2019 Planning and Forecasting Consultation Paper

February 2019

Scenarios, Inputs, Assumptions, Methodology, Timeline, and Consultation Process

Important notice

PURPOSE

The publication of this Consultation Paper commences AEMO's consultation on AEMO's planning and forecasting inputs, scenarios and assumptions for use in its 2019 publications for the National Electricity Market (NEM).

AEMO has also prepared this document to seek feedback on AEMO's 2018 Integrated System Plan (ISP) and National Transmission Network Development Plan (NTNDP), and outlines AEMO's view of the material issues to be considered in the 2019 ISP.

This Consultation Paper includes the information required by clause 5.20.1(a) of the National Electricity Rules.

This publication has been prepared by AEMO using information available at 31 December 2018. Information made available after this date may have been included in this publication where practical.

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VERSION CONTROL

Version	Release date	Changes
1	05/02/2019	

Executive summary

AEMO delivers a range of planning and forecasting publications for the National Electricity Market (NEM), including the NEM Electricity Statement of Opportunities (ESOO) and the Integrated System Plan (ISP).[1] AEMO has prepared this document to:

- Provide information and seek stakeholder submissions on considerations for the 2019 publications, including:
  - Proposed scenarios, inputs and assumptions for use in AEMO's 2019 NEM planning and forecasting publications.
  - Material issues to be considered in the preparation of the next ISP, and preliminary views on how those issues should be resolved.
- Outline and seek feedback on AEMO's proposed consultation process for the 2019-20 ISP.

AEMO will model consistent scenarios for forecasting and planning publications related to both the NEM and eastern and south-eastern Australian gas markets.

AEMO is committed to continually improve its suite of planning publications to better meet stakeholder needs. AEMO respects the expertise of its stakeholders and values all feedback, which is critical in guiding meaningful progress and developing a strategic vision for the future development of Australia's energy system.

AEMO strives to ensure its planning and forecasting publications remain transparent, providing a valuable information resource to stakeholders that represents a holistic view of the NEM.

2019-20 ISP and 2019 ESOO scope and scenarios

For the 2019-20 ISP and 2019 ESOO, AEMO intends to build on the scenario analysis approach used last year to identify the requirements for optimal power system development under a range of different futures, and to identify requirements for managing increasing uncertainties and the key material issues that impact reliability, generation, and transmission development.

AEMO seeks feedback on its proposed scenario approach:

- A neutral outlook – based on best available extrapolation of current policies and trends.
- Two credible bookend scenarios which explore futures with faster and slower rates of change in the energy sector, with rates of change affected by the timing of retirements of existing generators, changes in the cost competitiveness of new utility-scale renewable generation, level of decentralisation and economic/population growth experienced in Australia.
- A number of sensitivities to explore the impacts of specific uncertainties such as the availability/location of new pumped hydro opportunities and the speed of uptake of distributed energy resources.

Proposed scenarios, inputs, and assumptions to be used in 2019

AEMO's stakeholder engagement on assumptions for 2019 planning and forecasting publications commenced in August 2018, with initiation of the "GenCost" project. GenCost is a collaboration between the Commonwealth Scientific and Industrial Research Organisation (CSIRO), AEMO, the Australian Renewable Energy Agency (ARENA), and industry stakeholders, to deliver annual updated estimates of electricity

[1] For National Electricity Rules purposes, the ISP will largely incorporate the information required to be contained in the National Transmission Network Development Plan (NTNDP). This consultation incorporates the formal requirements for consultation on NTNDP inputs, material issues and other matters specified in the rules prior to the development of an NTNDP.

generation costs. Extensive stakeholder engagement was undertaken with a number of workshops from August to November 2018, with the inaugural GenCost report published in December 2018[2].

The proposed inputs and assumptions for 2019 planning and forecasting publications have also been informed by:

- Feedback on the appropriateness of scenarios used in the 2018 ISP, received from the Forecasting Reference Group (FRG) through questionnaires and forum discussion.
- Targeted stakeholder outreach to review the 2018 ISP assumptions workbook.
- Feedback provided to the Energy Security Board (ESB) during its consultation workshops in November 2018.

The publication of this Consultation Paper commences AEMO's formal consultation on the inputs and assumptions that will be used to support a 2019-20 actionable ISP[3]. Where relevant, these inputs and assumptions will also be used in forecasting reliability under the Retailer Reliability Obligation (RRO), although additional consultations will be conducted as required to cover information specific to the RRO.

Material issues and modelling improvements for focus in 2019

AEMO is seeking feedback on an initial list of issues it considers to be material for 2019 planning and forecasting publications, as outlined below:

- Understand the reliability of ageing thermal plants, the timing and scale of existing thermal generators retiring and what new energy sources will replace them. This will include an assessment of whether there will be adequate supply to maintain reliability following the closure of the Liddell Power Station. It will also include an assessment of whether revenues for the ongoing operation of existing coal- and gas-fired plants are sufficient for their reliable operations and/or could lead to early closure.
- Enhance the understanding of pumped storage, with specific emphasis on the Snowy 2.0 and Battery of the Nation projects.
- Use improved cost, storage, lead time, and demand management assumptions, based on the GenCost project.
- Take into account the increasing consumer investment trends towards rooftop photovoltaics (PV), battery storage, demand side participation, energy efficiency and other forms of Distributed Energy Resources (DER). This will include considering the role that Virtual Power Plants (VPPs) could play in future.
- Identify necessary measures to enhance the resilience of the future power system through network and non-network services, which includes addressing technical issues such as frequency stability, voltage control and power system strength.
- Developing an approach to value measures that enhance the resilience of the power system to climate change risks. This aspect will incorporate insights from the Australian Government funded project between CSIRO, the Bureau of Meteorology (BOM), and AEMO to support implementation of improved climate and extreme weather information for the electricity sector.
- Commencing tri-sector integration of electricity, gas, and transport in AEMO's co-optimisation model. This work will leverage AEMO's work with Infrastructure Victoria, ARENA, CSIRO, and industry on the "zero emission vehicle" roadmap.
- Developing early insights on the potential impact of a transition to a hydrogen economy (noting AEMO needs to develop and test functional changes in its modelling tools and collect more data before including hydrogen as a full scenario in future ISPs).

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[2] CSIRO. *Annual update finds renewables are cheapest new-build power*, available at https://www.csiro.au/en/News/News-releases/2018/Annual-update-finds-renewables-are-cheapest-new-build-power.

[3] ESB. *Converting the ISP into action*, available at http://www.coagenergycouncil.gov.au/publications/energy-security-board-converting-isp-action.

Based on feedback received, AEMO will use these material issues as the focus areas for its 2019 publications, including insights papers, the 2019 ESOO, and the 2019-20 ISP.

Many of the identified uncertainties will be captured through scenario modelling.

A key focus in 2019 is to improve stakeholder engagement and the quality of inputs, enhance modelling processes, and deepen understanding of risks and opportunities arising during the transition of the energy system.

Questions on which AEMO seeks feedback

AEMO seeks feedback from all interested parties on the proposed engagement process, scenarios, inputs and assumptions, and the material issues and modelling improvements to be AEMO's key areas of focus for planning and forecasting activities for 2019.

Questions are presented in the chapters of this report where AEMO is seeking evidence-based commentary and guidance. These chapters have been selected to combine related areas to aid review and facilitate considered feedback.

Table 1 Summary of chapters for consultation

Chapter	Summary
2. Stakeholder engagement	Proposed timetable, consultation forums, workshops and publication dates for 2019-20.
3. Scenarios	Summary of proposed core scenarios for planning and forecasting publications in 2019-20.
4. Inputs and assumptions	Proposed assumptions and parameters for key input assumptions for planning and forecasting models in 2019-20.
5. Material issues for 2019	Material issues to be addressed as part of AEMO's 2019 forecasting and planning activities.
6. System strength and inertia	Summary of methodologies for assessing system strength and inertia requirements
7. Feedback on the 2018 ISP	Summary of the 2018 ISP feedback received.

AEMO values any feedback stakeholders are in a position to provide and welcomes written submissions on any observations or approaches outlined in this report. Submissions need not address every question posed and are not limited to the specific consultation questions contained in each chapter.

Invitation for written submissions

AEMO invites written submissions on the matters raised in this consultation paper by Wednesday 20 March 2019. Please email submissions to forecasting.planning@aemo.com.au. Where possible, please provide evidence to support your view(s).

Stakeholders who have additional suggestions on ways AEMO can improve its ISP or ESOO, other than the topics outlined in this document, should also include these ideas in their submission.

Further stakeholder engagement opportunities

On 19 February 2019, AEMO will hold a workshop with interested stakeholders on scenarios, inputs, and assumptions. Please email forecasting.planning@aemo.com.au by 13 February 2019 if you would like to take part in this workshop.

Following receipt of written submissions, AEMO will convene another workshop to discuss and resolve any outstanding issues of concern and finalise the scenarios, inputs and assumptions. This workshop is likely to be held on 2 April 2019. Further details will be provided closer to the time.

Contents

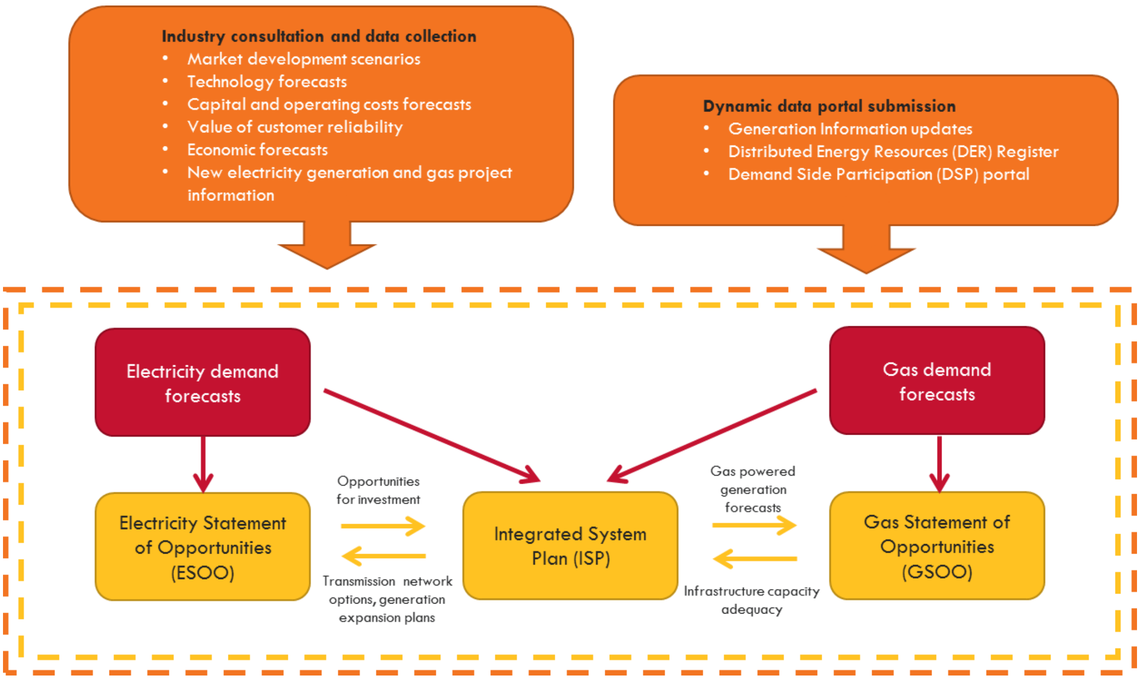
1. Introduction

AEMO provides planning and forecasting information for the National Electricity Market (NEM), and eastern and south-eastern gas systems, as part of its functions under the National Electricity Law and the National Electricity Rules and the National Gas Law and the National Gas Rules. An overview of AEMO's comprehensive suite of planning and forecasting publications is shown in Figure 1 below. Primary annual publications include:

- Electricity Statement of Opportunities (ESOO) – provides a 10-year supply adequacy assessment of the NEM, with market and technical data to assess the reliability of the electricity market, and incorporates an independent 20-year forecast for annual consumption and maximum and minimum demand.
- Gas Statement of Opportunities (GSOO) – reports on the transmission, production, and reserves supply adequacy of Australia's eastern and south-eastern gas markets over a 20-year outlook period, incorporating an independent forecast for gas consumption, and maximum gas daily consumption.
- Integrated System Plan (ISP) – identifies a whole of system plan over a 20-year outlook period to reliably and securely supply customers, while minimising the overall cost of the NEM. The ISP is intended to address most or all of the content of the National Transmission Network Development Plan (NTNDP) currently required under the National Electricity Rules (NER). Discussion in this Consultation Paper on modelling inputs, material issues for consideration, inertia requirements and system strength requirements includes those matters referred to in the NER for NTNDP purposes.

AEMO's suite of forecasting and planning reports project the potential evolution of the NEM and the eastern and south-east Australian gas network across the long term. Each report typically presents several alternative futures, given the uncertainty of point forecasts when market and economic drivers can change significantly over the forecast period.

Figure 1 AEMO's primary national planning and forecasting publications – NEM, and eastern and south-eastern gas systems



1.1 From information to action

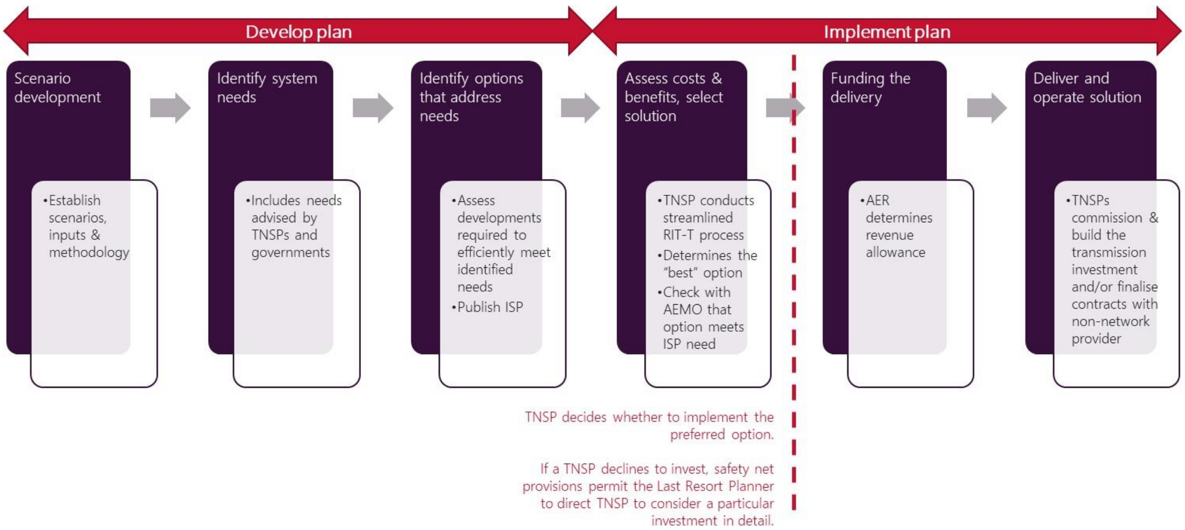
AEMO's forecasting and planning publications for the NEM and eastern and south-eastern gas markets were once for information only, but this is changing.

At the 21st meeting of the COAG Energy Council on 19 December 2018, "Ministers discussed progress on the 2018 ISP and agreed on an approach, set out by the ESB [Energy Security Board], to deliver the identified Group 1 projects as soon as possible, including rule changes to streamline regulatory processes. Ministers also asked the ESB to consider how these reforms could be applied to other priority projects such as the SA to NSW interconnector. The ESB will report back to Council by end March 2019 for a decision as soon as possible. Ministers noted that a rigorous cost benefit analysis will be an essential part of the process to ensure costs to consumers are minimised, and agreed that the ESB do more work on further measures to operationalise the ISP including regular updates and re-assessments of Group 2 and 3 projects"[4].

The ESB, Australian Energy Regulator (AER), Australian Energy Market Commission (AEMC), and AEMO are collaborating to enshrine the ISP status in the transmission investment decision-making process and enhance AEMO's national planning role. The ESB's action plan provides a high-level outline of a proposed model, shown in Figure 2, which incorporates feedback from ESB stakeholder workshops in November 2018.

Also at the December 2018 COAG meeting, Ministers agreed to the ESB's proposed Retailer Reliability Obligation (RRO) which will come into effect by 1 July 2019, aiming to incentivise investment in dispatchable generation for improved power system reliability.

Figure 2 Overview of ESB's proposed framework for system-wide planning



In recent years, the GSOO has also been a key publication that the Federal Minister for Resources and Northern Australia takes into consideration in determining whether to declare a gas shortfall year as part of the Australian Domestic Gas Security Mechanism (ADGSM).

These mechanisms mean AEMO's work will be relied on for decision-making, so AEMO's commitment to producing credible, accurate, and insightful forecasts and planning publications in a transparent manner is more critical than ever. Forecasting in a rapidly changing energy industry is challenging, and understanding and articulating key risks and uncertainties is important to allow for informed decision-making. AEMO relies heavily on industry expertise, insights, and critique to ensure its inputs and assumptions are credible and the information and insights provided through its publications deliver value for stakeholders. This consultation

[4] COAG Energy Council. *21st COAG Energy Council Communique*, available at http://coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/21st%20COAG%20Energy%20Council%20Communique.pdf

provides stakeholders with the opportunity to provide formal written submissions on proposed inputs, assumptions, and scenarios that will influence 2019 analysis used to help shape the future power system.

2. Stakeholder engagement

2.1 Consultation timeline

AEMO is seeking written views on the scenarios, inputs, assumptions and methodologies to be used in its planning and forecasting including the ISP and ESOO.

Submissions will guide finalisation of inputs and assumptions critical to AEMO's forecasting and planning work in 2019. Please email submissions to forecasting.planning@aemo.com.au.

AEMO's indicative timeline for this consultation is outlined below. Dates may be adjusted depending on the number and complexity of issues raised in submissions and any meetings with stakeholders.

Table 2 Consultation timeline for this report

Key milestone	Indicative date
Forecasting and Planning Consultation published	Tuesday 5 February 2019
Stakeholder workshop to address any questions of clarification conducted	Tuesday 19 February 2019
Submissions on Forecasting and Planning Consultation received	Wednesday 20 March 2019
Stakeholder workshop to finalise scenarios and resolve issues conducted	Tuesday 2 April 2019
Consumer Engagement Panel workshop conducted	April/May 2019 – to be confirmed
Final scenario and assumptions report published	Thursday 16 May 2019

In addition to this document, the associated 2019 Input and Assumptions workbook, and other supplementary materials listed in the next section, AEMO will also run two workshops prior to finalising scenarios, inputs and assumptions. These workshops will be offered as an open forum for all energy stakeholders (energy consumers, generators, network businesses, technology providers, market bodies, other interested parties) to enable discussion of diverse views. The objectives of each workshop are summarised in Figure 3.

Figure 3 Objectives of consultation workshops

Stakeholder briefing and scenario exploration
One day workshop 1 on 19 February 2019

Agenda
- Share purpose and approach of ISP 2019-20
- Summarise key inputs sought during consultation
- Discuss priority issues to explore through this ISP
- Review the key global, Australian and sector specific trends that will shape Australia's energy future
- Combine the trends into logically consistent set of draft scenarios and sensitivities
- Test that key issues can be explored with scenarios

Scenario finalisation and key issue exploration
One day workshop 2 on 2 April 2019

Agenda
- Feedback assumptions, scenario implications and key open issues from the written consultation responses
- Discuss and where possible resolve the key open issues from the consultation process
- Finalise the combination of trends into scenarios and sensitivity analysis
- Develop a narrative for each of the scenarios and refine the scenario names if needed

2.2 Supplementary materials

Table 3 provides links to additional information related to AEMO's forecasting and planning inputs, assumptions and methodologies that supplement this report.

Table 3 Additional information and data sources

Information source	Website address
2019 Input and Assumptions workbook	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-Forecasting-and-Planning---Inputs-and-Assumptions---v1.0.xlsx
CSIRO, 2018, GenCost 2018; Updated projections of electricity generation technology costs	https://www.csiro.au/~/media/News-releases/2018/Annual-update-finds-renewables-are-cheapest-new-build-power/GenCost2018.pdf
GHD, 2018 AEMO costs and technical parameter review	AEMO costs and technical parameter review report, available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/9110715-REP-A-Cost-and-Technical-Parameter-Review---Rev-4-Final.pdf AEMO costs and technical parameter review databook, available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/GHD-AEMO-revised---2018-19-Costs_and_Technical_Parameter.xlsb
Entura, 2018, Pumped hydro cost modelling	https://projectmarinus.tasnetworks.com.au/assets/Report-Pumped-Hydro-Cost-Modelling.pdf
Core Energy, 2019 wholesale gas price outlook	Wholesale Gas Price Outlook Report, available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/CORE-Delivered-Wholesale-Gas-Price-Outlook_16-January-2019.pdf Wholesale Gas Price Outlook Databook, available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/CORE-Eastern-Australia-Gas-Price-Projections-Databook_16-January-2019.xlsx
Wood Mackenzie, 2016 forecast coal costs	http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2016/Data_Sources/AEMO_Coal-Outputs_20160512_.xlsx
AEMO, 2018 Demand Forecasting methodology information report	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Demand-Forecasting-Methodology-Information-Paper.pdf
AEMO Market modelling methodologies report	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Market-Modelling-Methodology-Paper.pdf
System strength and inertia methodology reports	AEMO, 2018, System Strength Requirements Methodology, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf AEMO, 2018, Inertia Requirements Methodology, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf

Information source	Website address
CSIRO 2018 forecast of small scale technologies	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/Projections-for-Small-Scale-Embedded-Technologies-Report-by-CSIRO.pdf
Integrated System Plan (ISP) 2018	http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Integrated-System-Plan-2018_final.pdf 2018 Integrated System Plan Appendices (including methodology documentation), available at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/ISP-Appendices_final.pdf
National Transmission Network Development Plan (NTNDP) 2018	http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2018/2018-NTNDP.pdf
Electricity Statement of Opportunities (ESOO) 2018	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf
Gas Statement of Opportunities (GSOO) reports, including methodology report	https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities
Forecasting reference group webpage	https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Forecasting-Reference-Group
AEMO Generation Information pages	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

2.3 Enhanced engagement with energy consumers

Throughout 2019, AEMO will facilitate an enhanced engagement program with energy consumers, including a Consumer Engagement Panel, to make forecasting and planning material more accessible to consumers.

Consumer Engagement Panel

AEMO intends to form a Consumer Engagement Panel (CEP), comprising qualified representatives who can be consulted and provide robust review of AEMO's forecasting and planning outcomes. The CEP will provide an effective way for AEMO to engage with consumers to understand their key interests and issues as part of guiding effective planning for development of the NEM.

AEMO will seek input and advice from the CEP on key consumer issues during the development of the ISP and AEMO's other forecasting and planning deliverables. The CEP will facilitate the consideration of the consumer perspective to achieve a balanced consideration of all views by AEMO. AEMO will hold CEP sessions throughout the year to review and provide input at key milestones.

2.4 Increased engagement with stakeholders

AEMO will facilitate enhanced engagement with stakeholders through a series of programs on forecasting, modelling, reliability analysis, renewable energy, and other topical items. Focus workshops will be held throughout 2019, with continuing regular engagement in forums and regular one-on-one engagements.

In addition to workshops and consultations, AEMO will also undertake wider public consultation seeking written input on key deliverables, including scenarios and approach (this report), methodology reports, and the draft ISP. These consultations, along with submissions received and commentary on how AEMO has considered this feedback, will be published on AEMO's website in the relevant webpages.

Details of upcoming events are provided in Section 2.5.

Forecasting Reference Group forums

The Forecasting Reference Group (FRG) is a forum in which industry's forecasting and modelling specialists share expertise and explore new approaches to addressing the challenges of forecasting both supply and demand in a rapidly changing energy industry. The forum seeks to facilitate constructive discussion on matters relating to gas and electricity forecasting and market modelling.

Meetings are held monthly or as needed, by video conference across AEMO's offices (limited access is also available via teleconference). All material is published on AEMO's website[5].

Joint planning with TNSPs

AEMO and Transmission Network Service Providers (TNSPs) collaborate on modelling and planning activities to develop the ISP and implement its outcomes in a coordinated and aligned manner. The bodies meet regularly to share information and align planning activities, supporting the development of the ISP and aligned implementation in the TNSP planning activities.

Government engagement

During the development of the ISP and other forecasting and planning outcomes, AEMO continues to engage directly with the Federal and State Governments on matters relevant to their jurisdictions.

2.5 Key events for 2019-20

The milestones in Table 2 directly apply to this consultation on scenarios, inputs, assumptions and material issues, together with inertia and system strength methodologies. Table 4 lists other key upcoming events, and more events may be added and dates firmed as 2019 proceeds.

Table 4 Key events for 2019-2020

Event	Information	Date*
Electric Vehicles Workshop	Cross-sector workshop on electric vehicles to start developing a road map for integrated energy and transport planning	4 March 2019
Forecasting Reference Group	Forum to discuss draft forecasts used as input to electricity demand forecasts.	27 March 2019
Reliability Forecasting Workshop	Workshop on assumptions and method for calculating reliability forecast and reliability gap.	April 2019
Modelling and REZ Workshop	Workshop on modelling approaches and renewable energy zones.	July 2019
ESOO	Release of ESOO and RRO reliability forecast	August 2019
Technology costs workshops	Stakeholder workshops on technology cost projections (including generation costs)	July-September 2019
ISP Stakeholder Forum	Stakeholder forum on early draft modelling outcomes, refinement of renewable energy zone outcomes, for the ISP	September 2019
Forecasting and Planning Consultation	Public consultation seeking written input on scenarios, inputs, assumptions, methodologies for AEMO's forecasting and planning work in 2020.	November 2019 to January 2020
Draft ISP	Release of a full draft ISP, for public review and formal feedback, to guide finalisation of the ISP	December 2019
ISP Workshops	Stakeholder workshops on the draft ISP outcomes; one in Melbourne and one in Brisbane	Early December 2019

[5] AEMO. *Forecasting Reference Group*, available at http://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Forecasting-Reference-Group.

Event	Information	Date*
Consumer Engagement Panel	Session on scenarios, inputs, assumptions for use in next ISP. Meetings in Melbourne and Brisbane.	February 2020
Final ISP	Final ISP released	30 April 2020
ISP Stakeholder Forum	Stakeholder forum presenting final ISP findings and recommendations, implications, and outlook	Early May 2020

* Where date unspecified, details to be determined and will be advised.

2.6 Questions for consultation

Q1 How could AEMO further improve stakeholder engagement and confidence in the results of the 2019-20 ISP and 2019 ESOO?

3. Scenarios

Each year, AEMO assesses future forecasting and planning requirements under a range of credible scenarios over a 20-year period, to reflect uncertainties in future inputs and assumptions.

3.1 Scenario overview

In 2018, AEMO investigated the reliability and durability of the NEM and the eastern and south-eastern gas network to be able to cope with a changing generation mix and meet the demands of consumers over the medium to long term. This was assessed in key publications including the 2018 GSOO, the 2018 ESOO, and the 2018 ISP. In these publications, AEMO applied the concept of scenario analysis to help stakeholders understand risks and opportunities across the time horizon, and identify the potential value provided by infrastructure investment, particularly, in the NEM, the value of stronger electricity transmission networks to aid the delivery of geographically diverse generated electricity.

In 2018, the scenarios investigated were:

- Fast Change – a future where Australia's economy is booming, population growth is strong, and emission reduction targets are aggressive, leading to rapid decarbonisation of the both the stationary energy sector and the transport sector. Consequently, growth in grid demand is relatively strong and there is a material change in the large-scale generation mix over time.
- Neutral – a future where modest economic and population growth is experienced, and existing carbon abatement policies are met and extended on a similar trajectory. Consequently, grid demand is relatively static, and change in the large-scale generation mix is largely driven by timing of coal-fired generation retirements.
- Slow Change – a future where Australia's economic and population growth is weak, and proportionately more of the decarbonisation occurs through decentralisation, with a greater proportion of households and commercial businesses installing rooftop photovoltaic (PV) systems to help reduce energy costs. The transition towards zero emission vehicles is slow, as people have less disposable income and are buying new vehicles less often. Consequently, grid demand is in decline and the change in large-scale generation mix over time is less pronounced.
- High DER – a future similar to the Neutral scenario, but with greater decentralisation. Distributed rooftop PV generation, battery storage, and demand side response at the consumer level are relatively high, as the result of drivers including policy and regulatory objectives, or more favourable pay-back periods.

AEMO's forecasting and planning publications also considered several sensitivities, highlighting the variability in near- and long-term outcomes depending on the area of focus. For example:

- In the 2018 ISP, AEMO examined the effect of increased investment in strategic hydro storage initiatives (Neutral with storage initiatives) or the impact of earlier coal generator retirements to understand the value of transmission investment under various potential futures.
- In the 2018 ESOO, AEMO assessed future reliability with and without new, as yet uncommitted, ISP generation development.

In October 2018, AEMO reviewed the scenarios and the consistency of their drivers via the FRG and received informal feedback through various other channels. AEMO concluded that the core scenarios used in 2018 still strike the right balance between plausibility and stretching to capture key uncertainties that could materially impact forecasts.

Some minor changes are proposed to capture additional potential developments, improve internal consistency and add further value to stakeholders:

- Modify the Fast Change scenario to exclude the development of a seventh Gladstone liquefied natural gas (LNG) export facility, or train. Feedback from across the industry has identified this as an outlier scenario.
- Adjust demand side participation (DSP) and distributed energy resource (DER) settings to increase internal consistency between drivers affecting uptake of DER components, such as rooftop PV, battery systems, and electric vehicles. The scenarios will explore the impact of these devices on consumption patterns, considering the charging and discharging behaviours of consumer storage.
- Tune scenarios to cover a range of emission reduction outcomes based on different timings of coal-fired generation retirements, rather than imposing arbitrary stationary energy sector emission reduction targets to 2050.

These changes are discussed in more detail in the following sections. Limiting changes to the scenarios to these types of improvements will assist year-on-year comparisons.

Through consultation, stakeholders frequently raised two key material uncertainties which are not currently tested through AEMO's scenarios and sensitivities:

1. How policy uncertainty should be captured, in particular with respect to Federal and State Governments' renewable energy targets.
   – A common suggestion was for AEMO to consider exploring sensitivities in the modelling that would assist in quantifying the impact of a specific policy, notionally, through the use of counter-factual simulations, effectively with and without the policy in place.
2. Whether a hydrogen scenario should be included.
   – AEMO has been asked to consider the implementation, or consideration, of an expanded hydrogen industry, specifically the impact on variable renewable generation development and supplementing/ complementing gas supplies.

3.1.1 Policy certainty

AEMO's forecasting and planning studies will incorporate current policy settings. The 2018 ISP demonstrated that changes in timings of ageing coal-fired generation retirements, and the rate of new investment in renewable generation are now the two greatest influences on power system development needs over the next 20 years and these are no longer solely driven by policy. As such, decarbonisation in AEMO's scenarios will be an outcome of changes in these two factors rather than presuming or anticipating changes in policy settings.

3.1.2 The role of hydrogen

Key recent publications[6] have highlighted the potential opportunity for hydrogen production, consumption, and export. As efficiencies increase and costs reduce, some stakeholders anticipate that the hydrogen industry in Australia will expand, impacting on the development and operation of the NEM and Western Australia's Wholesale Electricity Market (WEM).

In 2019, AEMO proposes to spend time working with industry and researchers to collect the necessary information to extend its gas and electricity co-optimisation planning model to incorporate transport and consider cross-sectoral benefits and implications, including interactions with the emerging hydrogen industry. Further research and development is required before hydrogen can be included as an ISP scenario, but work activities planned for this year should place AEMO in a better position to consider the role of hydrogen in future studies.

[6] CSIRO, 2018, *2018 National Hydrogen Roadmap*, available at https://www.csiro.au/en/Do-business/Futures/Reports/Hydrogen-Roadmap and Hydrogen Strategy Group, 2018, *Hydrogen for Australia's future*, available at https://www.chiefscientist.gov.au/wp-content/uploads/HydrogenCOAGWhitePaper_WEB.pdf

3.2 Proposed 2019 scenario descriptions

The proposed scenarios for 2019 are still framed around the rate of transformation of the energy sector, and, as summarised in Table 5, vary in three dimensions:

1. Level of DER.
2. Uptake of utility-scale renewable generation (and thermal generation retirement timings).
3. Level of energy demand.

Table 5 Scenario dimensions

Scenario	DER uptake	Large-scale renewable generation uptake	Energy demand
Neutral	Medium	Medium	Medium
Fast change	Low	High	High
Slow change	High	Low	Low
High DER	High	Low	Medium

The anti-correlation between growth in large-scale renewable generation uptake and consumer preferences for DER is deliberately imposed, to provide maximum stretch on the transmission network and balance the drivers for investment provided across the scenarios. "High" or "low" DER in this context will reflect consultant's views on a plausible upper or lower level of forecast uncertainty plausibly associated with the conditions described in the scenario. For example, in absolute terms the DER uptake may still be higher in the Fast change scenario than the Low change simply due to differences in population growth, but consumer preferences may differ.

Other combinations of the three dimensions could be tested as scenarios, but would generally result in power system development outcomes that fall within the bounds of these proposed scenarios.

3.2.1 Neutral scenario

The Neutral scenario reflects a future energy system based around central estimates of all key drivers.

In this scenario, the Australian economy grows at long-term average levels. This expansion supports the export-facing sectors of Australia's industrial economy, including significant energy-intensive trade-exposed resource businesses in mining, metals, and manufacturing. Labour force growth through natural population expansion and immigration continues to develop Australia's domestic services economy.

In terms of energy sector developments, the scenario incorporates Australia's collection of domestic energy policies from Federal and State Governments, including renewable energy policies (Large-scale Renewable Energy Target [LRET] , Victorian Renewable Energy Target [VRET], and Queensland Renewable Energy Target [QRET]), energy efficiency policies affecting appliance and building standards, domestic gas reservation policies (Western Australia), gas onshore exploration moratorium (affecting Australia's east coast) and policies ensuring gas supply adequacy (Australian Domestic Gas Security Mechanism [ADGSM] and the Gas Supply Guarantee).

Internationally, this scenario assumes moderate achievements to emissions reduction objectives, according to agreed targets. As such, global deployment of renewable energy results in significant reductions in renewable generation technology costs in particular, as manufacturing maturity and technological advancements are discovered. Local installation costs in Australia reflect this reducing cost trend. Reducing capital costs are mostly expected from maturing renewable generation technologies, with relatively minor gains across other technologies. However, the reductions are not as aggressive as they could be if more rapid energy sector transformations occurred globally.

The scenario ultimately reflects a moderate rate of change in Australia's energy sector. Drivers of energy consumption growth are offset by deployment of DER and increasing energy efficiency advancements, while increasing energy prices are expected to play a role in stifling growth. Significant capacities of ageing coal and gas assets require re-investment or replacement over the medium term.

3.2.2 Fast change scenario

Key differences from the Neutral Scenario are:

- Stronger economic and population growth.
- Faster decarbonisation of stationary energy sector and transport sector.
- Accelerated retirement of existing generators and faster development of renewable generation.
- Proportionately less decentralisation.

The Fast change scenario reflects a future world which has stronger drivers for energy system transformation, acknowledging that there are many drivers that may influence the overall scale and direction of potential change, including the speed of decarbonisation, level of decentralisation, and population and economic growth.

This scenario is characterised by strong economic fundamentals driving increased operational energy consumption from the grid, and reflects a growing domestic economy, supported by stronger international financial conditions and therefore investor confidence. Stronger labour force growth than the Neutral scenario is expected to expand Australia's domestic services economy. The Australian economy transitions to one which is less reliant on raw material exports, with existing manufacturing businesses enjoying a milder degree of growth than other sectors.

It is important to note that this scenario is not driven by significant growth in energy commodity prices that could lead to increases in gas prices, due to the perceived fragility of Australia's industrial sector to rising energy costs, particularly energy-intensive industries with exposure to potential competitors in mature and emerging economies. A scenario with high commodity prices could lead to demand destruction that is not consistent with strong energy consumption.

The Fast change scenario broadly incorporates the same collection of Australia's domestic energy policies from Federal and State Governments as the Neutral scenario, but with faster investor-driven development of new renewable generation, and accelerated retirement of coal-fired generation. Internationally, this scenario reflects more aggressive emissions reduction objectives. As such, global deployment of renewable energy results in more significant reductions in renewable generation technology costs. This scenario has the strongest expected generation cost reductions.

The scenario ultimately reflects a more rapid rate of change for Australia's energy sector. Consumers embrace the availability of capital to invest in new electric vehicles, helping decarbonise the transport sector but providing new challenges for energy infrastructure. Strong cost reductions in utility-scale renewable generation and storage technologies shift focus away from DER, and slower per capita uptake of rooftop PV and battery storage systems are observed.

3.2.3 Slow change scenario

Key differences from the Neutral Scenario are:

- Weaker economic and population growth.
- Slower decarbonisation of stationary energy sector and transport sector.

- Life extensions of existing generators leads to a slower retirement schedule.
- Proportionately higher decentralisation.

The Slow change scenario reflects a future world which has weaker drivers for energy system transformation.

This scenario is characterised by weaker energy consumption reflecting a relatively stagnant domestic economy[7]. While domestic and international economic conditions are weaker than other scenarios, deployment of new technologies internationally is led by emissions abatement targets in line with current announced commitments. Weaker domestic conditions lead to slower labour force growth than the Neutral scenario, and weaker international conditions soften opportunities for the industrial, mining, and manufacturing sectors.

In terms of energy sector developments, the scenario incorporates Australia's collection of domestic energy policies from Federal and State Governments, as in the Neutral scenario. As such, global deployment of renewable energy results in cost reductions in renewable generation technologies in particular, in line with the Neutral scenario.

The scenario ultimately reflects a slower rate of change for Australia's energy sector. Weaker economic fundamentals slow growth in energy consumption. Given consumer concerns about energy costs, investment in DER and tariff reforms are more advanced than the Neutral scenario, encouraging proportionally more investments in rooftop PV and consumer batteries. Softer economic conditions and consumer spending restrict continued investments in energy devices in the home, delaying uptake in new technologies including electric vehicles. Coal-fired generators are kept running beyond the assumed 50-year life if safe to do so, to get the most out of the existing infrastructure and defer new capital investment. The stationary energy sector is expected to experience slower adoption of new energy sources, although investments in the medium term are still expected to be driven by existing generator retirements.

3.2.4 High DER scenario

Key differences from the Neutral Scenario are:

- Higher uptake of DER.
- Increased engagement by consumers.
- Evolving the role of transmission.

The High DER scenario considers a future where there is a stronger growth in DER, that is, where distributed rooftop PV generation, battery storage, and DSP at the consumer level are higher than in the Neutral case.

The core econometric drivers under the High DER scenario are the same as the Neutral outlook for economic and population growth. Similarly, renewable development and emissions abatement policies are also consistent across these scenarios. As a number of these policies consider the contribution of DER, it is anticipated that under this scenario there would be a migration away from large-scale generation developments to commercial and residential systems to achieve these policy targets.

This migration is further accelerated by the increased engagement and sophistication of commercial and residential consumers looking to explore the capabilities of a system with high proportion of battery storage coordination and aggregation. More rapid uptake of battery behind-the-meter also helps drive faster reductions in utility-scale battery costs.

In the context of forecasting and planning publications for 2019, the primary purpose of this scenario is to examine how increased DER could impact on investment needs for utility-scale generation and storage and transmission, and how this would influence the long-term development outlook for the NEM.

[7] AEMO's weaker economic growth outlook still reflects positive long-term growth outcomes. It does not reflect a period of recession or economic contraction.

3.2.5 Summary of scenario parameters

The scenario descriptions above have been translated into scenario parameters and tabulated for ease of comparison in Table 6 below. Proposed changes compared to AEMO's 2018 modelling are shown in red, with strikeouts of the 2018 parameters visible.

Table 6 Scenario parameters summary

Scenario	Neutral	Slow change	Fast change	High DER
Demand settings				
Economic growth and population outlook	Neutral	Weaker than Neutral	Stronger than Neutral	Neutral
Rooftop PV – up to 100 kW	Neutral	Proportionally more household installations than in Neutral ~~Neutral~~	Proportionally fewer household installations than in Neutral ~~Neutral~~	Strong
Non-scheduled PV – from 100 kW to 30 MW	Neutral	Proportionally more installations than in Neutral	Proportionally fewer installations than in Neutral	Strong
DSP	Neutral	Less need for DSP ~~Strong~~	Stronger need for DSP ~~Weak~~	Stronger need for DSP
Electric vehicle uptake	Neutral	Weaker than Neutral	Stronger than Neutral	Neutral
Battery storage installed capacity	Neutral	Proportionally more household installations than in Neutral ~~Neutral~~	Proportionally fewer household installations than in Neutral ~~Neutral~~	Strong
Battery storage aggregation by 2050	Central estimate	Greater adoption of consumer energy management opportunities, leading to greater aggregation	Slower adoption of consumer energy management opportunities, leading to lesser aggregation	Greater adoption of consumer energy management opportunities, leading to greater aggregation
Policy settings (will reflect policies of the day at commencement of modelling)				
Emissions trajectory	~~28% 2005 – 2030~~ ~~70% 2016 – 2050~~ Coal retirement timings adjusted to give effect to similar trajectories	~~28% 2005 – 2030~~ ~~70% 2016 – 2050~~ Coal retirement timings delayed to give effect to a less aggressive trajectory than Neutral	~~52% 2005 – 2030~~ ~~90% 2005 – 2050~~ Coal retirement timings accelerated and more renewable generation to give effect to a more aggressive trajectory than Neutral	~~28% 2005 – 2030~~ ~~70% 2016 – 2050~~ Coal retirement timings adjusted to give effect to similar trajectories
Energy efficiency improvement	Neutral	Weak	Strong	Neutral
Supply side settings				
Generator cost trajectories	Neutral (CSIRO's 4-degree scenario)	Neutral (CSIRO's 4-degree scenario) ~~Slow~~	Stronger than Neutral (CSIRO's 2-degree scenario) ~~Neutral~~	Neutral (CSIRO's 4-degree scenario)
Battery cost trajectories (utility and behind the meter)	Neutral	Neutral	Neutral	Stronger than Neutral
Gas market settings				
Gas prices	As forecast by AEMO's independent consultant, consistent to deliver central gas demands	As forecast by AEMO's independent consultant, consistent to deliver lower gas demands	As forecast by AEMO's independent consultant, consistent to deliver stronger gas demands	As forecast by AEMO's independent consultant, consistent to deliver central gas demands
New gas supplies	As forecast in AEMO's 2019 GSOO	As forecast in AEMO's 2019 GSOO	As forecast in AEMO's 2019 GSOO	As forecast in AEMO's 2019 GSOO

3.3 Proposed 2019 sensitivity analyses

In any scenario analysis, it is important for assumptions which are perceived to be significant drivers are tested through sensitivity analyses. Fundamentally, in scenario analysis, modelling scenarios are used to investigate alternative futures, whereas sensitivities are designed to validate the significance of key assumptions within a given future.

AEMO approaches sensitivity analysis considering the outcomes of the base scenarios, and through analysis identifying drivers for further investigation. Depending on the publication, AEMO will examine different assumptions. For example, in conducting the 2018 ISP, AEMO considered several sensitivities, examining the impact of stronger DER developments and lower gas prices.

For the 2019-20 ISP, AEMO proposes to also use sensitivities beyond the core scenarios to examine sensitivity of outcomes to:

- Assumptions around pump hydro storage potential and costs.
- Variations in timing of coal-fired generation retirements.
- Variations in choice of weighted average cost of capital (WACC) and/or social discount rate.

AEMO is initially seeking feedback through this consultation process on material uncertainties that should be tested through sensitivity analysis across each publication, and will continue to articulate and refine the sensitivities it proposes to apply based on this feedback.

3.4 Questions for consultation

Q2 Do you agree that the proposed scenarios outlined in this section provide plausible and internally consistent future worlds for use in planning and forecasting publications? Do they provide sufficient stretch for forecasting and planning purposes? How could they be improved?

Q3 What additional sensitivities should be explored in the 2019-20 ISP or 2019 ESOO, that could materially impact power system planning?

4. Inputs and assumptions

The key data required for AEMO's supply forecasting models comprises:

- Energy consumption forecasts.
- Energy policy settings.
- Technical and cost data of existing, planned and candidate generators, storages and transmission paths.

The following sections outline the key scenario-specific assumptions AEMO proposes to use in its 2019 planning and forecasting publications.

A full summary of the input assumptions initially proposed to be used for the 2019 modelling year has been collated in the 2019 Input and Assumptions workbook[8]. Stakeholders are welcome to provide feedback and alternative views with evidence on any value presented in the workbook during this consultation process. Where appropriate, AEMO will issue updates to this workbook throughout the year as more information and data becomes available.

4.1 Key components for forecasting energy consumption

AEMO uses independent consultants to assist with forecasting various components of consumption. This includes broader economic forecasts and the interactions between energy sub-sectors due to economic drivers, projections of uptake of small-scale DER (in particular, the effect DER may have on consumption patterns), and energy efficiency trends.

In each case, AEMO seeks the consultant's best view of each component, consistent with the scenario definitions that AEMO provides, ensuring internal consistency with the broader forecasts developed by AEMO's forecasting division.

This consultation paper is not actively seeking advice on the demand forecasting methodology or its key drivers, although any feedback on areas for improvement are always welcome.

AEMO recently sought industry feedback on how effectively AEMO's Forecasting Methodology Paper explains the forecasting methodologies, and subsequently updated its methodology description to improve clarity.

AEMO also conducts regular industry workshops to identify potential improvements to its methodologies, discusses demand forecast input and draft results in FRG forums, and publishes a Forecasting Accuracy Report which reflects on the most recent forecasts against actual demand outcomes and may also identify potential forecasting improvements[9].

For the 2019 planning and forecasting publications, AEMO proposes using the demand and energy forecasts produced for the latest ESOO and GSOO. The publication of these forecasts is in August and March respectively for electricity and gas, and updates are also provided when AEMO becomes aware of material new information.

Any planning and forecasting publications which commence modelling prior to August annually will likely use the previous year's forecasts, but those published after August may use the current year's forecasts. For example, the 2018 ISP commenced modelling in early 2018, and as such used (updated) forecasts based on the 2017 ESOO demand forecasts, whereas AEMO's 2018 Energy Adequacy Assessment Projection (EAAP), published in November 2018, used the 2018 ESOO forecasts.

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[8] AEMO. *Generation Information*, available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[9] Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Forecasting-Accuracy-Reporting.

The updated economic, DER, electric vehicle and energy efficiency forecasts provided by consultants are a key input to AEMO's operational electricity consumption and maximum demand forecasts, and are needed by the second quarter of each year. The scenarios used to inform these consultancies are based on the proposed scenario narratives outlined in this document. Any material changes to scenarios in response to feedback received from this Forecasting and Planning Consultation will be provided to the consultants for incorporation into their forecasts if there is time to do so.

4.1.1 Customer distributed energy resources

In 2018 AEMO integrated the rooftop PV, energy storage system (ESS), and electric vehicle consumer uptake forecast for the first time. This was performed by CSIRO[10], with AEMO also requesting half-hourly forecasts indicating the way in which DER could be used, such as the time-of-day charging expected for commercial vehicles versus residential vehicles, electric vehicle charging from rooftop PV vs evening/convenience vs overnight off-peak. AEMO also included sensitivities for Virtual Power Plant (VPP) adoption from ESS in the different scenarios.

Since this time, AEMO has engaged in more research of DER both internally and through industry consultation, and has identified modelling aspects of DER to be improved. AEMO has identified that specific consideration, in the context of the scenarios, needs to be made of:

- Usage of electric vehicles:
  - Current driving behaviour and future driving behaviour (e.g. trip duration, trip distance, time of day).
  - Current tariff uptake.
  - Different tariff adoption (such as off-peak home charging) or convenience charging (such as public fast charging) along with integration with other DER (for example, home PV systems),
  - Proportion of vehicles charging for all charge types, for scenario across each half-hour over the forecast period,
  - Requirements to securely integrate electric vehicles into the power system.
- Usage of ESS:
  - Charging/discharging profiles (30-minute daily trace) for each sector assuming:
    - Current tariff uptake.
    - Future smart tariff sensitivity (such as those to incentivise a virtual power plant).
- The opportunities and challenges for possible growth in hydrogen vehicle adoption.
- Impact of possible growth in autonomous vehicles on vehicle adoption rates.
- The potential for electric vehicles to also act as a substitute to stand-alone batteries (and/or discharge into the grid), to quantify the amount in the forecast, and assess the requirements to securely integrate this innovation.
- Details on infrastructure required (for example, transport and electricity network) for each scenario setting.
- Requirements for inverter standards for all inverter-connected technology, in particular rooftop PV systems due to the existing high penetration.

In addition, stakeholders requested access to the half-hourly traces for ESS, PV, and electric vehicles. AEMO will work to make the internal systems, including these separate traces, available as part of the publication data release.

[10] CSIRO, 2018, *Projections of Small-Scale embedded technologies*, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/Projections-for-Small-Scale-Embedded-Technologies-Report-by-CSIRO.pdf.

4.1.2 Half-hourly traces

In modelling Australia's energy systems, AEMO's models translate the annual demand forecast targets (including energy consumption, maximum demand and minimum demand) into time-sequential 'traces' providing an hourly reflection of consumption patterns.

These traces reflect the historical patterns observed in up to eight previous financial years, or 'reference years'. AEMO applies a consistent methodology to develop these reference year traces to effectively ensure that weather patterns affecting energy consumption also affect available renewable energy generation resources and temperature-sensitive transmission line thermal ratings. As such, all market modelling is conducted on an internally consistent basis.

For the 2019 planning and forecasting publications, including the 2019-20 ISP, AEMO proposes to continue to develop and apply traces on this basis. Depending on the objective of the assessment being modelled, AEMO will model up to eight reference years, to ensure reasonable weather variations and consumer behaviours are captured and understood in developing AEMO's key insights for reliability assessments and potential future development of the NEM.

AEMO's forecasting and planning models are regional in nature, and include network constraint equations to capture intra-regional limitations. AEMO expects 2019 publications will continue to rely on this implementation, although potential improvements will be considered. Any improvements to be implemented will be communicated via the FRG or other forum as appropriate.

4.1.3 Virtual power plants

A VPP broadly refers to an aggregation of resources, coordinated using software and communications technology to deliver services that have traditionally been performed by a conventional power plant. In Australia, grid-connected VPPs are focused on coordinating rooftop PV systems and battery storage. AEMO is collaborating across the industry to establish VPP demonstrations to identify the role VPPs could have in providing reliability, security, and grid services.

While VPPs in the NEM are currently on a small scale, several large-scale VPP projects, and government subsidies to support VPP capable systems, have been announced recently, with targets that equate to up to 700 MW of VPPs operating in the NEM by 2022.

AEMO is proposing to model a projected level of aggregation among distributed storage systems which would operate to meet system peaks (rather than household drivers), effectively acting as a VPP. The 2022 targets will be included in all scenarios, along with requirements for additional auxiliary services. The schedulable component of the aggregated batteries (the VPP) would be operated in the market models in the same way as large-scale batteries. These batteries are assumed to operate with perfect foresight and optimise charge and discharge to minimise system cost. If supply-demand balance is tight, this will mean batteries are operated to offset as much unserved energy as possible.

Battery systems installed by homeowners and not aggregated would be assumed to behave to minimise grid costs for that household, which may impact the charging and discharging behaviours of these assets. As such, this much more passive behaviour may not optimally discharge to meet market signals, reducing the system benefits relative to VPPs.

AEMO proposes to further consider the operating patterns and likely uptake rates of battery systems, and the degree of VPP versus household batteries (considering incentives provided by various government schemes), as part of independent analysis provided by AEMO's consultants for the 2019 forecasts.

Household and utility-scale batteries are currently modelled with 2 kWh/kW energy to power ratio only, and 90% or 80% round-trip efficiency respectively. This means that, from fully charged, the battery could provide two hours of supply if discharging at full capacity, although to meet consumer energy needs the battery may not be operated in this manner, as discussed above.

4.1.4 Demand side participation

AEMO's forecast maximum demand (and half-hourly demand traces created to match this forecast) excludes DSP, meaning it represents forecast maximum demand in the absence of any DSP occurring. Instead, AEMO incorporates a forecast of DSP into its modelling as a "supply" resource available to meet forecast demand.

AEMO's latest DSP forecast is from March 2018[11]. AEMO will update this forecast in the first half of 2019 for use in subsequent 2019 forecasting and planning publications.

These forecasts are based on two key sources of information:

- Major loads that may respond as reported to AEMO through the DSP information collection process;
- Smaller loads are based on reported capacity of DSP programs targeting smaller customers.

AEMO forecasts non-scheduled generation and its contribution to peak demand separately, so the forecast DSP response is from loads only.

The methodology used in previous years to estimate NEM DSP capability based on this information is as follows:

- For major loads, their average historical responses to various price levels has been calculated and used as forecast response when regional prices reach those levels. Any retailer-operated aggregation programs of smaller loads have been assumed to be active from $300/MWh.
- The reliability response (the DSP response during actual Lack of Reserve [LOR] 2 or LOR 3 conditions[12]) has been estimated from the average response when prices exceed $7,500 a MWh plus response from any network reliability programs.

These DSP estimates were used directly in the ESOO and other reliability assessments.

For 2019, with the introduction of the RRO, this approach may need to change. AEMO is working closely with the AER and ESB during the drafting of the RRO to understand implications for its ESOO modelling, and will separately consult on appropriate treatment of DSP as part of that process.

For long-term planning studies like the ISP, AEMO proposes to continue including DSP assumptions in the system plan, and assumes DSP may grow over time, with growth estimates varying by scenario[13]. The method for assessing the current level of DSP may vary to align with guidelines on firmness that will be developed by the AER as part of the RRO.

4.2 Key policy settings affecting energy supplies

4.2.1 Emissions reductions

The 2018 ISP identified that timing of coal-fired generation retirements, renewable generation targets, and the cost trajectory of new renewable generation and storage had a far greater influence on transmission development than emission reduction targets, which are themselves highly uncertain over the planning horizon. For 2019 planning and forecasting, the focus is therefore on changes in the generation mix that may impact the power system, with emission reductions being an output of the simulations rather than a driver.

Emissions reductions in the Neutral and High DER scenarios will be driven by current Federal and State Governments' renewable energy policies, and assumed 50-year end-of-life of coal-fired generation assets.

The Fast change scenario projects lower emissions as a result of the accelerated timelines for retirement of existing generators and greater investment in renewable generation. The Slow change scenario also projects,

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[11] Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Demand-Forecasts/Electricity-Forecasting-Insights/2018-Electricity-Forecasting-Insights/Demand-Side-Participation .

[12] See National Electricity Rules, rule 4.8.4 for definitions.

[13] See the 2018 ISP Assumptions workbook, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/2018-Integrated-System-Plan--Modelling-Assumptions.xlsx.

emission reductions due to lower demand and growth in renewable generation driven by existing policies, but the rate of reduction is slowed due to the life-extension of existing coal-fired generation.

Additional sensitivities may also be run, varying the timings within each scenario.

AEMO's new and preferred approach treats emissions as an output of the changing resource mix and while it does not make presumptions on future policies provides sufficient insights on the impact of potential future policies and emission trajectories on the timing of new transmission developments, and total requirements for reliability, security, and implementation.

To determine total NEM emissions, AEMO applies an emissions intensity for each generator, as estimated by an independent consultant. AEMO recently completed an engagement with GHD[14] which included analysis of generator efficiency and emissions intensity for existing generators and new entrant technologies. AEMO proposes to apply these values in modelling to be conducted in 2019.

No carbon price will be assumed in any of the scenarios.

4.2.2 Renewable energy targets

Large-scale Renewable Energy Target (LRET)

The federal LRET provides a form of stimuli to renewable energy development.

In modelling the LRET, AEMO takes account of the legislated target (33,000 GWh), as well as commitments to purchase Large-scale Generation Certificates (LGCs) by developed desalination plants and customers who opt-in to accredited GreenPower scheme[15] providers. AEMO applies the LRET in proportion to the energy consumption in the NEM versus non-NEM energy regions, resulting in approximately 84% of the LRET target being targeted for development in the NEM.

Currently in the NEM, AEMO identifies 6,800 MW of currently committed large-scale renewable energy generators (solar PV or wind generation technologies) and over 45,000 MW of proposed renewable projects[16]. As such, while the LRET is legislated to produce 33,000 GWh large-scale renewable generation by 2020, and continuing until 2030, the LRET is a declining driver of new renewable developments.

Additional policies applied to modelling the NEM include various Federal and State Government energy efficiency policies[17], driving improvement in building and appliance efficiency standards, and state renewable development schemes. In particular, AEMO proposes to continue to apply the following state-based schemes.

Victorian Renewable Energy Target (VRET)

The VRET mandates 25% of the state's generation being sourced from renewable sources by 2020, and 50% by 2030. The scheme is expected to be completed via direct contracting of the necessary capacity by a sequence of reverse capacity auctions[18]. The first auction, completed in September 2018, supports the development of over 900 MW of new renewable generation projects[19]. AEMO proposes to treat these

[14] GHD, 2018 AEMO costs and technical parameter review accessible at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/9110715-REP-A-Cost-and-Technical-Parameter-Review---Rev-4-Final.pdf.

[15] The GreenPower scheme is a voluntary program requiring electricity retailers to source customers' energy from renewable energy sources. Details are available https://www.greenpower.gov.au.

[16] Committed and proposed projects in AEMO's January 2019 Generation Information page update, available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[17] Energy efficiency policies which will influence the total customer demand are assessed by an independent consultant as part of AEMO's demand forecasting process. The 2018 report on the influence of energy efficiency programs is available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/Energy-Efficiency-Impacts-on-Electricity-and-Gas-Demand-to-2037-38-by-Strategy-Policy-Research.pdf.

[18] Victorian Government, 2017. *Victoria's renewable energy targets*, available at https://www.energy.vic.gov.au/renewable-energy/victorias-renewable-energy-targets.

[19] Details of VRET Stage 1 auction winners are available at https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-auction-scheme.

projects as committed for the purposes of 2019 market modelling in all scenarios, irrespective of each projects' achievement of AEMO's broader commitment criteria[20].

Queensland Renewable Energy Target (QRET)

The Queensland Government has a commitment to a 50% renewable energy target by 2030. AEMO proposes to implement the QRET in all scenarios, which it considers reasonable given renewable development interest in Queensland. Currently in the state there are over 1,700 MW of committed or proposed wind generation projects, and almost 12,000 MW of committed or proposed solar generation projects (which is almost 50% of all solar generation projects across the NEM).

Distributed Energy Resources policies

Various policies exist across NEM jurisdictions to support uptake of DER, including:

- South Australia: Home Battery Scheme[21].
- Victoria: Solar Homes Package[22].
- New South Wales: Clean Energy Initiatives[23].
- Queensland: Solar battery rebates[24].

AEMO proposes to review and incorporate each of these schemes in the DER uptake and behavioural analysis performed within the 2019 demand forecasts for the ESOO. This assessment of DER development (including electric vehicles) is supported by independent analysis from AEMO's consultants.

4.3 Key technical and economical settings affecting energy supply

Information has been provided by generators, industry experts, and potential generation developers about key operational parameters of current generating units and future planned projects. This information included:

- Committed generation projects.
- Generation project advanced proposals.
- Generating unit capacities and seasonal ratings.
- Planned and forced generating unit outages.

The latest generator information is available from the AEMO's online Generation Information page[25] and provides most of the required data on existing and committed generators for the 2019 planning and forecasting publications.

Since AEMO's 2018 ISP publication, the cost and performance of new generation technologies has changed significantly, with lowered costs and improved performance. It is critical to regularly capture the most current pricing to create a robust process for estimating future cost and performance data of new generation technologies. To this end, AEMO has collaborated with the Clean Energy Council (CEC), CSIRO, GHD, and

[20] Generation commitment criteria is defined in each regional spreadsheet of the Generation Information page, available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[21] Details are at https://homebatteryscheme.sa.gov.au/.

[22] Details are at https://www.solar.vic.gov.au/.

[23] Details are at https://energy.nsw.gov.au/renewables/clean-energy-initiatives.

[24] Details are at https://www.qld.gov.au/community/cost-of-living-support/concessions/energy-concessions/solar-battery-rebate.

[25] Data on existing and committed generators is given in each regional spreadsheet of the Generation Information page, available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

other stakeholders through the GenCost project[26] to develop estimates of future generation costs and other resource parameters. This information will be updated annually and includes:

- Generator fuel costs (not used by AEMO).
- Fixed and variable operating and maintenance costs.
- Thermal efficiency factors.
- Emissions factors.
- Unit auxiliary loads.
- Capital costs for new generation developments.
- Resource availability and build limits.

AEMO has incorporated most, but not all, of this information in the 2019 Input and Assumptions workbook that forms part of this consultation. Where AEMO has deviated from the assumptions in the CSIRO and GHD reports, explanations are provided in this consultation document. AEMO is seeking evidence-based feedback on the appropriateness of all of these assumptions. The CSIRO and GHD reports provide additional background and assumptions that will help inform stakeholders in providing this critique.

4.3.1 Technology build costs

To capture the most current pricing for a more reliable future cost and performance estimation process, AEMO has engaged GHD and CSIRO to review and update new entrant costs and technical parameters across a selection of generation and storages technologies.

GHD's main role in this engagement was to provide AEMO with current technology costs and performance data for a range of candidate technology options. CSIRO's main role was to produce cost projections for the current technology costs provided by GHD.

For the 2019 planning and forecasting publications, AEMO proposes using cost projections to build new generation technologies developed by CSIRO's Global and Local Learning Model (GALLM), based on the current technology cost produced by GHD after extensive consultations with stakeholders (detailed in Electricity generation technology cost projections: 2017-2050)[27].

One of the most notable updates of this review is providing the technology costs for a range of geographic regions across Australia, and a broader range of storage capacity to energy ratios.

Candidate generation technology options

GHD and CSIRO produced projected build costs for a range of new generation technologies. For the 2019-20 ISP, a filtered list of technologies – selected from those provided by GHD and CSIRO – will be considered, based on technology maturity, resource availability, and energy policy settings.

Table 7 below presents the lists of GHD and CSIRO generation technologies and the filtered list of generation technologies proposed to be considered in the 2019-20 ISP for all scenarios.

Currently, there is no actual proposal for nuclear-based power generation in Australia, and as such this technology has been excluded. Similarly, while carbon capture and storage (CCS) can play a unique role in reducing CO_2 emissions from the power sector, generation technologies with CCS will not be considered in the three core scenarios due to its operational characteristics, higher costs, and challenges associated with commercial deployment of storage reservoirs.

[26] CSIRO, 2018, *GenCost 2018; Updated projections of electricity generation technology costs*, available at https://www.csiro.au/~/media/News-releases/2018/Annual-update-finds-renewables-are-cheapest-new-build-power/GenCost2018.pdf.

[27] GHD, 2018 AEMO costs and technical parameter review accessible at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/9110715-REP-A-Cost-and-Technical-Parameter-Review---Rev-4-Final.pdf.

Table 7 Candidate generation technology options[28]

List of GHD candidate options	List of CSIRO candidate options	List of candidate options proposed in AEMO's 2019 modelling
CCGT – with CCS	CCGT – with CCS	-
CCGT – without CCS	CCGT – without CCS	CCGT – without CCS
OCGT – without CCS	OCGT – without CCS	OCGT – without CCS
Reciprocating engine without CCS	-	-
Supercritical PC – black coal with CCS	Supercritical PC – black coal with CCS	-
Supercritical PC – black coal without CCS	Supercritical PC – black coal without CCS	Supercritical PC – black coal without CCS
Supercritical PC – brown coal with CCS	Supercritical PC – brown coal with CCS	-
Supercritical PC – brown coal without CCS	Supercritical PC – brown coal without CCS	Supercritical PC – brown coal without CCS
Ultra Supercritical PC – black coal with CCS	-	-
Ultra-Supercritical PC – black coal without CCS	-	-
Advanced Ultra-Supercritical PC – black coal with CCS	-	-
Advanced Ultra-Supercritical PC – black coal without CCS	-	-
Synchronous condenser	-	Synchronous condenser
Biomass (wood) – electricity only	Biomass (wood) – electricity only	Biomass (wood) – electricity only
Biomass (wood) – cogeneration	Biomass (wood) – electricity only with CCS	-
Biomass (refuge) – electricity only	-	-
Biomass(refuge) – cogeneration	-	-
Nuclear (SMR)	Nuclear (SMR)	-
Solar PV – single axis tracking	Solar PV – single axis tracking	Solar PV – single axis tracking
Solar thermal central receiver with storage	Solar thermal central receiver with storage	Solar thermal central receiver with storage
Solar thermal central receiver without storage	-	-
Wind – onshore	Wind – onshore	Wind – onshore
Wind – offshore	-	-
-	Enhanced geothermal	-
-	Tidal/ocean current	-

[28] OCGT = open cycle gas turbine, CCGT = combined cycle gas turbine, PC = pulverised coal, CCS = carbon capture and storage, PV = photovolataics

Locational cost factors

Developing new generation is a labour- and resource-intensive process, and the ultimate project cost depends on access to specialised labour and appropriate infrastructure to deliver and install components to site. Access to ports, roads, rail, and regional labour cost differences all contribute to locational variances, even for a given technology (ignoring site-specific costs associated with geological/social issues).

GHD has estimated cost differences based on various zones within each NEM region. The methodology and application of these regional cost factors are explained in detail in GHD's 2018 AEMO costs and technical parameter review [29].

Locational cost factors developed by GHD for each of the cost components are given in Table 8. Cost projections to build new generation technologies developed by GHD are the overnight costs for construction in Melbourne. To calculate the capital costs of these technologies elsewhere in Australia, the locational cost factors, which are a multiplicative scaler, are applied to the respective generation development costs.

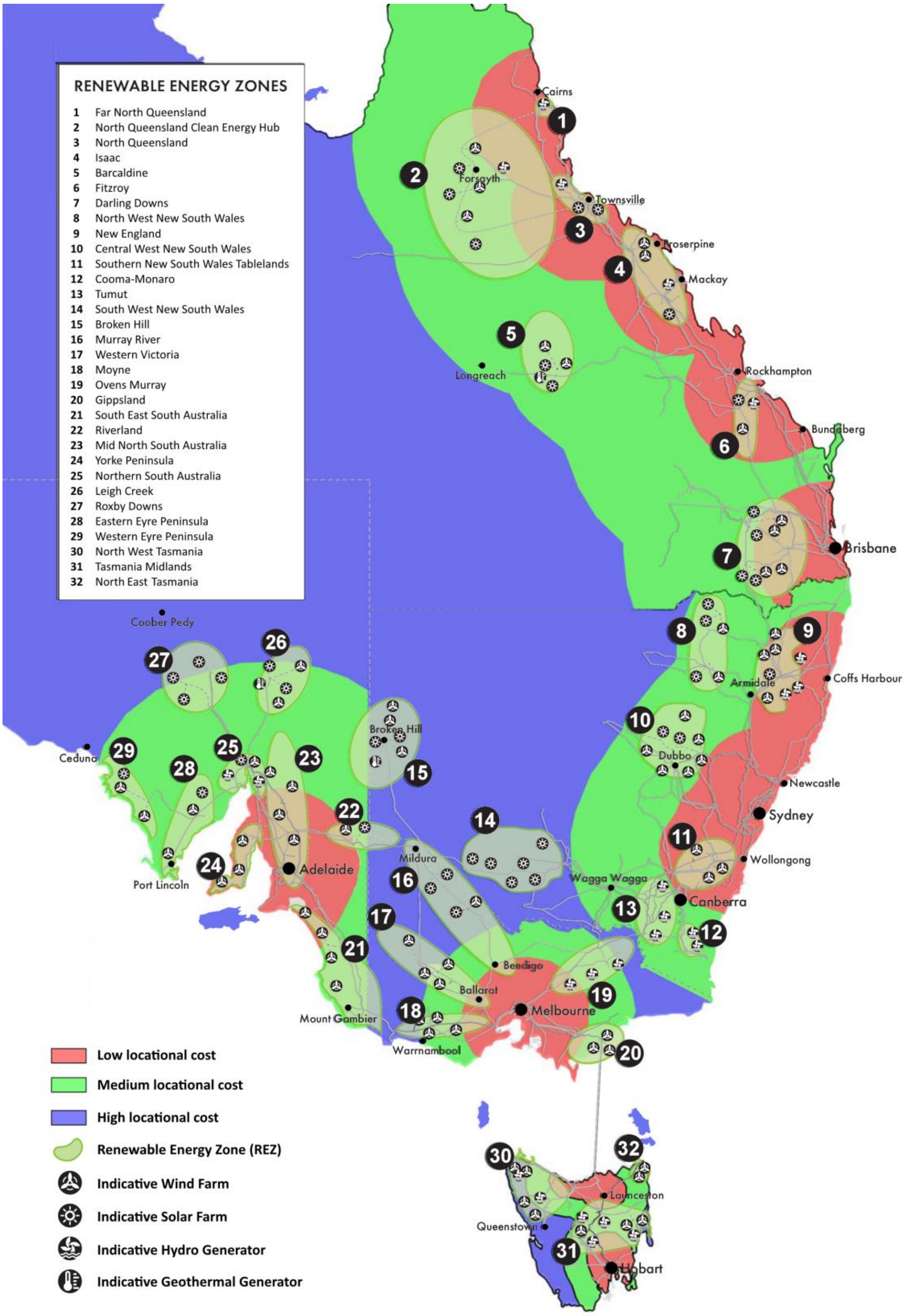
Figure 4 presents the overlaid regional cost factor map prepared by GHD over the REZ map. Three cost regions are presented: low, medium, and high.

Table 8 Locational cost factors

Region	Grouping	Equipment costs	Fuel connection costs	Cost of land and development	Installation costs	O&M costs
Victoria	Low	1.00	1.00	1.00	1.00	1.00
	Medium	1.03	1.03	1.00	1.03	1.03
	High	1.05	1.05	1.00	1.05	1.05
Queensland	Low	1.00	1.05	1.00	1.10	1.07
	Medium	1.05	1.16	1.00	1.27	1.20
	High	1.10	1.27	1.00	1.44	1.34
New South Wales	Low	1.00	1.09	1.00	1.18	1.13
	Medium	1.05	1.17	1.00	1.30	1.22
	High	1.10	1.26	1.00	1.42	1.32
South Australia	Low	1.00	1.01	1.00	1.02	1.01
	Medium	1.05	1.11	1.00	1.17	1.13
	High	1.10	1.21	1.00	1.32	1.25
Western Australia	Low	1.00	1.06	1.00	1.11	1.08
	Medium	1.05	1.22	1.00	1.39	1.29
	High	1.10	1.38	1.00	1.67	1.50
Northern Territory	Low	1.00	1.13	1.00	1.27	1.19
	Medium	1.05	1.32	1.00	1.59	1.42
	High	1.10	1.50	1.00	1.90	1.66
Tasmania	Low	1.00	1.04	1.00	1.07	1.05
	Medium	1.05	1.11	1.00	1.18	1.14
	High	1.10	1.19	1.00	1.29	1.23

[29] GHD, 2018 AEMO costs and technical parameter review accessible at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/9110715-REP-A-Cost-and-Technical-Parameter-Review---Rev-4-Final.pdf.

Figure 4 Locational cost map



Build cost scenarios

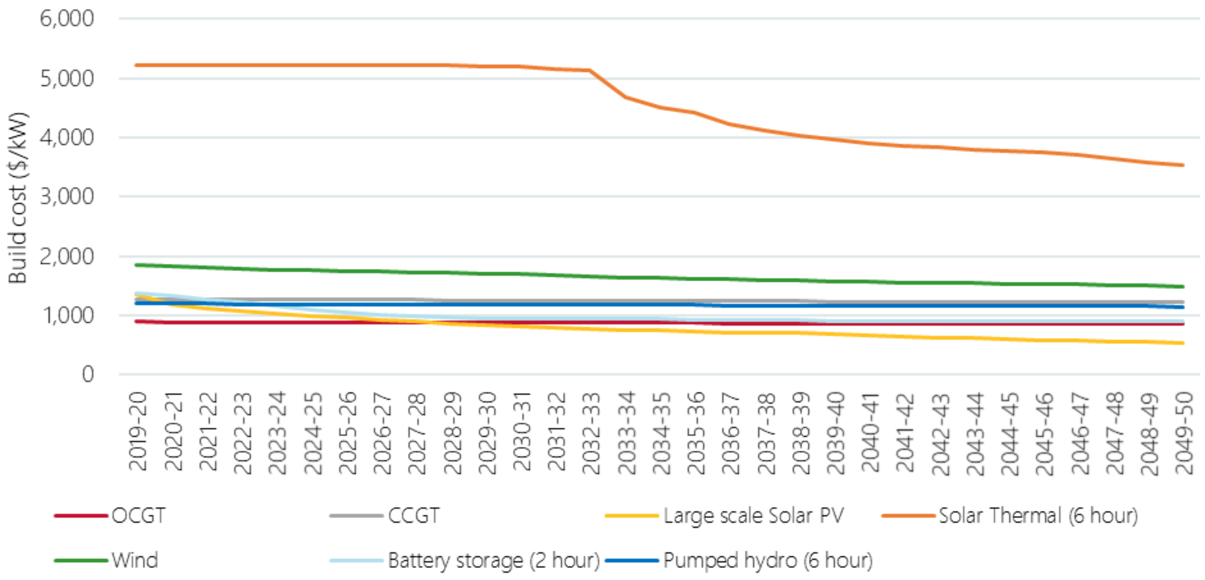
CSIRO GALLM build cost projections are a function of global and local technology deployment. As the global technology deployment depends on the global climate policy, CSIRO GALLM build cost projections are given for two scenarios, termed "4-degrees" and "2-degrees"; these describe the global climate policy goal. It is proposed to use 4-degrees and 2-degrees build cost projections for the Neutral and Fast change scenarios of the 2019-20 ISP respectively.

Figure 5 presents CSIRO GALLM build costs projections for selected technologies chosen for construction in Melbourne for the 4-degrees scenario, excluding the connection costs.

As Figure 5 shows, large-scale solar PV is projected to experience a long-term rapid decline in costs; in contrast, the rate of capital cost reduction of wind is relatively modest.

While the capital cost of wind generation technology may not be improving as fast as solar PV, levelised cost of wind is falling. This can be attributed to larger wind turbines being deployed, which are able to generate power at lower wind speeds, resulting in higher capacity factors.

Figure 5 Build cost projection for selected technologies for 4-degrees scenario ($/kW)



Wind build costs, site quality deterioration, and efficiency improvements

CSIRO has forecast modest capital cost reductions for wind technologies and improvements in wind turbine efficiencies with larger turbines. This technology improvement is expected to lead to more energy output for the same installed capacity, lowering the investment cost per unit of energy ($/MWh). To reflect this trend in AEMO's models, transformation of the CSIRO inputs is required.

The capital cost of wind technology reported in AEMO's 2019 Inputs and Assumptions Workbook has been adjusted to effectively mirror the $/MWh cost reductions while maintaining a static wind turbine resource profile. AEMO considers this a reasonable approach, given the development of renewable technologies such as wind is targeted largely to provide energy, rather than peak capacity, and therefore accurate representation of the cost per unit of energy is more appropriate than per unit of capacity.

AEMO recognises that, like some other technologies, wind farms can suffer from site quality deterioration – as more farms are built in the same area, the quality of the resource may decline as the best sites are typically utilised first. AEMO captures this through two capacity tranches representing high quality sites and average quality sites, with capacity factors reflecting these varying resources, as outlined in Section 4.5.2.

Modelling offshore wind

AEMO recognises that in many energy systems globally there is an existing role for offshore wind facilities, often with greater and more consistent energy output than onshore alternatives. Australia enjoys relatively strong onshore wind resources, and as yet only limited activity has been directed to developing offshore projects (although there are current active projects).

AEMO considers that it would be a desirable improvement to allow offshore wind to be considered in its modelling, but does not currently have information available to it to do so. The data estimates required to compare and contrast the value of on-shore and off-shore REZs includes, at a minimum, both:

- Offshore wind resource profiles, and
- The costs associated with building and operating offshore turbines (including connection costs for the undersea cables to connect back to the mainland).

Through this consultancy, AEMO is seeking relevant offshore wind data from the industry, if available, for inclusion in its 2019-20 ISP. If no information is available, AEMO will not be able to consider offshore wind in modelling this year.

4.3.2 Hydro generator modelling

AEMO models each of the large-scale hydro schemes using inflow data for each generator, or aggregates some run-of-river generators, as explained in AEMO's market modelling methodology document[30].

Through collaboration with Snowy Hydro and Hydro Tasmania, improvements to AEMO's modelled storage and generator topologies have been identified and will be applied in AEMO's capacity expansion and time sequential models. These improvements include:

- Utilising historical hydro inflow data for historical years to better capture the variability in production from Snowy Hydro and Hydro Tasmania.
- Revising the cascaded topology of the Snowy Hydro scheme to better reflect actual operation and to improve the interaction between the existing scheme and the Snowy 2.0 development.
- Redeveloping the approach to modelling Hydro Tasmania generation assets. AEMO has applied a seven-pond model developed in collaboration with Hydro Tasmania to better reflect the existing flexibility in the Tasmanian generation fleet.
- Representing the repurposing of the existing Hydro Tasmanian scheme to deliver approximately 400 MW greater capacity, in the event MarinusLink is built[31].

4.3.3 Storage technology modelling

Storage can play a key strategic role in systems with renewable generation developments. Based on the material levels of storage penetration in the 2018 ISP, a range of short and long storage options will be considered in the 2019 planning studies. These include 2-hour batteries complemented by pumped hydro storage of 6 hours, 12 hours, 24 hours, and 48 hours as build candidates.

Larger and more detailed schemes, such as Snowy 2.0 or Battery of the Nation, will be considered in the modelling explicitly based on predetermined sensitivities to the core scenarios, if they do not meet AEMO's commitment criteria before modelling commences for the various forecasting and planning publications.

Batteries

Large-scale battery build candidates will be modelled based on a fixed energy to storage ratio considering 2 hours of discharge at full output capacity. The batteries will have the flexibility to charge and discharge to achieve the optimal least-cost outcome for the system.

Due to the unique characteristics of large-scale batteries, their respective technical life is in the order of 10 years. Considering the forecast period undertaken in AEMO's modelling, there is the possibility that a

[30] AEMO Market Modelling Methodology Paper, July 2018, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Market-Modelling-Methodology-Paper.pdf.

large-scale battery could be developed and retire during the modelling period. The model then has the option to address this reduction in storage in a least-cost manner from the full suite of technology options.

The technical life is considered for all new entrant development candidates. However, due to the typical technical life of other technologies exceeding the 20-year outlook period, replacement of these build candidates is not explicitly captured in the modelling.

Pumped hydro

The candidate pumped hydro schemes will be modelled as closed systems; no natural inflows are captured.

Significant consultation has been undertaken to date to ascertain a set of key parameters for the generic pumped hydro build candidates. For example, GHD has provided pumped hydro build costs for two storage sizes specifically – 4-6 hours of storage and more than 150 hours of storage – while presenting maximum build limits for each region.

While generally the GHD data was well received as an initial step, to examine short and long storage schemes with sufficient model granularity in the 2019-20 ISP, four pumped hydro storage options need to be considered: 6, 12, 24, and 48 hours of storage.

Build costs and locational costs for these pumped hydro storage sizes have been obtained from Entura[32]. The cost projections of these four different pumped hydro sizes for future years are determined by the rate of capital cost reduction of 6 hours pumped hydro storage, given in the CSIRO GALLM report.

Table 9 below presents the regional build costs for the four different pumped hydro storage sizes derived from the Entura data. Where build costs and built limits are given for sub-regions, volume weighted build costs are used as regional build costs.

Table 9 Regional build costs of pumped hydro for different storage sizes

Region	MW weighted build cost ($/kW)			
	6-hour storage	12-hour storage	24-hour storage	48-hour storage
New South Wales	1,578	1,805	2,119	2,512
Queensland	1,530	1,830	2,084	2,944
South Australia	1,930	2,640	3,750	–
Tasmania	1,160	1,280	1,390	1,570
Victoria	1,530	1,750	2,250	3,380

Pumped hydro build limit assumptions are based on data provided by a range of sources including, but not limited to, GHD, Entura, CSIRO workshops, and the New South Wales Government's recent pumped hydro roadmap[33].

Entura outlined the total amount of storage available per NEM region for each storage size (6-hour storage, 12-hour storage, 24-hour storage, and 48-hour storage). However, the identified build limit for each storage size was not exclusive, e.g. the capacity limit for 48-hour storage could also be used for 24-hour storage, 12-hour storage, and 6-hour storage. AEMO proposes to split the identified storage limits to individual storage sizes, to reduce the overall computational size of AEMO's capacity outlook model.

AEMO aims to approach this issue by dividing the shared limits of each storage size. This shared build limit dividing approach is given in the table below, using Victoria as an example. As shown below, AEMO's proposed approach of dividing the shared limits of each storage size involves starting from the highest

[32] Entura, 2018, Pumped hydro cost modelling, available at https://projectmarinus.tasnetworks.com.au/assets/Report-Pumped-Hydro-Cost-Modelling.pdf.

[33] NSW Government, 2018, NSW pumped hydro roadmap, available at https://energy.nsw.gov.au/media/1546/download.

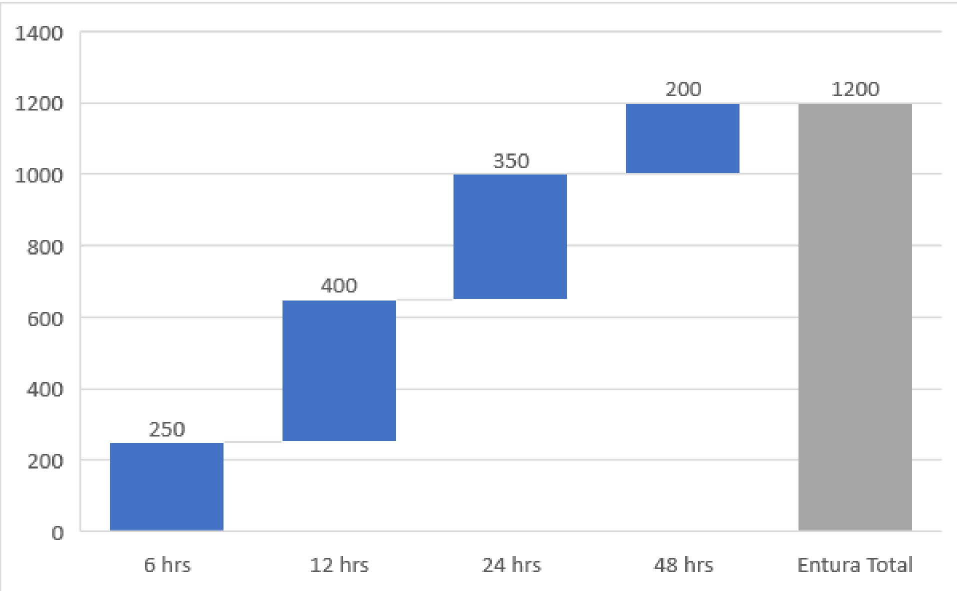
storage size and allocating half of its incremental capacity to itself; the remainder is then allocated to the second-highest storage size. For example:

- The incremental capacity of 400 MW is available at the 48-hour storage limit; thus, the halved incremental capacity of 200 MW is allocated to the 48-hour storage build limit and the remaining 200 MW is allocated to the 24-hour storage build limit.
- The incremental capacity of 300 MW is available at the 24-hour storage build limit. Thus, the halved incremental capacity of 150 MW is allocated to the 24-hour storage build limit; this is additional to the 200 MW that was allocated from the 48-hour storage build limit, resulting in a total of 350 MW allocated to the 24-hour storage build limit. The remainder (150 MW) is allocated to the 12-hour storage build limit and the pattern continues.

Table 10 Example storage build limits allocation, Victoria

Storage Size	Entura Storage Limit (MW)	Incremental Capacity (MW)	AEMO proposed allocated capacity
6 hrs	1,200	0	250
12 hrs	1,200	500	400
24 hrs	700	300	350
48 hrs	400	400	200

Figure 6 Example storage build limits allocation Entura to AEMO conversion, Victoria



This approach is applied to every region. Where publicly announced pump hydro capacity projects exceed these limits, the limits are relaxed to reflect known development interest. For example, in the New South Wales Government's pumped hydro roadmap, six areas across the state (in the North East, Lower North Coast, Central West, Shoalhaven, South East, and Riverina) were identified as showing high potential for pumped hydro[34]. AEMO has ensured that the pump hydro limits assumed in New South Wales will allow for this potential to be realised if modelling shows this to be economically efficient.

[34] See http://re100.eng.anu.edu.au/research/re/site/nsw.php.

Final limits and build costs are reported in AEMO's 2019 Inputs and Assumptions Workbook for review and feedback.

Storage technologies

AEMO considers this collection of battery and pumped hydro storage options reasonably allows the modelling to identify various benefits of storage solutions to support the generation mix.

AEMO proposes capturing the round-trip energy storage using a static auxiliary load applied to pumps and to battery charging devices. Based on GHD's data and stakeholder feedback, a battery charge and discharge efficiency of 90% and pumped hydro pumping efficiency of 76% will be utilised. For pumped hydro, this is consistent with the estimated efficiency of Snowy 2.0 reported in Marsden Jacobs Associates 2018 NEM Outlook and Snowy 2.0 report prepared for Snowy Hydro Limited[35].

In its forecasting, AEMO does not currently consider potential ancillary services benefits of battery and pumped hydro storage options. AEMO has engaged an external consultant to investigate how to quantify these potential additional benefits and will report on outcomes through an insights paper when the results are available.

Solar thermal technology

AEMO will model concentrating solar thermal technology with 8-hour storage sizes. AEMO has identified current and future technology costs and capabilities for this technology via the collaboration with CSIRO and GHD. The integrated solar and storage development would apply solar resource profiles to determine the hourly generation available, and therefore the daily charge and discharge profile of this generation technology will reflect the available solar resource.

Given the use of a resource profile to develop the generation profile, AEMO proposes to simplify the computation complexity in the capacity outlook modelling by applying a similar profile of generation discharge. While this won't optimise arbitrage opportunities for solar thermal, it will reasonably reflect the available storage on a daily basis and follow the daily operational demand curve to discharge when operational demand is greatest.

In time-sequential modelling, any solar thermal plant built will be fully optimised within the model.

Hydrogen

As addressed in Section 3.1.2, AEMO does not currently propose to incorporate a hydrogen storage/ammonia production option through electrolysis for its 2019 publications. Currently there is insufficient data available to reasonably apply costs and technical capabilities to a similar degree of confidence as other generation technologies.

WACC and social discount rate

The WACC is the rate a company is willing to pay to finance its assets, or similarly the return that it would expect to receive from a similar asset with equivalent risk.

AEMO proposes to use an equivalent WACC for all development options – including transmission and the various generation technologies outlined in this Consultation Paper. In its recent technology cost assessment[36], GHD estimated a WACC for renewable generation technologies of 6.25% (pre-tax, real), with a relatively high debt to equity ratio. AEMO proposes to adopt this long-term WACC across all technologies, as each generation technology can be considered as part of the overall generation portfolio funded through available capital investing in the energy market in a technology- neutral manner.

[35] See https://www.snowyhydro.com.au/wp-content/uploads/2018/01/MJA_ReportFinal_Jan2018.pdf.

[36] GHD, 2018 AEMO costs and technical parameter review accessible at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/9110715-REP-A-Cost-and-Technical-Parameter-Review---Rev-4-Final.pdf.

Feedback received from some stakeholders suggested that a risk premium should be added to new coal-fired generation to reflect carbon price risk. AEMO recognises that carbon price risk may differ by technology and could impact financing costs but is of the view that inclusion of a risk premium on coal-fired generation would not materially impact the outcomes. The CSIRO generation technology cost forecasts suggest that renewable generation technologies will be cost-competitive with new thermal generation technologies in the future, even without taking finance costs into consideration. AEMO therefore prefers to take a technology- agnostic approach for WACC assumptions.

While the WACC represents the cost of financing energy investments, AEMO applies a social discount rate for determining the discounted value of cash flows over the long-term planning horizon. This social discount rate reflects the value society places on the present relative to the future – the opportunity cost associated with consumption versus investment. Social discount rates are typically lower than the WACC, as they are associated with lower risk premiums than commercial investments.

In the 2018 ISP, AEMO applied a social discount rate of 7%, commonly used for this purpose and recommended by New South Wales Treasury for cost benefit analysis[37]. In 2018, various suggestions were proposed for social discount rates, including a recommendation of 4% by the Australian Government Standing Committee on Infrastructure, Transport and Cities[38]. For 2019, given feedback received through stakeholder consultation to date, and from peer review of 2018 inputs, AEMO proposes to revise its discount rate to reflect this recommendation, and apply a 4% rate, lowering it below the WACC.

4.4 Existing generation assumptions

4.4.1 Generator operating parameters

Forced outage rates

Forced outage rates are a critical input for AEMO's reliability assessments and for modelling the capability of dispatchable generation capacity more generally. AEMO collects information from all generators on the timing, duration, and severity of unplanned forced outages, via an annual survey process. This data is used to calculate the probability of full and partial forced outages, which are randomly applied to each generating unit in market modelling. In the past, AEMO has aggregated all forced outage parameters by technology to protect the confidentiality of the individual data provided when information is published.

In the 2018 ESOO Appendix A1.3[39], AEMO provided an analysis on the performance of forced outage rates (along with summer generator ratings) in modelling aggregate generator availability on hot summer days. It was observed that, for some technology aggregations (brown coal, black coal, and gas-fired steam turbines), there had been a deterioration in generator reliability. For these technology aggregations, AEMO used only the most recent three years of outage data to calculate the outage parameters used in ESOO modelling.[40]

Given the importance of forced outage rates in reliability forecasting, from 2019 AEMO intends to use specific outage information for each power station. Trends may still be reported in aggregate, but the modelling will be using the best information available to AEMO at the power station level.

In 2019, the following method is proposed to be adopted for determining the forced outage rates to be used for each power station:

- Conduct generator survey to collect availability data for summer 2018-19.

[37] New South Wales Government guide to Cost Benefit Analysis, March 2017, available at https://www.treasury.nsw.gov.au/sites/default/files/2017-03/TPP17-03%20NSW%20Government%20Guide%20to%20Cost-Benefit%20Analysis%20-%20pdf.pdf .

[38] Parliament of the Commonwealth of Australia, September 2018, Building Up and Moving Out, available at https://www.aph.gov.au/Parliamentary_Business/Committees/House/ITC/DevelopmentofCities/Report .

[39] See page 83 at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf.

[40] Further details were provided in the FRG meeting in August 2018, available at https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Working_Groups/Other_Meetings/FRG/2018/FRG-Meeting-10---Meeting-Pack.zip.

- Analyse the historical time series of outage information to identify potential changes in performance over time. This will influence whether forced outages should be derived from the full historical data set or a subset of data.
- Submit proposed assumptions on future reliability to the power station owner and provide opportunity for this assumption to be revised based on further evidence. This may be particularly appropriate where recent maintenance has been carried out to improve the future reliability of plant.
- Assess, with assistance from the Australian Energy Regulator, whether this new information justifies varying the historically observed trend.

Auxiliaries

AEMO's modelling of demand forecasts is done on a sent-out basis. However, AEMO's modelling of generator capacity is on an as-generated basis. Rather than assume an annual auxiliary consumption and auxiliary demand at the time of peak, AEMO's models dynamically take into account auxiliary load based on generator dispatch in each modelling interval.

AEMO currently sources per unit auxiliary rate assumptions from GHD's 2018 AEMO costs and technical parameter review.[41]

Operating and Maintenance costs

Generator operating and maintenance (O&M) costs data for AEMO's 2019 planning and forecasting publications are sourced from GHD and feedback from stakeholders. The 2018 GHD fixed O&M costs for coal generators do not include these mine costs, and AEMO estimated and added these costs based on anecdotal evidence from some stakeholders.

AEMO seeks feedback on generator fixed O&M costs given in the 2019 ISP assumption book, noting the inclusion of an estimate of fixed costs associated with adjacent mines. These unavoidable cost assumptions will influence any revenue sufficiency analysis undertaken (see Section 5.2.2).

4.4.2 Retirements

AEMO explicitly identifies and applies end-of-life retirement timings for all existing coal plant and gas projects throughout the NEM. AEMO assesses the cost of mid-life refurbishments on high-utilisation thermal assets (such as coal and closed-cycle gas turbines [CCGTs]), to ensure the ongoing operation at high loading is efficient and presents the least financial cost to the system despite the large capital outlay associated with mid-life turbine refurbishment.

Peaking thermal plant, such as diesel and open cycle gas turbines (OCGTs) that provide flexible and firm capacity, as well as renewable generators, are not retired based on a technical life, on the basis that these facilities would be more likely to be repurposed at lower cost than greenfield developments.

AEMO proposes incorporating redevelopment costs of these assets as annualised operations and maintenance costs. AEMO considers this a reasonable model simplification while capturing the financial impact of asset replacement in the least-cost assessments. However, an improvement to be implemented this year is to assess the revenue sufficiency of existing coal-fired generation and CCGTs (particularly at assumed time of mid-life refurbishments) to determine whether the economic life may be shorter than the unit's technical life and retire earlier if this is deemed to be the case. For CCGTs, this will include assessing whether conversion to an OCGT may be economically viable. As part of this Consultation, AEMO seeks feedback from industry on the appropriate costs to convert existing CCGTs to OCGTs providing a peaking, rather than major energy production, role. Discussion of revenue sufficiency is included in section 5.2.2.

[41] Available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/9110715-REP-A-Cost-and-Technical-Parameter-Review---Rev-4-Final.pdf.

For new technologies, AEMO applies the technical life of the asset within the capacity outlook model and assumes future market and regulatory arrangements will support this investment throughout the asset's life. This application effectively retires new builds according to the technical life assumption only, with new developments needed to replace the retiring facility.

Because, given the timing of the installation, the typical technical life of these technologies well exceeds the outlook period, replacement of these build candidates may not be explicitly captured in the modelling. For some technologies with a relatively short operating life (such as batteries), and early developments, there may be instances of greenfield replacement of new developments. AEMO considers that capturing this is important to reflect the true costs of the various technologies.

4.4.3 Fuel prices

Gas Prices

The 2019 planning and forecasting publications will use the gas prices revised in December 2018 by AEMO in collaboration with the external consultant Core Energy & Resources Pty Limited (CORE)[42].

Figure 7 presents updated regional gas prices for gas-powered generation (GPG) for the Neutral scenario. It shows that, compared to last year's forecasts, gas prices are forecast to be higher in all regions in eastern Australia after 2024-25. This is due to the relatively tight supply/demand balance and competition for supply between domestic and LNG markets predicted by CORE.

Figure 7 Regional gas prices for gas-powered generation in time-sequential modelling (Neutral scenario)

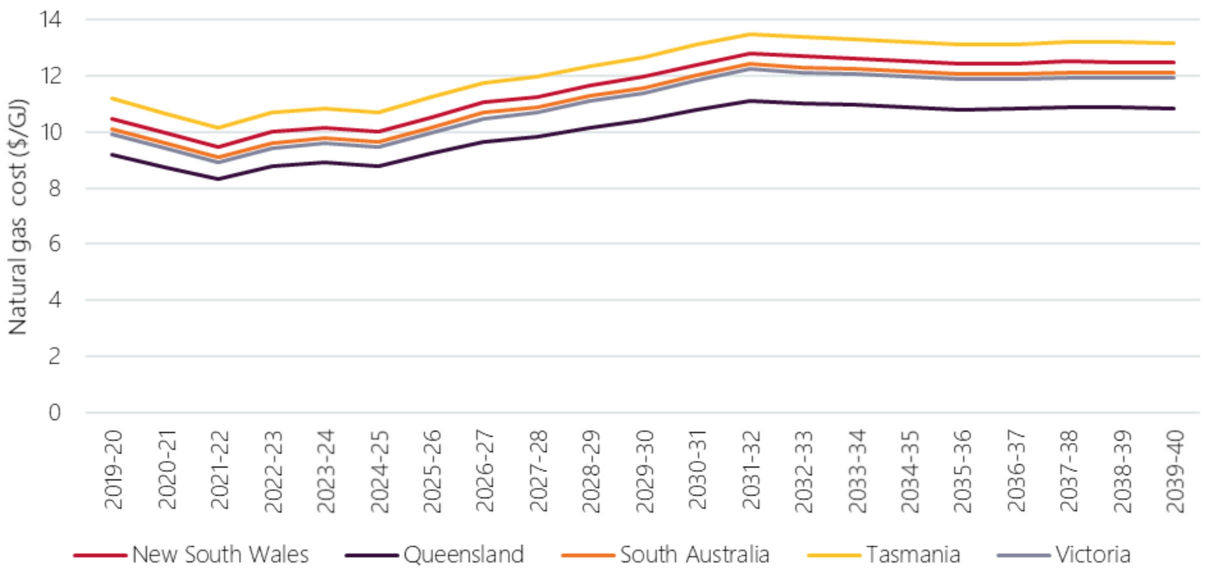
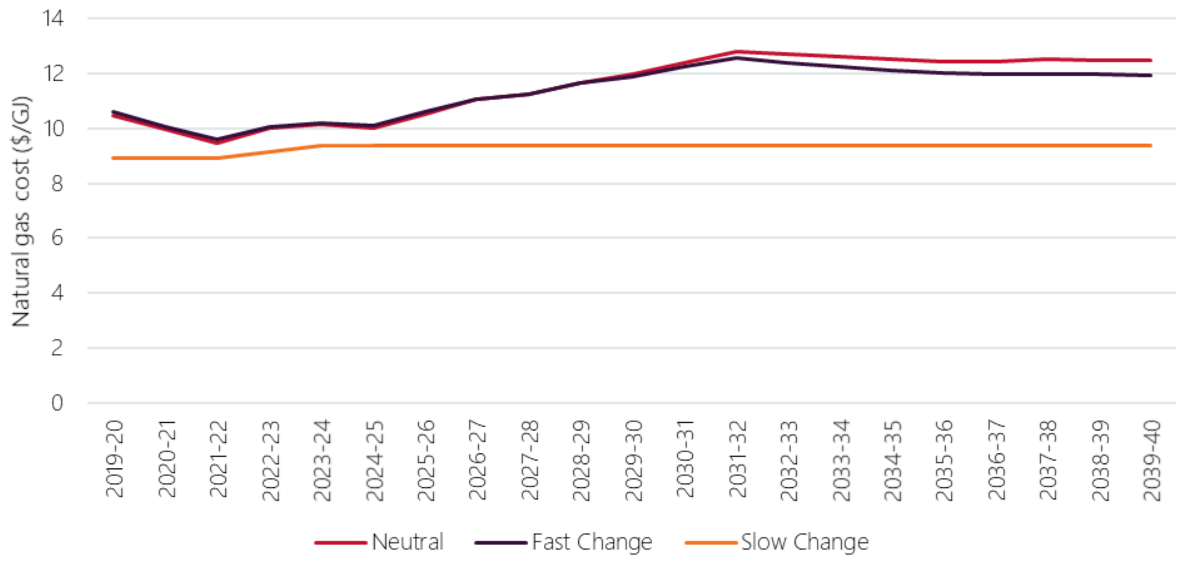


Figure 8 presents a comparison of New South Wales average gas prices for GPG between Neutral, Fast change, and Slow change scenarios.

[42] CORE Energy, 2018 wholesale gas price outlook, available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/CORE-Delivered-Wholesale-Gas-Price-Outlook_16-January-2019.pdf

Figure 8 Weak, strong and neutral gas price scenarios for gas powered generation (New South Wales)

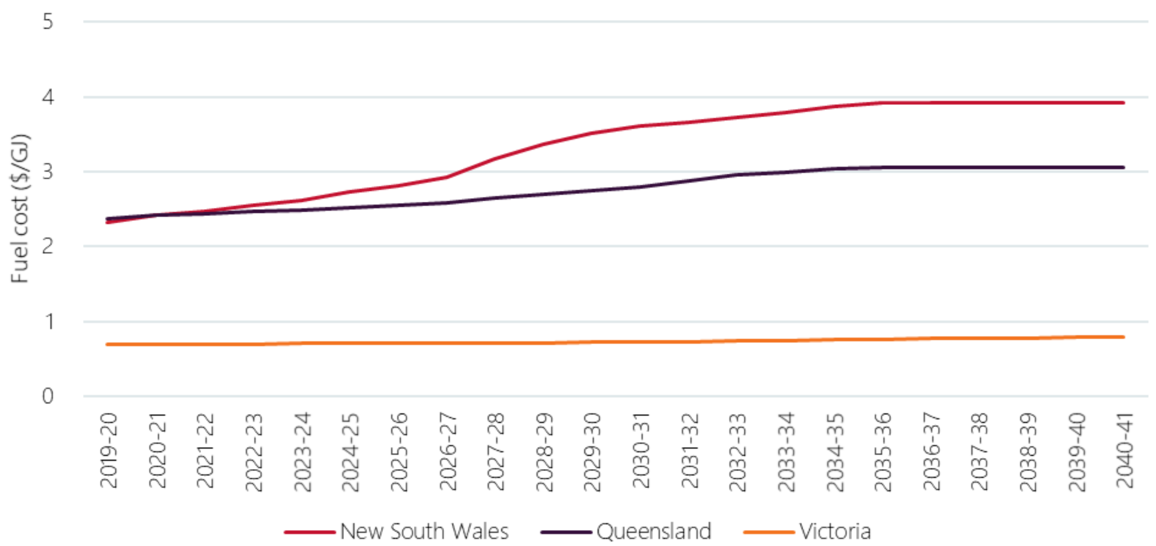


The gas prices for the Neutral and Fast change scenarios are almost the same until 2031-32. After that, gas prices of the Fast change scenario are forecast to be lower than the Neutral scenario. This is because gas price projections for the three scenarios take into consideration, among other influences, oil price and exchange rate scenarios. Fast change and Neutral oil price trajectories are assumed to be the same in CORE's latest analysis, based on the scenario narratives provided by AEMO, while there is a noticeable exchange rate increase in the Fast change scenario compared to the Neutral scenario, particularly after 2031-32. Due to this reason after year 2031-32, we can see that Fast Change scenario gas prices for GPG are lower than that for the Neutral scenario.

Coal prices

Figure 9 presents the average coal prices of Queensland, New South Wales, and Victoria used in 2018 ISP. AEMO is updating these in the first quarter of 2019 based on new forecasts from consultants. Any feedback received on previous coal price assumptions during the course of this consultation will be provided to the consultants for due consideration.

Figure 9 Average coal prices in Queensland, New South Wales and Victoria (Neutral case)



4.5 Renewable energy zones (REZs)

REZs are areas in the NEM where clusters of large-scale renewable energy can be efficiently developed, promoting economies of scale in high-resource areas, capturing important benefits from geographic and technological diversity in renewable resources, and recognising the critical physical must-have requirements for power system security.

An efficiently located REZ can be identified by considering a range of factors, primarily:

- The quality of its renewable resources (wind or sun).
- The cost of developing or augmenting transmission connections to transport the renewable generation produced in the REZ to consumers.
- The proximity to load, and the network losses incurred to transport generated electricity to load centres.
- The critical physical must-have requirements to enable the connection of new resources, particularly inverter-based equipment, and ensure continued power system security.

The 2018 ISP identified a number of highly valued REZs across the NEM with good access to existing transmission capacity. To connect renewable projects beyond the current transmission capacity, further action will be required (for example, increasing thermal capacity, system strength, and developing robust control schemes).

The next ISP will continue to consider how to best develop REZs in future that are optimised together with necessary power system developments, identifying indicative timing and staging that will best coordinate REZ developments with identified transmission developments to reduce overall costs.

4.5.1 REZ candidates

During the 2018 ISP project, 34 REZ candidates were identified across the NEM, through consideration of a mix of resource, technical, and other considerations. The purpose of this analysis was to identify the timing, scale, and location of REZs that would minimise the total cost of supply to consumers.

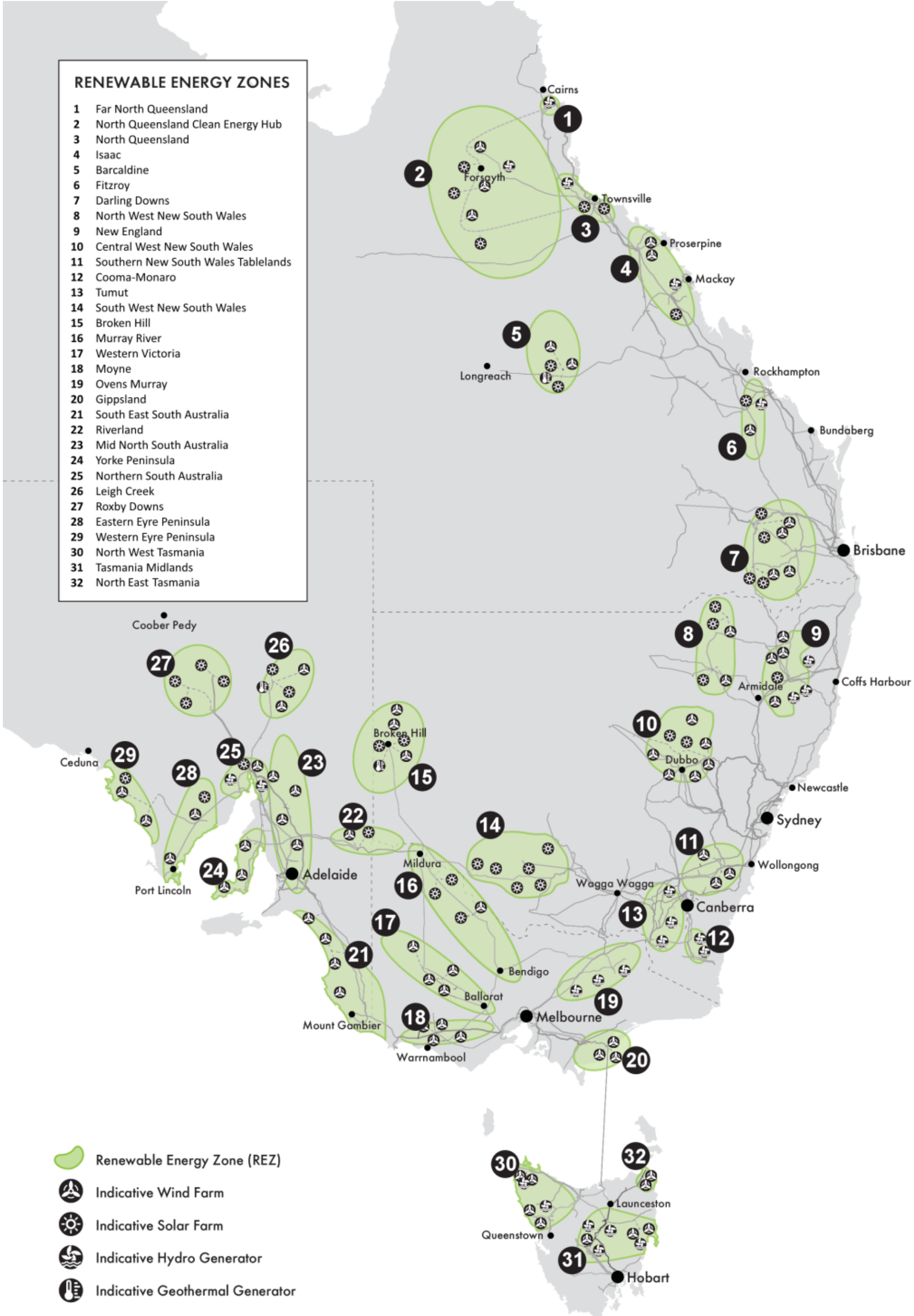
AEMO's selection of REZ candidates was conducted in early 2018, through formal consultation, industry working groups, and advice from consultants. This approach considered the following factors:

- Wind resource – a measure of high wind speeds (above 6 m/s).
- Solar resource – a measure of high solar irradiation (above 1,600 kW/m2).
- Demand matching – the degree to which the local resources correlate with demand.
- Electrical network – the distance to the nearest transmission line.
- Cadastral parcel density – an estimate of the average property size.
- Land cover – a measure of the vegetation, waterbodies, and urbanisation of areas.
- Roads – the distance to the nearest road.
- Terrain complexity – a measure of terrain slope.
- Population density – the population within the area.
- Protected areas – exclusion areas where development is restricted.

Figure 10 shows the results of this analysis, with the highest rating potential areas for development of wind and solar farms in green.

While these factors were used to determine the candidate areas for establishing a REZ, only the first four were considered in determining the optimal REZ expansion size and timing. AEMO welcomes feedback on how information on cadastral parcel density, land cover, road access, terrain complexity, and population density can be used to influence transmission and generation development costs within a REZ.

Figure 10 REZ candidates



Over the past 12 months, AEMO has received feedback on the 2018 REZ candidates. Based on this feedback, and on the 2018 ISP studies, the following changes have been made to REZ candidates:

- Based on feedback from the New South Wales state government[43]:
  - The former Northern New South Wales Tablelands and New England REZs have been joined and redrawn.

[43] NSW Government. NSW Government Submission on AEMO's Integrated System Plan. Available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Round-2-Submissions/NSW-Government---Submission-on-Integrated-System-Plan.PDF.

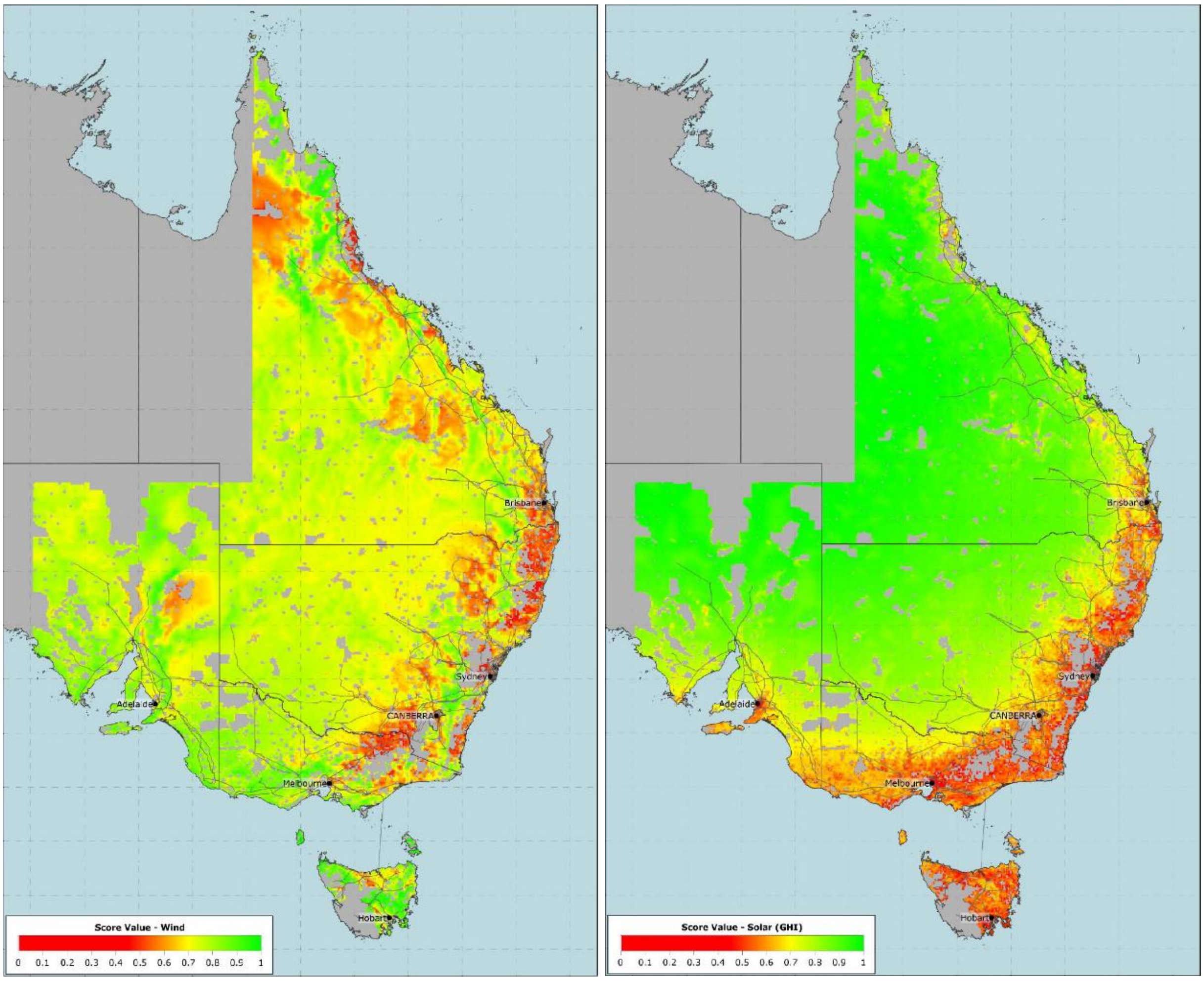
– The former Central New South Wales Tablelands and Central West New South Wales REZs have been joined and redrawn.
– The former Murray River REZ was split into two separate zones and redrawn.

- Tasmanian REZs were refined to focus on areas with observed generator connection interest.
- The Gippsland REZ in Victoria was expanded to include off-shore wind capability – to be considered if the modelling information becomes available (see Section 4.3).

4.5.2 Renewable generation resource profiles

For AEMO's planning models, energy availability data for individual wind and solar generators are given as time-sequential traces, providing an hourly reflection of resource specific profiles at sufficient granularity to appreciate resource diversity. The wind and solar resource traces for new wind and solar farms are developed using DNV-GL sourced maps (Figure 11) which indicate the areas underlying renewable energy resource for each of these technologies.

Figure 11 Weighted wind (left) and solar (right) resource heat map



4.5.3 REZ cost assumptions

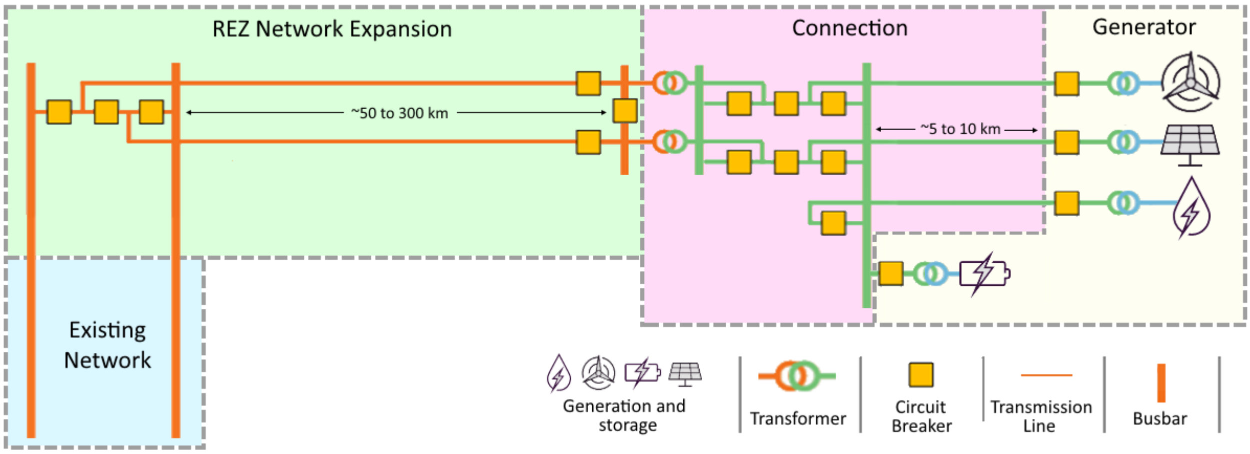
There are several important costs to consider when estimating the cost of a REZ:

- REZ network expansion costs – the cost of expanding the transmission network to provide access for generator and storage connections.

- Connection costs – the cost of connecting a generator to the hub of the REZ (that is, the local high-voltage network).
- Generator costs (see Section 4.3.1) – the cost involved in establishing generation or energy storage projects (including a generator transformer).

An example of how these costs are allocated is shown in Figure 12.

Figure 12 Division of REZ costs



Note: The connection cost of battery storage is lower than other storage and generation options because battery storage has more flexibility in its location. Due to resource location, wind, solar, and pumped hydro projects will often be located 5 to 10 km from the existing network.

REZ network expansion costs

REZ network expansion costs consider increasing network capacity to a REZ. In some instances, this could require building new transmission, and in others, could require upgrading existing transmission. These costs are generally dominated by the cost of long transmission lines. This cost component generally includes:

- Circuit breakers and switchgear at an existing substation.
- Transmission line (for example, 50 to 300 km per line).
- Substation site establishment (15,000 square metres).
- Communication (SCADA).

Connection costs

Generator connection costs are dominated by transmission and transformation components. These costs include:

- Circuit breakers and switchgear.
- Transformer (if voltage step is required).
- Transmission line (for example, 5 to 10 km per feeder).
- Substation site establishment (15,000 square metres).
- Communication (SCADA).

Connection costs for each REZ and each technology are listed in the 2019 Input and Assumptions workbook. These costs vary based on technology and location because of the distance of resources to transmission infrastructure.

Generator costs

Generator and energy storage costs are outlined in Section 4.3.1.

4.5.4 Network losses

Network losses occur as power flows through transmission lines and transformers. Increasing the amount of renewable energy connected to the transmission network remote from load centres will increase network losses. As more generation connects in a remote location, the higher the power flow over the connecting lines and on the alternating current (AC) system, and the higher the losses.

In the NEM, transmission network losses are represented through Marginal Loss Factors (MLFs).

Marginal Loss Factors

Energy is lost as it travels through the transmission network, and these losses increase as more generation connects in locations that are distant from load centres. In the NEM, MLFs are applied to market settlements, adjusting payments to reflect the impact of incremental energy transfer losses.

MLFs are used to adjust the price of electricity in a NEM region, relative to the regional reference node[44], in a calculation that aims to recognise the difference between a generator's output and the energy that is actually delivered to consumers. In dispatch and settlement in the NEM, the local price of electricity at a connection point is equal to the regional price multiplied by the MLF. A renewable generator's revenue is directly scaled by its MLF, through both electricity market transactions and any revenue derived from LGCs created if accredited under the LRET.

Increasing generation within a REZ is likely to increase losses between the REZ and the regional reference node, decreasing the MLFs for the REZ. The MLFs attributable to generators located in some REZs will be more sensitive to change as a result of new connecting generators than other REZs, particularly where they are distant from major load centres and interconnection is relatively weak.

Investors in new generation are concerned about the effect of lower MLFs on their potential returns, and the uncertainty of how MLFs can vary from one year to the next. Generators in locations that are strongly connected to major load centres have MLFs that are less likely to change over time.

For generation, an MLF represents the amount of electricity delivered to the regional reference node for a marginal (next MW) increase in generation; for load, the MLF represents the amount of power that would need to be generated at the regional reference node for a marginal (next MW) increase in demand. In simple terms, a higher MLF is good for a generator's revenue, while a lower MLF is good for a load (as it means lower payment for energy lost before it reaches the load). MLFs will change over time, most often decreasing as additional generation connects in an area.

A range of factors affect how much the MLF at a given connection point will change:

- Transmission and distribution network – if new generation is added at an electrically distant connection point, the MLF decreases by more than if it had been added close to the high-voltage network.
- Generation profile in the area – if new generation is only running at the same times other nearby generators are also running, the MLF decreases by more. For example, solar generators in an area all produce power at the same time, so adding more of this type of generator will decrease the MLF more than if a different technology generator was added.
- Load profile in the area – if new generation mainly produces power at times when there is light load in the area, the decrease in MLF will be greater.
- Intra-regional and inter-regional flows – wider trends affecting MLFs include decreasing consumption, increasing distributed generation, changing industrial loads, and retiring generators.

For example, the planned connection of over 1,200 MW of new solar generation in north and central Queensland led to MLFs falling by up to 12% from the 2017-18 financial year to 2018-19.

In addition to new generator connections, a number of other events can cause large changes in power flow across the transmission network, and corresponding large changes in MLF. These include:

[44] The reference point (or designated reference node) for setting a region's wholesale electricity price.

- Retirement of generation – the retirement of Northern Power Station in South Australia in 2016 caused power flow from Victoria to South Australia to increase, contributing to MLFs in south-east South Australia falling by around 6%. The retirement of Hazelwood Power Station in Victoria in 2017 resulted in increased power flow south from Queensland and New South Wales, contributing to a reduction in northern New South Wales MLFs of around 5%.
- Change in fuel mix – the availability of cheap "ramp" gas in Queensland in 2014 and 2015 led to an increase in GPG in southern Queensland. This caused increased power flow from Queensland to New South Wales, contributing to MLFs in northern New South Wales falling by up to 10%.
- Changes in electrical load – the closure of the Point Henry Aluminium Smelter in Victoria in 2014 contributed to MLFs in the area falling around 2.5%.

The projected increase in development of renewable generation across the NEM will result in changes to network flow patterns, the network itself where augmentations or new interconnection is undertaken, and network losses as different parts of the network are utilised in different ways. This means MLFs will change.

In AEMO's forecasting and planning studies, especially relating to REZs, it is important to model the transmission system and its losses. Each candidate REZ is studied to assess the sensitivity of its MLF to increased renewable generation, based on the existing network. The results are used as a guide to determine how sensitive each proposed REZ would be to changes in MLF. While MLFs are important in projecting investment decisions, total system losses are considered when calculating net market benefits.

AEMO's studies will consider each REZ individually, using network snapshots from the previous 12 months. Various levels of renewable generation are connected in the model to represent the REZ, then an MLF is calculated. The MLFs calculated are only indicative and are not determined using the full Forward Looking Loss Factor Methodology[45] applied under the NER. The studies use existing electrical system strength levels and the existing generation and load profiles and consider some proposed network augmentations.

Effect of energy storage on MLFs

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

Modelling MLFs in capacity expansion

MLFs are an important consideration for generators connecting to the network, especially within a REZ. As generation connects within a REZ, the MLF will generally decline for all generation in the area – especially generation with correlated output. This decline is a direct inhibitor to further investment, given it reduces the effective revenue received for the energy generated at that location.

This year, AEMO proposes to make improvements to the application of MLFs in its generation expansion modelling, to more directly reflect the impact of MLFs on REZ selection. Because of the complexity in estimating a future MLF, and the impact that wider network augmentations and other investment decisions will have on an MLF, an iterative approach is proposed.

In this iterative approach, existing MLFs in a location will be used as a first pass for generation and network expansion. In this first pass, the integrated model may decide to increase network capacity to accommodate the new generation. After running the model, each new generator's MLF will be tested to validate the outcome. If the MLF changes materially, the modelling will be repeated to determine if the change in MLF is likely to result in an alternative site being picked.

[45] AEMO. *Methodology for Calculating Forward-Looking Transmission Loss Factors*, available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries.

The level of detail that AEMO will investigate and publish for each REZ will be determined by the optimal timing of that REZ:

- REZs that are urgently required (2018 ISP group 1 projects) will be explored in the most detail – with multiple network and non-network options considered and consulted on.
- REZs that are required within the next 10 years or so may need to be designed and planned soon. These REZs (ISP group 2 projects) will be explored in moderate detail and will be refined in the following year's ISP.
- REZs that are not required for 10 years or more (ISP group 3 projects) will be assessed at a high level.

4.6 Interconnector augmentation options

In the 2018 ISP, AEMO consulted on a wide range of interconnector upgrade options. The ISP set out a network development strategy that optimised the timing and scale of these augmentations. Following the publication of the 2018 ISP, interconnector upgrade assessments were initiated under the Regulatory Investment Test for Transmission (RIT-T) to implement this strategy.

In the next ISP, AEMO will consider the latest information that becomes available through active RIT-T assessments and will reassess and refine its development strategy. Regardless of the perceived probability of approval, AEMO proposes to only lock in network upgrades once they have received final regulatory approval under the relevant framework (the RIT-T). Projects that are still under active assessment by TNSPs will be re-evaluated in the ISP.

The 2019 Input and Assumptions workbook includes details of each interconnector augmentation currently proposed for assessment – including cost, capacity, and descriptions. Following the publication of the 2018 ISP, all TNSPs are now undertaking RIT-T assessments to determine efficient solutions to increase interconnection in line with the ISP strategy. The following sections provide a high-level overview of the options that will be considered in the 2019-20 ISP.

4.6.1 New South Wales to Queensland

TransGrid and Powerlink are currently conducting a RIT-T to determine efficient solutions to upgrade interconnector capacity between New South Wales and Queensland[46]. The options presented by TransGrid and Powerlink are largely consistent with those considered in the 2018 ISP. AEMO proposes using these options for consideration in the next ISP and will consider feedback made available to AEMO through the ISP or through the RIT-T consultation.

Incremental upgrades

Incremental upgrades to the New South Wales to Queensland interconnector can be implemented faster than major upgrades and could improve reliability in New South Wales following the Liddell Power Station closure in 2022. These options include:

- Upgrade existing assets and increase reactive support – uprate Liddell to Tamworth Lines and install new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks. With an estimated cost of approximately $142 million, this option is expected to increase network capacity during peak demand by approximately 100 MW towards New South Wales and 170 MW towards Queensland.
- Add new switching stations – cut in Armidale–Dumaresq (Line 8C) at Sapphire substation and establish mid-way switching station between Dumaresq and Bulli Creek substations. With an estimated cost of approximately $45 million, this option is expected to increase network capacity during peak demand by approximately 100 MW towards New South Wales only.

[46] TransGrid & Powerlink. *Expanding NSW-QLD Transmission Transfer Capacity*, available at https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity.

Major upgrades

Major network augmentation between New South Wales and Queensland can accommodate an increasing need for power transfer capability and generator connection along the interconnector path. The following major upgrades are proposed for investigation in the next ISP:

- Establish a new 330 kV single-circuit link – install an additional new 330 kV single circuit from Braemar to Bulli Creek to Dumaresq to Armidale to Tamworth to Liddell. With an estimated cost of approximately $855 million, this option is expected to increase network capacity during peak demand by approximately 845 MW towards New South Wales and 445 MW towards Queensland.
- Establish a new 330 kV interconnector – install a new 330 kV double-circuit line between Armidale and Bulli Creek. With an estimated cost of approximately $560 million, this option is expected to increase network capacity during peak demand by approximately 230 MW towards New South Wales and 170 MW towards Queensland.
- Establish a new 330 kV extended interconnector – install a new 330 kV double-circuit line between Braemar and Liddell via Uralla with establishment of a 330 kV substation at Uralla. With an estimated cost of approximately $1,505 million, this option is expected to increase network capacity during peak demand by approximately 1,120 MW towards New South Wales and 995 MW towards Queensland.
- Establish a new 330 kV interconnector with 500 kV extension in New South Wales – install new 500 kV single circuits between Uralla and Wollar and between Uralla and Bayswater, with establishment of Uralla 500/330 kV substation. Establish a 330 kV double circuit between Braemar and Uralla. With an estimated cost of approximately $2,039 million, this option is expected to increase network capacity during peak demand by approximately 1,510 MW towards New South Wales and 1,160 MW towards Queensland.
- Establish a new 500 kV interconnector – install new 500 kV single circuits between Uralla and Wollar and between Uralla and Bayswater and 500 kV double circuit line from Uralla to west of Dumaresq to Bulli Creek to Western Downs. With an estimated cost of approximately $2,360 million, this option is expected to increase network capacity during peak demand by approximately 1,460 MW towards New South Wales and 1,865 MW towards Queensland.
- Establish a new back-to-back HVDC link – establish a HVDC back-to-back converter at Bulli Creek to decouple the Queensland AC system from the rest of the NEM. With an estimated cost of approximately $825 million, this option is expected to increase network capacity during peak demand by approximately 740 MW towards New South Wales and 660 MW towards Queensland.
- Establish a new HVDC interconnector – install a new HVDC bipole transmission network between Western Downs and Bayswater. With an estimated cost of approximately $2,100 million, this option is expected to increase network capacity during peak demand by approximately 1,950 MW towards New South Wales and 2,055 MW towards Queensland.

Non-network solutions

AEMO's ISP modelling considers energy storage, generation, and demand response in combination with network augmentations. TransGrid and Powerlink have proposed the following project for consideration in their RIT-T:

- Battery energy storage system – install a battery energy storage system of 600 MW at Halys and Liddell 330 kV substations. With an estimated cost of approximately $1,000 million, this option is expected to increase network capacity during peak demand by approximately 600 MW towards New South Wales and 595 MW towards Queensland.

4.6.2 Victoria to New South Wales

AEMO and TransGrid are currently conducting a joint RIT-T to determine efficient solutions to upgrade interconnector capacity between Victoria and New South Wales[47]. This RIT-T is focused on delivering upgrades quickly to support reliability in New South Wales, and to enable VRET-driven renewable energy in Victoria to be exported.

The options presented by AEMO and TransGrid are largely consistent with those considered in the 2018 ISP. AEMO proposes using these options for consideration in the next ISP and will consider feedback made available to AEMO through the ISP or through the RIT-T consultation.

Incremental upgrades

Because of the nature of the transmission limits between Victoria and New South Wales, one option was considered in the 2018 ISP to incrementally improve Victoria to New South Wales transfer capacity, and another option to incrementally improve New South Wales to Victoria transfer capacity.

The RIT-T being progressed by AEMO and TransGrid will investigate variations of the option to increase transfer capacity from Victoria to New South Wales (for example, installing dynamic reactive plant rather than a braking resistor to address stability limitations):

- Incremental Victoria to New South Wales upgrade – install a second 500/330 kV transformer at South Morang, uprate the Dederang – South Morang 330 kV lines and series capacitors, the Canberra – Upper Tumut 330 kV line, and install a plant[48] to improve the transient stability. These works, with estimated costs in the order of $90 to $210 million, is expected to increase network capacity by approximately 170 MW towards New South Wales. Additionally, a selected number of transmission lines between Snowy and Sydney may also need uprating to capture the full benefits of this project, and these works carry an additional estimated cost of $36 to $112 million depending on their extent.
- Incremental New South Wales to Victoria upgrade – install a series compensation on the Wodonga–Dederang 330 kV line, and a phase angle regulator on the Jindera–Wodonga 330 kV line. Upgrade the Dederang – South Morang 330 kV line and associated series capacitors with high thermal rating. With an estimated cost of $115 million, this option is expected to increase network capacity by approximately 400 MW towards Victoria only.

Major upgrades

Major options to upgrade the Victoria to New South Wales interconnector include:

- Dederang–Jindera–Wagga path – install a new 330 kV single circuit from Dederang to Jindera to Wagga. Uprate the Dederang – South Morang, Murray – Upper Tumut and Yass–Marulan 330 kV circuits. With an estimated cost of $530 million, this option is expected to increase network capacity by approximately 600 MW towards New South Wales and 400 MW towards Victoria.
- Murray – Dederang – South Morang path – install an additional new 330 kV double circuit line between Murray and Dederang and a single 330 kV circuit between Dederang and South Morang. With an estimated cost of $542 million, this option is expected to increase network capacity by approximately 550 MW towards New South Wales and 1,000 MW towards Victoria.
- SnowyLink – install a 500 kV double circuit line from Sydenham to Ballarat to Bendigo to Kerang to Darlington Point to Wagga, a 500 kV line single circuit from Wagga to Snowy 2.0 to Bannaby and a 500 kV single circuit from Wagga to Bannaby. With an estimated cost of $2,700 million, this option is expected to increase network capacity by approximately 2,100 MW towards New South Wales and 1,800 MW towards

[47] AEMO & TransGrid. *Victoria to New South Wales Interconnector Upgrade RIT-T*, available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Regulatory-investment-tests-for-transmission.

[48] AEMO is currently reviewing options to improve the Victorian transient stability export limit. Plant currently being considered includes synchronous condensers, SVC, batteries with fast response inverters, and a braking resistor.

Victoria. Installation of a 500 kV double circuit line is being considered as part of the Western Victoria Renewable Integration RIT-T.[49]

- Bendigo–Wagga path – install a 500 kV double circuit line from Sydenham to Ballarat to Bendigo to Wagga with a switching station between Bendigo and Wagga, a 500 kV line single circuit from Wagga to Snowy 2.0 to Bannaby and a 500 kV single circuit from Wagga to Bannaby. With an estimated cost of $2,200 million, this option is expected to increase network capacity by approximately 1,700 MW towards New South Wales and 2,000 MW towards Victoria. Installation of a 500 kV double circuit line is being considered as part of the Western Victoria Renewable Integration RIT-T.
- Ballarat–Bendigo–Kerang–Darlington Point path – install a 500 kV double circuit line from Sydenham to Ballarat. Install a 330 kV double circuit line from Ballarat to Bendigo to Kerang to Darlington Point. Install an additional 330 kV circuit from Darlington Point to Wagga. Install a 500 kV line single circuit from Wagga to Snowy 2.0 to Bannaby and a 500 kV single circuit from Wagga to Bannaby. With an estimated cost of $2,300 million, this option is expected to increase network capacity by approximately 800 MW towards New South Wales and 800 MW towards Victoria.

Non-network solutions

AEMO's ISP modelling considers energy storage, generation, and demand response in combination with network augmentations. AEMO and TransGrid have sought feedback on non-network options to address the identified system need.

4.6.3 South Australia interconnection

ElectraNet is current conducting a RIT-T to facilitate South Australia's energy transformation[50]. Because this project is likely to pass the RIT-T during AEMO's ISP modelling, it is proposed that this project be considered as committed (and included in all scenarios). If the preferred solution changes, or the RIT-T is unsuccessful, AEMO will revise this approach.

- Proposed South Australia to New South Wales interconnector[51] – install a 330 kV double circuit from Robertstown to Buronga to Darlington Point, 330 kV single circuit from Darlington Point to Wagga, and two 330/275 kV transformers at Robertstown and a 330/220 kV transformer at Buronga. With an estimated cost of $1,500 million, this option is expected to increase network capacity by approximately 750 MW in either direction between South Australia and New South Wales, establishing a new interconnector.

4.6.4 Tasmania interconnection

TasNetworks is currently undertaking a RIT-T for an additional interconnector between Tasmania and Victoria (Project Marinus). The options presented by TasNetworks are generally consistent with those considered in the 2018 ISP. AEMO proposes using these options for consideration in the next ISP, and will consider feedback made available to AEMO through the 2019-20 ISP or through the RIT-T consultation.

The following two options are being considered:

- MarinusLink Option 1 – a 600 MW monopole HVDC link, including associated AC transmission network augmentation and connection assets. With an estimated cost of $1,400 to 1,900 million, this option is expected to increase network capacity by approximately 600 MW in either direction between Tasmania and Victoria.
- MarinusLink Option 2 – a 1,200 MW bipolar HVDC link, including associated AC transmission network augmentation and connection assets. With an estimated cost of $1,900 to 2,700 million, this option is expected to increase network capacity by approximately 1,200 MW in either direction between Tasmania and Victoria.

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[49] Wstern Victoria RIT-T project, available at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/RITT.

[50] ElectraNet. *South Australia Energy Transformation*, available at https://www.electranet.com.au/projects/south-australian-energy-transformation/.

[51] The proposed South Australia to New South Wales interconnector project was referred to as "Riverlink" in the 2018 ISP.

TasNetworks is currently investigating connection points of MarinusLink options 1 and 2 and AEMO proposes modelling these connection points.

4.7 Non-network technologies

In the ISP, AEMO considers potential non-network options alongside network solutions to develop an efficient power system strategy. Depending on their relative costs and benefits, the capital costs of large network augmentation could be deferred or avoided in some cases. Non-network options include a range of technologies, including:

- Generation investment (including embedded or large-scale).
- Storage technologies (such as battery storage and pumped hydro).
- Demand response.

As part of the proposed plan to make the ISP actionable, where non-network solutions are considered likely to be efficient for urgent projects, non-network solution providers will be invited to participate in the regulatory process that will follow the 2019-20 ISP (that is, through a RIT-T conducted by the local TNSP). At this stage, AEMO is seeking information on non-network technologies so ISP modelling can flag opportunities for competitive non-network investment.

4.8 System security constraints

A regional representation of the NEM is not explicitly capable of considering intra-regional power flows, either as a model result or for the purposes of modelling the physical limitations of the power system. In the real-time NEM Dispatch Engine (NEMDE), a series of network constraint equations control dispatch solutions to ensure that intra-regional network limitations are accounted for. The time-sequential model contains a subset of the NEMDE network constraint equations to achieve the same purpose.

The subset of network constraint equations includes approximately 2,500 to 3,000 pre-dispatch,[52] system normal equations reflecting operating conditions where all elements of the power system are assumed to be in-service. They model important aspects of network operation and include contingency for maintaining secure operation in the event of outage of a single network element.

In general, the following constraint equations are included:

- Thermal – for managing the power flow on a transmission element so it does not exceed a rating (either continuous or short-term) under normal conditions or following a credible contingency.
- Voltage stability – for managing transmission voltages so that they remain at acceptable levels after a credible contingency.
- Transient stability – for managing continued synchronism of all generators on the power system following a credible contingency.
- Oscillatory stability – for managing damping of power system oscillations following a credible contingency.
- Rate of change of frequency (RoCoF) – for managing the rate of change of frequency following a credible contingency.

[52] NEMDE contains equation sets for dispatch, pre-dispatch, Short Term Projected Assessment of System Adequacy (ST PASA), and Medium Term Projected Assessment of System Adequacy (MT PASA). Within these sets, other sets cover specific network conditions such as outages, rate of change, frequency control ancillary services, and network service agreements. Pre-dispatch equations are used because dispatch equations contain terms that rely on real-time SCADA measurements not available to simulation models.

The effect of committed projects on the network is implemented as modifications to the network constraint equations that control flow. The methodology for formulating these constraints is in AEMO's Constraint Formulation Guidelines[53].

A set of network constraints is produced and applied for every scenario modelled. This set may reflect:

- Extracted constraints from the AEMO Market Management Systems (MMS).
- Network augmentations appropriate for the scenario.
- Adjustments to reflect the impact of new generation capacities.
- Other adjustments to reflect assumptions of system operating conditions.

The constraint equations used in market modelling activities will be published with the 2019-20 ISP.

Excluded constraint equations

Operationally, AEMO also uses other types of constraint equations that are invoked as required depending on system conditions. These may include:

- Outage constraint equations.
- Frequency control ancillary service (FCAS) constraint equations.
- Condition-specific constraint equations such as RoCoF and network support agreements.

These constraint equation types are commonly excluded from the market simulations as they may be operational in nature or caused by transmission outage or non-credible events.

Shadow generators

Since the exact location and connection points of all possible new entrant generators cannot be determined in advance, AEMO assumes future generation would be connected to nodes where there are already existing commissioned generators. This allows the new entrant power plant to 'shadow' the impact of the existing capacity to the network (thermal constraints and MLF).

The criteria for selecting a node to connect the possible new entrant depends on:

- Available network capacity.
- Proximity to the specified zone the new entrant is modelled to be connected.
- Access to fuel source (such as pipelines).

Existing thermal constraints are modified to reflect impact of these new entrant generators on the network.

Stability constraints and RoCoF constraints are sometimes not adjusted, because this is not as straightforward as the thermal constraints adjustment.

Inter-regional loss model

In the time-sequential model, losses on notional interconnectors are modelled using the MLF equations defined in the List of Regional Boundaries and Marginal Loss Factors report[54]. For most interconnectors, these are defined as a function of regional load and flow.

AEMO uses proportioning factors to assign losses on interconnectors to regions. Operationally, this is used to determine settlement surplus. In long-term modelling, proportioning factors are used to allocate losses to demand in each region. Proportioning factors are derived from MLFs, as described in Proportioning of Inter-Regional Losses to Regions. Proportioning factors are given in the annual List of Regional Boundaries and Marginal Loss Factors report.

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[53] AEMO. *Constraint Formulation Guidelines*, available at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2016/Constraint_Formulation_Guidelines_v10_1.pdf.

[54] AEMO. *Loss Factors and Regional Boundaries*, available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries.

Future augmentation options between regions not currently interconnected will have a proportioning factor of 50% assigned to each region.

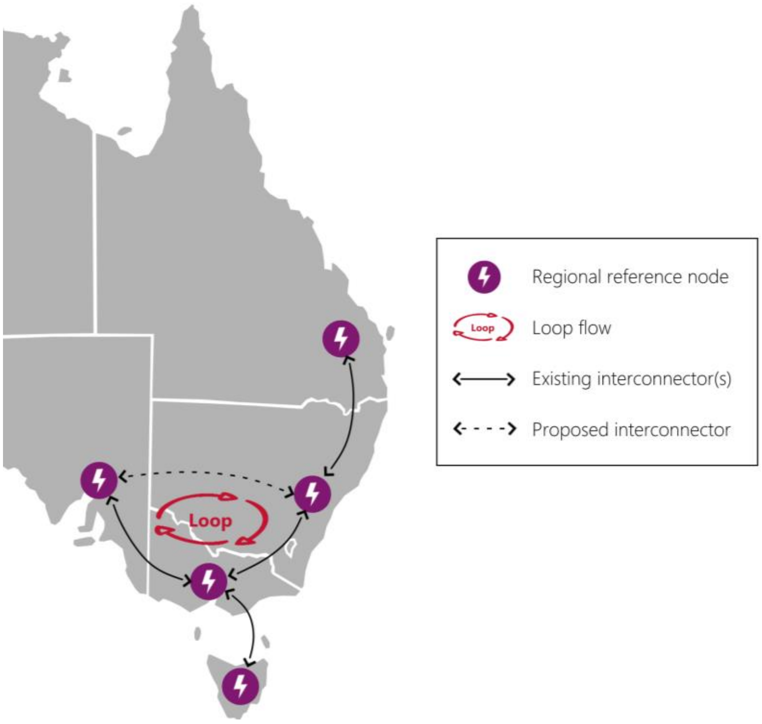
Modelling a South Australia to New South Wales interconnector

A new transmission connection between South Australia and New South Wales (see Section 4.6.3) would create a loop between NEM regions (see Figure 13 below), which can affect market operation of the electricity market. This will require a review of NEM market design.

This loop in major transmission paths would require several key considerations:

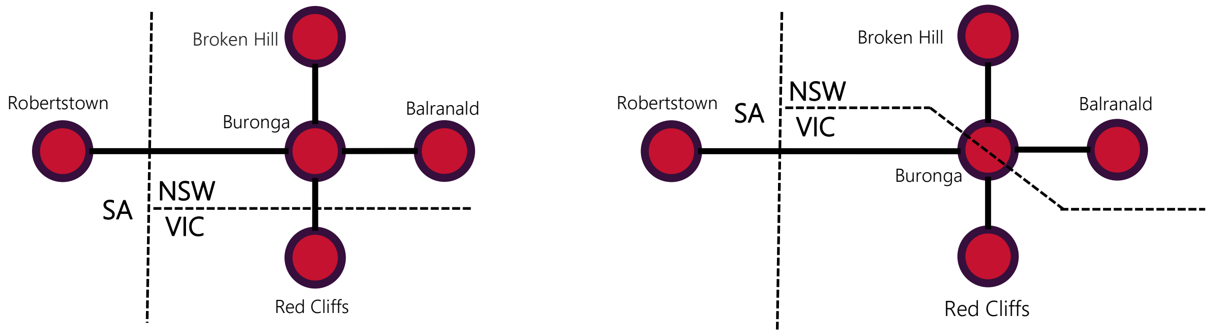
- Separate parallel AC interconnectors are physically related and cannot be separately dispatched based on market forces (electricity flows through the path of least resistance). A form of flow-based market coupling will be required to ensure the physical relationship between the two interconnectors is maintained.
- Models that determine transmission losses will become complex and may necessitate design changes to NEMDE.
- Under some constrained conditions, market prices can increase above the prices bid by generators (the "spring washer effect").
- Inter-regional settlement residues will become more complex and may require market design solutions.

Figure 13 Loop flow resulting from South Australia to New South Wales connection



While adding a new interconnector to the electricity market model is feasible, an alternative is to redefine the regional boundaries. This would involve shifting the Victoria to New South Wales boundary slightly, so the South Australia to New South Wales interconnector connects to a portion of the Buronga substation that is redefined as being in Victoria (see Figure 14).

Figure 14 Region boundary before (left) and after (right) possible boundary shift



Modelling approach

AEMO proposes the following assumption for modelling a South Australia to New South Wales link in this year's forecasting and planning studies:

- In the capacity outlook model (see Section 5.1), a South Australia to New South Wales link will be explicitly modelled as connecting the South Australia and New South Wales regional reference nodes. This will facilitate least-cost investment decisions to be optimised based on physical network topology.
- In the short-term time-sequential model (see Section 5.1), a region boundary shift will be implemented. This avoids the pricing and constraint complexity of dealing with a loop flow (for example, the spring-washer effect, flow-based market coupling), and enables investment decisions from the capacity outlook model to be verified against a different market design.

If the South Australia to New South Wales interconnector proposal successfully passes the RIT-T, AEMO will conduct a separate consultation to determine any required changes to the NEM market design.

4.9 Questions for consultation

Q4 Do the proposed inputs and assumptions provide a reasonable basis for assessing the value and direction of the future energy market transition? If not, please provide suggestions for improvement, particularly with regard to consumer embedded investments, large-scale generation technologies, and network and non-network options to support Australia's future energy system.

Q5 Do you have any other feedback on AEMO's proposed inputs and assumptions?

Specific consultation requests:

Q6 Do you have specific feedback and data on:

a. The list of candidate generation technologies for assessment?
b. The current and future generation technology costs assumed?
c. Generator fixed O&M costs, noting the inclusion of fixed costs associated with mines?
d. The appropriateness of AEMO's assumptions around various storage technologies?
e. The approach on generator retirements, including appropriate costs to convert existing CCGTs to OCGTs providing a peaking, rather than major energy production role?

5. Material issues for 2019

Based on discussions, webinars and workshops held with stakeholders in 2018, and feedback received during ESB workshops held in November, AEMO considers the following to be material issues to be considered as part of the 2019 forecasting and planning activities:

- Valuing outcomes that improve the integrity of the power systems by increasing resilience and robustness in the face of climate change, weather variability, fuel disruptions, and unexpected early closures of large thermal generation.
- Improving understanding of the value of REZs, renewable energy diversity, and renewable energy integration requirements.
- Understanding the increasing influence of consumer investment trends such as rooftop PV, battery storage, DSP, energy efficiency, and electric vehicles, as well as understanding the consumer impacts of future power system development.
- Understanding and addressing emerging technical challenges related to the energy transformation, such as frequency stability and power system strength.
- Developing and consulting on the process for producing an actionable ISP and a suitable ESOO for the purposes of the RRO.

To address these material issues, AEMO has identified enhancements to the inputs, modelling, and stakeholder engagement processes.

5.1 Modelling framework

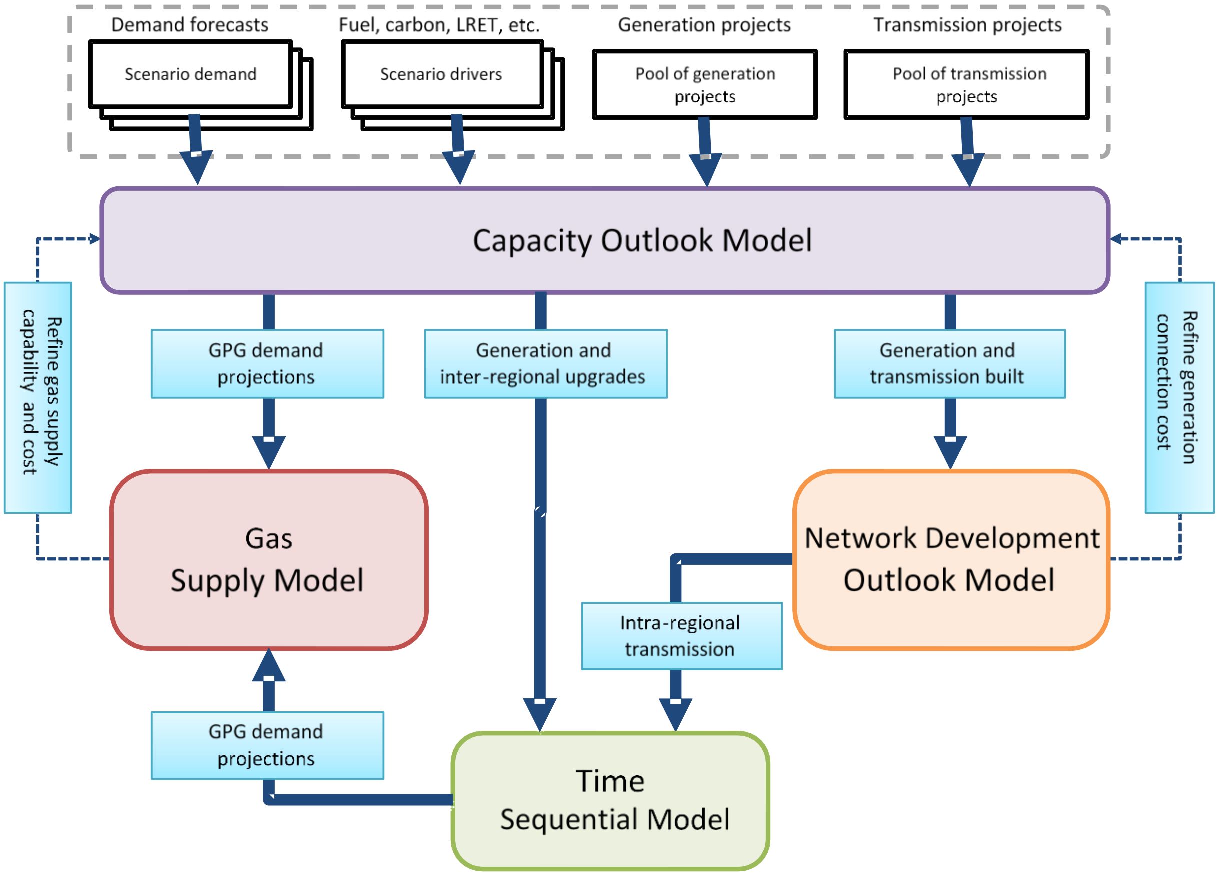
AEMO maintains four mutually-interacting planning models, shown in Figure 15. These models incorporate assumptions about future development described by the scenarios, and simulate the operation of energy networks to determine a reasonable view as to system development needs under different demand, technology, policy, and environmental conditions.

The role of each model is outlined below:

- Capacity outlook model – this model actually comprises two models that differ with respect to the breadth of sectors co-optimised, length of planning horizon, and chronological resolution:
  - Long-term integrated model (IM model) – this long-term co-optimised model considers the interdependencies between gas and electricity markets to determine optimal thermal generation investments, retirements and interconnection investment plans for each ISP scenario, over the longest time horizon (to 2050).
  - Detailed long-term model (DLT model) – the DLT model looks at the electricity system in isolation and optimises new generation investments using transmission developments and other long-lived thermal generation developments from the integrated gas and electricity long-term model. The planning horizon is split into shorter time steps, with each step modelled with finer chronological resolution to assess the optimal mix of wind, solar, storage, and flexible peaking generation for a given transmission development. The DLT is also key in validating timing and cost-effectiveness of transmission investments pathways identified by the integrated model.
- Short-term time-sequential model (ST model) – the short-term time-sequential dispatch model looks to validate the results of the capacity outlook model by optimising hourly generation dispatch subject to power system limitations and network constraints. A modified version of this model may also be used to assess impacts on prices and revenue sufficiency of generation assets.

- Network development outlook model – this PSS®E (Power System Simulation/Engineering) model examines the transmission network in detail with interconnector upgrades, new generation planting, storage and retirement of coal generators. Network augmentation options are identified and incorporated into the ST time-sequential model to validate the generation and transmission development outlook.
- Gas supply model – the gas supply model assesses reserves, production and transmission capacity adequacy for the GSOO. 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.

Figure 15 Market modelling process flow



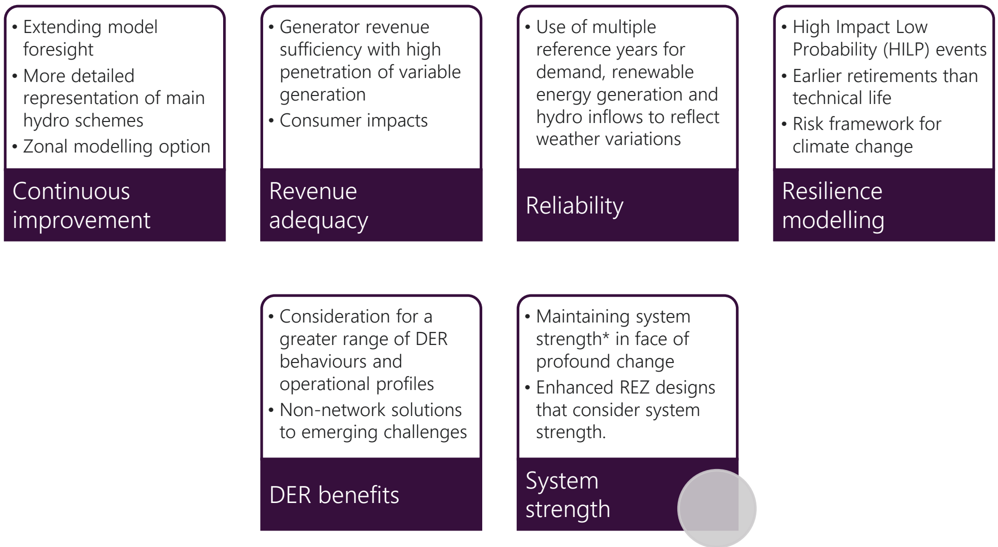
More information on AEMO's modelling suite is provided in AEMO's Market Modelling Methodology report.[55]

5.2 2019 and beyond: proposed modelling improvements

AEMO has identified some areas where the models may be enhanced to address the material issues outlined above, and as part of continuous improvement. This section outlines proposed improvements as well as aspects of the modelling AEMO is considering enhancing for future studies.

[55] AEMO, Market Modelling Methodologies, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Market-Modelling-Methodology-Paper.pdf.

Figure 16 2019 and beyond: proposed market modelling improvements



* System strength is a measure of the ability of a power station to remain stable under normal conditions and to return to a steady state condition following a system disturbance.

5.2.1 Continuous improvement

For the 2018 ISP, the traditional NTNDP market modelling approach was significantly improved, to:

- Reflect the gas and electricity system co-dependencies.
- Understand future investment risks as the market continues to evolve.
- Capture the value of geographic and technical generation diversity.
- Adequately represent the operating characteristics of storage.
- Incorporate REZ development opportunities.
- Enable decision-making in the presence of uncertainty.
- Understand the system security and reliability implications of any potential grid development plan.
- Highlight the value of building a resilient plan.

This modelling complexity required AEMO to adopt a multi-staged modelling approach, with each stage helping to build a more complete analysis of the strengths and weaknesses of various future grid development options. The range of models was selected to exploit certain advantages and strengths that come from varying modelling approaches. Consideration of computational effort and solution robustness was balanced at each stage, with the models used in a sequential and iterative fashion to deliver the ISP.

Since delivering the 2018 ISP, AEMO has been investigating ways to further improve the efficiency of the modelling process, to allow more detail to be considered at each stage and ideally reduce the number of iterations required between models. Such improvements would allow for a more fully optimised development plan and allow more granular modelling to place further focus on reliability risks, resiliency, benefits of geographic and technical diversity, and value of storage.

While still needing to balance level of detail with computational feasibility, for 2019 AEMO is aiming to add further detail into the DLT model in at least one of three ways:

- Extended foresight – currently the DLT model breaks the planning horizon into steps of five years, so in any step, generation expansion decisions are made with only a few years' foresight. Given assumed continued cost reductions of renewable and storage technologies, limited future foresight has been considered an acceptable trade-off unlikely to result in significant regret cost, particularly when used in conjunction with the IM model. However, AEMO is working with the software vendor to find ways for the model to run using larger steps to test this assumption.

- Increasing chronological resolution – the DLT model is a chronological optimisation which has greater resolution relative to the IM model, but still groups some contiguous hourly periods together into blocks where load levels are similar. AEMO is further testing the materiality of this simplification, particularly when it comes to modelling a wider range of storage capacity:energy ratios.
- Zonal or sub-regional topography – in some NEM regions, such as Queensland, a sub-regional topography may be more appropriate for capturing intra-regional thermal transmission limitations and the impact of interconnector augmentations, and increase sophistication in identifying and developing potential REZs. Moving to a more disaggregated topography does increase the computational effort, and may require simplification of some other model components. Such changes would only be made if these simplifications do not compromise the integrity of the modelling.

AEMO will continue to explore and report on the outcomes of this work during the year.

5.2.2 Revenue adequacy

As discussed in Section 4.4.2, AEMO's modelling assumes thermal generators will retire at the end of their technical lives, or earlier if the modelling indicates it is cost-effective to do so. This takes a centrally co-ordinated view of the needs of the system, but, in reality, generation companies need to provide an adequate return to shareholders, and may close plant earlier if not able to make sufficient revenue to cover fixed and variable costs. These decisions to retire often coincide with timing of major maintenance, with generation companies needing to balance economic end-of-life assumptions against the cost of maintaining the plant. This can have implications for both the reliability and performance of the plant as it reaches end-of-life, and may lead to closures of ageing coal-fired and gas-fired generators earlier than assumed in the 2018 ISP.

AEMO's forecasting and planning studies focus on the most efficient pathway to achieving reliable and secure power supply. Perfect competition is assumed, as this achieves the maximum producer and consumer surpluses. In practice, this means generators are assumed to be dispatched in short-run marginal cost merit order, subject to physical constraints on the system.

This is appropriate for planning purposes, however, to assess price outcomes and generator revenue in an energy only market, it is necessary to make assumptions around strategic bidding to emulate actual market outcomes. Internally, AEMO uses two models to estimate future electricity prices using a combination of historical bidding patterns to mimic behaviours for the next five years, and a Nash-Cournot game theoretic model to capture longer-term bidding strategies that may be employed as the NEM starts looking profoundly different from today.

Recognising that a level of subjectivity is applied when developing future bidding strategies and company ownership structures, AEMO has also engaged external consultants to assess revenue adequacy of coal and gas-fired generators based on the 2018 ISP. This external consultation will be used to help validate and refine AEMO's internal modelling.

It is anticipated that this analysis will assist in determining and identifying key behavioural and operational changes to the thermal generation fleet, specifically identifying;

- The potential economic-based retirement outlook for both thermal coal and gas generators.
- Timing of any conversion of CCGT to OCGTs.
- Implication of material fixed and rehabilitation costs on the generators as a going concern.

This work will be presented in an ISP insights paper around April 2019, and will be used to inform development of retirement sensitivities in forecasting and planning publications. Some degree of revenue adequacy assessment will also be applied in the ISP market modelling, to ensure inflexible plant in particular are not being retained in the model beyond economic life.

Price modelling will also allow assessment of the consumer impacts in each region where appropriate, although, due to the time-intensive nature of price forecasting, this may need to be published as an insights paper subsequent to the ISP, rather than a key component of the planning and forecasting processes.

5.2.3 Reliability

With increasing renewable generation penetration, both demand and supply are now exposed to the variability of weather. In recent years, reliability assessments for the ESOO have been run sampling half-hourly traces of demand, wind and solar availability from the last eight historical years. This captures effects of heatwaves, coincident peak demand across regions, and correlations between high temperatures and wind/solar output. Within each reference year, the modelling samples a number of different thermal generation forced outage states. The variation in unserved energy results between different reference years tends to be greater than the variation in results driven by different forced outage conditions, highlighting the power system's exposure to weather events.

This means it is important to capture the variability of weather in power system planning, so the future system remains reliable and dispatchable in all hours, even when the wind is not blowing and the sun is not shining.

While for reliability assessments multiple reference years have been used for several years, in capacity expansion models for the ISP and NTNDP, a single reference year of data (2013-14) has typically been used for simplicity, with system reliability subsequently tested in time-sequential modelling. A limitation of this approach is that it may favour one particular technology over another if, say, the reference year selected happened to be more or less favourable to wind at time of system peak.

For the 2019 capacity expansion models, AEMO proposes to develop renewable energy traces based on a reference year rolling system using eight reference years (2010-11 to 2017-18) to capture year-to-year variation of resource availability. Annual hydro inflow variability will also be included for major hydro schemes such as Snowy and Hydro Tasmania.

It is intended that with the use of these synthetic rolling reference years the long-term expansion model will be exposed to a wider range of operational states. By developing an expansion plan that is influenced by a range of operational states, a more reliable development plan is expected to be identified that is robust regardless of weather conditions.

The use of multiple reference years would then be further explored in the short-term modelling framework on an individual basis. For example, the expansion plan based on the rolling years would be applied in the short-term model based on a single reference year only for the forecast period. This would be repeated for each of the respective reference years to better assess the robustness of the development plan to weather variations including periods of wind or hydro droughts, heat waves or co-incident peak demands.

By reporting the average, maximum and minimum market benefits across the sampled reference years, a richer picture of the performance of candidate plans under various weather conditions will be formed to assist decision-making.

5.2.4 Resilience modelling

The environment within which the NEM operates is changing, and the future power system will need to be resilient to factors such as:

- Natural disasters and extreme weather that may be compounded by climate change.
- Cyber-attacks or physical threats.
- Sudden, unexpected closure of large thermal generation.
- Fuel disruptions.

With increased concerns on the impacts of high-impact low frequency (HILF) events upon the power sector, a growing number of jurisdictions are actively engaged in the process of developing frameworks for assessing how best to manage the risk of these new and emerging threats. However, a standard framework for resilience analysis and an accepted set of resilience metrics/measurements are still unavailable. Risk tolerances need to be understood, risk frameworks established, and quantification techniques evolved.

In Australia, these High Impact Low Probability (HILP) events are currently quantified in Regulatory Investment Tests by assessing the market impact and weighting by the probability of occurrence. But when the probability of occurrence is very small, this approach tends to mask the severity of the event when it does happen. It also fails to capture broader societal costs and benefits associated with the disruptive event, impacts on other critical infrastructure sectors, and the utility (consumer preference ordering) of solutions that may help minimise the severity of the impact.

AEMO's preferred approach to enable informed decision-making is to explicitly report the risks of high impact disruptions under various candidate system plans and test the utility with consumers.

Establishing a risk framework

AEMO is working with market participants, the Australian Cyber Security Centre, and the Critical Infrastructure Centre on a framework to improve the cyber security resilience of the grid.

A similar standardised, cross-industry risk framework is being developed in Australia to build in resilience to extreme weather events and disasters across the supply chain.

As identified in the Finkel Review[56], the NEM is particularly exposed to climate change impacts:

"An increase in the frequency and intensity of extreme weather events can increase stress on the power system in several ways:

- *Transmission and distribution networks are vulnerable to extreme weather events.*
- *High ambient temperatures reduce generator efficiency, and can lead to breakdowns and an increase in maintenance costs.*
- *Many elements in the power system have maximum operating temperatures above which they disconnect to avoid damage. These controls will be triggered more frequently and new investment may be required to make the equipment more resilient to high temperature events."*

Depending on the severity of the risk, and the speed of recovery possible, the most cost-effective mitigation strategy may be to adapt (plan the system differently) or respond (change operational procedures to improve ability to operate through and recover quickly from the disaster.) By way of example, Figure 17 shows the strategy employed by National Grid to build resilience. Choice of action may depend on the level of resilience market bodies and jurisdictions assess should be borne by customers.

Figure 17 Building resilience

SOURCE: National Grid, National Grid Electricity Transmission Resilience Stakeholder Workshop October 2018.

Any changes to technical approaches or standards identified through development of the NEM risk framework will be included in the 2019-20 ISP if available in time.

Until this new risk framework is developed, AEMO proposes to adopt two of the criteria used by US utility PJM in its approach to resilience in transmission planning:

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[56] *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, 2017. Available at https://www.energy.gov.au/sites/default/files/independent-review-future-nem-blueprint-for-the-future-2017.pdf.

- Do no harm – ensure that any new infrastructure does not lead to deterioration in grid resilience. Building additional transmission lines along a bush-fire prone transmission corridor would be an example of resilience deterioration.
- Opportunistic – where there is an opportunity to increase resilience at minimal cost to consumers, the more resilient option will be taken. This helps inform the decision-making process, but is not a key driver of investment.

Extreme weather events and climate change – the need for information

Appendix B of the 2018 ISP outlined some of the power system vulnerabilities under extreme weather – such as high temperatures, bush fire risk, wind and hydro droughts, and floods – and highlighted that improvements in climate and extreme weather information are needed to enable more informed risk analysis and decision-making to improve the integrity of the grid.

The Australian Government is providing $6.1 million over three years, from 2018-19, to improve climate and extreme weather information for the electricity sector, as part of a response to the Finkel Review.

This project will make existing climate change data and information more accessible and useful for those making decisions on electricity infrastructure, with a view to supporting improved long-term climate risk planning. The work will be undertaken by CSIRO and the Bureau of Meteorology in collaboration with AEMO.

As this information becomes available, AEMO will use it to improve its demand and supply forecasting and planning. This will be critical for future ESOOs and ISPs to better assess the risks of climate change on various parts of the grid.

In the meantime, AEMO has assessed best practice approaches to evaluating power system resilience based on information currently available to it, as discussed below.

Evaluating system resilience

In evaluating the system's resilience to HILP events, there are five main things to consider. They are:

- What events are cause for concern?
- What indicators are utilised to measure the impacts of HILP events?
- What approach is used to integrate resilience analysis in the existing models?
- What mitigation options are considered to reduce the impacts of HILP events on the system?
- What approach is used to evaluate the different mitigation options?

What indicators may be used to measure resiliency?

As the name suggests, HILP disruptive events can have great impacts on the system and, thus, the society as a whole. Measuring the magnitude of the impact in a given disruptive scenario is a critical task in the system resilience analysis.

The question of which indicators can be utilised to measure the system impacts of HILP events then arises. Resilience of a system is defined as:

"*the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such events'* (FERC, 2018)[57].

The possible impacts on the system following a disruption include load shedding, total blackouts, voltage violations, and use of demand response options to reduce the load shedding. Therefore, the possible measures of system impacts following a disruption are hours of load shedding, unserved energy, unmet spinning reserve, hours of unmet reserve, hours of voltage violation, MW of demand response used, and hours of demand response used.

[57] FERC (2018) Grid Reliability and Resilience Pricing (Document No. RM18-1-000) and Grid Resilience in Regional Transmission Organizations and Independent System Operations (Document No. AD18-7-000).

AEMO reviewed several international studies to assess the best approaches to modelling power system resilience, including;

- Conceptual Framework for Developing Resilience Metrics for the Electricity, Oil, and Gas Sectors in the United States by Sandia National Laboratories[58].
- Fuel Security Analysis: A PJM Resilience Initiative[59].
- USA Western Interconnection gas-electricity interface study by Wood Mackenzie[60].
- Framework for modelling High-Impact, Low-Frequency Power Grid Events to Support risk- Informed decisions by Pacific Northwest National Laboratory[61].
- Future Resilience of the UK electricity system – by the Energy research partnership[62].

The proposed frameworks for system resilience analysis in these studies are largely based on the same approach; minor deviations include the model used for system operation simulations and the resilience metrics/indicators used to measure the system resilience. Most of studies follow these main steps in their approach to resilience analysis:

Step 1: Develop a representative base case capacity expansion plan for resilience analysis.

Step 2: Develop a list of disruption scenarios that need to be analysed.

Step 3: For each scenario, identify the affected transmission lines or power plants.

Step 4: Simulation of the operation of the {NEM} for the base case plan using time-sequential models to estimate impacts of different disruptive scenarios (for example the unserved energy, hours of load shedding, unmet spinning reserve).

Step 5: Implementation of a stress test of the system for different possible disruptions.

Step 6: Identification of mitigations options to reduce the system impacts.

Step 7: Re-running the time-sequential models to quantify the reduction of system impacts following mitigation options.

Step 8: Analysing the mitigation options based on their costs and quantify benefits in terms of the reduction in economic impact.

AEMO intends to use a similar approach in assessing NEM system resilience. AEMO's key focus is on the assessment of how various candidate system plans may build grid resilience to disruptive events such as extreme weather, wind or hydro droughts, and unexpected coal closures.

5.2.5 Incorporating benefits of DER

The 2018 ISP identified that the incorporation of DER technologies with transmission expansions can have broad-ranging benefits for the development of the NEM. AEMO intends to continue working with CSIRO and ARENA in the next GenCost project to better capture costs and potential of DER. These enhancements are unlikely to be included in the 2019-20 ISP, but will allow AEMO to better assess how to include this detailed information in future ISPs.

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[58] Sandia National Laboratories, Conceptual Framework for Developing Resilience Metrics for the Electricity, Oil, and Gas Sectors in the United States, available at https://cfwebprod.sandia.gov/cfdocs/CompResearch/docs/EnergyResilienceReportSAND2014-18019o.pdf.

[59] Pennsylvania New Jersey Maryland Interconnection LLC (PJM), Fuel Security Analysis: A PJM Resilience Initiative, available at https://www.pjm.com/-/media/library/reports-notices/fuel-security/2018-fuel-security-analysis.ashx.

[60] Wood Mackenzie, Western Interconnection Gas-Electric Interface Study Public Report, available at https://www.wecc.biz/Administrative/WECC%20Gas-Electric%20Study%20Public%20Report.pdf.

[61] US Department of Energy Office of Scientific and Technical Information (OSTI), Framework for modelling High-Impact, Low-Frequency Power Grid Events to Support risk- Informed decisions, available at https://www.osti.gov/biblio/1228355.

[62] Energy research partnership, Future Resilience of the UK electricity system, available at http://erpuk.org/wp-content/uploads/2018/11/4285_resilience_report_final.pdf.

5.2.6 Maintaining system strength in the face of profound change

As the penetration levels of non-synchronous generation connecting to the grid continues to increase, increasingly additional steps are needed to maintain sufficient system strength for secure operation of the network. The current NER frameworks[63] require that system strength requirements for new generation connections must be met by the proponents connecting, and that responsibility for maintaining fault levels at the defined fault level nodes must be met by TNSPs.

It is expected that there will be a requirement to offset some generator connection costs in relation to the size and location of new connections to take these system strength requirements into account. These requirements will also need to take into account the timings and scope of other network upgrades such as interconnector upgrades and new REZs.

5.3 Questions for consultation

Q7 For 2019 planning and forecasting activities, what, if any, material issues should be prioritised ahead of the issues proposed by AEMO?

Q8 What other material HILP events should be considered in assessing resilience?

Q9 What mitigation options could be considered to increase grid resilience, and how should these options be evaluated? Is AEMO's proposed approach reasonable?

[63] AEMC. Managing power system fault levels, available at https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels.

6. Inertia and system strength requirements methodologies

As an outcome from the AEMCs 'Managing the rate of change of power system frequency'[64] and 'Managing power system fault levels'[65] Rule changes, in July 2018, AEMO published its initial:

- Inertia Requirements Methodology, together with the first report on inertia requirements and shortfalls in the NEM[66]
- System Strength Requirements Methodology, together with the first report on system strength requirements and fault level shortfalls in the NEM[67].

These methodologies are used to identify and quantify shortfalls in inertia and system strength respectively. Based on the inertia requirements methodology, AEMO identified the projected inertia shortfall for the South Australian region that was declared in the 2018 NTNDP, published in December 2018.[68] AEMO has not identified any necessary changes to the methodologies at this stage.

As part of this consultation, AEMO seeks views on what other factors it should consider in the methodologies, or proposed improvements, for use in 2019 to determine future inertia or system strength requirements[69].

6.1 Questions for consultation

Q10	What other factors should be considered in the methodologies or proposed 2019 improvements to determine future inertia or system strength requirements?

[64] AEMC. Managing the rate of change of power system frequency, available at https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-freque.

[65] AEMC. Managing power system fault levels, available at https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels.

[66] AEMO. 2018 Inertia Requirements Methodology and 2018 Inertia Requirements and Shortfalls, available at http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

[67] AEMO. 2018 System Strength Requirements Methodology, System Strength Requirements and Fault Level Shortfalls, available at http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

[68] AEMO. 2018 National Transmission Network Development Plan, available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan.

[69] The 'System Strength Impact Assessment Guidelines', which are focussed on requirements for new generation connections, are not part of this consultation process.

7. Feedback on the 2018 ISP

Following publication of the 2018 ISP, AEMO has sought feedback on it through a range of engagements, including presentation to COAG Energy Council, the ISP Webinar, ESB Workshops, the Market Modelling Working Group, the FRG, a Market Modelling Workshop, a Gas Forecasting Workshop, and a Systems Engineering Society of Australia workshop.

This chapter discusses the key themes in feedback received to date. AEMO encourages further feedback to be incorporated into written submissions to this consultation process.

7.1 Stakeholder engagement

Compared to AEMO's previous planning projects, the level of stakeholder interest has expanded considerably for the ISP – submissions increased from 5 to 65 from one year's planning publication to the next. Based on this increased stakeholder interest, and on feedback from our stakeholders, AEMO will aim to step up the level of stakeholder engagement considerably. This will include:

- Enhanced engagement with consumers – AEMO will form the CEP (see Section 2.3), comprising qualified representatives who can be consulted and provide robust review of AEMO's forecasting and planning outcomes.
- Consultation on a draft ISP prior to finalising the ISP – AEMO will publish a draft ISP, seeking written feedback, and will host a public forum to present and discuss the draft outcomes.
- More stakeholder forums – AEMO will host more stakeholder forums on topics like REZs, modelling approaches, generation, and network expansion.
- Greater government engagement – AEMO continues to welcome both feedback and engagement from governments.
- Consultation on scenarios, inputs, assumptions, and methodologies for AEMO's forecasting and planning work – this document, which will be supported by a stakeholder workshop on 19 February 2019.

See Chapter 2 for more information on AEMO's proposed stakeholder engagement strategy.

7.2 Scope and approach

Key feedback to date on the scope and approach to AEMO's forecasting and planning work includes:

- A standardised approach for planning resilience – AEMO will seek to establish a "best practices" approach to planning a resilient power system. This will include an international review, engagement with industry through working groups, and a public consultation process.
- A mechanism to agree on policy – stakeholders largely agreed that the ISP should incorporate both Federal and State Government policies, and that a mechanism is needed to determine what policies should be included in the ISP scenarios.
- Risk analysis – AEMO will seek to improve its risk-based analysis in the ISP, considering the Australian Standard for Risk Management (AS ISO 31000:2018).
- Hydrogen in the economy – AEMO has received feedback to consider the implementation or consideration of an expanded hydrogen industry specifically on variable renewable generation development and supplementing/complementing gas supplies. See Section 3.1.2 for more information.

7.3 Modelling and inputs

Feedback regarding AEMO's modelling and inputs was largely gathered through the Market Modelling Working Group, the FRG, a Market Modelling Workshop, and a Gas Forecasting Workshop. Key recommendations from these groups included:

- Improved locational information for energy storage – the 2018 ISP demonstrated a long-term role for energy storage in the NEM. Based on the significance of this finding, AEMO's energy storage modelling is being expanded (see sections 4.3.2 and 4.3.3).
- Enhanced consideration of MLFs – MLFs are one of the most significant aspects that will affect generator investment decisions. Modelling techniques will be refined this year to refine previous modelling techniques (see Section 4.5.4).
- Consideration of generator revenue sufficiency – a key area of exploration for AEMO in 2019 is to examine the revenue sufficiency of the existing generator fleet and the impact of earlier generator retirements.
- Better modelling and reporting of supply intermittency – AEMO will expand its analysis and reporting on variable generation, explaining how the power system of the future will endure extended periods of low wind or solar energy (wind and solar droughts).
- Easement investigation – AEMO will work with local transmission and distribution owners to refine network augmentation options.
- More detailed reporting on solutions to system strength and inertia – in addition to providing critical energy production and dispatchable power, conventional generators have also traditionally been relied on to provide essential grid security services, such as inertia, system strength, and frequency control. AEMO will continue to explore and report on efficient solutions to deliver these system services.
- REZ cost refinements – further exploration of how known REZ parameters (such as land cover) will affect generation costs (see Section 4.5).

7.4 Evolution of the regulatory framework

In September 2018, the COAG Energy Council asked the ESB to "*identify a work program (including possible changes to the RIT-T) and convert the ISP into an actionable strategic plan*"[70]. The ESB held workshops with a broad range of stakeholders and submitted a range of recommendations to the COAG Energy Council to make the ISP an actionable plan, including recommendations that seek to expedite the regulatory process applying to key Group 1 projects.

In December 2018, the AEMC completed its Coordination of Generation and Transmission Investment (CoGaTI) Review[71], recommending clear links between the ISP and network investment decisions to remove duplication and streamline the regulatory process.

On 20 December 2018, the ESB published a series of 12 recommendations[72] on:

- How Group 1 projects in the ISP can be delivered as soon as practicable.
- How Group 2 and 3 projects should be progressed.
- How the ISP would be converted into an actionable strategic plan.

In particular, the recommendations suggested that the NTNDP currently provided for in the NER should be replaced by the ISP, and that the ISP should be developed every two years, with updates between plans if there is a defined material event. AEMO will issue guidelines to stakeholders on how and when an update to

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[70] COAG Energy Council. *Energy Security Board Converting the ISP into action*, available at http://www.coagenergycouncil.gov.au/publications/energy-security-board-converting-isp-action.

[71] AEMC. *Coordination of generation and transmission investment*, available at https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi.

[72] ESB. *Integrated System Plan – Action Plan*, available at http://www.coagenergycouncil.gov.au/publications/integrated-system-plan-action-plan.

the ISP would be done.

The nature and extent of the changes underway in the NEM power system means careful coordination and integration of projects will be crucial to successfully managing a smooth transition – not only for economic objectives, but also to meet the essential technical engineering requirements by which the power system operates. AEMO is confident that the ISP provides this blueprint, and is committed to evolving the ISP to meet the evolving needs of Australia's energy sector.

A1. Questions

Submissions are not limited to the specific consultation questions contained in each chapter, and not all questions are expected to be answered in each submission. AEMO welcomes written submissions on any observations or approaches outlined in this report.

ENGAGEMENT

Q1 How could AEMO further improve stakeholder engagement and confidence in the results of the 2019-20 ISP and 2019 ESOO?

SCENARIOS

Q2 Do you agree that the proposed scenarios outlined in this section provide plausible and internally consistent future worlds for use in network planning and forecasting publications? Do they provide sufficient stretch for forecasting and planning purposes?

Q3 What additional sensitivities should be explored in the 2019-20 ISP or 2019 ESOO, that could materially impact power system planning?

INPUTS AND ASSUMPTIONS

Q4 Do the proposed inputs and assumptions provide a reasonable basis for assessing the value and direction of the future energy market transition? If not, please provide suggestions for improvement, particularly with regard to consumer embedded investments, large scale generation technologies, and network and non-network options to support Australia's future energy system.?

Q5 Do you have any other feedback on AEMO's proposed input and assumptions?

Specific consultation requests:

Q6 Do you have specific feedback and data to support AEMO on:

a. The list of candidate generation technologies for assessment?
b. The current and future generation technology costs assumed?
c. Generator fixed O&M costs, noting the inclusion of fixed costs associated with mines?
d. The appropriateness of AEMO's assumptions around various storage technologies?
e. The approach on generator retirements, including appropriate costs to convert existing CCGTs to OCGTs providing a peaking, rather than major energy production role?

MATERIAL ISSUES FOR 2019

Q7 For 2019 planning and forecasting activities, what, if any, material issues should be prioritised ahead of the issues proposed by AEMO?

Q8 What other material HILP events should be considered in assessing resilience?

Q9 What mitigation options could be considered to increase grid resilience, and how should these options be evaluated? Is AEMO's proposed approach reasonable?

SYSTEM STRENGTH AND INERTIA REQUIREMENTS METHODOLOGIES

Q10 What other factors should be considered in the methodologies or proposed 2019 improvements to determine future inertia or system strength requirements?