited to:

- Frequency control.
- System restart.
- Network support and control.
- Regional inertia services.
- Regional system strength services.

There are also a number of ongoing reviews and rule change proposals that have the potential to introduce new services or markets, such as:

- Inertia/fast frequency response (FFR) markets.
- Localised system strength services.
- Operational reserves.
- Primary frequency control.

For the timeframes being considered in the ISP, it is also plausible that there will be requirements for services not currently seen as required in the NEM. Examples could include (but not be limited to) aspects such as grid formation.

It can be a challenge therefore to assess:

1. How to determine the actual requirements for the services into the future.
2. How to cost and model the services, especially given the fast pace of technology change.
3. Therefore, which services actually need to be considered, and which can be deemed to not change overall outcomes.

For the anticipated services that are modelled, the ISP will concentrate on determining the quantum of services required, and likely costs of these services, without trying to anticipate the exact mechanism (for example, TNSP procurement or market service). The modelling of security services is also expected to need to be done in an iterative manner due to the requirements themselves depending on outcomes such as synchronous generation retirements, size and location of inverter-based resource builds, new storage requirements, and transmission network builds.

This allows a holistic solution to be studied that considers all system security services together, not in isolation. For example, a synchronous condenser could provide system strength, reactive compensation, and inertia.

Transfer limits (such as thermal capacity, transient stability, voltage stability)

Existing methodologies are described in the 2020 ISP Methodology[23], and AEMO is not proposing changes to how these are determined and modelled for the 2022 ISP.

Reactive compensation and voltage control

Costs for new reactive compensation are considered and included as part of network upgrade costs. Known Network Support and Control Ancillary Services (NSCAS) contracts and future augmentations will be considered.

[23] AEMO, Appendix 9. ISP Methodology, at https://www.aemo.com.au/-/media/files/major-publications/isp/2020/appendix--9.pdf?la=en.

System restart

AEMO's previous ISP studies have projected a significant amount of resources that can provide system restart services – primarily hydroelectric generation, pumped storage, battery storage and gas-powered generation. Changes to system restart ancillary service (SRAS) costs are therefore not anticipated to significantly vary between network development outcomes, and AEMO does not propose to assess them.

Frequency control

In the market modelling only system normal (network intact) conditions are studied. Under these conditions it is expected that the frequency control ancillary services (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, and given the computational overhead, it has not been seen to be necessary to model the FCAS market.

Where local regional requirements could result in a need for FCAS services being available in that specific region at all times, ensuring a minimum number of units are online for this purpose has been modelled.

To date, the impact of this has only been considered to be significant (and therefore modelled) for the South Australia region. The planning assumptions and modelling methodology relating to this are documented in the Appendix 7: Future Power System Security Appendix of the 2020 ISP[24].

For the 2022 ISP Methodology, AEMO proposes documenting similar assumptions for other NEM regions where synchronous unit retirements could result in a need for constraining units on later in study timeframes. Preliminary assumptions on this have been documented in the Draft 2021 IASR[25]. The impact of new interconnectors to these regions will then be considered to eliminate the need for local services at all times.

System strength

Accurate modelling of system strength requirements for a NEM region, or even on a project by project basis requires detailed electromagnetic transient (EMT) studies. Undertaking EMT studies for periods even five years into the future would be extremely time-consuming, and would ultimately be unreliable given the very broad assumptions that would need to be made for modelling of uncommitted plant (both generation and transmission) that have no detailed models available. For this reason, in this instance simpler fault level calculations are used as a proxy to indicate system strength requirements and costs.

Existing regional fault level node requirements[26] and generator connection point available fault levels have been used to determine system strength mitigation requirements, with the calculation methodologies documented in the 2020 ISP Methodology[27] document.

System strength requirements can be localised, and depend on a number of factors such as:

- Location within the network.
- Future network upgrades.
- Typical synchronous generation dispatch.
- Proximity to synchronous condensers.
- Amount of nearby inverter-based resources,
- Location of new synchronous generation (such as pumped hydro or CCGTs).
- Inverter technology (grid forming or grid following).

[24] At https://www.aemo.com.au/-/media/files/major-publications/isp/2020/appendix--7.pdf?la=en.

[25] At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/draft-2021-inputs-assumptions-and-scenarios-report.pdf?la=en.

[26] Current requirements are detailed in the 2020 System Strength and Inertia Report, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2020/2020-system-strength-and-inertia-report.pdf?la=en.

[27] AEMO, 2020 ISP, Appendix 9. ISP Methodology, at https://www.aemo.com.au/-/media/files/major-publications/isp/2020/appendix--9.pdf?la=en.

AEMO does not consider it is feasible to try to build all these aspects into a capacity outlook optimisation. These costs have previously been calculated by including constraints (for example, synchronous unit requirements in South Australia) or post-processing of modelling results.

For the 2022 ISP Methodology, AEMO proposes improving the consideration of system strength mitigation costs by including these initially post-processed cost outcomes into connection costs, REZ expansion costs, and network augmentation costs. For example, system strength mitigation requirements could be calculated with fault level studies, based on the initial network and generation build/retirement outcomes and the time-sequential market modelling dispatch outcomes. The costs for these services would then be proportioned as part of connection costs or REZ expansion costs, (depending on the timing of when mitigation is needed) into the next market modelling simulation.

An outcome from these studies could be a change to network build assumptions; for example, a higher-cost network option may be preferable if this results in lower overall costs when taking into account system strength mitigation.

Another outcome could be that system strength mitigation costs also form part of an interconnector upgrade, in which case they will be included as part of the interconnector costs (for example Project EnergyConnect includes synchronous condensers).

To take into account anticipated lead times for large synchronous condensers, in early projection timeframes prior to 2025, AEMO proposes constraining on synchronous generation within a region to ensure minimum synchronous generation combinations are online. For later timeframes, the costs for installing synchronous condensers to meet the system strength mitigation needs will be used (unless other solutions are known)[28]. While AEMO acknowledges that other solutions or technologies are possible (for example grid-forming inverters), the use of a mature technology is expected to result in a conservative and consistent outcome across scenarios, at least until other technologies are proven.

Preliminary assumptions on these costs have been documented in the Draft 2021 IASR[29].

Inertia

Currently, minimum inertia requirements[30] are only enforced when a NEM region is either operating as an island, or at risk of islanding; this has a potential impact on Tasmania, South Australia, and Queensland.

Tasmania currently meets the local inertia requirements by contracting hydro generation to operate in synchronous condenser mode, and South Australia is installing large synchronous condensers with flywheels and contracting FFR from batteries. These solutions are outside of the energy market, in that they do not require constraining generation on or off [31], and as such have been post-processed in previous ISP studies. The calculation methodology and assumptions for inertia are documented in the 2020 ISP Methodology[32]. To ensure sufficient inertia is available in future, AEMO assumes that new large synchronous condensers installed for system strength mitigation can include flywheels, and need to be costed as such. AEMO will consult on synchronous condenser costs as a part of the Draft Transmission Cost report scheduled for May 2021.

Online inertia is determined from time-sequential market modelling dispatch outcomes. These are post-processed to also include inertia from synchronous condensers, as well as consideration for FFR from new batteries. This will be compared to the local regional inertia requirements prior to assessing any need for additional inertia services. If new interconnectors are built between regions, the need for local inertia services based on existing requirements may also be eliminated.

---

[28] For example, in Tasmania hydro generation is contracted to operate in synchronous condenser mode.

[29] At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/draft-2021-inputs-assumptions-and-scenarios-report.pdf?la=en.

[30] Current requirements are detailed in the 2020 System Strength and Inertia Report, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2020/2020-system-strength-and-inertia-report.pdf?la=en.

[31] South Australia does have interconnector limits to ensure for the non-credible loss of Heywood that the post-contingent RoCoF is within defined limits, and this is included with the market modelling limits.

[32] AEMO, Appendix 9. ISP Methodology, at https://www.aemo.com.au/-/media/files/major-publications/isp/2020/appendix--9.pdf?la=en.

Similar methodologies are proposed for the 2022 ISP Methodology. There are also ongoing studies to assess the need for a minimum NEM-wide inertia safety net[33], and any outcomes or new requirements from these studies will need be incorporated into assessing the need for any future inertia investment.

Ramping/operational reserves

With high penetration levels of VRE, it is expected that there will be periods where wind or solar generation will increase or decrease at high rates of change, and that these fast changes will require dispatchable generation sources to compensate in order to prevent security issues from arising. For example, a fast ramp down of wind generation in the South Australian region has the potential to increase flow on the Heywood interconnector past secure limits unless generation within the South Australian region can increase output in time to compensate.

This could result in a need to ensure sufficient headroom in Tasmania, South Australia, and Queensland, due to their reliance on single interconnectors.

While the time-sequential market modelling captures this variability to an extent, some aspects are not captured, due to:

- If using a 30-minute simulation timestep, the 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 thermal generators if offline (start-up time can be dependent on time previously offline).

AEMO therefore proposes using maximum VRE ramp rates, as determined in AEMO's Renewable Integration Study (RIS) Stage 1 report[34], as indicators of required online headroom at all times. Once additional interconnection is in place for these regions, this requirement can be relaxed.

AEMO has previously modelled the need to maintain online generation for this purpose for South Australia, and for the 2022 ISP Methodology, and proposes expanding on this to include other NEM regions.

Matters for consultation

- Do you agree with the proposed assumptions regarding which system security costs are to be accounted for in the cost benefit assessments?
- Are the proposed assumptions regarding the need for high-level planning assessments to model system security impacts reasonable?
- Do the existing methodologies and proposed improvements capture the level of detail required to ensure the treatment of system security costs is transparent? If not, what aspects still need further improvement?

Infrastructure delivery

Infrastructure delivery is an important consideration related to the engineering assessment. It is possible that construction of several proposed ISP projects will overlap, not just within the energy sector but also with major projects in other sectors within Australia, such as building and transport. This has the potential to cause

[33] AEMO. Frequency Control work plan, at https://aemo.com.au/-/media/files/electricity/nem/system-operations/ancillary-services/frequency-control-work-plan/external-frequency-control-work-plan.pdf?la=en.

[34] Appendix C: Variability and Uncertainty, at https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-c.pdf?la=en.

a tightening of the market for both labour and materials, which in turn can have a flow-on effect, increasing costs for building transmission.

Infrastructure delivery sits alongside the core ISP methodology. AEMO is partnering with Infrastructure Australia and University of Technology Sydney, who will deliver the 'Employment and Material Requirements for Transmission and Generation under the Integrated System Plan' project. This work will run through to mid-2021, and will also contribute to Infrastructure Australia's broader work reporting on infrastructure market capacity.

The project aims to identify labour and material requirements for REZs (including generation and network development) by estimating job numbers and material requirements for selected ISP scenarios. This will allow governments, TNSPs, developers and market bodies to:

- Identify risks from labour, material, or other shortages.
- Plan to smooth boom and bust cycles[35] in the renewable energy industry.
- Maximise Australian job creation by both minimising the requirement for imported labour and potentially increasing local content.

Matters for consultation

- How might the 2022 ISP, or subsequent ISPs, consider smoothing the delivery of multiple simultaneous large ISP infrastructure projects – especially considering the relationship with infrastructure projects outside the energy sector?

Distribution network considerations

Distribution network investments will play an important role in unlocking the potential of DER. AEMO has begun discussions with Energy Networks Australia (ENA) to improve consistency in distribution and transmission network planning approaches. So far, these discussions have identified value in:

- AEMO, ENA and DNSPs aligning inputs, assumptions, and scenarios so that long-term network plans are on a consistent basis.
- An improved understanding on how to best accommodate high penetrations of DER and embedded generation in the power system from a technical standpoint, and develop strategies to do so.
- Examining the relative merits of investment across the power system, including the distribution network and DER.

AEMO recognises the importance of the distribution network in delivering an efficient, reliable, and secure power system and is seeking to strengthen the links between the ISP and distribution network planning processes.

Matters for consultation

- What additional matters should AEMO consider regarding the interplay between distribution and transmission networks?

[35] The boom and bust cycle describes alternating phases of economic growth and decline typically associated with industries supporting the fluctuating needs or demands of a sector or product.

3. Cost benefit analysis methodology

The CBA methodology is the way in which the ODP is determined through the use of market modelling in the ISP. The methodology details the approach to determining a set of development paths, how net market benefits are calculated relative to a counter-factual development path, and how the ODP is determined by comparing the market benefits of each development path between the different scenarios.

3.1 Existing approach

The current CBA methodology is the approach that was used to determine the ODP in the 2020 ISP and was described in both the ISP main report[36] and in Appendix 2[37]. The following sections provide a generalised summary of the approach that was applied.

Process for selecting candidate development paths for cost benefit analysis

In the 2020 ISP, candidate development paths (CDPs) were identified by determining least cost development paths for the core scenarios from a range of network and non-network investment options with variations in timing. These CDPs maintained the preferred timing of each interconnector identified in their respective optimal scenario, and tested these developments in all other scenarios to quantify the relative risks and regrets of over- or under-investment.

In addition to the least-cost development paths for core scenarios, other CDPs were added to test the option value of staged projects. These CDPs examined potential benefits in variations in the timing of staged investments, whereby projects could be either delivered at the earliest time needed across scenarios, or delayed, depending on decisions made at a future date. To enable this flexible delivery schedule, early works investments were factored into the cost of the CDP.

Selecting an optimal development path

The process of selecting the ODP from these CDPs involved determining the net market benefits of each of the CDPs under each of the core scenarios and market event sensitivities. To do so, the net present value (NPV) of all costs (transmission, storage and generation investment and production costs) associated with these CDPs was compared against the NPV of a counterfactual development path, with no future network development other than committed and anticipated ISP projects, or small intra-regional augmentations and replacement expenditure projects. Lower NPV costs in a CDP compared to the counterfactual for a specific scenario are considered the net market benefits of that CDP in that scenario.

Two approaches were used by AEMO to conclude the final ODP:

- A 'scenario-weighted' approach, in line with the then draft CBA Guidelines published by the AER. In this approach, the net market benefits of each CDP across each scenario and market event sensitivity are weighted by the relative likelihood of each scenario taking place. The CDP with the greatest weighted average net market benefit is ranked the highest using this approach.

[36] At https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en.

[37] At https://aemo.com.au/-/media/files/major-publications/isp/2020/appendix--2.pdf?la=en.

- A 'least-worst regrets' approach, which identifies the potential 'regret cost' for each CDP. The regret associated with a CDP refers to the impact of decisions made now with a scenario (allowing for future adaptive decisions to be made) compared to the decisions that would be made in that scenario assuming perfect foresight. For example, this could be committing to an investment which is then not beneficial, or not proceeding with an investment that then cannot be delivered when needed. The CDP that results in the least amount of regret across all scenarios would be given the highest ranking in this approach.

These two approaches, as well as improvements in the methodology AEMO is proposing to employ when determining the ODP, are further discussed below.

3.2 Amendments considered

The ISP identifies actionable transmission projects that should continue to be investigated through regulatory investment tests and preparatory activities. Potential actionable projects are identified as those that would need to commence development prior to the subsequent ISP. For some projects, the economic value of the development is forecast as high in all scenarios, however this is not always the case.

This section outlines the key principles and high-level approach AEMO proposes to apply in the ISP CBA framework, based on the information provided in the AER's CBA guidelines. This approach is similar to the methodology applied in the 2020 ISP, as AEMO's approach in the 2020 ISP endeavoured to align with the AER's draft guidelines where possible. This section follows the steps that are laid out in the CBA guidelines and outlines AEMO's proposed approach for applying the guidelines. Additional detail has been provided here to provide sufficient context for stakeholders to provide feedback on any potential issues related to AEMO's proposed application of the guidelines.

Selecting development paths

The first step in determining the ODP continues to be the simulation of many alternative Development Paths (DPs), involving different combinations of transmission augmentations and timings of those augmentations, including non-network options where relevant. DPs consist of a set of projects that together address power system needs. Projects included in the DP are those that are, or may become, ISP projects.

Some non-network options, such as virtual transmission lines, are suited to be considered in the determination of the ODP at this first stage. However, non-network options are also developed once a potential transmission investment becomes actionable. This is usually the case when the non-network option works in conjunction with the actionable network project, deferring or reducing the size of the investment[38].

For non-network options which can only be developed once a network project becomes actionable, including these in the determination of the ODP is difficult to envisage. They often require detailed and/or commercial in confidence information on non-network options which is only realistically obtainable through engagement with potential non-network proponents following a project becoming actionable.

As outlined in the previous section, the first stage in AEMO's process is to identify the least-cost development path for each scenario, assuming perfect foresight. This includes consideration of physical staging of an interconnector augmentation, for example a small upgrade followed by a large upgrade at a later point in time.

The second stage of the process is then to apply each scenario's least-cost development path across all the other scenarios, as CDPs similar to the 2020 described method. Only the potential actionable project from the least-cost development path would be fixed in other scenarios, but the timing of those classified as 'future projects' would be varied to minimise costs within each scenario, in accordance with the Final CBA Guidelines. This may result in different project timings across the different scenarios for future projects.

For example, if Project A and Project B were determined to be Actionable in the least-cost development path, these projects would be fixed in the CDP's assessment across other scenarios. Project C and Project D, if

[38] See 2020 ISP, Appendix 9, Section A9.4.2.3, at. https://aemo.com.au/-/media/files/major-publications/isp/2020/appendix--9.pdf?la=en.

identified as Future Projects, would be able to be flexibly delivered across scenarios. The table below demonstrates this concept.

Table 4 Example treatment of actionable and future projects within the assessment of each CDP

	Project A	Project B	Project C	Project D
CDP 001: Least-Cost Development in Scenario 1	*2023-24 (Actionable)*	*2025-26 (Actionable)*	2032-33 (Future)	2038-39 (Future)
CDP001 (Scenario 2)	*2023-24 (Actionable)*	*2025-26 (Actionable)*	2028-29	-
CDP001 (Scenario 3)	*2023-24 (Actionable)*	*2025-26 (Actionable)*	2034-35	2036-37
CDP001 (Scenario 4)	*2023-24 (Actionable)*	*2025-26 (Actionable)*	2032-33	2038-39
CDP001 (Scenario 5)	*2023-24 (Actionable)*	*2025-26 (Actionable)*	-	-

As the example above shows, while the Actionable Projects are maintained in all scenarios, the Future Projects are flexibly delivered depending on the benefits of those projects in each scenario.

Further CDPs may be added to test the inclusion and/or exclusion of further potential actionable projects, earlier or later development timings, or further staging of ISP projects, including early works.

This process will therefore result in a suite of alternative CDPs which test combinations of potential actionable projects. These CDPs take into account the flexibility to adapt to future market conditions within the scenarios and also provide the means to test the option value that could arise from proceeding with only early works on some projects, rather than committing to the complete project.

Matters for consultation

- Is the approach described for selecting DPs appropriate? If not, what improvements could be made to this approach?
- Does the approach described fully capture option value and flexibility considerations?
- What approaches are possible to improve the consideration of non-network options in the assessment?

Defining the counterfactual development path

To identify the benefits of the transmission projects associated with each CDP, counterfactual DPs need to be developed for each scenario which do not model any material augmentations to existing transmission capacity beyond committed and anticipated developments[39]. This counterfactual case considers the development of the system without any transmission augmentation, and is used to identify the additional economic value to consumers of transmission augmentations (including inter-regional and intra-regional developments).

[39] Some network augmentations unrelated to the ODP may theoretically exist in the counterfactual DPs, including replacement capital expenditure known as 'repex', and other immaterial developments that may not be captured by the market modelling.

Modelling inputs for the counterfactual case include:

- Existing and committed transmission capacity.
- Existing intra-regional transmission capacity – no REZ developments beyond existing transmission access are allowed.

Because of the lack of transmission capacity augmentation in the system under the counterfactual case, it is highly possible that existing limits for renewable developments are insufficient to meet system and policy requirements. Alternative REZ expansion developments are enabled in close proximity to brown-field sites, when network capacity becomes available as a result of coal plant retirements.

In the 2020 ISP, the inclusion of these 'Shadow REZs' in the optimisation was limited to the counterfactual development paths. These were defined based on the additional network hosting capacity made available once thermal plant retire:

- Mount Piper Shadow REZ – initial build limit is zero, then increased by the amount of Mount Piper Power Station capacity retired.
- Bayswater Shadow REZ – initial build limit is zero, then increased by the amount of Bayswater Power Station capacity retired.
- Victoria Shadow REZ – build limits depend on Victorian brown coal capacity, renewable developments, and network hosting capacity in Gippsland REZ.

Shadow REZ limits are implemented as constraints in the optimisation to allow dynamic availability of capacity for new renewable developments when coal capacity starts retiring. It is important to note that additional network capacity due to coal closures in Queensland is already covered by existing REZ assumptions and is therefore not required for the counterfactual case.

For the 2022 ISP, AEMO is proposing to include the Shadow REZs in both the counterfactual modelling and in the optimisation within each development path. In the testing of development paths, the resource limit within these shadow REZ would be limited to a quantity equivalent to the use of land in close proximity to the existing power stations. This is to recognise the impact of competing for higher value land use and higher population density in the shadow REZs compared to other REZs.

In the counterfactual, a higher level of availability is included (described above) given that these are required to meet power system needs. This additional development would likely be at a higher cost given the issues described, but accounting for these effects is difficult to quantify.

Matters for consultation

- Is the proposed approach described for identifying the counterfactual DPs appropriate? What other techniques could be used to allow system and policy requirements to be met without transmission augmentation?
- How could AEMO better account for the costs and constraints on developments in Shadow REZs in both the testing of development paths and in the counterfactual development path?

Identification and quantification of costs/market benefits

Each of the DPs and counterfactual DPs are simulated to determine the discounted total system cost. The costs considered in the ISP modelling include:

- Capital expenditure, fixed and variable operating and maintenance costs, rehabilitation costs, and fuel costs on generation.
- Capital expenditure, and fixed and variable operating and maintenance costs on storage.

- Capital expenditure, and fixed and variable operating and maintenance costs on transmission projects including REZ network costs.
- Voluntary load curtailment (through Demand Side Participation) and involuntary load shedding costs.

Additional classes of benefits may also be considered, including the changes in costs due to intra-regional network losses, ancillary services, and competition benefits. The magnitude of these benefits classes is typically low, and may be challenging to quantify appropriately given the level of uncertainty regarding future outcomes. AEMO will consider the appropriate degree of inclusion for these benefits classes, particularly if they are expected to materially affect the assessments.

For the ISP, the NPV represents the present value of annual costs and benefits for the modelling horizon. Capital investment in generation, storage and transmission infrastructure is converted into an equivalent annuity to allow like-for-like comparison on assets with different economic lives. No terminal value is included, on the assumption that benefits associated with the transmission development continue to accrue at similar (or greater) levels beyond the modelling horizon. This is a reasonable assumption to make if one believes that the NEM will continue to transition away from coal-fired generation and towards renewable generation.

An alternative approach to capture terminal value would increase the complexity of the CBA assessment, accounting for the future value that may exist across the collection of assets developed and operating. To assess terminal value, one must consider the ongoing benefit stream expected to be provided by each asset, which would either require an assumption of persisting benefits observed in the last years of the modelling horizon (that is, that the NEM is fully transformed and therefore the benefits of each asset is static), or assumptions regarding the continued evolution of asset value given continued transition. The proposed approach to consider the present value of annual costs and benefits is consistent with the CBA Guidelines method for valuing market benefits. Once these costs are calculated, the net market benefits of each DP in each scenario is determined by subtracting the discounted total system cost from the counterfactual DP cost in that scenario. This results in a measure of the cost saving or net market benefit of each DP.

Matters for consultation

- Is the approach described for the identification and quantification of costs and market benefits appropriate?

Selecting an optimal development path

Under the CBA guidelines, AEMO is able to use different approaches to rank the CDPs. One mandated approach under the CBA guidelines is the scenario-weighted approach. This approach calculates the weighted average net economic benefits of each CDP by applying scenario weights based on scenario relative likelihood to each of the net market benefits calculated in each scenario.

The mandatory 'scenario-weighted' approach:

1. Ascribe probabilities (acknowledging that ascribing likelihood is inevitably subjective) to each of the scenarios considered, $P_1, \ldots, P_n$, where n is the number of scenarios considered for the cost benefit analysis.
2. Calculate the total system costs for the each of the CDPs (1, 2,…i) where i is the total number of CDPs, for each of the scenarios: $C_{1,1}, C_{1,2}, \ldots, C_{i,n}$.
3. Calculate the total system cost for each of the scenario-specific counterfactuals: $CF_1, \ldots, CF_n$.
4. Calculate the net system benefits for each CDP-scenario combination, by subtracting $C_{i,n}$ from CF_n: $B_{1,1}, B_{1,2}, \ldots, B_{i,n}$.

5. Calculate the scenario-weighted net system benefit A_1 of the first candidate path across all scenarios: $A_1 = (B_{1,1}*P_1 + B_{1,2}*P_2 + ... + B_{i,n}*P_n)$.
6. Repeat step 5 for all CDPs considered to determine the set of scenario-weighted benefits (A_1, ..., A_i).
7. Rank the DPs in order from highest to lowest scenario-weighted net market benefit.

An alternative approach that AEMO has employed in previous ISPs is the least-worst regrets (LWR) approach, which avoids making assumptions on likelihood of each scenario. Instead, it aims to minimise the risk of highly regretful outcomes if a CDP is locked in, yet the future reflects any of the defined scenarios.

In the least-worst regrets approach, AEMO would first identify, 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 DP will be 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), associated to all other CDPs.

This approach then requires identifying, for each CDP, the largest regret across all scenarios. The set of CDPs would then be ranked from least-regret to greatest-regret.

The alternative 'least-regret' approach:

1. Calculate the total system costs for the each of the CDPs (1, 2,...i) (where i is the total number of CDP and n is the total number of scenarios considered for the cost benefit analysis), for each of the scenarios: $C_{1,1}, C_{1,2}, ..., C_{i,n}$.
2. Calculate the total system cost for each of the scenario-specific counterfactuals: CF_1, ..., CF_n.
3. Calculate the net system benefits for each CDP-scenario combination, by subtracting $C_{i,n}$ from CF_n: $B_{1,1}, B_{1,2}, \dots , B_{i,n}$.
4. For each scenario, identify the CDP that results in the largest net market benefit: ($LB_1, LB_{2,\dots} LB_n$).
5. Calculate the 'regret cost' for all other CDP in each scenario, by subtracting net system benefits for each CDP-scenario combination $B_{i,n}$ from that scenario's LB_n. This results in a range of regret costs for all DP-scenario combinations: $R_{1,1}, R_{1,2}, \dots , R_{i,n}$.
6. Identify, for each CDP, the worst of the possible regret costs across all scenarios: $W_1, W_2, \dots , W_i$.
7. Rank the DP in order from least-worst regret cost to greatest-worst regret cost.

In the 2020 ISP, both approaches agreed on the highest ranking DP, but this does not necessarily have to be the case, as highlighted in the below example using illustrative CDP examples sourced from the AER CBA guidelines[40]. Table 5 presents three alternative scenarios, for which three CDPs are presented. CDP 3 results in the highest net market benefits for the Slow Growth scenario, CDP 2 for Moderate Growth, and so on. CDP 1 has the highest weighted net benefits amongst all CDPs (once weighted by likelihood) and is therefore ranked no.1.

Table 5 Illustrative net market benefits ($, mill) of scenario and CDP combinations

	Slow Growth	Moderate Growth	Fast Growth	Weighted net benefits	Rank
Likelihood	15%	50%	35%	-	-
CDP 1	-20	180	125	131	1
CDP 2	80	220	-20	115	2
CDP 3	220	195	-50	113	3

[40] See page 31, Table 7 in the CBA guidelines, at https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

Table 6 below calculates the regret cost for each CDP-scenario combination. The maximum regret for each CDP is calculated, and the CDP with least-worst regret is ranked no. 1 – in this case, CDP 2, a different CDP than above.

Table 6 Illustrative regret cost for Scenario and CDP combinations

	Slow Growth	Moderate Growth	Fast Growth	Worst regret	Rank
CDP 1	240	40	0	240	3
CDP 2	140	0	145	145	1
CDP 3	0	25	175	175	2

However, if the likelihood of the Moderate Growth scenario is increased to 65% (from 50% above), and the likelihood of Fast Growth is lowered to 20% (from 35%), the weighted net benefit of CDP 2 would be the highest amongst all CDPs, rather than CDP 1 – in line with the LWR ranking.

Although the LWR approach does not always choose the option with the largest average net benefit (noting this can occur as discussed above), the approach provides a robust decision against the range of uncertainties examined, clearly demonstrates risks, and minimises the chance of particularly adverse outcomes impacting consumers.

The LWR approach also means the determination of the ODP is not potentially skewed by the subjective allocation of relative likelihood, as evidenced in the example above. However, if the scenario that drives a CDP to be ranked no. 1 in the LWR approach has a very low relative likelihood, the LWR approach could drive investment based on outcomes highly unlikely to occur. In these situations, AEMO would propose to eliminate the scenario from the LWR approach. This would be clearly outlined in the Draft ISP.

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 LWR) and professional judgement to select the ODP.

The choice of approach AEMO will use in the ISP is necessarily reliant on the outcomes and risks observed in the market modelling. The approach selected, and AEMO's justifications in doing so, will be documented in the Draft ISP to provide the opportunity for stakeholders to provide feedback. Any deviation from the scenario-weighted approach would clearly explain how the decision balances risks for consumers, and the potential cost associated with selecting the ODP based on the LWR approach compared to the scenario-weighted approach.

Matters for consultation

- Which approach do you consider most appropriate for selecting the ODP and why? What do you consider to be the benefits of that approach relative to the alternative?
- Would another approach provide a more appropriate, considered framework for assessing benefits and investment risks?
- Do you consider that the risk appetite for consumers is such that a solution that minimises risks under some conditions may be preferred over a solution that delivers the lowest expected cost? Would you support the inclusion of a condition that excludes LWR outcomes that result in expected costs exceeding the scenario-weighted approach by some threshold?

In identifying the ODP, AEMO will consider whether any project should be actionable with decision rules. This will depend on whether there are clear trigger events under which a project is beneficial. Where no clear trigger event is evident, the remaining stage of the project (beyond early works) will remain a Future ISP project which would be reassessed in subsequent ISPs.

Testing the optimal development path

Once AEMO has selected an ODP, the AER's CBA guidelines require AEMO to undertake sensitivity testing and/or cross checks. The sensitivities tested will be informed by the preliminary determination of the ODP.

Matters for consultation

- What tests do you consider to be most critical in testing the ODP?

TOOT analysis

AEMO will confirm that each actionable ISP project makes a positive contribution to the net economic benefit in the Central scenario using the take one out at a time (TOOT) analysis. The aim of the TOOT analysis is to determine a project's incremental market benefit.

AEMO proposes to use the TOOT approach as part of the ISP CBA process in the following ways:

- As a cross-check of the ODP, to test whether actionable ISP projects make a positive contribution to the net economic benefit of the ODP in the Central scenario.
- As an ISP feedback loop for actionable ISP projects, to assess whether the preferred option under the RIT-T assessment is aligned with the ISP ODP and its cost does not change the status of the project as part of the ODP.

The TOOT approach removes the actionable ISP project from the ODP, along with any REZ transmission access upgrades provided by the project.

The TOOT assessment includes the following steps:

1. Identify the expansion plan of the ODP and calculate the total system cost.
2. Lock down the REZs expansion outcome from the optimal case as an input for the TOOT case.
3. Remove the actionable ISP project from the ODP and adjust REZ expansion limits.
   - For REZs not affected by the actionable project, the adjusted limits consider the transmission access and any additional REZ expansion from the ODP. If the outcome of the ODP results in intra-regional transmission augmentation, the limit is increased to reflect the additional generation capacity from this augmentation. For example, if in 2029-30 an additional 500 MW REZ expansion occurred beyond the 1,000 MW hosting capacity at a given REZ as part of the ODP, the REZ adjusted limit for the TOOT case will then be 1,500 MW from 2029-30.
   - For REZs affected by the actionable project, the additional hosting capacity associated with the development of the actionable project is removed from the hosting capacity and the adjusted limit will only consider the initial hosting capacity plus any additional REZ expansion from the ODP. For example, assume the hosting capacity is 1,000 MW, which consists of an initial hosting capacity of 300 MW and an upgrade of 700 MW from the actionable project in 2026-27. If in 2029-30 an additional 500 MW REZ capacity expansion occurred (over and above the additional capacity provided by the earlier actionable project), the REZ adjusted limit for the TOOT case in 2029-30 will be 800 MW (300 MW of initial hosting capacity plus 500 MW of additional expansion identified in the optimal development plan).

   Table 7 illustrates the REZ limit calculation for the two cases described above.

Table 7 Total REZ limits example

REZ limit component	REZ not affected by IC MW)	REZ affected by IC MW)
Hosting capacity	300	300
Additional transmission capacity due to Actionable ISP project	700	-
Transmission augmentation – REZ capacity expansion	500	500
Total REZ limit for TOOT case (by 2029-30)	1,500	800

Other aspects for the TOOT case include:

- All other transmission augmentations (committed, anticipated, actionable and future ISP projects) will remain as stated by the ODP.
- No transmission developments are allowed beyond the adjusted expansion limits as described above, with the expectation that VRE is relocated to other REZs, or alternative generation technologies are considered, if required.
- Policy settings continue to be the same as the ODP with an option of not enforcing renewable energy targets if it is not technically feasible to meet the requirement.
- Optimise the TOOT case and calculate the total system cost.
- Determine the net market benefits of the actionable project by comparing total system costs between the ODP and the TOOT case.

Further analysis in the TOOT

For REZ developments which are determined to be actionable projects, AEMO proposes to 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. By testing the potential benefits of using additional storage to reduce network investment, the ISP can provide an indication of whether non-network options are likely to be beneficial.

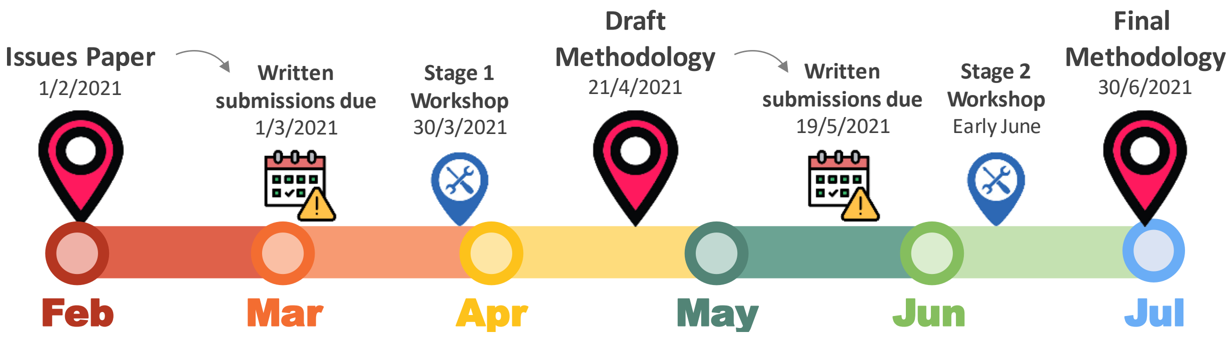
Matters for consultation

- Is the methodology described for the TOOT analysis appropriate? What improvements would you propose for this approach?

4. Next steps

This Issues Paper commences the ISP Methodology process shown below in Figure 4 below[41].

Figure 4 Timeline for ISP Methodology process



Issues Paper

Stakeholders are invited to submit written responses to this Issues Paper **by 1 March 2021**. Submissions should be sent via email to ISP@aemo.com.au. AEMO requests that, where possible, submissions should provide evidence and information that support any views or claims that are put forward.

Between 2 and 30 March 2021, AEMO will undertake a review of submissions received.

Stage 1 workshop/webinar

A workshop or webinar will be held **on 30 March 2021** to provide a further opportunity for stakeholders to provide views on the Issues Paper. Written submissions to this Issues Paper will inform the scope and approach to engagement in this workshop or webinar.

Draft Methodology

A Draft Methodology will be published on 21 April 2021. This will be informed by views and information received from stakeholders through written submissions, as well as any subsequent meetings held as part of the first stage of consultation. Stakeholders will be invited to submit written responses to the Draft Methodology **by 19 May 2021**.

Stage 2 workshop/webinar

A workshop or webinar will be held in early June to provide further opportunity for stakeholders to provide views on the Draft Methodology. Written submissions to the Draft Methodology will inform the scope and approach to engagement in this workshop or webinar.

Final Methodology

The Final Methodology will be published on 30 June 2021, and will take into account views from all submissions received as part of the two-stage consultation process.

---

[41] This timeline was developed in accordance with the requirements of NER cl. 5.22.8(b) and Appendix A of the Forecasting Best Practice Guidelines.

Abbreviations

Term	Definition
AER	Australian Energy Regulator
CBA	Cost Benefit Analysis
CCGT	Closed-cycle gas turbine
CDP	Candidate development path
DER	Distributed energy resources
DP	Development path
ELCC	Effective Load Carrying Capacity
EMT	Electromagnetic transient
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities
EV	Electric vehicle
FCAS	Frequency control ancillary services
FFR	Fast frequency response
GSOO	Gas Statement of Opportunities
HVDC	High voltage direct current
IASR	Inputs, Assumptions and Scenarios Report
ISP	Integrated System Plan
LDC	Load duration curve
LNG	Liquified natural gas
LWR	Least-worst regrets
MW	Megawatt/s
MWh	Megawatt hour/s
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net present value

Term	Definition
NSP	Network service provider
NSCAS	Network Support and Control Ancillary Services
ODP	Optimal development path
POE	Probability of exceedance
PV	Photovoltaic
REZ	Renewable energy zone
RIS	Renewable Integration Study
RIT-T	Regulatory Investment Test for Transmission
SRAS	System restart ancillary services
TNSP	transmission network service provider
TOOT	Take-one-out-at-a-time (analysis)
USE	Unserved energy
VNI	Victoria – New South Wales Interconnector
VRE	Variable renewable energy