Market Modelling Methodologies

For Forecasting and Planning the National Electricity Market and Eastern and South-Eastern Gas Systems

July 2018

Important notice

PURPOSE

AEMO has prepared the Market Modelling Methodology to provide information about how AEMO fulfils its [long term forecasting and planning] functions under the National Electricity Law and the National Electricity Rules and the National Gas Law and the National Gas Rules.

This report updates the previous methodology information provided within the *Market Modelling Methodology and Input Assumptions Report, December 2016*, available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.

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VERSION CONTROL

Version	Release date	Changes
1	12/07/2018	Initial Release

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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.

AEMO produce a comprehensive suite of planning and forecasting publications each year, including:

- **Electricity Statement of Opportunities (ESOO) –** a supply adequacy assessment of the NEM. Provides market and technical data to assess the reliability of the electricity market over a 10-year outlook period. The ESOO incorporates an independent forecast for electricity consumption, maximum demand, and minimum demand over a 20-year outlook period for the NEM, previously referred to as the National Electricity Forecasting Report (NEFR).
- **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. The GSOO incorporates an independent forecast for gas consumption, and maximum gas daily consumption, previously referred to as the National Gas Forecasting Report (NGFR).
- **Integrated System Plan (ISP) –** identifies transmission developments over a 20-year outlook period which, as part of the portfolio of resources needed to reliably and securely supply customers, will minimise the overall cost of the NEM.
- **Victorian Annual Planning Report (VAPR) –** considers the adequacy of the Victorian transmission network to meet its reliability requirements, and identifies development opportunities to address emerging network limitations.

These reports comprise AEMO's forecasts of 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.

An overview of the suite of planning and forecasting publications is shown in Figure 1 below.

AEMO generally uses four models to perform market modelling activities:

- The capacity outlook model, including two variants of differing granularity,
- The time-sequential model,
- The network development outlook model, and
- The gas supply model.

These models and other supporting activities form an iterative loop ensuring market modelling activities' quality, completeness, and robustness.

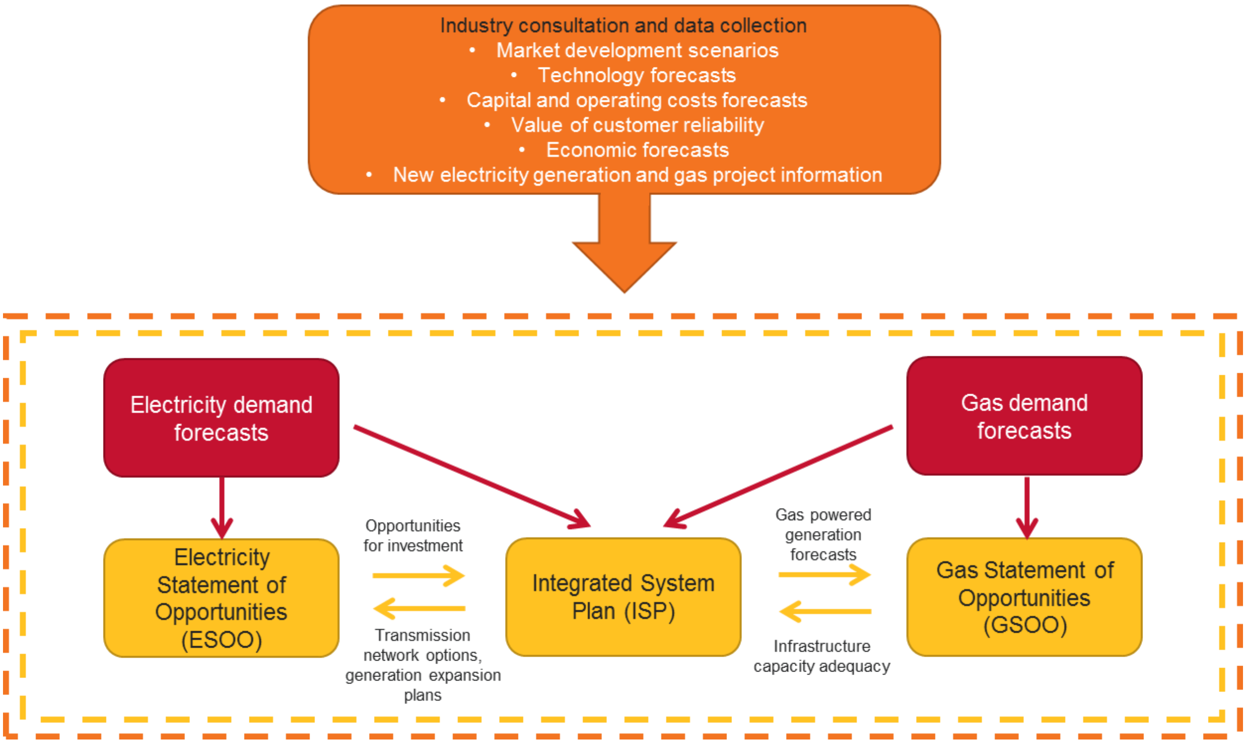
This document provides an overview of methodologies employed to support AEMO's market modelling activities across a range of publications. Supplementary methodology and input assumption reports are also provided with each publication[1],[2],[3]. These highlight specific assumptions or approaches of relevance in that planning publication cycle. Independent methodologies also are provided to explain AEMO's forecasting approach for electricity and gas consumption, maximum demand, minimum demand, as well as connection point forecasts.

[1] AEMO. *Gas Statement of Opportunities methodology*. Available at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities

[2] AEMO. *Electricity Statement of Opportunities methodology*. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

[3] AEMO. *ISP methodology*. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

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



1.1 Data sources and flow

Assumption data originates from many sources, both externally and as a result of AEMO's activities in the national gas and electricity markets. Individual publications produce bespoke methodology or assumptions reports, those values should take precedence to that presented here. At a high level:

- electricity and gas demand forecasts are available at AEMO's forecasting portal (http://forecasting.aemo.com.au/)
- generator technical and economic parameters are available as part of the ISP database (available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan)
- Regional boundary definitions and marginal loss factors are published annually, and available at: 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)

Appendix A1 presents default data sources and the items taken from each.

Data updates become available at different times of the year. Each planning report uses the latest data that is available when modelling commences.

2. Scenarios

AEMO's long-term planning begins with the development of a series of credible global economic and technological development scenarios.[4] These scenarios are designed to cover a wide range of potential future development pathways, and describe the environment in which Australia's energy networks may operate for in the long term.

The scenarios are intended to explore a range of credible futures, with each scenario based on themes of development such as fast or slow economic growth, high or low technology costs, or relaxed or strict carbon policies. Additional sensitivities are often used to supplement the scenarios where appropriate, across the publications.

AEMO scenarios are developed in conjunction with industry working groups. Representatives were selected to capture generation businesses and network development, energy consumers, policy makers, and promoters of emerging technologies.

Table 1 shows major drivers that influence market modelling results.

Table 1 Major drivers typically varied in scenario analysis

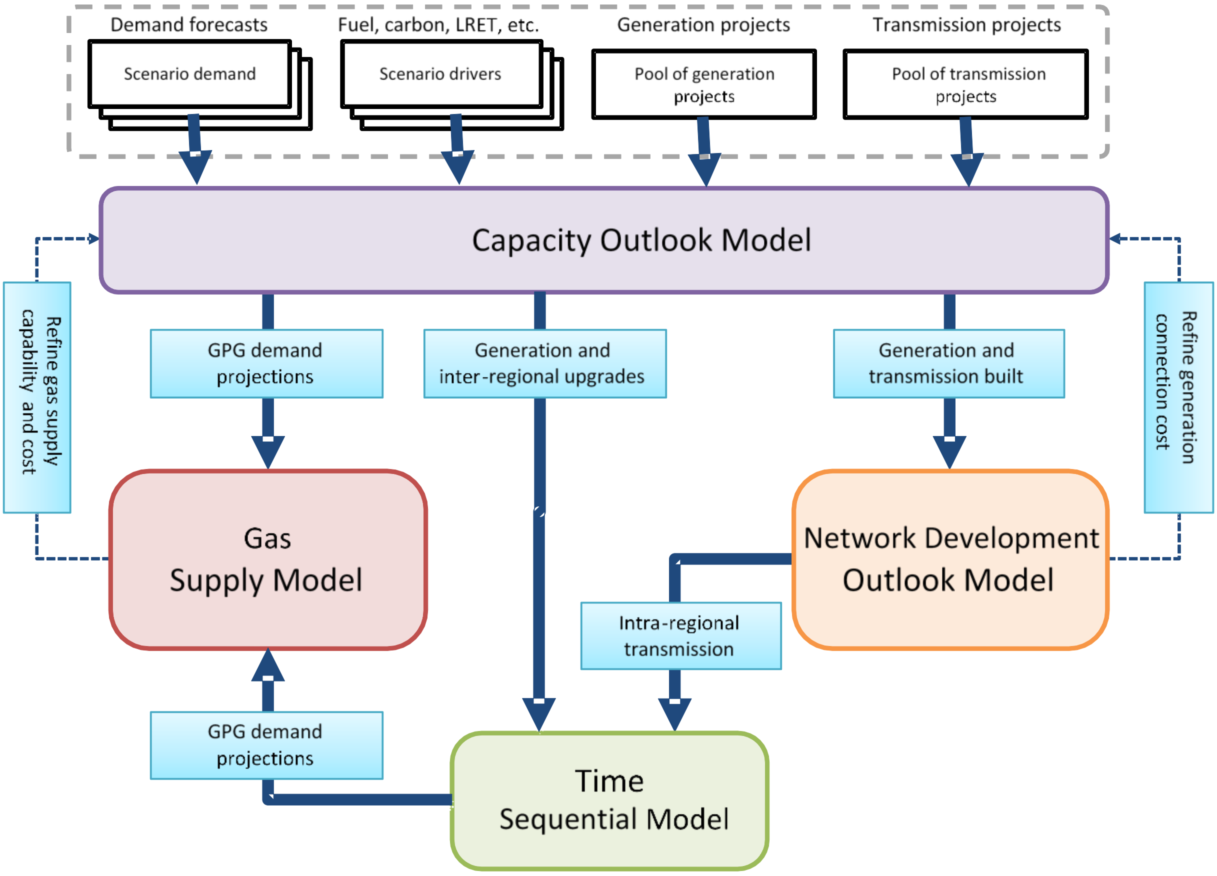
Scenario drivers	Description	Relevance	Common Source
Demographic changes and economic activity	Reflects the impact of population growth and economic projections on electricity demand	Economic activity drives electricity consumption	External consultation and in-house studies
Emerging technologies	A technology scan of relevant and likely technologies that could significantly impact the electricity market	Disruptive technologies may significantly change system needs and operating regime	External consultation
Capital and operation cost trajectories	An assessment of the price impact of upstream and downstream industries	Investment and operating costs define the total system cost of running the electricity market	External consultation and public reports
Emissions abatement policies and objectives	National, state-wide and company policies enforce transition to low carbon economy	Incentivise investment in renewable energy and penalise heavy carbon emitters	Government legislation and stated policy positions
Network development options	Augmentation options for emerging network limitation	Limits efficient operation of the power system	In-house studies and in consultation with TNSPs

[4] In the context of AEMO planning, a scenario is a set of assumptions covering economic and policy settings, estimates of generation technology costs, fuel and carbon cost trajectories, price-demand relationships, and other externalities that influence but are not materially affected by the generation and transmission outlook developed by capacity outlook modelling.

3. Models

AEMO maintains four mutually-interacting planning models, shown in Figure 2. These models incorporate the assumptions about future development described by the scenarios, and simulate the operation of energy networks to determine a reasonable view as to how those networks may develop under different demand, technology, policy, and environmental conditions.

Figure 2 Market modelling process flow



The ESOO, ISP, and VAPR primarily use three models to deliver their key outputs:

- **Capacity outlook model** – determines the most cost-efficient long-term trajectory of generator and transmission investments and retirements to maintain power system reliability. Two variants exist:
  - **Long Term Integrated model (IM)** – co-optimised model which considers interdependencies between gas and electricity markets to determine optimal thermal generation investments, retirements, transmission and pipeline investment plans, over the longest time horizon (25 years or beyond).
  - **Detailed Long Term (DLT) model** – co-optimised model of the electricity system in isolation to the gas market, optimising new generation investments and sub-regional transmission developments, using inter-regional transmission and other long-lived thermal generation development decisions produced by the IM capacity outlook model. The DLT model is a more granular capacity outlook approach that provides chronological, detailed representations of the long term via a multi-step solve, thus with reduced foresight relative to the IM.

- **Time-sequential model**[5] **–** carries out an hourly simulation of generation dispatch and regional demand while considering various power system limitations, generator forced outages, variable generation's availability, and bidding models. This model validates insights on power system reliability, available generation reserves, emerging network limitations, and other operational concerns. Depending on the study this model is used for, the generation and transmission outlook from the capacity outlook model may be incorporated.
- **Network development outlook model –** examines and investigates possible engineering and operational solutions to emerging transmission network limitations identified by the capacity outlook model and time-sequential model.

The **Gas supply model** is used primarily in the GSOO, with daily granularity to deliver its key outputs.

The capacity outlook model, time-sequential model and gas supply model all make use of the PLEXOS Integrated Energy Model platform developed by Energy Exemplar.

The network development outlook model utilises PSS/e software.

3.1 National Electricity Market topology

The NEM is comprised of the five Commonwealth States of Queensland, New South Wales, Victoria, South Australia, and Tasmania, referred to as regions and shown in Figure 3.[6] AEMO's electricity modelling replicates these regions, representing the network as a system of five regional reference nodes connected by inter-regional flow paths.

The regional topology allows the model to respond to regional changes in demand, and to optimise regional generation and inter-regional transmission expansion. This arrangement also mirrors the operation of the National Electricity Market Dispatch Engine (NEMDE), which is responsible for directing generation dispatch in the NEM.

Figure 3 Regional representation of the NEM, including existing interconnectors

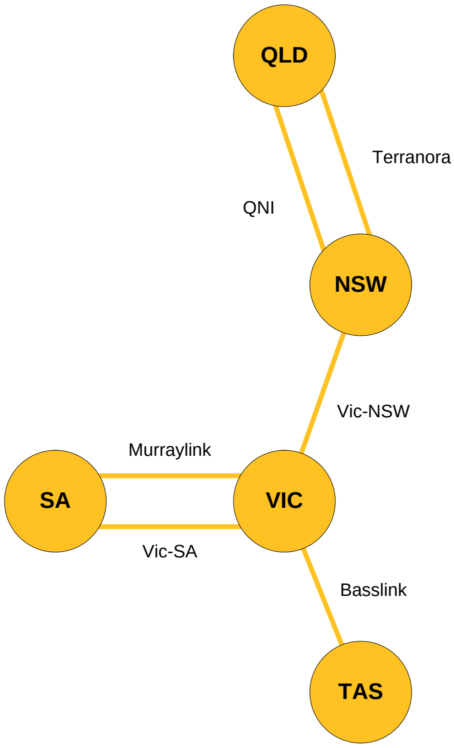


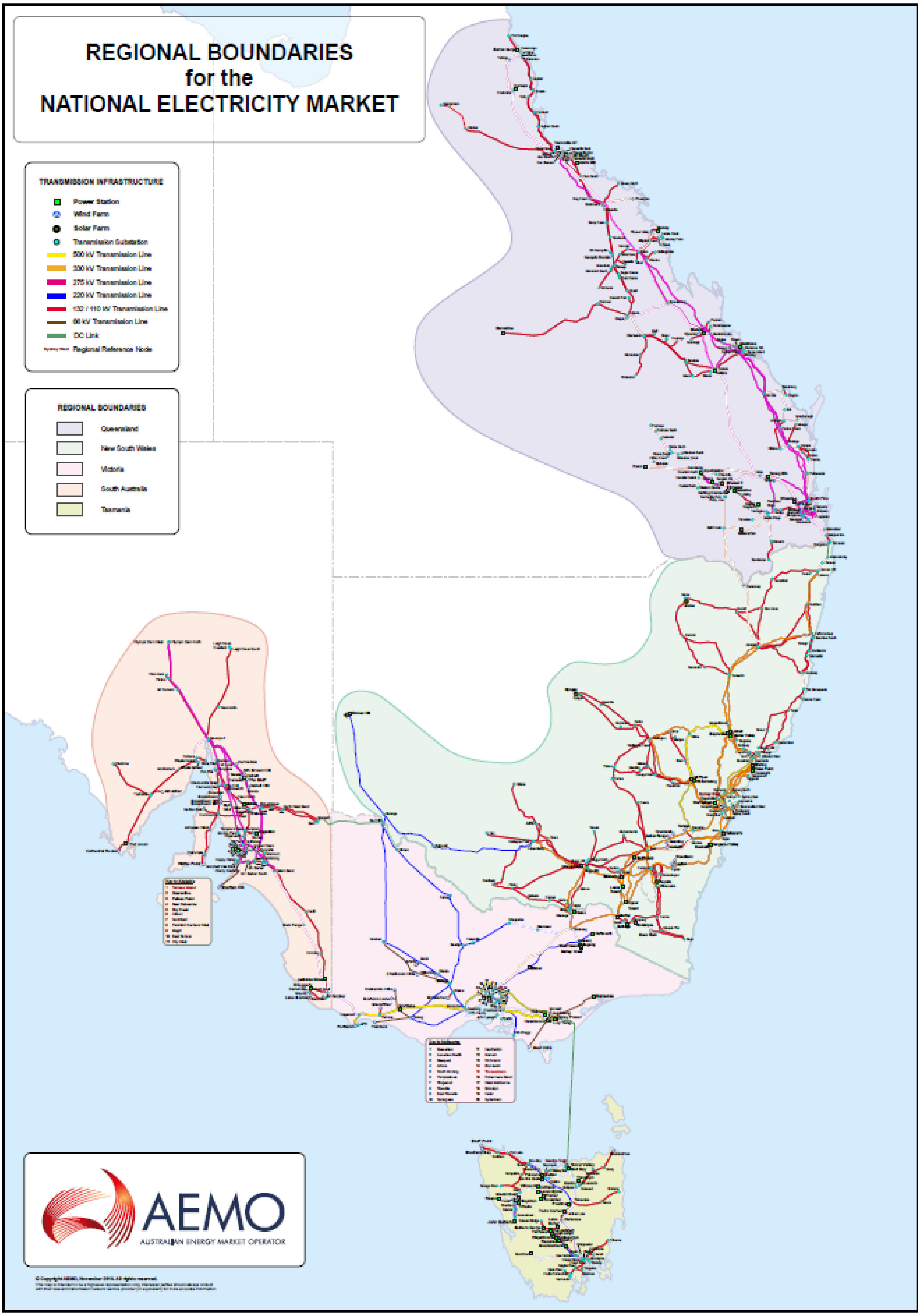
Figure 4 shows the electricity infrastructure and the latest regional boundaries definition for the NEM. AEMO also produces an interactive map that contains a clear visualisation of regional definitions as well as key outcomes from AEMO's planning and forecasting publications.[7]

[5] The time-sequential model is composed of three simulation phases: 1. PASA – schedules maintenance, 2. Medium-term schedule – optimises energy production schedule, 3. Short-term schedule – hourly simulation.

[6] The Australian Capital Territory is included within the New South Wales NEM region.

[7] AEMO Interactive Map, available at: http://www.aemo.com.au/aemo/apps/visualisations/map.html

Figure 4   NEM regions and power system infrastructure



3.1.1 Geographical and electrical diversity

A regional representation cannot account for differences in energy resources and infrastructure limitations within a region. To incorporate these aspects, AEMO's electricity modelling defines planning zones subject to the specific modelling exercise, shown in Table 2. Each zone is modelled considering the expected quality and availability of generation resources, including the correlation of renewable generation resources, to inform the capacity outlook model and time sequential modelling.

Energy resource availability and cost, along with generation build limits dictated by the intra-regional network dynamics, are defined according to these zones. Network constraint equations capture transmission limits between zones.

Zones with the greatest resources, or those with the lowest resource cost, will likely receive new generation first, provided network limits do not unduly constrain that generation.

In some cases, the low cost of generation in a particular zone may justify both investment in generation and transmission infrastructure to supply power elsewhere.

AEMO has in 2018 identified Renewable Energy Zones (REZ) – an extension to previous planning zones. REZs are geographical areas in the NEM where clusters of large-scale renewable generation can be developed to promote economies of scale. Ideally, REZs will also allow for geographical and technological diversity for large scale renewable projects.

The purpose of identifying the location and timing of REZs is to enable the efficient connection of new geographically diverse generation sources while maintaining reliable supply to consumers. To efficiently and reliably connect this generation will require complementary network development at both intra and inter-regional level. The REZs identified by AEMO are shown in Table 3 and Figure 5.

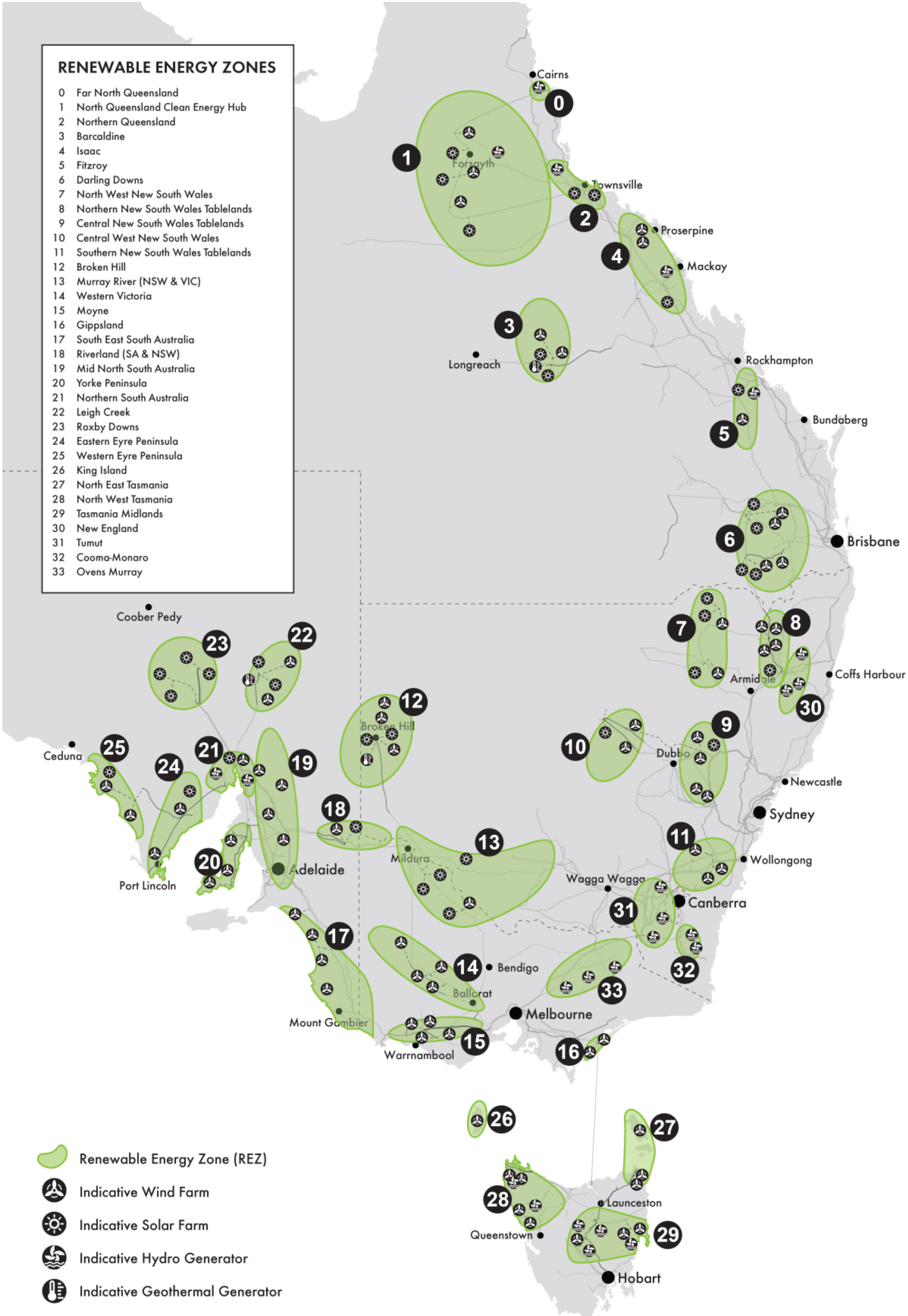
Table 2 Electricity planning regions and zones

Region	Zones
QLD (Queensland)	NQ (North Queensland)
	CQ (Central Queensland)
	SWQ (South West Queensland)
	SEQ (South East Queensland)
NSW (New South Wales)	NNS (Northern New South Wales)
	NCEN (Central New South Wales)
	CAN (Canberra)
	SWNSW (South West New South Wales)
VIC (Victoria)	LV (Latrobe Valley)
	MEL (Melbourne)
	CVIC (Country Victoria)
	NVIC (Northern Victoria)
SA (South Australia)	ADE (Adelaide)
	NSA (Northern South Australia)
	SESA (South East South Australia)
TAS (Tasmania)	TAS (Tasmania)

Table 3 Renewable Energy Zones

Region	Zones	Renewable Energy Zone
NSW (New South Wales)	CAN	Southern NSW Tablelands
		Tumut
		Cooma-Monaro
	NCEN	Central NSW Tablelands
		Central West NSW
	NNS	North West NSW
		Northern NSW Tablelands
		New England
	SWNSW	Broken Hill
		Murray River (NSW)
		Riverland (NSW)
QLD (Queensland)	CQ	Barcaldine
		Fitzroy
	NQ	Far North QLD
		North Qld Clean Energy Hub
		Northern Qld
		Isaac
	SWQ	Darling Downs
SA (South Australia)	NSA	Riverland (SA)
		Mid-North SA
		Yorke Peninsula
		Northern SA
		Leigh Creek
		Roxby Downs
		Eastern Eyre Peninsula
		Western Eyre Peninsula
	SESA	South East SA
TAS (Tasmania)	TAS	King island
		North East Tasmania
		North West Tasmania
		Tasmania Midlands
VIC (Victoria)	CVIC	Western Victoria
	LV	Gippsland
	MEL	Moyne
	NVIC	Murray River (Vic)
		Ovens Murray

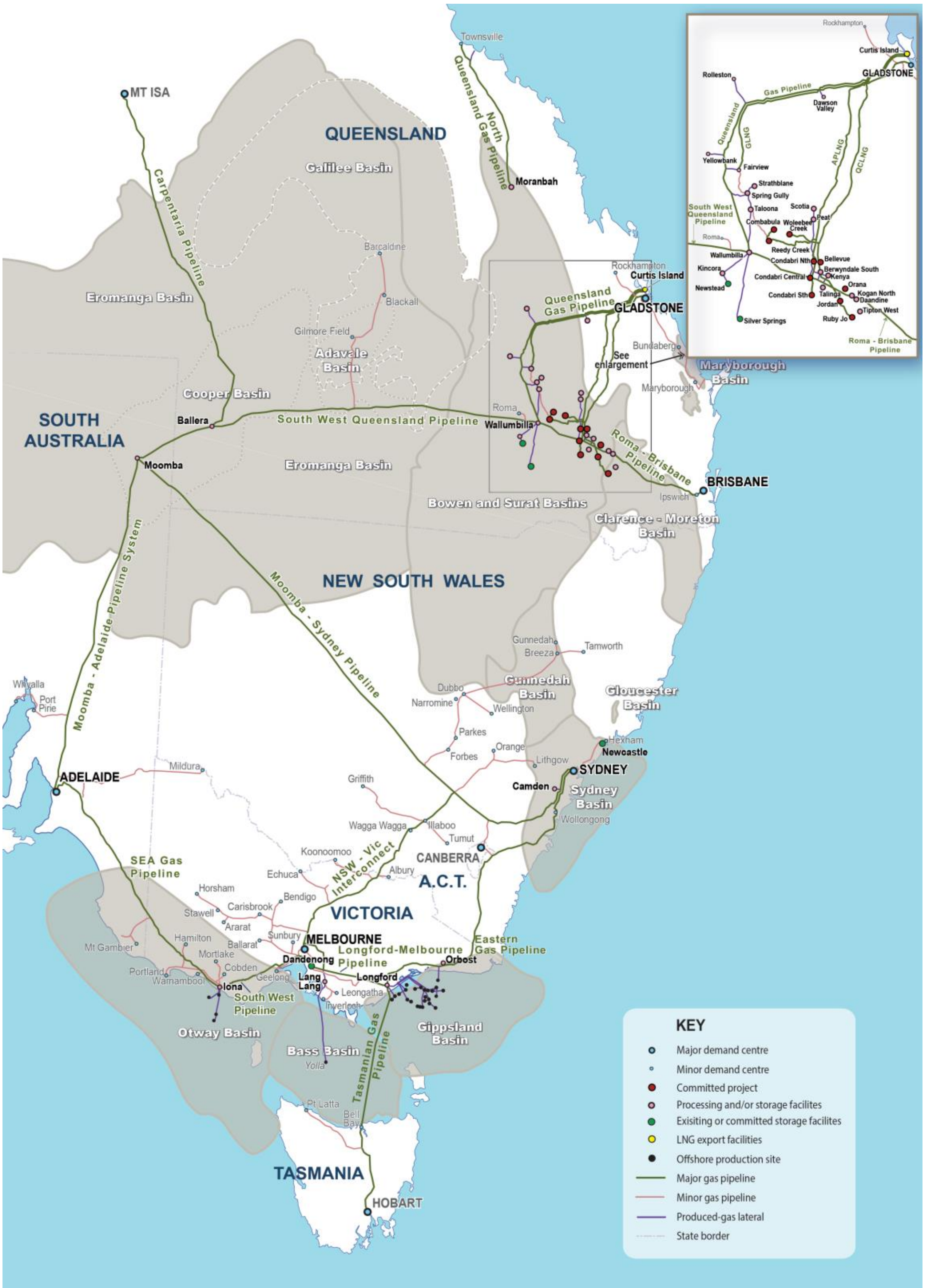
Figure 5 Renewable Energy Zones map



3.2 Gas network topology

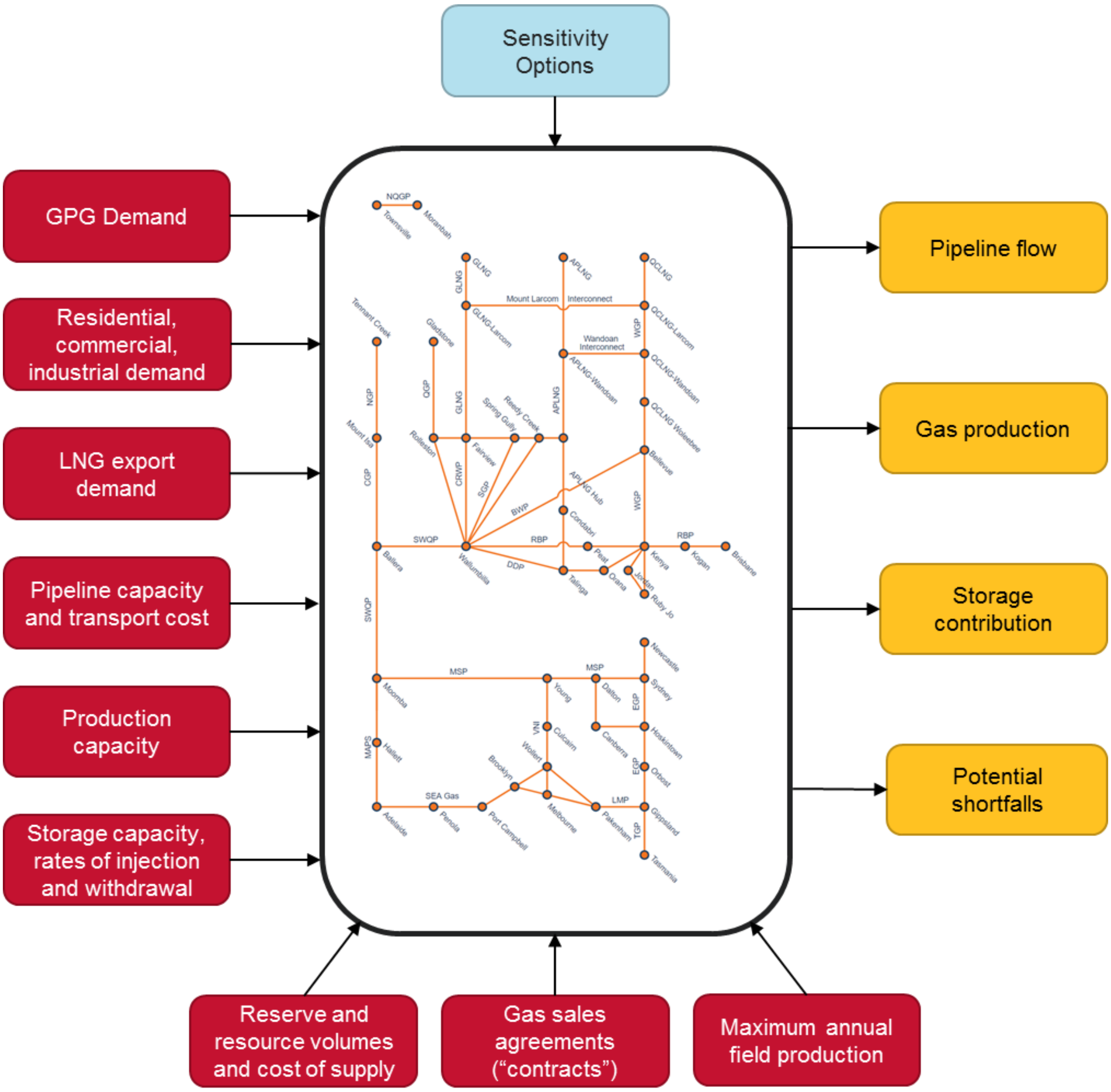
Major gas transmission and production infrastructure in eastern and south-eastern Australia is shown in Figure 6. Not included on the map (but captured in the Gas Supply Model) is the connection of the Northern Gas Pipeline (NGP), a new pipeline linking Tennant Creek with Mt Isa. It is currently under construction, due to come online by late 2018.

Figure 6 Eastern and south-eastern Australian gas production and transmission infrastructure



The gas supply model incorporates major gas transmission pipelines, demand centres and production facilities, as shown in Figure 7.

Figure 7 Gas model topology, inputs, and outputs



3.3 Capacity outlook model

The capacity outlook model consists of two separate models - the IM and DLT models - which complement each other in identifying the optimal generation and transmission pathway in the long-term across different scenarios.

The IM co-optimises electricity generation and transmission investment and withdrawals, along with gas production and pipeline infrastructure, to efficiently meet future operational demand and government policy objectives (such as renewable generation development) at lowest cost.

The objective of the capacity outlook models, in combination, is to minimise the capital expenditure and generation production costs over the long term planning outlook (at least 20 years), subject to:

- Ensuring there is sufficient supply to reliably meet demand at the current NEM reliability standard[8], allowing for inter-regional reserve sharing.

[8] The reliability standard specifies that the level of expected USE should not exceed 0.002% of operational consumption per region, in any financial year. Australian Energy Market Commission (AEMC) Reliability Panel. Available at https://www.aemc.gov.au/our-work/developing-electricity-guidelines-and-standards

- Meeting legislated and advanced policy objectives.
- Observing physical limitations of the generation plant and transmission system.
- Accounting for any energy constraints on resources.

The modelling approach applies a mathematical formulation of a mixed integer linear program to solve for the most cost-efficient generation and transmission development schedule (considering size, type, location, and commissioning and retirement date of generation and transmission assets).

The capacity outlook model is rich in options for the location and technology of new generation, candidates for retirement, and transmission augmentation options. These options are outlined in the ISP database published each year.[9]

Due to the size of the problem and the length of the planning horizon, it is necessary to make some simplifying assumptions, trading off some model accuracy for computational manageability. These simplifications may include:

- Aggregating hourly demand across the 20+ year planning horizon into a representative number of load blocks
- Breaking the optimisation into smaller steps.
- Simplifying the network representation, using static notional interconnector limits
- Reducing the number of integer decision variables by linearising generation and transmission build and retirement decisions (effectively allowing partial units to be built if desired).
- Using minimum capacity reserve levels to approximate the amount of firm capacity required in each region to meet the reliability standard.
- Using minimum capacity factors and load levels to represent minimum technical and economic duty cycles for coal generators.
- Simplifying the representation of existing hydro schemes via inter-temporal energy constraints mimicking water availability over time
- Relaxing convergence thresholds

The DLT model is a chronological optimisation which has greater resolution relative to the IM, although some load aggregation is still required. Computational feasibility of this model is maintained by breaking the optimisation into smaller steps. This technique allows increased granularity to preserve the original chronology of demand time series, thus ensuring a greater reflection of renewable intermittency, storage balancing capabilities and other inter-temporal constraints which require a chronological relationship between simulation intervals.

As the capacity outlook models rely on some problem simplifications to manage simulation timeframes, detailed analysis is subsequently carried out using the time-sequential model. Where necessary, a feedback loop is included allowing the time-sequential model to inform the capacity outlook model. This feedback might include limiting the amount of build in a particular region, if generation is constrained off due to transmission limitations, or adding additional firm peaking capacity in a region if unserved energy (USE) in excess of the reliability standard is observed in the time-sequential model.

Consequently, generation and transmission expansion development is finalised through an iterative modelling process where the capacity outlook model and the time-sequential model are used to deliver a range of expansion plans for all scenarios. Where possible, decisions made by the modelling during the early stages of the development are 'locked down' if common to many of the simulations. This helps improve the robustness of the expansion/retirement plan by reducing the number of decisions to be made in subsequent iterations and improves stability between scenarios.

3.3.1 Load blocks

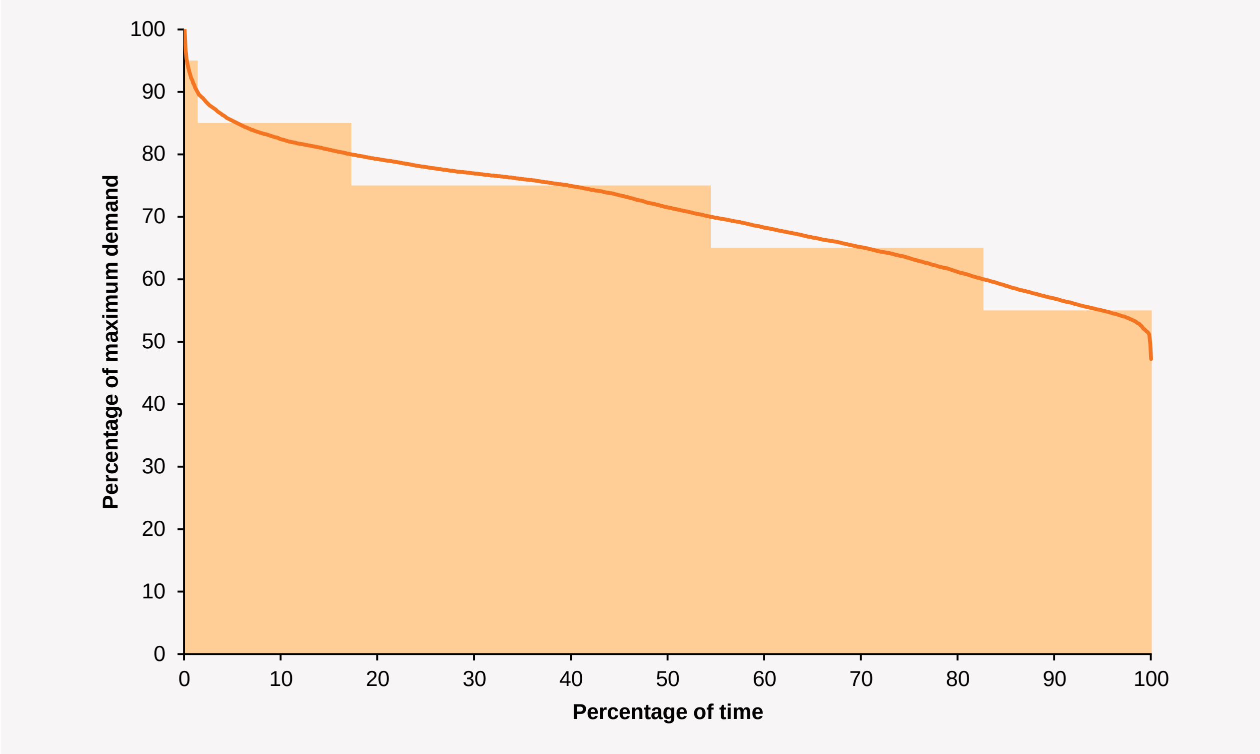
The IM model uses the Load Duration Curve (LDC) approach to approximate hourly demand.

Load blocks are created for each month modelled, using a 'best-fit' approach to approximate the monthly load duration curves, as demonstrated in Figure 8. The monthly partitioning captures seasonal variation and maximum and minimum demands are preserved, but within each month the demand chronology is lost.

To ensure supply capacity adequacy, 10% probability of exceedance (POE) demand curves are used. Operational consumption 'sent out' is used rather than 'as generated' to account for the fact that new generation technologies may exhibit different amounts of auxiliary loads.

[9] AEMO. ISP Database. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database

Figure 8 A load duration curve partitioned into five load blocks



When modelling operational consumption, the hourly rooftop PV generation trace is first netted off the underlying consumption trace before aggregating into load blocks. This ensures the load blocks represent periods of similar operational demand, which is more relevant for determining scheduled dispatch.

Each load block typically represents a number of time periods within the month with similar operational demand levels. However, other time-varying data, such as wind and solar generators' availability, could vary considerably within that same load block. The LDC approach effectively averages these to a single representative availability value, smoothing the hourly intermittency and chronology of wind and utility-scale solar generation.

AEMO has developed the DLT to compensate for these known yet necessary simplifications. The DLT simulates with aggregations at a daily level in a chronological fashion, thus increasing dramatically the model's granularity. The regional demand time series fed into the DLT is fitted with a step function so that the total number of simulation periods per day is reduced from twenty-four hours to an appropriate number of load blocks. These load blocks are created using a weighted least-square fit method which performs an optimisation that minimises the sum of squared errors (i.e. the square of the difference between the hourly demand fed into the model and the step function approximation). The weighted least square approach has the advantage of fitting the step function more tightly to the original demand time series – allocating more blocks to higher load periods and less to periods of low demand. The duration of each block can therefore vary depending on how the underlying intervals are grouped together.

Figure 9 provides an example of eight load blocks approximating the forecast hourly underlying demand of New South Wales for a sample day in 2018-19. The methodology produces a load block 'trace' that varies to reasonably fit the hourly demand profile. More load blocks are reserved to shoulder and peak periods as a result of the weighted least-squares approach, whereas off-peak hours are generally represented by less and thus longer blocks. Given the diurnal nature of solar generation, the increased granularity of the model during peak demand periods, particularly during daylight hours, increases the ability of the model to value renewable energy despite resource intermittency.

Figure 9 Load blocks vs daily chronological demand

Due to computational limitations, the finer chronological resolution in this DLT is not able to model efficiently the length of planning horizon of the IM. Instead, the planning horizon is broken into multiple smaller steps of say, five years. In any step, generation expansion decisions are made with only a few years' foresight. Given assumed continued cost reductions of renewable energy technologies and storage technologies, allowing the model to invest in these technologies based on limited future foresight is not likely to result in significant regret cost (unlike build decisions for larger thermal plant, which may be exposed to volume risk as emission constraints become more constraining over time). The short planning step is therefore considered an acceptable trade-off for this second optimisation, to better assess the mix of generation technologies and locations that minimises total system costs, including the cost of transmission access and the need for balancing services such as storage.

3.3.2 Reserve modelling

The reliability standard, set by the National Electricity Rules, specifies that a region's maximum expected unserved energy (USE) should not exceed 0.002% of energy consumption per year.

Due to the lack of granularity in the IM model, it is not possible to get an accurate, probabilistic assessment of the USE level in any given year. Instead, minimum capacity reserve levels for each region are used as a proxy; more detailed assessments of supply adequacy can then be simulated in future modelling stages with more granular models. These minimum capacity reserve levels are generally set equal to the size of the largest generating unit (although may be adjusted over time if the time-sequential modelling indicates that more firm capacity needs to be built in a region to avoid reliability standard breaches). The capacity outlook models (both IM and DLT) ensure that sufficient firm capacity is installed/maintained within each region, or imported from neighbouring regions, to meet these minimum capacity reserve levels.

Key reserve modelling inputs included:

- Minimum capacity reserve levels (in the first instance, set to the size of the largest generating unit in the region).
- Maximum inter-regional reserve sharing (based on notional interconnector transfer capabilities).
- Firm capacities (discounted for wind farms and solar farms to reflect the intermittent nature of these technologies).

Firm contribution factors

AEMO develops wind and solar contribution factors that specify the amount of wind and solar generation that can be relied on during times of maximum demand. Wind generation during peak demand depends on both wind speed and the operational limitations of wind turbines across the region. Wind is intermittent by nature, with periods of low wind (and in some cases very high wind) resulting in low generation output. Solar generation during peak demand depends on levels of cloud cover and time of peak demand.

AEMO computes the wind contribution to peak demand to be the 85th percentile level of expected wind generation across summer or winter peak periods (top 10% of five-minute demand dispatch intervals) over the past five years.

These contribution factors are only used by the capacity outlook model to estimate the renewable generation contribution to meeting the minimum reserve margins.

The contribution of wind and solar to peak demand was most-recently reported as part of the latest Generation Information Page and South Australian Advisory Functions.[10]

Unit maintenance is captured through the use of maximum annual energy constraints.

3.3.3 New entrant candidates

AEMO generally considers a wide range of available generation technologies as new entrant candidates as specified in the respective assumptions book for each modelling exercise

To represent variation due to geographical location, AEMO includes distinct options for each of the planning zones described in Section 3.1.1. In this way, resource variability, particularly for intermittent renewable generators, is captured, and the model reasonably reflects potential geographical diversification within regions.

The financial economic viability of each generation technology (determined by its economic and technical parameters in Chapter 5) dictates the likelihood of the generator being developed in the model.

3.3.4 Linear build decisions

The capacity outlook model can build new generation or transmission developments of specific size or continuous size.

The first method better reflects the discrete and 'blocky' nature of new build and estimates costs with higher confidence (for example, the cost of a 300 MW OCGT is well-known), but results in a 'mixed integer program' which rapidly becomes computationally impractical.

The second method reduces computational overhead by allowing build of incremental capacities but results in non-standard capacities for new thermal generation or transmission augmentations, with costs more difficult to confirm (for example, the input costs assumed for a 300 MW OCGT are less likely to apply for a 94.2 MW OCGT).

To keep computation time manageable, the capacity outlook models employs the second method for all new generation build and retirements as well as transmission augmentations. Where partial outcomes are obtained, the following heuristics and iterations between IM and DLT models were used to resolve these linear decisions into realisable project sizes:

- **Interconnector augmentations –** selected augmentations of at least 50% of the notional interconnector size were manually validated by the DLT model, using 'installed' and 'not installed' variations to identify the decision of least overall cost. Sensitivities on augmentation timing were also undertaken to identify the optimal timing with respect to system costs.
- **Thermal generation investments -** High utilisation thermal generation developments such as coal plant and CCGTs are optimised by the IM and validated by the DLT model. This validation may involve optimising both with and without the investments to determine which choice, when converted to a whole development, is least cost. New generators are considered committed only if at least 50% of the notional generator size was built in the IM. For example, if 1.3 CCGTs were built in IM model, only one CCGT would be modelled in the DLT and subsequently in the time-sequential model.
- **Renewable generation builds -** Planting of new renewable generation is allowed to remain continuous, as the size of a wind/solar farm is less rigid than thermal generators. Renewable generators can typically be scaled to any size by adding more turbines / panels.

3.3.5 Build limits and lead times

In the capacity outlook model, the maximum amount of new generation of any technology type that can be established in any zone is limited in the model ("build limits"). Build limits associated with generation investments reflect minimum development timeframes for each generation technology, and maximum development levels for generation technologies on at least a regional basis, considering resource and transmission access. Construction lead times for each technology type are reflected in the model by specifying the earliest build date.

For renewable generators in REZs, different layers of constraints were designed to capture both resource potential as well as transmission limitations that could constrain the deliverability of energy produced in certain REZs. The limits represent existing transmission access, and these limits can change either due to:

[10] AEMO. South Australia Advisory Functions. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions; AEMO. Generation Information Page. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

- Interconnector developments which can improve transmission access to REZs, or
- Explicit transmission developments that increase, at an appropriate cost, transmission access between the NEM transmission network and the REZ.

The capacity outlook models choose to develop transmission only if it is economical to do so, considering the cost and benefit of transmission. In the context of REZs, estimated investment cost of mitigating intra-regional transmission congestions are converted into annualised charges and applied to the model as penalty prices on 'soft' REZ build limit constraints.

3.3.6 Retirement candidates

The capacity outlook model allows for existing generators to retire if the retirement minimises total system costs or if a predefined technical age limit is met (typically up to 50-60 years), or if a generator has advised AEMO of its intention to decommission generating capacity.

Retirement of under-utilised existing generation assets may avoid the overhead cost of keeping the unit in service but may advance rehabilitation costs for cleaning up the site. The capacity outlook model co-optimises these costs among other components when developing the generation and transmission development schedule.

To manage the size of the mathematical problem, retirement decisions may be optimised linearly in the IM model, thus leading to partial retirements Where partial retirements were obtained a rounding method was applied to determine whether and when a generator is retired. As per interconnector augmentations, any retirement of at least 50% of a unit by the end of the horizon was validated (as a whole unit retirement) by the DLT model.

3.3.7 Minimum capacity factors and operational levels

In the capacity outlook model, unit commitment cannot be modelled accurately due to the relative coarseness of the model. Instead, constraints such as minimum capacity factors and minimum operational levels are applied to baseload units. This avoids coal-fired generators operating with unreasonable duty cycles as they gradually get displaced by lower emission alternatives, but allows some flexibility for the units to adapt by potentially changing to two shift operation.

3.3.8 New transmission projects

The capacity outlook model includes network representations of committed, advanced, and proposed transmission augmentations. Projects differ in terms of lead time, investment costs and transfer capabilities, and are selected based on their ability to reduce total system costs. Some augmentations are dependent on the development (or non-development) of other projects – the models takes these interactions into consideration. The projects, and their related capabilities and assumptions, were developed in consultation with the relevant TNSPs.

Further to inter-regional augmentations the capacity outlook models feature soft constraints to represent intra-regional network limitations affecting REZs development. That is, it allows the increased access to generators connected to REZs so long as a penalty is paid, equivalent to the reasonable cost of augmentations specific to that REZ, as described in section 3.3.5 above.

3.3.9 Generic constraints

Inter-temporal constraints

Inter-temporal energy constraints limit the generation production, reflecting energy limits that mean that operational decisions at one point in time affect the availability of the generator to operate in the future. For example, hydroelectric generators with storage facilities are influenced by seasonal or annual water inflows, and the decisions to use stored water throughout the year. In some instances, energy constraints may be modelled simply, through the use of capacity factor constraints, while in others a generic constraint may be applied. In this case, the capacity outlook model and/or medium-term schedule (see Section 3.4.1) decides on a production schedule throughout the year with 'recycle' constraints to ensure that water storages at the end of a simulation period is the same as the initial level.

Generally, the model uses the same technique of scheduling production throughout the year for all inter-temporal constraints such as energy limitations and emission budget constraints.

Network limitations

The capacity outlook model limits inter-regional flows to the static forward and reverse[11] transfer capability of each interconnector. Operational interconnector limits change in response to a significant number of real-time variables that are impractical to consider in the context of long-term modelling. AEMO instead assesses the resulting generation and transmission development schedule's impact on the intra-regional limits in the time-sequential model.

[11] Each interconnector has a conventional 'forward' direction. For example, on Basslink positive or forward direction flow is from Tasmania to Victoria.

3.3.10 Network losses

Transmission lines are not perfect conductors, and power transfer between locations results in a loss of energy. To account for this, the underlying demand in the models includes an allowance for intra-regional transmission losses explicitly. The capacity outlook model also applies the marginal loss factors (MLFs) of generators as calculated annually by AEMO.[12] For new generator options, a 'shadow' generator is chosen based on the connection point of the generation option.

For inter-regional transmission flows, the models calculate losses as a quadratic function based on the demand in both connected regions and the flow on the interconnector itself.

Further discussion on the treatment of network losses is provided in Chapter 3.4.5.

3.4 Time-sequential model

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

The time-sequential model considers the modelled time horizon at a much higher resolution compared to the capacity outlook model. The time-sequential model optimises electricity dispatch for every hour in the modelled horizon, and includes Monte Carlo simulation[13] of generation outages, allowing the development of metrics of performance of generation (by location, technology, fuel type, or other aggregation) and transmission (flow, binding constraint equations).

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

- Possible breaches of the reliability standard.
- Feasibility of the generation and transmission outlook when operating conditions and network limitations are modelled.
- Number of synchronous generation online.
- Generation mix and fuel offtake.
- Network augmentation benefits.
- Impact of inter-regional demand diversity.
- Diversity between intermittent supply and demand.
- Unplanned generation outages.

Modification of the capacity outlook model, or further investigation using power flow studies, may be triggered by these insights.

3.4.1 Simulation phases

The time-sequential model is composed of three interdependent phases run in sequence. Designed to better model medium-term to short-term market and power system operation, these phases are:

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

3.4.2 Supply bidding models

While the investment and production costs are the primary drivers of the capacity outlook model, generator bidding behaviour drives the time-sequential model hourly dispatch results.

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[12] 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.

[13] The Monte Carlo approach simulates the model iteratively, taking into account random events to ensure that the result is statistically robust. See Section 7.1.

Bidding behaviours are typically difficult to determine as they depend on each company's risk profile, contract position, and future ownership of new entrants.

AEMO may use either of the following generator bidding models, depending on the purpose of the modelling:

- Short Run Marginal Cost (SRMC) model – the simplest bidding model, which represents perfect competition. This model assumes that all available generation capacities are bid in at each unit's SRMC. Consequently, this model is fast to solve and renders insights excluding competition benefits.
- Nash-Cournot model – used to study the modelled generators' production by dynamically changing generators bids such that their profit is maximised, given assumptions regarding costs and contract positions. The modelled generator may sacrifice cleared generation volumes in exchange for price increases and higher revenue if in so doing they increase the resulting price received.

3.4.3 Unit commitment

Unit commitment optimisation determines which generating units to switch on, and for how long. Apart from the dispatch cost, this optimisation also includes the generator units' assumed start-up cost, minimum uptime and minimum stable level. There may be periods when it is optimal to keep generators on at low generation levels, even when making a loss, to avoid the cost of restarting later.

This methodology solves the whole outlook period (24 hours) simultaneously and includes an additional day of look ahead at less granular resolution to inform unit commitment decisions towards the end of the 24 hours. Otherwise, units may choose to shut down towards midnight without considering the cost of restarting the next day.

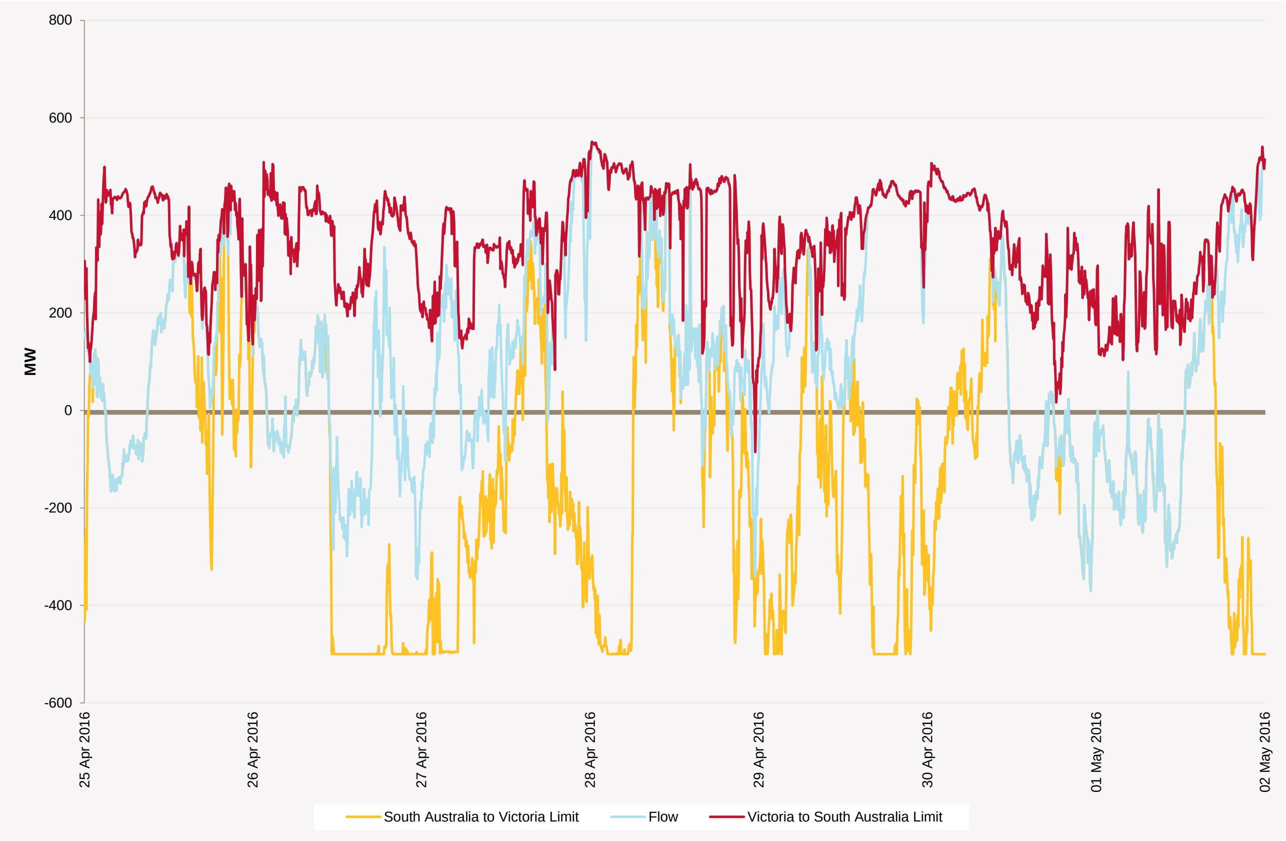
A combination of Nash-Cournot bidding model and unit commitment is used by AEMO to forecast the level of inertia and gas-powered generation (GPG) fuel offtake.

3.4.4 Transmission limits

Inter-regional constraint equations

Interconnector flow limits change in response to network conditions. Figure 10 shows 5-minute limits and flow on the Victoria–South Australia (Heywood) interconnector for one week in April 2016.

Figure 10 Interconnector limits in actual operation, Heywood Interconnector



AEMO implements these variations in interconnector flow limits in the time-sequential model by modelling dynamic power system constraints where inter-regional network limits change as a function of the state of the system, that is, individual generation level, transfer level, online inertia, and demand.

Intra-regional constraint equations

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 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,[14] system normal equations reflecting operating conditions where all elements of the power system are assumed 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) constraints – for managing the rate of change of frequency following a credible contingency.

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.[15]

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 latest set of constraint equations used in market modelling activities is in the ISP database.[16]

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.

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[14] NEMDE contains equation sets for dispatch, pre-dispatch, ST PASA, and 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.

[15] 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.

[16] AEMO. ISP Database. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database

Shadow generators

Since the exact location and connection point of all possible new entrant generators cannot be determined in advance, AEMO assumes they 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 marginal loss factor).

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 as this is not as straightforward as the thermal constraints adjustment.

3.4.5 Inter-regional loss model

In the time-sequential model, losses on notional interconnectors are modelled using the marginal loss factor equations defined in the *List of Regional Boundaries and Marginal Loss Factors* report.[17] 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 marginal loss factors, 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.

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

3.5 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.

Assessment of reserves requires the gas supply model to consider the difference between production and pipeline solutions to supply any shortfall. An augmentation of production near supply shortfall may draw on a different reserve to a pipeline augmentation solution, leading to different reserve depletion projections.

For example, a supply shortfall in Melbourne may be addressed by increasing production from the Gippsland Basin, increasing production from the Otway Basin, or increasing pipeline capacity between the Moomba–Sydney Pipeline and Melbourne, which will ultimately source gas from north-eastern South Australia or Queensland.

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

3.6 Network development outlook model

The network development outlook model contains a highly detailed representation of the physical transmission network underlying the NEM, including individual generating units, transmission lines, transformers, switching elements, reactive power management elements, and loads represented at transmission connection points. All major transmission elements and limitations in the NEM are represented.

In most cases, major transmission elements are those that operate at 66 kilovolts (kV) and above, however there are some radial elements operating that are not represented, and there are some elements operating at lower voltages that are represented because they perform transmission functions.

[17] 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

The model is used to assess intra-regional transmission system adequacy under a range of conditions.[18] Different types of planning studies require a different level of detail in the network representation as well as the adequacy assessment. For example, long-term planning studies such as the ISP are more exploratory in nature and require a higher level network representation than a study into the local needs of a specific area.

The assessment is performed by undertaking load flow analysis, which calculates the instantaneous flow of power between locations where energy is generated and where it is used. This modelling validates the generation and transmission outlook from the capacity outlook model and the dispatch outcomes of the time-sequential model by confirming that the power system continues to operate in a secure and reliable manner as demand changes and the generation mix changes.

Reliability is assessed by monitoring the loading on the transmission network when the power system is operating with all equipment in-service (system normal) and also under a potential unplanned outage of a transmission network element or generating unit. The assessment considers the capability of the transmission system for transfer of energy, and identifies network limitations[19] that may be constraining power flow.

3.6.1 Ratings

Ratings on modelled transmission elements change according to the instant of time considered in each model solution. In summer, transmission element capability ratings are generally lower because higher ambient temperatures make it more difficult for those elements to dissipate heat.

AEMO uses continuous ratings for pre-contingency load flow analysis.

Transmission elements may be operated above their continuous ratings for short periods of time. These short-term ratings are used for contingency load flow analysis, as contingencies are expected to be cleared relatively quickly by power system operators.

3.6.2 Response to network limitation

The primary result of the load flow analysis is a list of the transmission system elements that may be overloaded during times of high demand under the projected conditions of demand and generation and transmission expansion. To inform this assessment, hourly generation and interconnector flows for snapshots in time are obtained from the time-sequential model.

When the power system model identifies thermal overload on monitored power system elements, AEMO modelling addresses the overload using a series of techniques that attempt to minimise costs:

- Re-dispatch generation – more expensive generation closer to the load is dispatched in preference to the generation that was dispatched by the time-sequential model.
- If simple re-dispatch cannot address the overload, relocate new generation to an alternative connection point in the same planning zone.
- If relocation of generation in the same zone cannot address the overload, relocate new generation to an adjacent zone.
- If relocation and re-dispatch of generation cannot address the overload, choose an appropriate intra-regional transmission system augmentation to address the overload directly. This may be an option presented by jurisdictional planning bodies in their annual planning reports or an option developed by AEMO.
- If intra-regional transmission augmentation is required and the cost of identified augmentations is considered material to the generation and transmission outlook, the augmentation cost is added to the costs of new generation considered by the capacity outlook model, in the zone where the augmentation is required. The capacity outlook model is re-solved, which may result in the relocation of generation, different transmission system augmentations being chosen, a combination of both, or no change to the expansion plan. Alternatively, additional peaking generation capacity may be added to the region to support load if the network overload results in USE. The expansion plan is considered stable when no further locations of transmission overload are identified.

[18] The capacity outlook model contains options to augment inter-regional transfer capabilities but its regional representation prevents consideration of intra-regional limitations.

[19] Thermal limitations arise due to the resistance of transmission lines to the flow of electrical current. When energy flows, transmission lines heat up and begin to sag. Transmission lines may be damaged if allowed to become too hot for too long and if allowed to sag, they could breach minimum safety clearances. Thermal limitations constrain the flow of current to prevent unsafe operation or potentially damaging heating of the conductors.

4. Demand Assumptions

4.1 Demand forecasts

Change in demand for electricity and gas is one of the drivers of the evolution of energy production and transmission systems. Demand can change in two ways:

- The amount of energy that is consumed over the course of time.
- The amount of power that is consumed instantaneously.

For electricity, these are referred to as *consumption* and *maximum demand* (MD) respectively, and are measured in megawatt hours (MWh, energy) or megawatts (MW, power).

For gas, where instantaneous demand has a lesser impact on supply, the concept of instantaneous power is less relevant and gas demand is often expressed in terms of a specific timeframe: maximum hourly quantity (MHQ), maximum daily quantity (MDQ) or annual quantity. All are measured in gigajoules (GJ), terajoules (TJ) or petajoules (PJ) depending on the length of time under consideration.

AEMO uses scenarios to develop regional electricity and gas demand projections to suit long-term planning timeframes. The electricity forecasts present 10% and 50% POE MD and consumption projections for each NEM region up to 20 years into the future. These projections are extended to a longer range for use in all long-term market modelling activities. The 50% POE projections reflect an expectation of typical MD conditions. The 10% POE projections reflect an expectation of more extreme MD conditions driven by variations in weather conditions. Projected consumption is the same in each case.

The electricity forecasts may be represented as operational or underlying, 'sent out' or 'as generated'; typically they are represented as operational demand 'sent out':

- Operational demand refers to the electricity used by residential, commercial, and large industrial consumers, as supplied by scheduled and significant non-scheduled generating units. It does not include demand met by rooftop PV (that is, operational demand decreases as rooftop PV generation increases).
- 'Sent out' refers to operational consumption or demand that excludes generator auxiliary load.

4.2 Demand traces

The operational consumption and MD forecasts need to be converted into hourly demand traces for each region for use in the capacity outlook model and the time-sequential model. Demand trace development relies on historical reference years to provide guidance on the typical daily and weekly demand shapes, variations from hour to hour, and correlations with other regions.

The process used to develop the traces is:

- Representative traces are obtained using historical data. Estimated production by rooftop PV generators over the same period is added to the demand traces to obtain historical traces representing total underlying demand. Contributions from large-scale non-scheduled wind generation are also added to the reference year trace.
- The derived underlying historical traces are "grown" to represent future consumption and MD while preserving diurnal, weekday, weekend and seasonal patterns as much as possible.
- Further adjustments are applied to the resultant traces to reflect the impact of increasing uptake of battery storage and electric vehicles. Projections of demand from large industrial loads, such as the Queensland LNG export industry, are modelled to maintain expected consumption from these consumers, rather than influenced by broader regional drivers.

4.2.1 Multiple reference years

Demand and intermittent generation traces are developed based on up to eight historical reference years to capture year on year variations in demand correlations across regions and intermittent generation contributions during high demand periods. The choice of reference years, the number of those modelled, and the magnitude of peak demands (as described in the following section) may change depending on the purpose of the individual model. In general, short term models typically use maximum reference years to model risks associated with peak demand conditions with maximum rigour. Long term models typically use few (minimum of one) reference years given the greater problem sizes that capacity expansion modelling model.

4.2.2 Weather sensitive demand

While 10% and 50% POE load traces assume a different maximum demand, the energy consumption remains constant. Therefore, the 10% POE trace notionally reflects a heat wave over say a period of one week, but with weather conditions similar to the 50% POE trace for the rest of the year.

The trace development process includes:

- Produce annual energy consumption and minimum demand targets, and seasonal maximum demand targets
- Using historical observed regional demand, remove the influence of DER (predominantly rooftop PV systems)
- 'Stretch' the resultant 'underlying' demand trace to meet future energy and demand targets simultaneously. This requires a pull-and-push approach if peak demand, minimum demand and energy consumption growth rates are inconsistent (which is typical).
  - Isolating periods of near maximum demand observed in the historical reference data, stretch a limited number of days to meet maximum demand POE targets across both summer and winter seasons
  - Excluding those maximum demand days, stretch the remaining days to meet annual energy targets
  - For the lowest demand days, stretch to meet minimum demand POE targets
- Ensure that historical days line up with future days, such as weekends and weekdays and public holidays, so that normal consumer behaviours are maintained in future years as was observed in the reference year.

Using this process ensures the consumption forecast, on an hourly basis, evolves as intended to meet the underlying targets, potentially resulting in an increasingly 'peaky' demand trace if maximum and minimum demand is growing (in potentially opposite directions) faster than annual energy consumption.

The traces can be operational or underlying (with explicit development of rooftop PV traces, or other DER elements), depending on the purpose of the modelling performed. If targeting operational targets, the process may be performed a second time to ensure that the stretching process achieves the operational (rather than underlying) targets.

4.2.3 Small-scale generation

Demand projections are developed based on the demand that appears on the transmission system. Non-significant non-scheduled generators that are connected to a distribution network appear to the transmission system as a reduction in demand from that distribution network. The capacity outlook model and the time-sequential model include representations of scheduled, semi-scheduled, and significant non-scheduled generators so the intermittent nature of the significant non-scheduled generation is represented. Non-significant non-scheduled generators, which are not represented in the market models, are incorporated into the energy and MD projections.

The latest electricity forecast tables the non-scheduled generators that are incorporated into energy and MD projections (those that are used in annual energy forecasts and are *not* part of operational demand).

4.2.4 Rooftop solar photovoltaic uptake

In the time sequential models, rooftop PV generation is modelled explicitly to capture its intermittent impact on the NEM. Rooftop PV's contribution to demand therefore needs to be added to the operational forecasts to get a representation of underlying MD and consumption.

Rooftop PV modifies the shape of the demand curve. As rooftop PV installations increase, the operational MD is pushed to later in the day and minimum demand is projected to occur during the middle of the day. The rate of rooftop PV uptake is also projected to differ from the rate of change in underlying demand.

To accommodate the impact of rooftop PV uptake on the demand profile, AEMO adjusts the historical reference demand curves to remove the effect of rooftop PV prior to growing future demand traces (as discussed above). The resultant underlying demand traces are used in the market models, with rooftop PV modelled as one generator per region, following a projected hourly profile. Rooftop PV generation profiles are developed independently, taking into account changes in uptake forecast in the broader electricity forecasts, and output based on historical cloud cover.

4.2.5 Electricity demand for industrial block loads

When developing forecast load traces, step changes in load developments need to be accounted for separately from the organic growth or contraction of underlying demand. New industrial load developments, such as that associated with LNG production in Queensland, is removed from the reference year hourly trace before the underlying demand is grown to meet forecast energy consumption, maximum and minimum demands. The block load is then added back on at the end of the demand trace development process. This also applies for major load closures.

By isolating the regional demand net of step changes in large block loads, the appropriate shape of the underlying consumer load is maintained.

4.2.6 Electric vehicles and small scale battery storage

Electric vehicles are expected to become a new source of electricity demand within the typical timeframes of AEMO's long-term planning.

Electric vehicle demand is incorporated into the models by developing a daily charging profile consistent with charging behaviour assumptions, growing the profile to accommodate growth in demand due to increased uptake, and adding the resulting profiles to the projected regional demand profiles in each scenario.

Currently, reference year demand profiles are assumed not to contain time of day distortions due to electric vehicle load or battery charging and discharging. In this case, reference year historical demand profiles are not adjusted prior to application of projected future electric vehicle charging load profiles.

Uptake of electric vehicles and small scale storage systems may vary by scenario depending on the nature of the study.

4.2.7 Demand side participation

Demand-side participation (DSP) is an agreed, additional change in demand beyond price elasticity that can occur when the power system becomes stressed. It is often provided by industrial customers that have interruptible loads.

DSP is assumed 100% reliable and is available in several price bands.

Submissions to AEMO's DSP data portal[20] assists in developing these DSP projections.

4.3 Gas demand forecasts

Gas demand forecasts are produced for four customer categories:

- Mass market (residential and commercial) customers.
- Large industrial facilities.
- GPG.
- LNG export facilities.

Detailed forecasts are developed by AEMO each year and published in the GSOO. Detailed descriptions of daily gas demand development are presented in the GSOO methodology document.[21]

[20] AEMO. *Demand Side Participation Information Guidelines*. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Demand-Side-Participation-Information-Guidelines

[21] AEMO. *Gas Statement of Opportunities*. Available at http://www.aemo.com.au/-/media/Files/PDF/2016_GSOO_Methdology.pdf.

5. Supply Assumptions

5.1 Electricity production

5.1.1 Electricity parameters

All market simulation results are influenced by the generator's technical parameters used in the models. Table 4 provides a summary of the key parameters and describes how they are incorporated within the market models. Generator properties such as capacities, efficiency, marginal loss factors, minimum generation levels, and forced outage rates simultaneously drive the modelling results, details of these parameters are presented in the ISP assumptions book[22].

Table 4 Summary of generator technical parameters

Parameters	Description	Relevance	Modelling methodology
Rated capacities	Seasonal capacities reflect thermal generators weather dependence	Summer regional capacities tend to be lower than winter	Seasonal ratings of capacities
Minimum generation level	Technical minimum stable loading	Forces units to generate at a certain level	Constant minimum generation level
Firm capacities	Reliable capacity able to generate during peak demand	Contributes to the available capacity to serve maximum demand and minimum capacity reserve level	Seasonal ratings for scheduled generator Contribution to peak demand for variable generators
Ramp rate	Rate at which generation can increase output	May constrain generation output	Constant rate from minimum generation level to maximum capacity
Minimum uptime and minimum downtime	Technical limitation on the length of time thermal generators must remain online or offline	Impact the unit commitment schedule	Number of hours
Auxiliary load	Station load that supports operation of the power station	Lessens the generation supplied to the operational consumption	As percentage of 'as gen' production
Heat rate	Efficiency of converting the chemical or potential energy to electrical energy	Cost of electricity production	Constant conversion rate
Emission rate	CO2-e production for each MWh of electric energy produce.	Direct carbon abatement policies significantly impacts heavy carbon emitters	Constant emission production rate
Inflow rates	Long-term reservoir inflow average represented as monthly inflow rates	Hydroelectric generators availability depends on dam levels	Annual sequence based on long-term average
Outage rates	Historical maintenance and unplanned failure rates describes the probability of capacity deration of each technology	Further lowers the regional available capacity to serve operational consumption	Maintenance rates and probability of failure and derated capacities
Marginal loss factor	Impact of network losses on spot prices is represented as loss factors.	Incentivise generators that lowers network losses and penalize those the increase it	Factor for each node in the NEM

This information comes from a number of different sources. For all current assumptions please refer to the ISP database on AEMO's website.[23]

[22] AEMO. ISP Assumptions. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

[23] AEMO. ISP Database. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

The generation economic parameters outlined in Table 5 influence the results of both the capacity outlook model and the time-sequential model.

Table 5 Generator economic parameters summary

Parameters	Description	Relevance	Modelling methodology
FO&M cost	Annual fixed cost for keeping plants in service	Increases the cost of keeping the plants in service	Fixed cost per MW of installed capacity
VO&M cost	Additional cost for running the units	Impacts the generators' running costs	Fixed rate per MWh of electricity production
Gas fuel cost	Gas price path for each existing GPG and gas zones	Impacts the gas generators' running costs	Fixed rate per GJ of fuel consumed
Coal fuel cost	Coal price path for each existing coal plants	Impacts the coal generators' running costs	Fixed rate per GJ of fuel consumed
Build cost	Overnight investment cost for each available generation technology	Shift from one technology to another over the outlook period	Overnight cost per MW of capacity
Connection cost	Cost of accessing network	Represents additional cost for network access	Overnight cost per MW of capacity
WACC	Cost of capital	Amortisation of build cost	Percentage
Economic life	Project life	Capital payment period	Number of years
Minimum capacity factors	Represents the minimum technical and economic duty cycles	Applied on the Capacity Outlook Model to represent the minimum economic running regime	Percentage of total available energy for production
Reservoir initial dam level	Latest dam levels	Available water for generation at the start of every year	Dam volume levels are updated every year in GL

This information comes from different sources. The ISP database provides AEMO's current assumptions.[24]

5.1.2 Marginal loss factors

MLFs represent the incremental loss incurred for an incremental unit of power supplied at connection points and determines the marginal impact of losses on spot prices. It incentivises generator development and operation to locations that lowers network losses and penalises those the increase losses.

MLFs are pre-computed figures that are influenced by forecast demand, network configuration, and generation dispatch. This is modelled explicitly as a static factor that does not change over the outlook period.

AEMO performs an annual study to estimate the MLF for each connection point using historical network performance and forecast consumption. Generators are assigned with the MLF for the connection point they are connected to.

For further information, please refer to the latest *Loss Factors and Regional Boundaries* page.[25]

[24] AEMO. ISP Database. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

[25] 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.

5.2 Renewable resources

5.2.1 Variable generation

Generally, the following variable generation types are modelled, for planning purposes:

- All scheduled and semi-scheduled generation.
- Some significant non-scheduled generation with capacities greater than or equal to 30 MW.
- Those that are believed to impact simulated network capability.

As variable generation's output depends on their fuel source availability, wind farm generation is limited by the wind speed, and solar farms are limited by solar irradiance.

AEMO considered a range of requirements for the selection of preferred REZs. This section presents the methodology applied to determine resource quality, potential wind and solar generation capacity, transmission investment to develop REZs, projected network losses and diversity of renewable generation within the region and across REZs.

5.2.2 Resource quality

AEMO engaged consultants DNV-GL to provide information on the resource quality for potential REZs. Wind resource quality assessment was based on mesoscale wind flow modelling at a height of 150 m above ground level (typical wind turbine height), while Global Horizontal Irradiance (GHI) and Direct Normal Irradiance (DNI) data from the Bureau of Meteorology (BOM) were used to assess solar resource quality.

AEMO identified wind speeds and solar GHI values inside each of the REZs. This data was used to determine grading of resource quality. For wind generators, the 10% Probability of Exceedance (POE) resource was taken to determine the relative REZ quality, since 50% POE (median) values did not produce enough differentiation between all the different regions. For solar 50% POE values of GHI was taken to determine the grade. The 50% POE GHI values produced sufficient variation between all the REZs to give a meaningful relative grade for solar generation. Table 6 presents grading applied to differentiate REZs based on quality of resources.

Table 6 Grading for quality of resource

Grading	Wind speed (m/s), 10% POE within REZ	Solar GHI (kw/m^2) annual average, 50%POE within REZ
A	≥ 8.4	≥ 2000
B	≥ 7.2	≥ 1900
C	≥ 6.6	≥ 1800
D	≥ 6.0	≥ 1700
E	< 6.0	< 1700

5.2.3 Network capacity and transmission investment

High level network studies were undertaken to identify additional generation which can be accommodated within the existing network. In addition, interconnector expansion options were assessed to identify additional generation that may be enabled by interconnectors developed near or through REZs. The following steps were undertaken:

- Amount of additional generation which can be added within the existing transmission network capability.
- Amount of additional generation which can be added with inter-regional network upgrade options.
- Network expansion to connect REZs to the major transmission network and amount of generation which can be accommodated.
  - Cost estimate of transmission network expansion to connect REZs
  - Conversion of the cost estimate to a cost per MW for each REZs

The cost per MW for each REZ is then applied within the capacity outlook modelling, within the IM and DLT models, as a simple linear cost for development of REZs beyond existing transmission connection capabilities. In this way, each REZ may provide 'free' connection capacity up to existing assumed transmission capabilities. The market model can then expand intra-regional connections to improve transmission access to REZs if the cost of that access is outweighed by the benefits associated with the increased renewable generation that it enables.

5.2.4 Projected network losses

Projected network losses were determined based on the methodology described in AEMO's "Forward-Looking Transmission Loss Factors".[26] In particular,

- a complete year of 2017 historical data has been used as a reference;
- generators representing the REZ were added at connection points
- future wind and solar generation and load traces, which were developed PLEXOS market simulations, were applied;
- marginal loss factors (MLF) were calculated for those connection points representing the REZ.

A grading method was used to categorise the average value of current MLF at connection points inside REZ (initial loss factor) and sensitivity of MLF to additional generation inside REZ (Loss factor robustness). The measure used is the additional generation (MW) that can be added before the MLF drops by 0.05. Table 7 presents grading applied to differentiate REZs based on loss factors.

Table 7 Grading for loss factors

Grading	Initial loss factor	Loss factor robustness
A	≥ 1.00	≥ 1000
B	≥ 0.95	≥ 750
C	≥ 0.90	≥ 500
D	≥ 0.85	≥ 250
E	≥ 0.80	< 250
F	< 0.80	None

5.2.5 Diversity of renewable generation and demand

Diversity describes whether the REZ resources are available at the same time as each of the other REZs or at different times, using a statistical correlation factor. A low correlation gives a better score. Correlation was determined between the generators in one REZ to generators in each one of the other REZs using a statistical correlation factor to assist in the grading exercise.

Correlation between renewable resource of a REZ and regional demand was also determined. For demand, a positive correlation meaning generation in REZ is more likely to match the demand within the jurisdictional boundary.

One-year REZ generator trace and three different years (FY2018, FY2030 and FY2040) of regional demand traces were applied to determine correlation. Table 8 presents grading applied to differentiate REZs based on resource diversity.

Table 8 Grading for resource diversity

Grading	Resource Diversity	Demand matching
A	≤ 0.1	≥ 0.30
B	≤ 0.2	≥ 0.15
C	≤ 0.3	≥ 0.0
D	≤ 0.4	≥ -0.15
E	≤ 0.5	≥ -0.30
F	> 0.5	< -0.30

5.3 Hydroelectric generation schemes

The NEM contains scheduled hydroelectric generators in Tasmania, Victoria, New South Wales, and Queensland. These schemes are typically modelled in the time-sequential model with their associated reservoirs and water inflows. For each reservoir, the capacity, initial levels, and the expected inflows from rainfall all determine the availability of energy for hydroelectric generation.

Hydro schemes are generally grouped into three modelling methods:

- Generator constrained – for the Victorian hydroelectric generation scheme (excluding Murray).

[26] AEMO. http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Loss_Factors_and_Regional_Boundaries/2017/Forward-Looking-Loss-Factor-Methodology-v70.pdf. Viewed 1 June 2018.

- Storage managed – for the Tasmanian hydroelectric generation scheme.
- River chain – for all other hydroelectric generation scheme.

In the market simulations, AEMO applies a return to average conditions approach. Reservoir levels are restored to initial levels by the end of each simulated year. Reservoir levels are initialised with levels as at 1 July of the current year, while inflow data reflects long-term average conditions from the start of the simulation period.

For the capacity outlook models, some aggregations of some hydro schemes may be used if it is deemed not material to the overall objective of the modelling, and if it simplifies the problem size sufficiently to warrant the simplification.

5.3.1 Generation constrained

Victorian hydroelectric generators' production is modelled by placing a maximum annual capacity factor constraint of between 13% and 15% on each individual generator. The model schedules the electricity production from these generator across the year such that the system cost is minimised within this energy constraint.

5.3.2 Storage management

Tasmanian hydroelectric generation is modelled by means of individual hydroelectric generating systems linked to one of three common storages:

- Long-term storage.
- Medium-term storage.
- Run of river.

Table 9 identifies how individual generators are allocated across these storages, and provides an indication of the storage energy available to the units.

Energy inflow data for each Tasmanian hydro water storage is determined from historical monthly yield information provided by Hydro Tasmania. In both the capacity outlook model and time-sequential model, AEMO uses a scaled version of average monthly yield, extracted from records spanning 81 years, to deliver an annual inflow of 8,700 gigawatt hours (GWh).

Table 9 Storage energy (in GWh) of the three types of generation in Tasmania

Storage Type	Storage energy	Stations
Long-term	11,200	Gordon, Poatina.
Medium-term	3,200	Lake Echo, Tarraleah, Tungatinah, Liapootah, Wayatinah, Catagunya, Fisher, Lemonthyme, Mackintosh, Bastyan, John Butters.
Run of River	140	Meadowbank, Trevallyn, Wilmot, Cethana, Devils Gate, Reece, Tribute.

5.3.3 River chain

Other hydroelectric generation is represented by a physical hydrological model, describing parameters such as:

- Maximum volume.
- Initial storage volume.
- Monthly reservoir inflow rates reflecting average historical inflows.

Latest information on the monthly storage inflows used in market modelling studies can be found in the ISP database.[27]

Figure 11 to Figure 20 provide graphic representations of the hydrological models used in the market simulations, as well as the registered capacity of the adjoining generating units.[28]

[27] AEMO. ISP Database. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

[28] Storage capacities are defined in megalitres (ML)

Figure 11 Barron Gorge power station hydro model

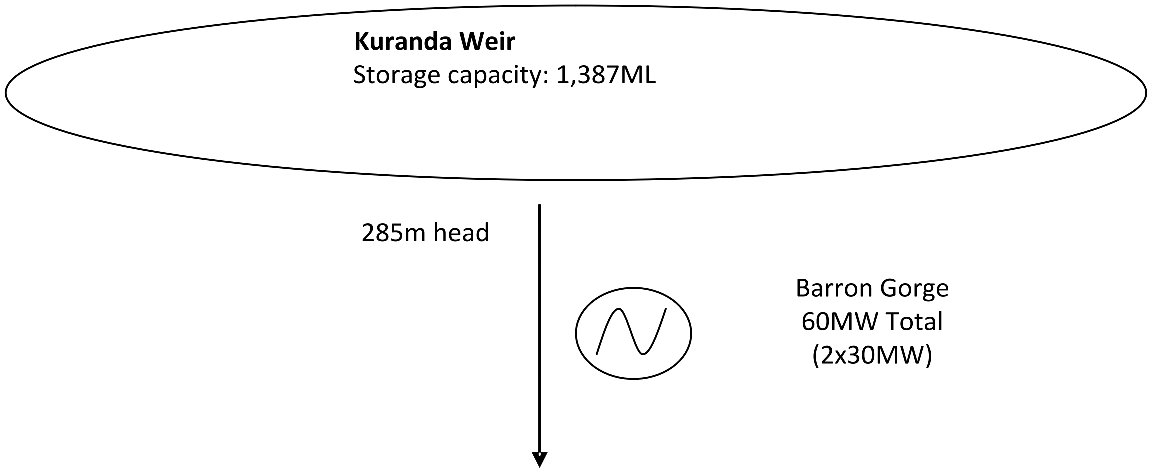


Figure 12 Blowering power station hydro model

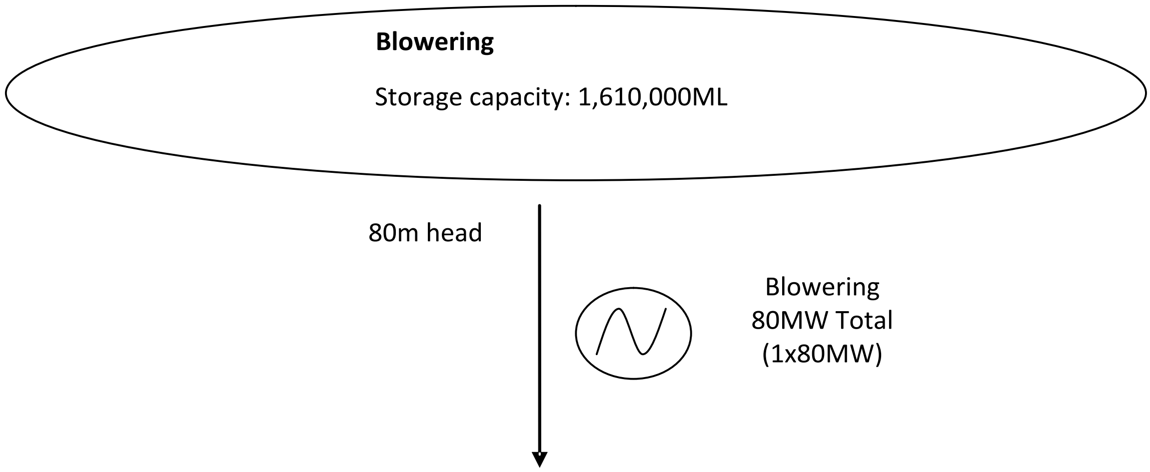


Figure 13 Hume power station hydro model

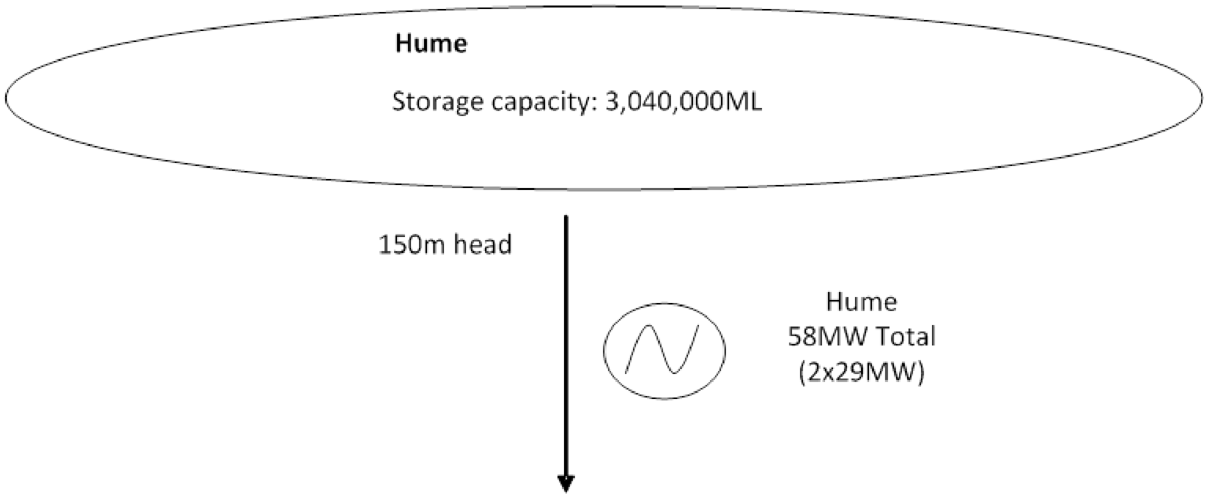


Figure 14 Kareeya power station hydro model

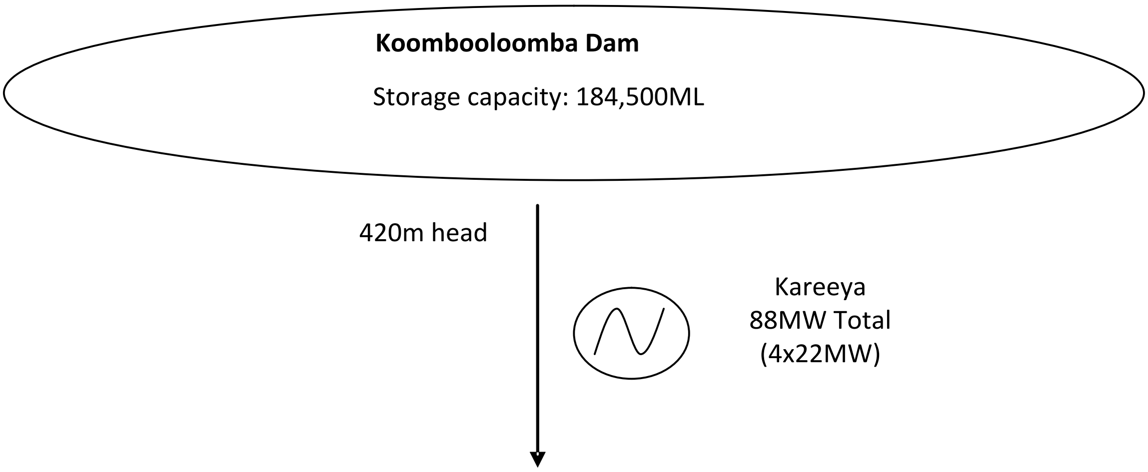


Figure 15 Guthega power station hydro model

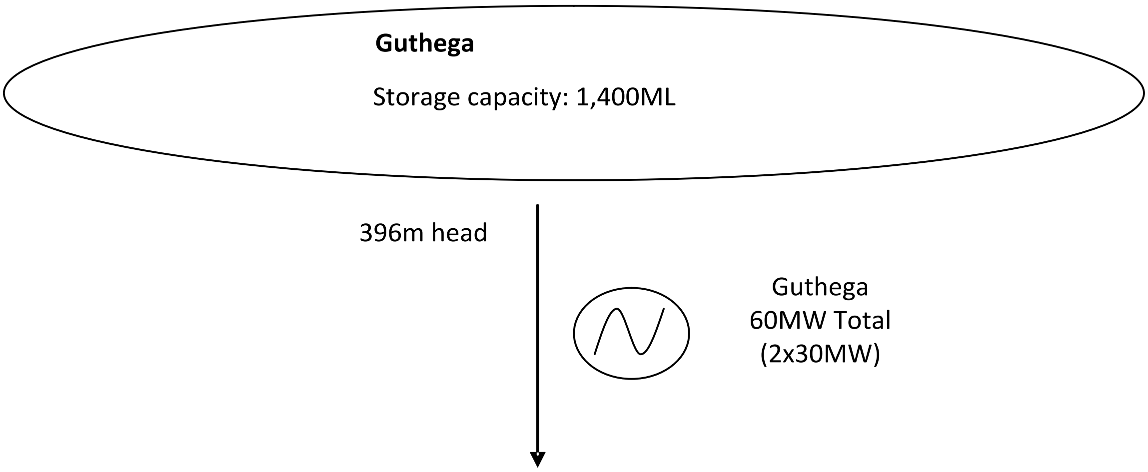


Figure 16 Shoalhaven power station hydro model

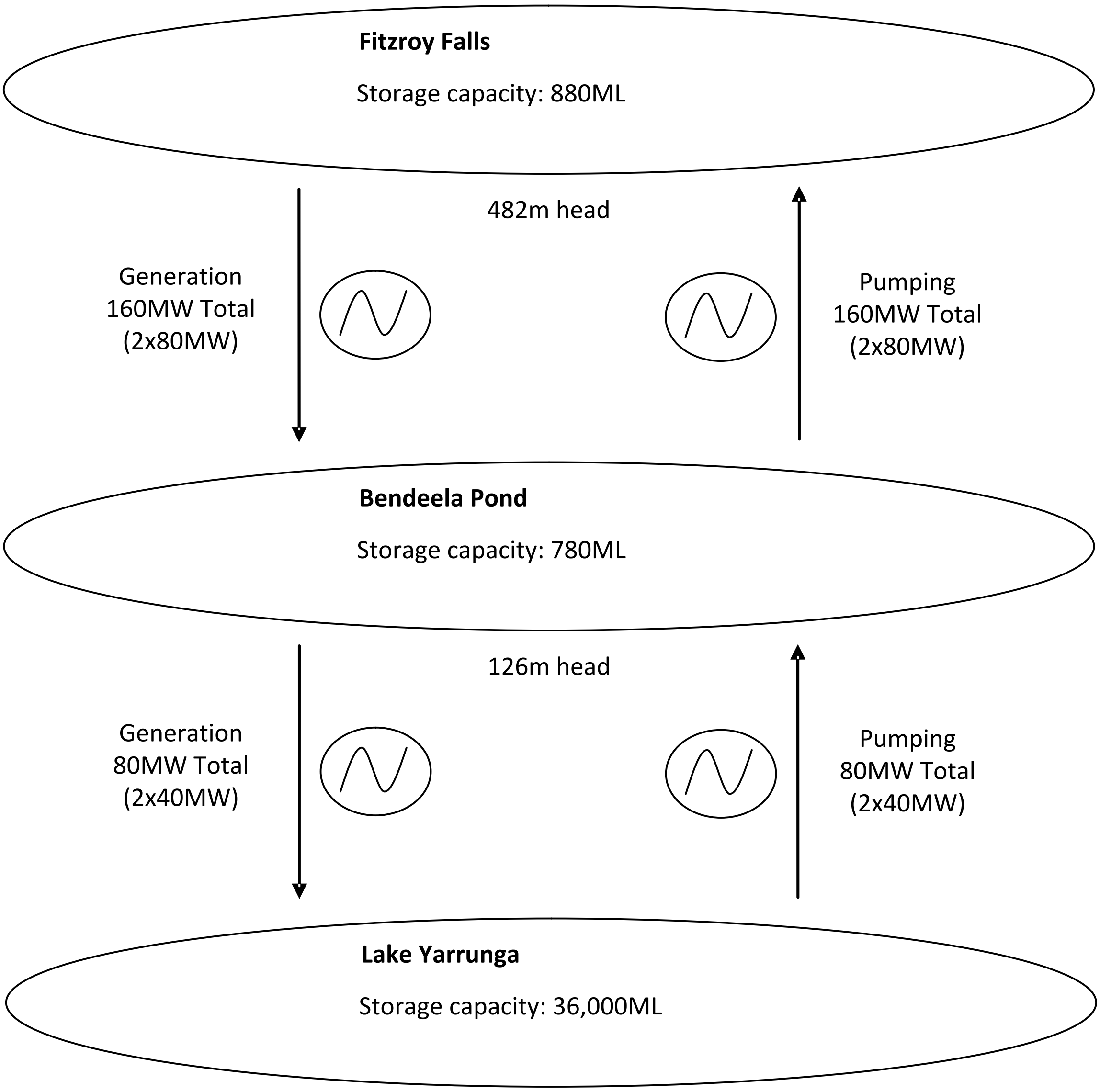


Figure 17 Upper Tumut, Lower Tumut, and Murray power station hydro models

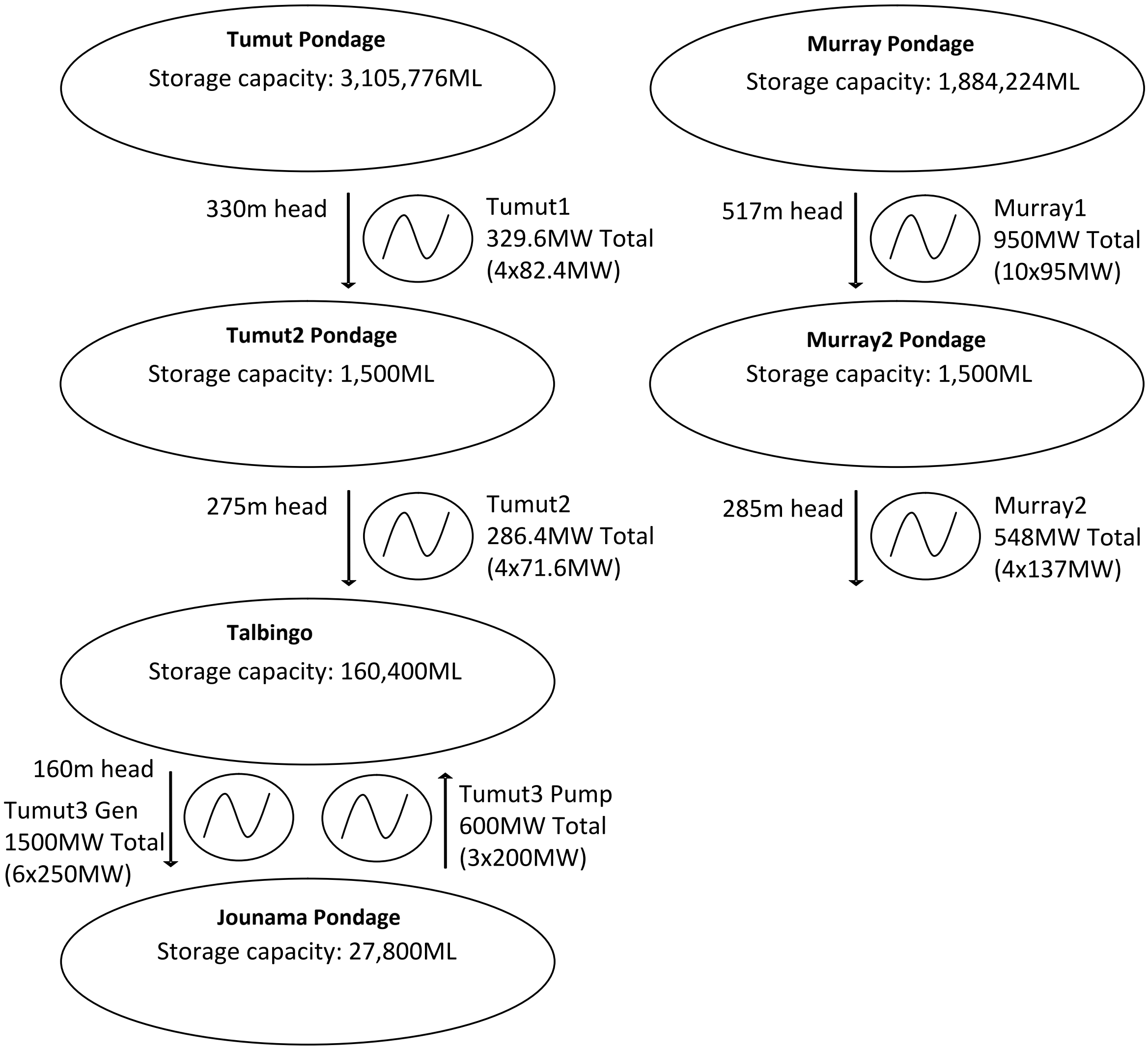


Figure 18 Wivenhoe power station hydro model

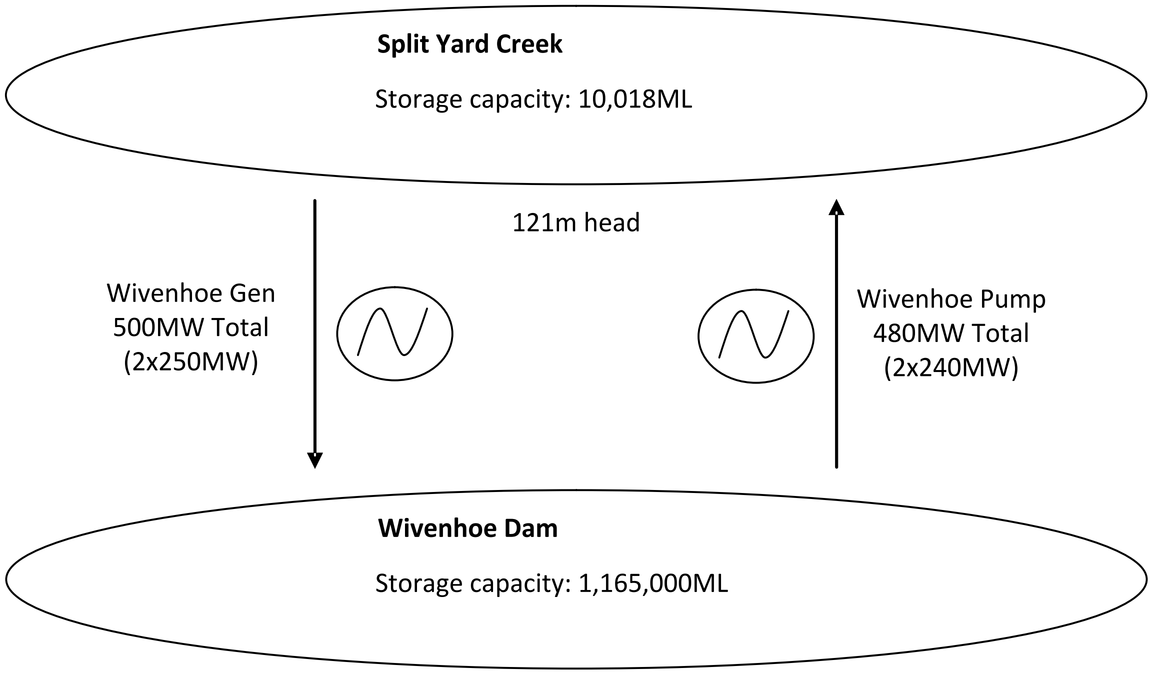


Figure 19 Eildon power station hydro model

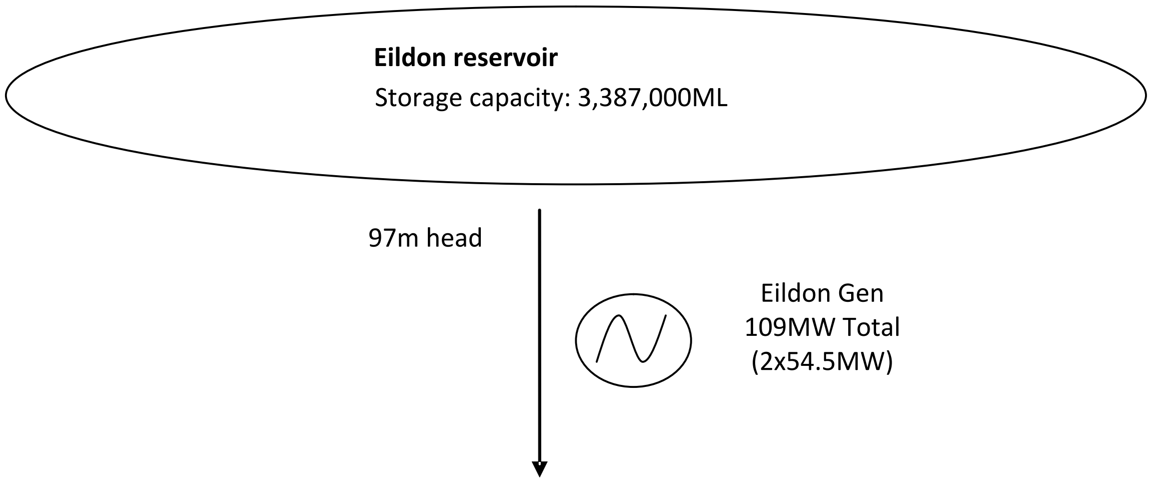
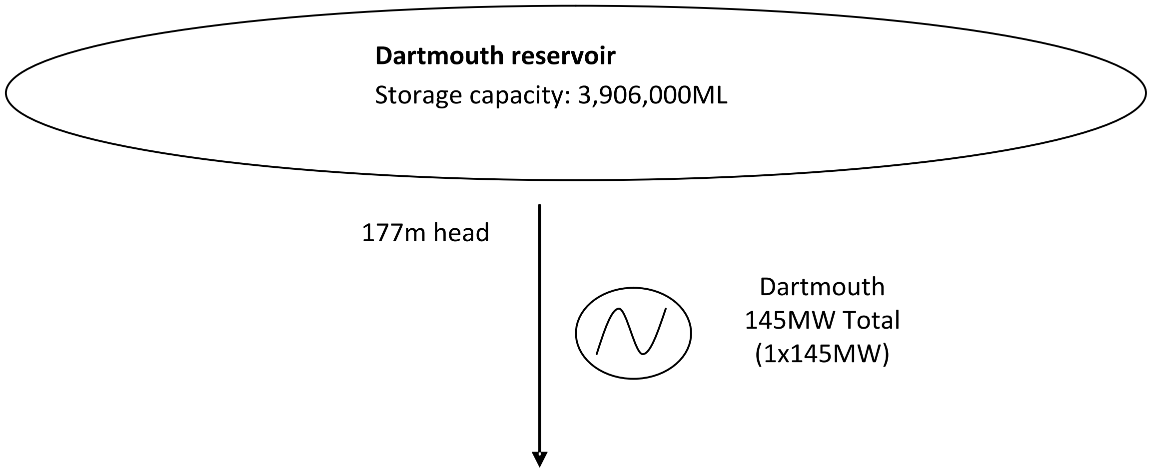


Figure 20 Dartmouth power station hydro model



5.4 Large-scale storage

Large-scale storage operation is expected to generate opportunistically based on price and the efficiency loss associated with charging and discharging the storage. For example, in a future energy mix with high renewable penetration, variable renewable energy may be smoothed by effectively charging storages when high renewable energy volumes are available, for later discharge when renewable energy is low.

Opportunistic generation depends on operators developing a forward view of price to inform the decision to divert energy to storage. The second phase of the time-sequential model (medium-term schedule) completes an energy management study across a year to schedule energy consumption and generation from storages. This is further refined by the third phase of the time-sequential simulation, where operational limitations are included.

The storage capacity and the rated power are defined for each modelled storage. The latest assumptions can be found on the most recent ISP database.[29]

5.5 Gas production

The gas supply model contains a representation of approximately 40 gas production facilities that inject gas into the eastern and south-eastern Australian gas transmission network. The representation is limited to the connection point and maximum supply capacity of each facility, and the annual field production limits.

The gas supply-demand outlook model does not contain information about forced outages, production ramp rates or maintenance schedules.

The gas supply model uses a representation of the cost of gas production at each facility to optimise network flows.

5.6 New energy facilities

Each model defines a set of new generation or gas production projects that may be included in the capacity outlook model, time-sequential model, or gas supply model simulations.

In the capacity outlook model, new generators are partitioned by fuel type, technology, and location within the electricity planning zone. Each technology will take on specific values for parameters of importance such as thermal efficiency, emission characteristics, minimum stable generation levels, standard capacities, build costs, and appropriate earliest dates for which the technology is considered current.[30] Each location imposes different fuel costs that reflect the fuel availability and transport requirements applicable to each zone.

The time-sequential model uses the generation and transmission outlook developed by the capacity outlook model.

The gas supply model includes committed production and transmission projects and a selection of proposals that are assessed for their efficacy in eliminating supply shortfall.

[29] AEMO. ISP Database. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

[30] Technologies that are not yet in commercial development are assigned an earliest build date.

5.6.1 Committed, advanced, proposed and conceptual

New production and transmission projects fall into one of five classes of certainty:

- **Committed** – projects that will proceed, with known timing, satisfying all five of the commitment criteria. That is, all categories are green. There are no equivalent commitment criteria for gas projects; however the principals of commitment outlined in Table 11 are applied for the purposes of gas modelling.
- **Advanced** – projects that are highly likely to proceed, satisfying Site, Finance and Date criteria plus either Planning or Components criteria. Typically included in sensitivity analysis for MLF, and included in base case for reliability assessments.
- **Maturing** – projects that have progressed with site, planning applications, and finance arrangements, but not to the point that they can be classified as advanced. Maturing projects may be explicitly included in scenario analysis to assess future reliability or market impacts and are tested for economic efficiency in capacity outlook modelling.
- **Emerging** – projects with financing arrangements, but site/planning approvals/construction is uncertain, and development is strongly subject to changes in policy or commercial environment. These projects may be explicitly included in scenario analysis to assess future market impacts, and are tested for economic efficiency in capacity outlook modelling. However, a higher weighted average cost of capital will be assumed to reflect greater development uncertainty compared to proposed projects.
- **Publicly announced** – these projects have been announced publicly, but do not yet have any finance arrangements in place. Costs and capabilities of these projects are developed using recently-completed projects and projections of cost components such as raw material supply and labour.

Additionally, the following minimum criteria must be satisfied for each classification:

Table 10 Minimum commitment criteria

Category	Committed	Advanced		Maturing	Emerging	Publicly Announced
Site	🟢	🟢	🟢	🟢	🔴	🔴
Components	🟢	🟡	🟢	🔴	🔴	🔴
Planning	🟢	🟢	🟡	🟡	🔴	🔴
Finance	🟢	🟢	🟢	🟡	🟡	🔴
Date	🟢	🟢	🟢	🔴	🔴	🔴

Table 11 Commitment criteria descriptions

Category	Criteria
Site	The project proponent has purchased/settled/acquired (or commenced legal proceedings to purchase/settle/acquire) land for the construction of the project.
Major components	Contracts for the supply and construction of major plant or equipment components (such as generating units, turbines, boilers, transmission towers, conductors, and terminal station equipment) have been finalised and executed, including any provisions for cancellation payments.
Planning consents, construction and connection approvals, EIS	The proponent has obtained all required planning consents, construction approvals, connection contracts (including Generator Performance Standard agreement from AEMO in the form of the 534A letter), and licences, including completion and acceptance of any necessary environmental impact statements.
Finance	The financing arrangements for the proposal, including any debt plans, must have been concluded and contracts executed.
Final construction and commercial use dates set	Construction of the proposal must either have commenced or a firm commencement date must have been set. Commercial use date for full operation must have been set.

5.6.2 New production projects

Electricity

Committed new generation projects will be sourced from AEMO's Generation Information Page, using the latest information available when modelling begins. Committed generation projects are included, with fixed timing and without build costs, in all electricity modelling.

Conceptual utility-scale generation and storage projects are developed using a combination of technology cost and performance data from different sources which can be found at AEMO's website[31].

The capacity outlook model develops a generation and transmission outlook for each studied scenario. The plant configurations selected as candidates for entry are included in the capacity outlook model.

Gas

For electricity, committed projects are those that satisfy AEMO's five commitment criteria, listed in Table 11. There are no equivalent commitment criteria defined for gas production, however the principals of commitment in Table 11 are applied to gas projects for modelling purposes.

[31] AEMO. ISP Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

6. Renewable Energy Targets

6.1 Large-Scale Renewable Energy Target (LRET)

The Australian Government sets targets for energy generated by renewable sources through the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). These targets are encouraged by requiring wholesale purchasers of electricity to purchase Renewable Energy Certificates (RECs) which, from 1 January 2011, are classified as either Large-scale Generation Certificates (LGCs) or Small-scale Technology Certificates (STCs) for the purposes of meeting the LRET and the SRES respectively.[32]

In the capacity outlook model, the LRET is modelled by setting an annual energy target that must be met by renewable generation (or penalty price paid). To incorporate the LRET into the capacity outlook model, four adjustments are made to the published LRET figures:

- The number of LGCs that are required to meet the target is scaled by an amount that reflects the energy generated in the NEM compared to the amount of energy generated Australia-wide.
- The calendar-year targets defined by the LRET are converted to financial year targets by averaging the targets in adjacent calendar years.
- The target in the first three years of the model is reduced to account for any surplus RECs currently available in the market.

The majority of STCs are generated by domestic rooftop PV installations. The uptake of rooftop PV is modelled as part of the demand projections, so no explicit representation of STCs is included in any of the models.

Renewable energy targets could be modelled as hard or soft constraints. AEMO generally models legislated policies that have no mechanism defined as hard constraints. For those where mechanisms, are already defined, AEMO chooses the most appropriate modelling methodology.

The LRET has several nuances, described in the following sections:

6.1.1 GreenPower

GreenPower is a federal government program to empower consumers to purchase electricity from renewable sources. Sales of GreenPower[33] electricity represent an additional requirement for renewable generation over and above the targets imposed by the LRET and the SRES. The Capacity outlook model and time-sequential model use renewable generation targets that are adjusted to include GreenPower sales.

6.1.2 ACT 100% Renewable Energy Target

In 2016, the ACT Government legislated a new target of sourcing 100% of the Territory's electricity from renewable sources located in the ACT or across the NEM by 2020.[34] This target[35] has been incorporated into the capacity outlook model.

6.1.3 Desalination

All major desalination plants in Australia are committed to purchasing renewable energy over and above the requirements of the LRET.

The end of drought conditions in eastern Australia has resulted in all major desalination plants being placed in standby mode. LGC purchase agreements for desalination plants usually apply in the long term, and are not affected by the plants' operational status. It is assumed that LGCs purchased under such agreements will be re-sold, however, so demand for LGCs from desalination plants do not add to the LRET when plant are non-operational.

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[32] Australian Government. Available at http://www.environment.gov.au/climate-change.

[33] http://www.greenpower.gov.au/.

[34] https://www.environment.act.gov.au/energy/cleaner-energy/renewable-energy-target-legislation-reporting

[35] http://www.environment.act.gov.au/energy/cleaner-energy and http://www.environment.act.gov.au/__data/assets/pdf_file/0007/987991/100-Renewal-Energy-Tri-fold-ACCESS.pdf.

Demand for LGCs from desalination plants is assumed to be zero.

6.2 Victorian Renewable Energy Target (VRET)

AEMO assumes that the Victorian Renewable Energy Target (VRET) will result in at least 25% of the energy generated in Victoria coming from renewable energy sources by 2020 and 40% by 2025. AEMO estimates the uptake of generation needed to achieve these energy targets and applies a capacity target to reflect expected auction allocations. This has a benefit of avoiding the model from choosing to operate other Victorian generators less to reduce overall Victorian generation, lowering the energy target.

For more details on the VRET please refer to the Victorian Government website.[36]

6.3 Queensland Renewable Energy Target (QRET)

AEMO assumes that the Queensland Renewable Energy Target (QRET) will result in at least 50% of the energy generated in Queensland coming from renewable energy sources by 2030. AEMO models this scheme as a hard target on energy generation. For more details on the QRET please refer to the Queensland Government website[37].

[36] http://earthresources.vic.gov.au/energy/sustainable-energy/victorias-renewable-energy-targets.

[37] https://www.dnrm.qld.gov.au/__data/assets/pdf_file/0018/1259010/qreep-renewable-energy-target-report.pdf

7. Analysis

7.1 Reliability assessments

AEMO's long-term market modelling activities take into account uncertainties in energy consumption, maximum demand, generator outages and variable generations' intermittence and coincidence with consumption by employing a Monte Carlo simulation approach. A Monte Carlo simulation is an iterative method of running models that:

- Uses different sets of input parameter sensitivities to generate a large population of results that supports statistically robust conclusions.
- In AEMO's market modelling, captures the impact of key uncertainties such as generator outage patterns, weather sensitive demand, intermittent generation availability, and coincidence of demand across regions.

For each iteration of the Monte Carlo simulation, AEMO uses a combination of generator random forced outages, a reference year, and a maximum demand. For reliability assessment studies such as the NEM ESOO, hundreds of Monte Carlo iterations are normally completed per simulation year to create statistically robust results and capture the impact of uncertainties around these parameters.

The ESOO methodology report should be the primary reference for the current methods employed when conducting reliability assessments.

7.2 Market benefits

Some modelling exercises (such as in a Regulatory Investment Test for Transmission (RIT-T) or the VAPR) are designed to determine the benefit to the market delivered by specific network or non-network augmentation projects.

To value any proposed augmentation, detailed costings of the augmentation, and the counterfactual scenario without the augmentation developed, are modelled. The difference in cost between these two cases represents the market benefit of the augmentation. Where an augmentation is expected to affect the development of generation, a generation expansion plan will also be developed for each case.

AEMO demonstrates the economic value of the augmentation options by providing a high level overview of the potential benefits that are allowable by the Australian Energy Regulator (AER) in a RIT-T.[38] The allowable market benefits may include:

- Capital costs benefits – indicates savings from deferring investments.
- Operating cost benefits – indicates operating costs reduction which may include fuel, operating, maintenance, and transmission loss costs savings.
- DSP benefits – the savings from avoiding price-sensitive responses.
- Reliability benefits – indicates customer reliability improvements measured by the reduction in USE. Reduction in USE due to long-term non-credible contingencies may also be evaluated.
- Environmental scheme benefits – savings from reduced payments for renewable targets.
- Competition benefits – optional under the RIT-T.
- Option value – refers to a benefit that results from retaining flexibility in a situation where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change, and the credible options available are sufficiently flexible to respond to that change.
- Ancillary services benefit – the reduction in net costs required to provide sufficient ancillary services to meet the projected system needs.

[38] Australian Energy Regulator, Final regulatory investment test for transmission, https://www.aer.gov.au/system/files/Final%20RIT-T%20-%2029%20June%202010.pdf. Accessed 2 December 2016.

The sum of these benefits represents the total market benefits of an augmentation. Comparing these potential market benefits with the cost of the augmentation provides an insight into whether this project is likely to be justified under the RIT-T.

Market benefit analysis requires comparison of a discounted cash flow of total system costs using the most up-to-date range of discount rates.

7.2.1 Generation capital costs

An augmentation may defer generation capital expenditure, saving the cost to finance investment during the deferral period. In extreme cases, generation may not need to be built at all. An augmentation may allow a less capital-intensive form of generation to be established in an alternate location.

Generation capital deferral benefits are determined by capacity outlook modelling outcomes.

7.2.2 Transmission capital costs

An augmentation may defer the need to build other transmission projects. Transmission capital deferral benefits are determined by capacity outlook model outcomes.

7.2.3 Operating cost benefit

An augmentation may relieve limitations on existing or new generation with lower fuel, emissions, fixed or variable operating costs, allowing lower-cost generation to operate more frequently.

System operating cost benefit includes:

- Production costs savings – due to lowered operational costs and includes transmission loss cost.
- Fixed operating and maintenance costs savings – due to decreased total fixed costs incurred for keeping generators in service.

7.2.4 Transmission system losses

An augmentation may allow generation to be dispatched closer[39] to the locations where energy is consumed, reducing the cost to transport energy on the network.

An augmentation may change the flow patterns on interconnectors in ways that reduce losses when transferring power between regions.

Transmission system loss benefits are determined by capacity outlook model outcomes (when new generation is established closer to load centres) and time-sequential modelling outcomes (when changes in network limitations change interconnector flow patterns).

7.2.5 Reliability benefits

A Value of Customer Reliability (VCR, usually expressed in dollars per kilowatt-hour) indicates the value different types of customers place on having reliable electricity supplies under different conditions. It is used to monetise USE so investment options can be compared on an economic basis.

An augmentation may reduce the amount of reported USE, reducing the penalties associated with failing to supply consumers. Reliability benefits are determined by time-sequential modelling outcomes.

7.2.6 Option value and competition benefits

AEMO's modelling activities may quantify option value or competition benefits if these benefits are considered to be material to the outcomes of the study.

[39] Electrical proximity. That is, substituted generation may be physically further away, but connected to a lower-loss transmission line, or operates in a way that reduces total losses in delivering energy to the point of consumption.

8. Financial parameters

Cost-benefit comparisons between augmented and unaugmented cases use a discounted cash flow (present value) calculation to determine the present day value to the market of spending that occurs in the future.

8.1 Inflation

Monetary values in the models refer to real value, as opposed to nominal value. That is, future values are not adjusted by assumptions about inflation, whereas values defined in the past are adjusted to account for inflation. For example, in AEMO's 2018 ISP, values are expressed in 2018–19 dollars. Australian dollars unless otherwise stated. Values that were originally expressed in dollars of earlier years are adjusted upwards by 2.5%, or the observed appropriate inflation measure, to account for inflation.[40]

Time value of money is reflected in the model by the most up-to-date range of possible discount rates.

8.2 Goods and Services Tax

Prices are exclusive of Goods and Service Tax.

8.3 Weighted average cost of capital

The capital cost of an investment is increased beyond its purchase price by the cost of finance. The weighted average cost of capital (WACC) is the rate that a company is willing to pay to finance its assets.[41] The WACC is the weighted sum of the cost of debt and the cost of equity, where the cost of debt is determined by interest rates, and the cost of equity is determined by reference against the returns received by other projects with similar risk.

AEMO uses real, pre-tax WACC values in its capacity outlook modelling.

8.4 Discount rate

Present value calculations estimate all future cash flows which are discounted to account for the amount of cash that would need to be invested in the present day to yield the same future cash flow.

AEMO may use a range of discount rates to calculate the Net Present Value (NPV) of future cash flows. Practically, lower discount rates emphasise market benefits that accrue later in the modelled horizon, while higher discount rates emphasise market benefits that accrue earlier in the modelled horizon. A higher discount rate can be used to accommodate the uncertainty inherent in the estimates of cost to operate modelled energy infrastructure, which increases with time.

8.5 Project lifetime

Capital investments are annualised over the life of the asset in order for costs to be compared against annual market benefits over the planning horizon.

[40] Inflation is calculated from Australian Bureau of Statistics consumer price index adjustments.

[41] The return the company would expect to receive from an alternative investment with similar risk.

A1. Summary of information sources

Table 12 Summary of information sources

Information	Source
Committed and proposed transmission augmentations	Annual Planning Reports Project Summary workbook. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.
Demand side participation	AEMO internal study, based on industry engagement, available in the ISP Assumptions Workbook. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database. AEMO Demand Side Participation estimates. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/2018-Electricity-Forecasting-Insights/Demand-Side-Participation.
Emissions intensity factors	Based on external consultation study performed by ACIL Allen – Emission Factors Assumptions Update[42], published in ISP Assumptions Workbook. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database.
Existing and new gas production, storage and transmission infrastructure	GSOO Inputs. Available at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.
Gas and coal prices	Prices are derived by AEMO based on wholesale gas and coal price forecasts produced by Core Energy and Wood Mackenzie. These wholesale prices reflect the underlying market conditions assumed in each of the forecast scenarios. AEMO has adjusted these external forecasts in the near term to reflect recent observations of wholesale prices. The price forecasts are available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database.
Gas production and transmission costs	GSOO Inputs. Available at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.
Gas reserves	GSOO Inputs. Available at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.
Generation inventory	Generation Information Page. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.
Generator performance parameters	Based on external consultation study performed by ACIL Allen – Fuel and Technology Cost Review[43], published in ISP Assumptions Workbook. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database.
Marginal loss factors and proportioning factors	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.
Minimum capacity reserve levels	AEMO internal study, published in ISP Assumptions Workbook. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database.

[42] Available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2016/Data_Sources/ACIL-ALLEN---AEMO-Emissions-Factors-20160511.pdf.

[43] Available at https://www.aemo.com.au/-/media/Files/XLS/Fuel_and_Technology_Cost_Review_Data_ACIL_Allen.xlsx.

Information	Source
New generation technology costs	Primarily from CSIRO – Electricity Generation Technology Cost Projections: 2017-2050. Other assumptions as published in ISP Assumptions Workbook. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database.
Projections of demand for LNG export	GSOO Inputs based on engagement directly with LNG producers and external consultation with Lewis Grey Advisory[44]. Available at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.
Regional electricity energy and maximum demand forecasts and gas demand forecasts	National *Electricity Forecasting Report, March 2017 Update*. Available at http://forecasting.aemo.com.au/. National Gas Forecasts, published in GSOO. Available at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities and http://forecasting.aemo.com.au/.
Reliability Standard	Reliability Standards (AEMC). Available at https://www.aemc.gov.au/our-work/developing-electricity-guidelines-and-standards.
Renewable energy targets	Clean Energy Regulator Available at http://www.cleanenergyregulator.gov.au/RET/. Implementation of GreenPower, ACT 100% renewables, QRET and VRET targets as described in ISP Assumptions Workbook. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database.
Significant constraint equations	AEMO internal development. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database.
Wind contribution to peak demand	Generation information page. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information. South Australian Advisory Functions. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions. DNV-GL – Multi-Criteria Scoring for Identification of Renewable Energy Zones. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database.

[44] Available at https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2018/Projections-of-Gas-and-Electricity-Used-in-LNG-2017-Final-Report-19--12-17.pdf.