# 2016 NTNDP METHODOLOGY AND INPUT ASSUMPTIONS

## FOR THE NATIONAL ELECTRICITY MARKET

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AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

# IMPORTANT NOTICE

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AEMO has prepared the 2016 National Transmission Network Development Plan (NTNDP) Methodology and Input Assumptions under clause 5.20.2 of the National Electricity Rules. This report is based on information available to AEMO up to 14 October 2016.

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## Version control

| Version | Release date | Changes |
|---|---|---|
| 1 | 23/12/2016 | |

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# CHAPTER 1. INTRODUCTION

The *National Transmission Network Development Plan* (NTNDP) provides an independent, strategic view of the efficient development of the NEM transmission grid across a range of credible scenarios over a 20-year planning horizon. This document provides more information on the methodologies and input assumptions employed in AEMO's 2016 NTNDP.[1]

The NTNDP is part of a comprehensive suite of annual AEMO planning publications. AEMO bases its suite of forecasting and planning publications on the same set of inputs and assumptions. The NTNDP builds on data and analysis that was carried out as part of the 2016 *National Electricity Forecasting Report* (NEFR)[2] and 2016 NEM *Electricity Statement of Opportunities* (ESOO).[3]

Input assumptions are developed in consultation with market participants through the NTNDP technical working group.[4] External consultants and other AEMO publications provide inputs to the NTNDP models. Figure 1 on the next page is a high level process flow showing the different inputs and studies that fed into the 2016 NTNDP.

Appendix A provides a list of sources comprising the 2016 NTNDP database. Chapter 3 provides further information on inputs and assumptions.

## 1.1 Scenarios

The 2016 NTNDP analysis explored three different scenarios:

1. Neutral – this scenario reflected AEMO's best estimate for grid demand based on a neutral economic outlook.
2. Low Grid Demand – this scenario explored the lower bound of grid demand by combining a weak economic outlook with a high uptake of energy efficiency and embedded technologies.
3. 45% Emissions Reduction – this scenario assessed the impacts of a stronger carbon abatement policy.

These are discussed in more detail in the main report.

[1] AEMO. *2016 National Transmission Network Development Plan*. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan.

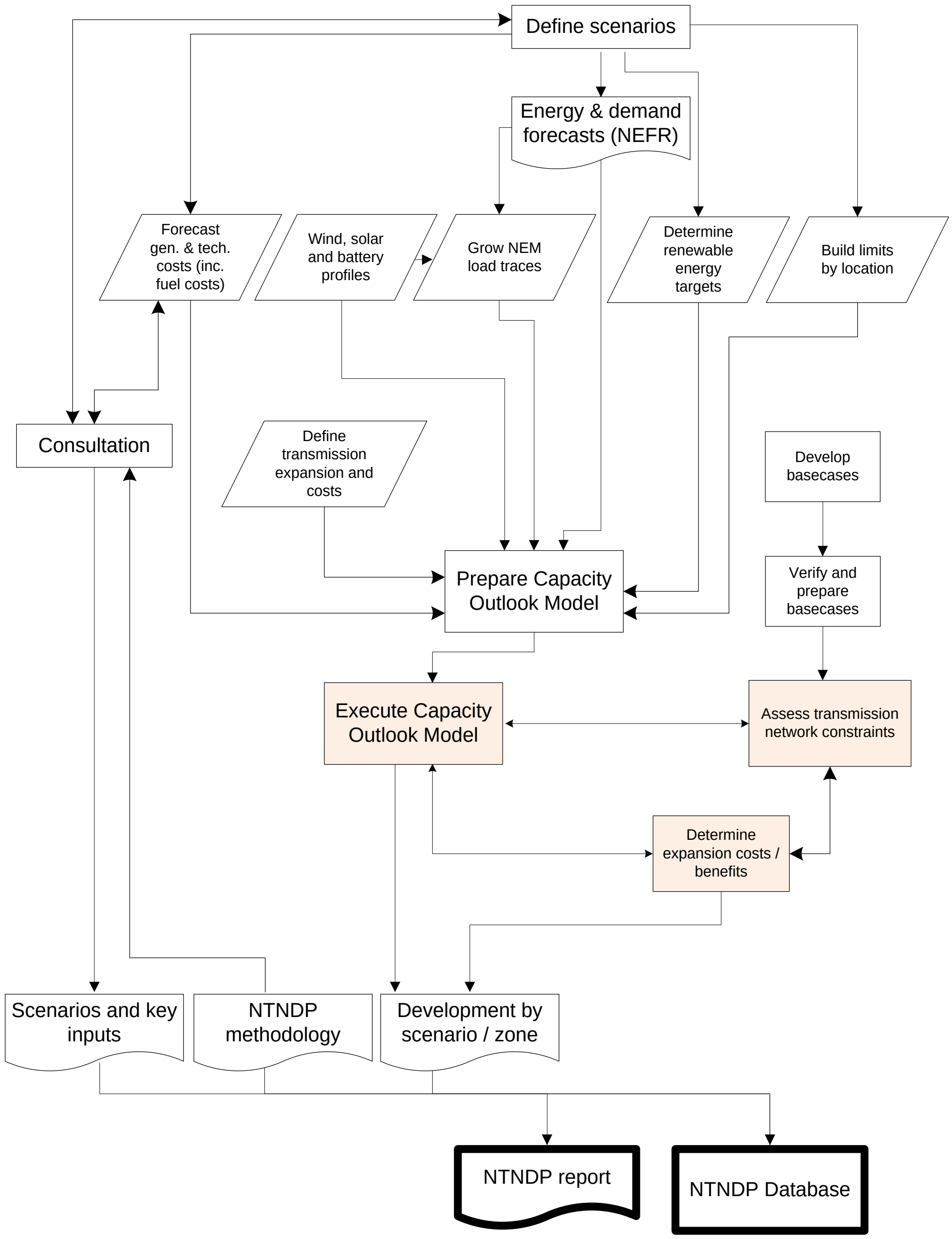
[2] AEMO. *2016 National Electricity Forecasting Report*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

[3] AEMO. *2016 NEM Electricity Statement of Opportunities*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

[4] AEMO. NTNDP Technical Working Group. Available: http://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/NTNDP-Technical-Working-Group.

## 1.2 Inputs and studies that fed into the 2016 NTNDP

**Figure 1 2016 NTNDP Process flow**



# CHAPTER 2. MODELS

AEMO maintained three interdependent models for the following purposes:

- **Capacity outlook model** – determined the least-cost long-term generation and interconnection investment plan without considering intra-regional network limitations. This model gradually and simultaneously added new generation and augmented interconnector capacity to the NEM while retiring existing generation capacities to solve for the most cost-efficient development trajectory of developing the NEM.
- **Time-sequential model** – validated the results from the previous model by carrying out hourly generation dispatch simulations while considering various power system limitations. This model did not make capacity expansion decisions but highlighted network limitations' potential costs.
- **Network development outlook model** – examined the physical transmission network in detail and validated the power system limitations identified from the time-sequential model as well as the feasibility of the capacity outlook model results. Network augmentation options were identified and high level costs were obtained from this model.

All three interdependent models' results were finalised through an iterative process of adjusting the input assumptions on one model based on the output of the others.

These models incorporated assumptions from the different scenarios described in Section 1.1.

## 2.1 Capacity outlook model

Generation capacity outlook modelling developed a plan that minimised the overall power system investment and operating costs over the modelling horizon by adding or retiring generation capacities of different technologies as well as augmenting interconnector capabilities.

This model produced a trajectory of generation expansion and retirement for each scenario described in Section 1.1.

This year's NTNDP followed the methodology described in detail in the *Market Modelling Methodology and Input Assumptions.*[5]

### 2.1.1 Demand simplification

In the 2016 NTNDP, the capacity outlook model was run aggregating regional demand using 12 load blocks per month to allow for practicality while maintaining acceptable resolution. This simplification enabled faster simulation and processing times, allowing more sensitivities to be studied.

### 2.1.2 Simulation accuracy

The generation capacity expansion plan model was a mixed-integer linear programming model that mathematically determined the least-cost investments required to meet operational consumption while satisfying carbon abatement policies.

This year's NTNDP covered more scenarios than previous years, to capture unprecedented changes to the NEM generation mix and the impact of different carbon abatement policies. Where slightly different scenarios are modelled, a tighter modelling tolerance is required. Hence, the 2016 NTNDP modelling reduced the error tolerance for calculating the least cost expansion trajectory from 0.01% to 0.0001%. This simulation requires high computing power and a high resolution, but results in a more robust solution.

[5] AEMO. 2016 NTNDP Database. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.

### 2.1.3 Generation build limits and lead times

In capacity outlook modelling, the maximum amount of new generation of any technology type that can be established in any zone is limited in the model ("build limits").

Once an expansion plan was produced by the capacity outlook model using the build limits, more detailed work was undertaken to explore the impact this would have on the network – and the costs of resolving any issues.

In some cases, this led us to modify the build limits to ensure the capacity outlook model took greater account of network limitations. This process of iteration can be repeated several times to settle on the final set of build limits used by the model.

For this year's NTNDP, AEMO assumed a construction lead time of two years for wind farms, while for gas-powered generation (GPG), a lead time of at least four years was assumed.

### 2.1.4 Transmission augmentations

The capacity outlook model included representations of the effect on the network and the cost of advanced and proposed electricity transmission projects that could increase the transfer capability of interconnectors. The model selected projects for inclusion in future network development based on their ability to reduce total costs.

AEMO surveys transmission projects suggested by jurisdictional planning bodies in annual planning reports (APRs). These projects are summarised and published in the Annual Planning Reports Project Summary workbook.[6] A subset of these projects was selected for inclusion in the model. AEMO may also develop new transmission projects where study requirements are not met by the APR survey.

## 2.2 Time-sequential model

The time-sequential model took a detailed look at the supply-demand balance at a much higher resolution. The model performed optimised electricity dispatch for every hour in the modelled 20-year horizon, with the aim of minimising running system costs to meet operational consumption across the NEM, subject to generation capability, fuel availability, demand side participation, transmission constraints, and emissions targets.

Time-sequential simulations were used in the NTNDP studies to provide insights on:

- Feasibility of the capacity outlook model results when considering network operating conditions and limitations.
- Emerging network limitations that could lead to reliability breaches or inefficient dispatch of generators.
- Available generation reserves under planned and unplanned generation outage conditions.
- Customer reliability and running cost improvement due to specific augmentations.
- Inertia level based on unit commitment status.
- Generation mix and fuel offtake that impacts upstream industries such as gas.

All these were obtained using different sets of bidding, unit commitment assumptions, and power system limitations. The results of the time-sequential model were validated in the network development outlook model and insights were fed back to the capacity outlook model in the iterative process.

For further details about the time-sequential model, please refer to the *Market Modelling Methodology and Input Assumptions*.[7]

[6] AEMO. 2016 NTNDP Database. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.

[7] AEMO. 2016 NTNDP Database. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.

### 2.2.1 Supply bidding models

For this year's NTNDP, AEMO used the following different generator bidding strategies:

- Short Run Marginal Cost (SRMC) model – this is the simplest bidding model and assumes all available generation capacities are offered in the market at the unit's SRMC, which includes variable costs, fuel cost, and an implicit emissions cost.[8] The SRMC bidding model represents a perfect competition model or the least-cost way to run the market in the short term while meeting the annual emission constraint. This bidding model is the fastest to solve and the least subjective, and is used to investigate transmission line flows, network congestion, and non-competition benefits for the outlook period. The inputs used in the SRMC calculation are presented in Chapter 4.
- Nash-Cournot model with unit commitment – this allows each participant to adjust the generation volume they offer to the market such that each portfolio's profit is maximised. Unit commitment decisions are also made, trading off the cost of restarting against the risk of running at a loss for short periods of time if staying on line. This model provides a more realistic approximation of generator dispatch and unit commitment than the SRMC model. It was therefore used to estimate GPG (for gas demand forecasting), and to investigate the amount of inertia that could be available in the system, to predict the likelihood of frequency stability concerns in the future.

### 2.2.2 Network limitations

Power system behaviour was considered in the time-sequential model by using constraint equations that modelled system limits for different system configurations and link augmentation.

In general, the following constraint equations were used in NTNDP studies:

- Thermal – for managing the power flow on a transmission element so that 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 was implemented as modifications to the network constraint equations that control flow. The methodology for formulating these constraints is described in detail in AEMO's Constraint Formulation Guidelines.[9]

## 2.3 Network development outlook model

The network development outlook model was a power system model that depicts the physical transmission network and all the main transmission flow paths, including individual generating units, transmission lines, and transformers, switching elements, reactive power management elements, and loads. Details from the sub-transmission and distribution networks was simplified in this model.

[8] The emissions cost is implicit as the dispatch is driven by an annual emissions constraint rather than any carbon price.
[9] AEMO. Constraint Formulation Guidelines. Available: http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/Constraint_Formulation_Guidelines_v10_1.pdf.

Transmission system adequacy was assessed under a range of conditions by performing load flow analyses, which calculated the instantaneous flow of power between locations where energy is generated and where it is used.

### 2.3.1 Validation of generation capacity and time-sequential models

Reliability was 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 considered the capability of the transmission system for transfer of energy, and identified thermal limitations that may be constraining power flow.

The hourly generation and interconnector flows for snapshots in time were obtained from the time-sequential models.

If a thermal limitation was identified, AEMO addressed the overload by taking the following actions:

- Re-dispatch generation – more expensive generation closer to the load was dispatched in preference to the generation that was dispatched by the time-sequential model.
- If simple re-dispatch could not address the overload, new generation was relocated to an alternative connection point in the same planning zone.
- If relocation of generation in the same zone could not address the overload, new generation was relocated to an adjacent zone.
- If relocation and re-dispatch of generation could not cannot address the overload, an appropriate intra-regional transmission system augmentation was chosen 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 was required and the cost of identified augmentations was considered material to the generation capacity outlook outcomes, the augmentation cost was added to the costs of new generation considered by the capacity outlook model, in the zone where the augmentation was required. The capacity outlook model was re-solved, which may have resulted in the relocation of generation, different transmission system augmentations being chosen, a combination of both, or no change to the capacity outlook.

This modelling validated the outcomes of 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 grows and the generation mix changes.

# CHAPTER 3. INPUTS AND ASSUMPTIONS

## 3.1 Traces

For the 2016 NTNDP, AEMO used the load shape and weather conditions from the 2013–14 reference year to derive hourly demand profile and variable generation hourly availability projections.

### 3.1.1 Demand

#### Regional demand

AEMO produces an annual *National Electricity Forecasting Report*[10] (NEFR), which provides independent electricity consumption forecasts for each NEM region over a 20-year forecast period. Generally, the NTNDP uses the regional demand forecasts from the NEFR. This year's NTNDP also modelled a Low Grid Demand scenario, which used the 2016 NEFR Weak scenario's underlying[11] maximum demand and energy targets but substituted the impact of the NEFR Strong[12] scenario's energy efficiency uptake, and the NEFR Strong scenario's customer uptake of rooftop photovoltaics (PV) and residential batteries. This gave a lower boundary for operational consumption.

The regional demand for both the Neutral and Low Grid Demand scenarios was assessed using the 10% probability of exceedance (PoE) maximum demand.[13]

#### Connection point demand

AEMO develops maximum demand forecasts for each transmission connection point, defined as the physical point at which the assets owned by a Transmission Network Service Provider (TNSP) meet the assets owned by a distribution network service provider (DNSP). These may also be known as bulk supply points (BSPs), terminal stations, or exit points, and in the NEM's market metering and settlements processes they are called transmission node identities (TNIs). More information about connection point forecasts and how they are developed is available in AEMO's *Connection Point Forecasting Methodology* report.[14]

Connection point demand forecasts for a 10% PoE were used in transmission asset utilisation studies, which are further discussed in Chapter 4.

#### Demand side participation

Demand side participation (DSP) refers to an agreed reduction in demand that can be triggered by high prices or critical system conditions. AEMO forecast DSP quantities for different price bands. For each region, DSP volume was nominated for $300, $500, $1000, $7500, and at market clearing price (currently at $14,000). The assumed volume of DSP available in each NEM region was based on the 2016 NEFR. Refer to the 2016 NEFR[15] for more information.

[10] AEMO. *National Electricity Forecasting Repor*t. Available: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.
[11] Underlying demand is defined as the actual consumption from the customer premises, ignoring the effect of rooftop PV and battery storage.
[12] The 2016 NEFR has Strong, Neutral, and Weak demand sensitivities
[13] Probability of exceedance (POE) is the likelihood that a maximum demand forecast will be met or exceeded. A 10% POE MD forecast is expected to be exceeded, on average, one year in 10. A 50% POE projection is expected to be exceeded, on average, one year in two.
[14] AEMO. *Transmission Connection Point Forecasting.* Available: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Transmission-Connection-Point-Forecasting.
[15] AEMO. *National Electricity Forecasting Report.* Available: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

## 3.2 Generation technical parameters

Generator technical parameters describe the physical characteristics and limitation of each units. All existing and new entrant generators' technical parameters were based on the latest information at the time of the modelling activity, and are summarised below.

**Table 1 Generation technical parameter input source**

| Parameters | Description | Relevance | Source | Links |
|---|---|---|---|---|
| Capacities | Reflect thermal generators capacities' dependence on season and weather.<br><br>Minimum stable loading reflects the lower bound for generation production. | Summer regional capacities tend to be lower than winter<br><br>Minimum generation relates to unit commitment schedule and amount of inertia online. | AEMO Generation Information Page<br><br>2015 Australian Power Generation and Technology Report | Generation Information Page [A]<br><br>and<br><br>2016 NTNDP Database [B] |
| Ramp rate | Rate at which generation can increase/decrease output | May constrain generation output | 2014 Fuel and Technology Cost Review – Data (ACIL Allen) | 2016 NTNDP Database |
| Auxiliary load | Station consumption that supports own operation | Lessens the generation supplied to the operational consumption | 2014 Fuel and Technology Cost Review – Data (ACIL Allen) | 2016 NTNDP Database |
| Heat rate | Efficiency of converting chemical or potential energy to electrical energy | Impacts the cost of electricity production and the amount of fuel consumed | 2014 Fuel and Technology Cost Review – Data (ACIL Allen) | 2016 NTNDP Database |
| Emission rate | $CO_2$-e production for each MWh of electric energy produce | Direct carbon abatement policies significantly impacts heavy carbon emitters | 2016 Emissions Factor Assumptions Update | 2016 NTNDP Database |
| Inflow rates | Long-term reservoir inflow average | Hydro-electric generators availability depends on storage levels | AEMO Planning Assumptions based on a suite of consultation | 2016 NTNDP Database |
| Outage rates | Historical maintenance and unplanned failure rates describe the probability of capacity deration of each technology type | Further lowers available generation capacity to serve operational consumption | AEMO Generator Forced Outage Rates | AEMO Internal Study |
| Marginal loss factor | Impact of generation on network losses is represented as loss factors. | Incentivise generators that lowers network losses and penalise those who increases it | AEMO Forward Looking Loss Factors | Loss Factors and Regional Boundaries [C] |

A AEMO. Generation Information Page. Available: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.
B AEMO. NTNDP Database. Available: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.
C AEMO. Loss Factors and Regional Boundaries. Available: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries.

## 3.3 Generation economic parameters

Generators' economic parameters controlled dispatch behaviour in the generation capacity outlook model and the time-sequential model. AEMO modelled generator costs for all existing generators units and all classes of possible new generators, as summarised in Table 2.

**Table 2 Generation economic parameter input source**

| Parameters | Description | Relevance | Source | Links |
|---|---|---|---|---|
| **FO&M cost** | Annual fixed cost for keeping plants in service | Increases the cost of keeping the plants in service | 2014 Fuel and Technology Cost Review – Data (ACIL Allen) | NTNDP Database[A] |
| **VO&M cost** | Additional cost for running the generator per unit of energy production | Impacts the generators' running costs | 2014 Fuel and Technology Cost Review – Data (ACIL Allen) | NTNDP Database |
| **Gas fuel cost** | Gas price path for each existing GPG and gas zones | Impacts the gas generators' running costs | 2016 Core Energy Gas Pricing Consultancy Databook | 2016 NEFR[B]<br>NTNDP Database<br>2016 NGFR[C] |
| **Coal fuel cost** | Coal price path for each existing coal plants and NTNDP zones | Impacts the coal generators' running costs | 2016 Wood Mackenzie Coal Cost Report | NTNDP Database |
| **Build cost[D]** | Overnight investment cost trajectory for each available generation technology | Maturing technologies has downward cost projection incentivizing delaying investment | 2015 Australian Power Generation and Technology Report, ESCRI and ARENA | NTNDP Database |
| **WACC** | Cost of investment financing which may include cost of equities, debt, interest and risk premium | Used in capacity outlook model to estimate annualised technology costs. | 2015 Bloomberg New Energy Outlook[E] | NTNDP Database |
| **Economic life** | Capital payment period | Spreads the payment longer or shorter affecting the net present value of the capital cost | 2014 Fuel and Technology Cost Review – Data (ACIL Allen) | NTNDP Database |
| **Minimum capacity factors** | Represents the minimum technical and economic duty cycles | Applied on the capacity outlook model to represent the minimum economic running regime | 2014 Fuel and Technology Cost Review – Data (ACIL Allen) | NTNDP Database |
| **Reservoir initial dam level** | Latest dam levels | Available water for generation at the start of every year | Bureau of Meteorology<br>HydroTas | Bureau of Meteorology[F] |

A AEMO. NTNDP Database. Available: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.
B AEMO. *National Electricity Forecasting Report*. Available: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.
C AEMO. *National Gas Forecasting Report*. Available: http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report.
D For scenarios using alternate exchange rate assumptions, such as the Low Grid Demand scenario (which uses AEMO's Weak planning scenario as its technology cost basis), AEMO moderates the APGT capital costs in the model to incorporate the sensitivity of construction costs to foreign exchange differences. AEMO uses the analysis performed by ACIL Allen Consulting to apply this. [16]
E Bloomberg New Energy Outlook. Available: https://www.bloomberg.com/company/new-energy-outlook/.
F Bureau of Meteorology. Available: http://www.bom.gov.au/.

## 3.4 New entrant candidates

The capacity outlook model built the most cost-efficient technology to serve changing consumption or replacing retiring plants. AEMO allowed the model to choose from most likely technology that could come online to limit the model's search options. The list of allowable technologies included in the 2016 NTNDP modelling includes:

- GPG:

[16] AEMO. NTNDP Database. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.

   - Combined cycle gas turbines (CCGT).
   - Open cycle gas turbines (OCGT).
- Renewable generation:
   - On-shore wind farms.
   - Large scale solar PV farms, including fixed flat plate (FFP), single-axis tracking (SAT), and dual-axis tracking (DAT) technologies.
- Storage technologies:
   - Large scale batteries, using lithium-ion storage technology.
   - Pumped storage hydro generation.
- Distributed generation technologies:
   - Rooftop PV systems.
   - Small scale batteries, using lithium-ion storage technology.

No new coal-fired generation, nuclear, or carbon capture and storage (CCS) technologies were assessed. Distributed generation technologies were not determined by the capacity outlook model, but were assumed to develop as forecast in the 2016 NEFR.

## 3.5 Retirements and retirement candidates

Apart from building new generation to meet consumption, the capacity outlook model also allowed retirement if this reduces total system costs. Where a generator had announced a retirement date, the model retired the generator in line with this announcement. AGL and Origin have also publicly announced that they do not expect to run the coal-fired generators in Table 3 beyond their operating lives.[17,18]

**Table 3 Coal-fired generation not expected to run beyond its operating life**

| Asset owner | Generation plant | Generation capacity / MW | Commissioned |
|---|---|---|---|
| AGL Energy Limited | Bayswater | 2,640 | 1985 |
| AGL Energy Limited | Loy Yang A | 2,180 | 1984–88 |
| Origin Energy Limited | Eraring | 2,880 | 1982–84 |

Assuming a 50-year operating life for these power stations, AEMO modelled these generator withdrawals between 2030 and 2040 in the generation outlooks. For other coal-fired generators, the capacity outlook model allowed for continued operation throughout the forecast period if an economic retirement was not identified by the model.

## 3.6 Interconnectors

### 3.6.1 Proposed South Australia Interconnector

Two options have been considered for a new South Australian interconnector:

- Option 1: RiverLink – a new 330 km 275 kV transmission line from Robertstown to Buronga. This option would upgrade the existing Buronga – Darlington 220 kV line to 275 kV operation, and require three 275/220 kV transformers and two 275/330 kV transformers.

[17] AGL. Available: https://www.agl.com.au/about-agl/media-centre/article-list/2015/april/agl-policy-to-provide-pathway-to-decarbonisation-ofelectricity-generation.
[18] Origin. Available: https://www.originenergy.com.au/blog/big-picture/paris-climate-change-deal-makes-history.html.

- Option 2: HorshamLink – a new 310 km 275 kV transmission line from Tailem Bend to Horsham and a new 275 kV 60 km transmission line from Tailem Bend to Tungkillo. This option would require two 275/220 kV transformers.

Both options would result in intra-regional constraints in South Australia, Victoria, and New South Wales, which were modelled in the NTNDP.

To achieve equitable load sharing between the new South Australian interconnector (either River Link or Horsham Link) and the existing Heywood interconnector, AEMO assumed that:

- Low impedance interconnecting transformers (Z = 8% on rating base) would be installed.
- A 275 kV / 275 kV phase shifting transformer with an impedance of 10% on a 700 MVA rating base and phase angle in the range ±60° would be installed at Horsham or Buronga for HorshamLink or RiverLink, respectively.

Although a range of interconnector capacities are possible, AEMO assessed 325 MW and 650 MW capacities for each route, although the market benefits were only assessed for the 325 MW option. Refer to Figure 2 for proposed technical parameters of the proposed South Australian interconnectors.

### 3.6.2 Second Bass Strait Interconnector

The second Bass Strait Interconnector (2BSI) was assumed to be connected to the 220 kV Tyabb bus in Victoria, and to a new 220 kV bus near Smithton in Tasmania. Smithton is located in the North West area of Tasmania, where many new wind generators are projected to be built. Tyabb is close to the major load centre in Victoria.

In Tasmania, a new double circuit 220 kV transmission line would be required from Smithton to Sheffield. This new line was assumed to be thermally unconstrained, since it would be sized to accommodate the import and export requirements of the 2BSI. Any congestion caused by the proposed new wind generation was assumed to be managed using automatic control schemes.

The new interconnector would have a capacity of 600 MW.

See 0 for proposed technical parameters of the 2BSI and its associated network augmentations.

### 3.6.3 Victoria to New South Wales and Queensland to New South Wales interconnector details

#### Victoria to New South Wales

The Victoria to New South Wales (VIC-NSW) interconnector augmentation would involve all of:

- A second South Morang 500/330 kV transformer.
- A braking resistor at Loy Yang.
- Uprating of the South Morang-Dederang 330 kV circuits.

#### Queensland to New South Wales

The Queensland to New South Wales (QNI) interconnector augmentation would involve 30% series compensation for the Bulli Creek to Dumaresq 330 kV line. This would avoid series compensation of the Armidale to Dumaresq 330 kV line, and would reduce the cost of future wind farm connections to that line.

**Figure 2 2nd South Australia AC interconnector options**

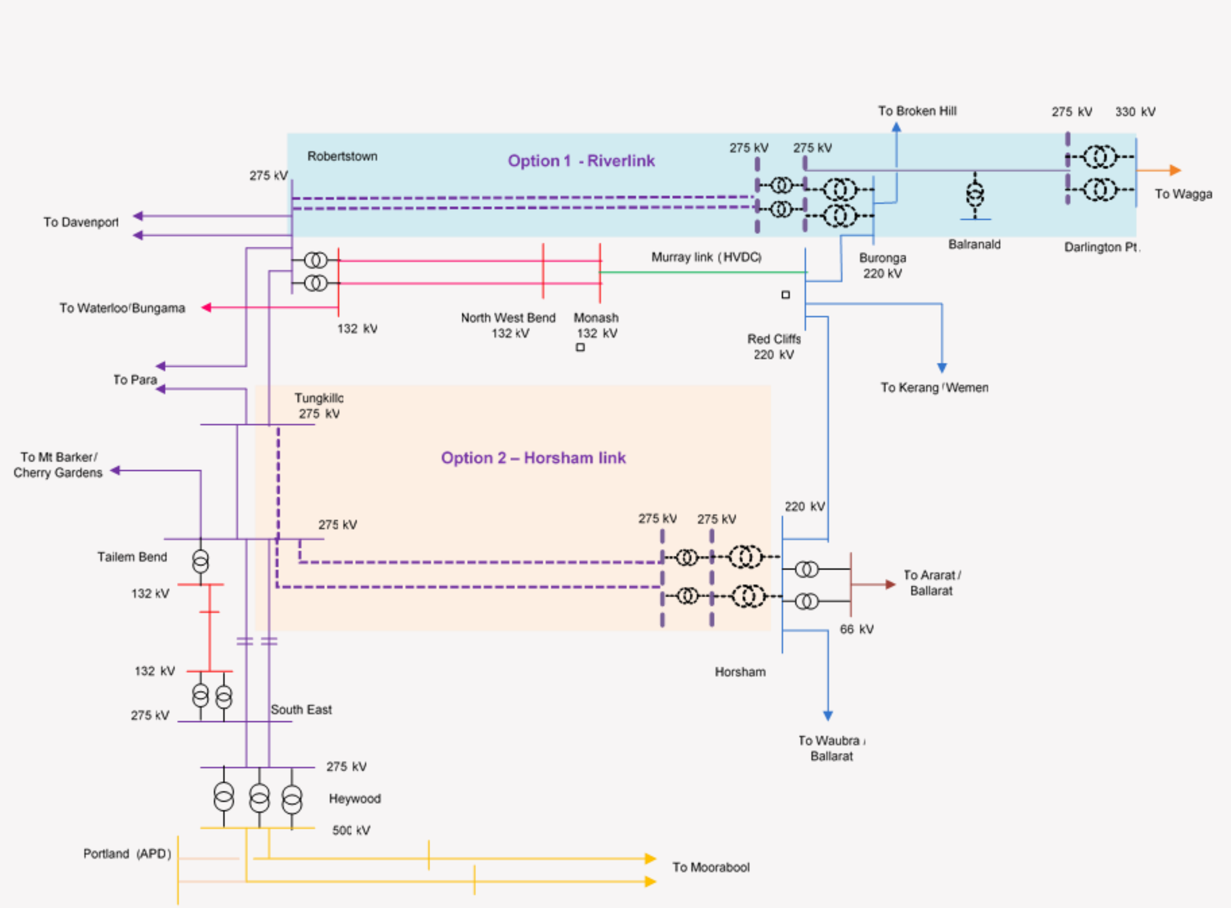
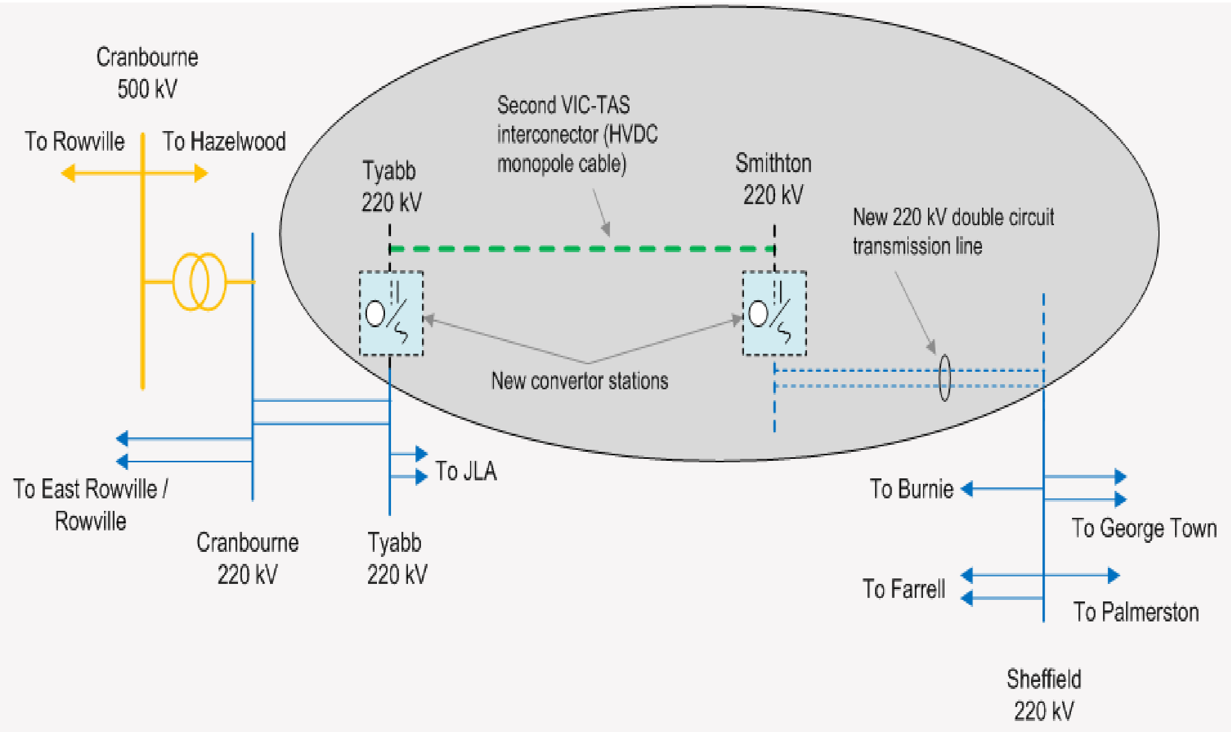


Figure 3 2nd Bass Strait Inter-Connector capacity ±600 MW




### 3.6.4 Impact of stability limits

High level stability analysis was performed on the proposed interconnector studies, and the offsets in Table 4 were applied to relevant stability constraint equations.

Table 4 Offsets applied to stability constraint equations

| Interconnector option | Transfer limit affected | Offset to transient stability |
|---|---|---|
| Second Bass Strait | VIC-NSW transient stability | Approximately +200 MW at 600 MW 2BSI flow |
| VIC-NSW upgrade | VIC-NSW transient stability | Approximately +170 MW |
| QNI upgrade | NSW-QLD transient stability and voltage collapse | Approximately +180 MW |
| RiverLink | VIC-NSW transient stability | Approximately +150 MW |
| RiverLink | VIC-SA transient stability | Approximately +380 MW |
| HorshamLink | VIC-NSW transient stability | Approximately +53 MW |
| HorshamLink | VIC-SA transient stability | Approximately +400 MW |

## 3.7 Carbon abatement policies

### 3.7.1 Large-scale renewable energy target (LRET)

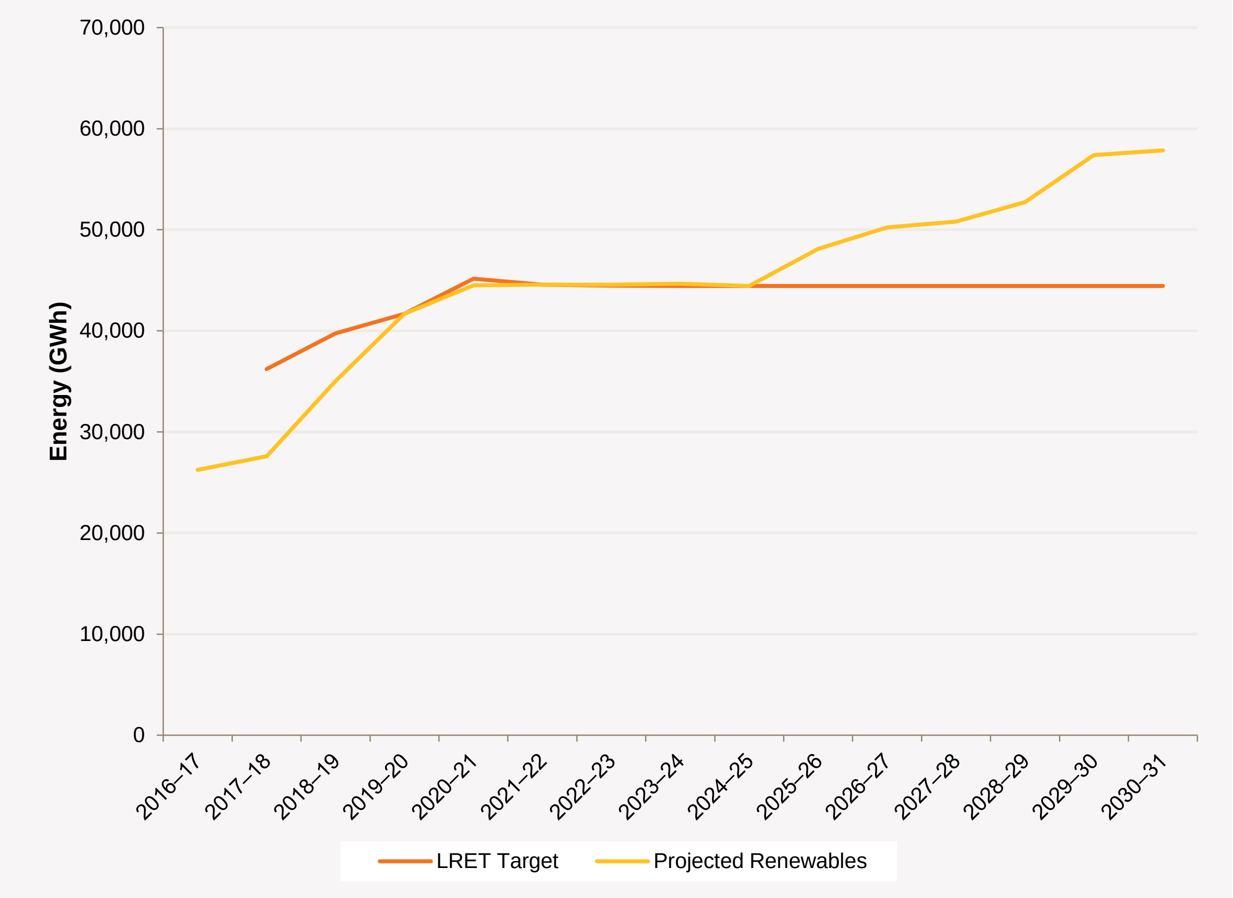
The Australian Government sets targets for energy generated by renewable sources through the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). These targets are implemented by requiring wholesale purchasers to purchase Large-scale

Generation Certificates (LGCs) or Small-scale Technology Certificates (STCs) for the purposes of meeting the LRET and the SRES respectively.

In the capacity outlook model, meeting the LRET was simulated by setting an annual renewable energy target and a penalty for violating it. To incorporate the LRET into the model, three adjustments were made to the published[19] LRET figures:

- The number of LGCs required to meet the target was 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 were converted to financial year targets by averaging the targets in adjacent calendar years.
- The target in the first three years of the model was reduced to account for any surplus LGCs currently available in the market.

**Figure 4 LRET trajectory and projected renewable generation development – Neutral scenario**




AEMO assumes that the gap between the Projected Renewables and the LRET Target before 2019–20 will be met by banked certificates.

The majority of STCs are generated by domestic rooftop PV installations. The projected level of generation from rooftop PV was included in the model, as estimated from the 2016 NEFR.

[19] 33,000 GWh of large scale generation must come from renewable energy sources by 2020. See: https://www.environment.gov.au/climate-change/renewable-energy-target-scheme.

### 3.7.2 GreenPower

GreenPower is a federal government program to empower consumers to purchase electricity from renewable sources.[20] Sales of GreenPower electricity represent an additional requirement for renewable generation over and above the targets imposed by the LRET and the SRES. The generation capacity outlook used renewable generation targets that were adjusted to include GreenPower sales.

### 3.7.3 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.[21] This target has been incorporated into the capacity outlook model.

### 3.7.4 Emissions reduction policy

Australia's commitment to the 21st Conference of Parties (COP21) in Paris, France sets a target to reduce carbon emissions by 26% to 28% below 2005 levels by 2030, and the Council of Australian Governments (COAG) Energy Council has agreed that the contribution of the electricity sector should be consistent with national emission reduction targets.

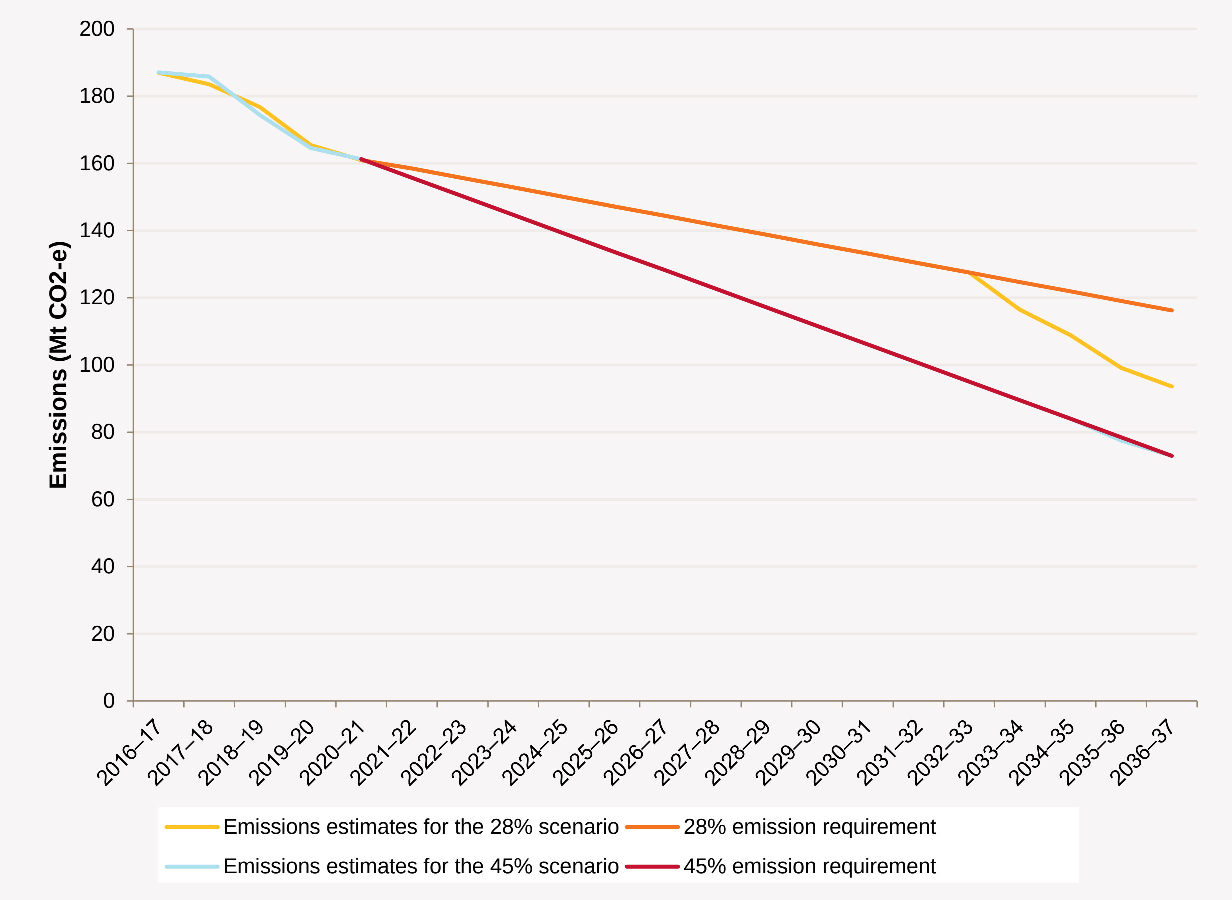
AEMO assumed that before 2020 there would be no emissions constraint, and assumed an annual $CO_2$ emission target that linearly declines from 2020 estimates to the 2030 target, and continues the downward trend post 2030. The figure below describes the trajectory.

Based on a review undertaken by ACIL Allen Consulting[22], the total NEM emissions in 2005 are estimated to be 179.5 Mt CO2-e. This translates to a 2030 target of 129.3 Mt CO2-e.

The stronger electricity target assumed in the 2016 NTNDP's 45% Emissions Reduction scenario is also displayed in the figure.

[20] http://www.greenpower.gov.au/#.
[21] http://www.environment.act.gov.au/energy/cleaner-energy/renewable-energy-target,-legislation-and-reporting.
[22] AEMO. NTNDP Database. Available: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.

**Figure 5 NEM emission target and estimates for the 28% and the 45% Emissions Reduction scenario**




### 3.7.5 Victorian renewable energy target (VRET)

AEMO assumed that the Victorian Renewable Energy Target (VRET) would result in at least 25% of Victorian energy generation coming from renewable energy sources by 2020, and 40% by 2025, as announced by the Victorian Government.

AEMO modelled this scheme as a hard target on energy generation, in conjunction with the latest inputs assumptions for this year's NTNDP modelling. For more details on the VRET, please refer to the Victorian Government website.[23]

## 3.8 Financial settings

Total system cost estimation used a discounted cash flow calculation to determine the present day value of all costs in the outlook period.

### 3.8.1 Inflation

Monetary values in the models refer to real value as opposed to nominal value. That is, future values were not adjusted by assumptions about inflation, whereas values defined in the past were adjusted to account for inflation.

All figures AEMO uses are in the 2016 real dollar value.

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

### 3.8.2 Goods and Services Tax

Prices were modelled exclusive of Goods and Service Tax.

### 3.8.3 Discount rate

AEMO used a 7% discount rate to estimate the time value of money, based on the latest economic indicators.

### 3.8.4 Value of Customer Reliability

A Value of Customer Reliability (VCR) in dollars per kilowatt-hour indicates the value different types of customers place on having reliable electricity supplies under different conditions.

In 2014, AEMO carried out a VCR review to improve understanding of the levels of reliability customers expect and to produce a range of VCR values for residential and business customers.[24] This VCR value was obtained through extensive consultation and surveys, and was used in NTNDP studies to evaluate cost-effective ways to build or upgrade infrastructure.

For estimating the reliability cost, AEMO did not distinguish between residential or business customers, but used an aggregated value for VCR for each region. This is published in the VCR Application Guide.[25]

#### HILP events

High Impact Low Probability (HILP) events can result in widespread and/or prolonged outages. The VCR application guide highlights that the VCR may not accurately estimate the impacts of widespread or prolonged outages[26], and that additional offsets might be required to extrapolate the VCR over time and space.

With the data currently available, AEMO used a sensitivity where VCR was doubled as a proxy to capture the direct and indirect economic impacts of a state-wide blackout. This approach broadly aligns with the South Australian Council of Social Service (SACOSS), who used AEMO's VCR and a sensitivity based on the economic impacts of a similar event, resulting in a multiple approximately 2.42 times the current VCR.[27]

Using the two VCRs, the NTNDP estimated the economic impact of a single hypothetical state-wide blackout in South Australia to be $472 million. This figure is well aligned with the "default blackout cost" of $476 million that was estimated by Deloitte for the Reliability Panel's review of SRAS standards.[28]

[24] AEMO. Value of Customer Reliability Review. Available: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review.

[25] AEMO. *Value of Customer Reliability Application Guide*, December 2014. Available: https://www.aemo.com.au/-/media/Files/PDF/VCR-Application-Guide--Final-report.pdf.

[26] The VCR approach was based on customer surveys. Respondents were not expected to have a good understanding of the social and safety impacts related to widespread or prolonged outages.

[27] SACOSS. Looking Around the Corner—A discussion on Current South Australian Power System Risks. Available: https://www.sacoss.org.au/looking-around-corner-discussion-current-south-australian-power-system-risks.

[28] Australian Energy Market Commission. Economic assessment of System Restart Ancillary Services in the NEM. Available: http://www.aemc.gov.au/getattachment/6e6ad6c7-584c-4993-98f3-7589fec6b506/Deloitte-Access-Economics-Economic-Assessment-of-S.aspx.

# CHAPTER 4. TRANSMISSION ASSET UTILISATION

The purpose of forecasting transmission network utilisation is to assist TNSPs in their decision-making on asset replacements. These calculations estimate power flows for all major transmission lines and transformers, and show the trend in utilisation of these assets.

## 4.1 Connection point traces

Connection point trace development is described in Chapter 4. Connection point traces for transmission asset utilisation were based on the 2013–14 reference year.

## 4.2 Nodal constraint equations

Constraint equations are described in Chapter 3.2. They generally have a single load term to represent the customer demand in an entire region, and are used to simulate generation dispatch. Nodal constraint equations however, have individual load terms for each connection point, and give a more granular representation of power system flows.

Nodal constraint equations were used to estimate the power flow across an individual transmission line or transformer, by calculating the contribution from generators, interconnectors, and loads. The nodal constraint equations used in this study were built from a single high demand snapshot of the NEM.

The following formulas were used:

Typical constraint equation:

$$\sum(\text{LHS Terms} \times \text{Coefficients}) \leq \text{SF} \times \text{Rating} + \text{Constant} + \sum(\text{RHS Terms} \times \text{Coefficients})$$

Rearranging the equation into the form FLOW ≤ RATING gives:

$$\left(\sum\left(\text{Term} \times \text{Coefficient} \times (1 \text{ if LHS Term}, \ -1 \text{ if RHS term})\right) - \text{Constant}\right)/\text{SF} \leq \text{Rating}$$

The left-hand side of this equation is equal to the flow:

$$\left(\sum\left(\text{Term} \times \text{Coefficient} \times (1 \text{ if LHS Term}, \ -1 \text{ if RHS term})\right) - \text{Constant}\right)/\text{SF} = \text{Flow}$$

The full equation used to calculate line flow:

$$P_i(t) = \left(\sum_{j=1}^{j}\left(C_{i,j} \times S_{i,j} \times V_j(t)\right) - K_i\right)\Big/ SF_i$$

where:

| | |
|---|---|
| $i$ | = line/equation |
| $j$ | = parameter |
| $T$ | = time period |
| $P_i(t)$ | = MW flow for line i at time period t |
| $C_{i,j}$ | = Coefficient for parameter j in constraint equation i |
| $S_{i,j}$ | = Which side of equation i parameter j is on (1 if LHS, -1 if RHS) |
| $V_j(t)$ | = Value of parameter j at time period t |
| $K_i$ | = Constant for equation i |
| $SF_i$ | = Scaling Factor for equation i |

The hourly generation and interconnector flows were obtained from the time-sequential models described in Chapter 3.

## 4.3 Normalised flows

The flows were then normalised to the highest flow value observed over the NTNDP outlook period. All values are presented as a percentage of the peak flow observed to provide a normalised flow value.

## 4.4 Scenario assessed

The Neutral scenario with a 10% PoE demand was used to estimate transmission asset utilisation.

## 4.5 Results

The transmission asset utilisation studies will not give a true indication of asset utilisation, since they do not account for any changes in line flow after a credible contingency. These studies are only meant to give TNSPs an indication of asset utilisation trends over the 20-year outlook period.

The 2016 NTNDP included future-looking utilisation data for interconnectors out to 2036. Intra-regional utilisation was assessed based on historical data only.

# CHAPTER 5. SYSTEM RESILIENCE ASSESSMENT

Power system resilience is a complex area with a wide range of inter-related topics. To assess the economic benefits of improving system resilience, AEMO investigated the impacts of non-credible contingencies and prolonged outages on future models of the power system.

## 5.1 Frequency stability

To provide a realistic projection of the risk posed by frequency stability, AEMO calculated the maximum RoCoF for historic and projected conditions. RoCoF was calculated using the following formula:

$$RoCoF\ (t = 0) = \frac{\Delta P}{2H} f_o$$

where:

t = 0 refers to the instantaneous period following a contingency event.

$\Delta P$ = Contingency size, measured in MW.

$H$ = Inertia remaining in system following contingency (MW.s).

$f_o$ = Initial frequency (50 Hz).

For frequency stability studies, AEMO utilised a competitive generator bidding model (Nash-Cournot with unit commitment modelling, see Section 3.2.1) to project likely unit commitment, generation dispatch and interconnector flow. The results of this market simulation were used to calculate the scale of RoCoF for different contingencies.

## 5.2 Weighted Short Circuit Ratio (WSCR)

Power electronic converters are designed to operate with a minimum Short Circuit Ratio, below which they can exhibit various forms of instability including:

- Steady-state voltage collapse.
- Inability to ride through a credible fault.

Generators that are connected to the grid via power electronic converters include wind turbine generators, solar inverters, and static VAr compensators. High Voltage Direct Current interconnectors like Basslink also require a minimum Short Circuit Ratio to operate properly.

Short circuit ratios were generally calculated as the ratio of total fault current (in MVA) over MW capacity of generation. When multiple generators utilising power electronic converters are expected to be connected in close proximity, a Weighted Short Circuit Ratio (WSCR) calculation was carried out as described below:

$$WSCR = \frac{\sum_{i}^{N} S_{SCMVAi} * P_{RMWi}}{(\sum_{i}^{N} P_{RMWi})^2}$$

where:

$S_{SCMVAi}$ = The fault contribution in MVA of the studied bus

$P_{RMWi}$ = $P_{max}$ of all nearby power electronic converter generators

In reality, the WSCR at a given location will fluctuate depending on generator output, but AEMO has assumed that all power electronic converter generators are at maximum output to obtain a more conservative result.

AEMO has run a study, in Section 4.3.1 of the NTNDP, which identifies the maximum capacity of wind generation that can be connected to a given bus, before the WSCR at that bus reaches 3.5.

The 2016 NTNDP reports on the expected trend in WSCR of all regions, based on the Neutral scenario.

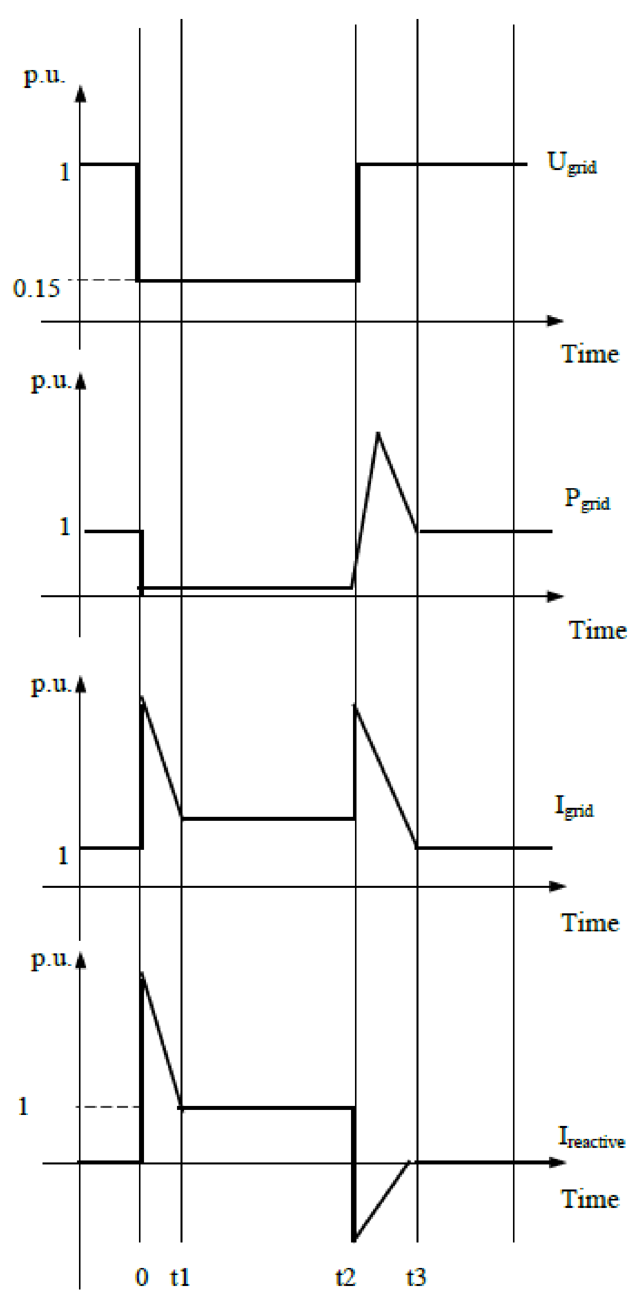
## 5.3 Voltage dips

When a fault occurs in the power system, voltages can dip down to 0 p.u. before the fault is cleared by protection. This temporary reduction in voltage magnitude is called a voltage dip. The depth, spread and duration of a voltage dip are generally worse in weak areas of the power system.

In the 2016 NTNDP studies, AEMO investigated the voltage ride-through characteristics of wind turbines. At a certain threshold (generally between 0.8 p.u. and 0.9 p.u.), most wind farms will suspend active power production and increase reactive power. This can support voltage recovery. Widespread voltage dips, however, have the potential to impact power system frequency, due to the total reduction in active power output. This could lead to protection systems separating areas of the network in response to a power swing.

Wind turbine behaviour during low voltage events is shown in the next figure.

**Figure 6 Wind turbine behaviour during low voltage events**




When a fault occurs at t=0, the wind turbine initially provides a high fault current contribution, ramping down until the time t1. At that stage, the turbine converter takes control and the fault current is maintained at around the rated current. From time t1 through to t2, the wind turbine injects sustained reactive current to assist network voltage recovery. As the voltage returns to normal at t2, active and reactive currents start to ramp back to their pre-fault values.[29]

AEMO used a power system dynamics model to simulate voltage dip in response to network faults in South Australia in today's network. The minimum observed voltage at transmission voltages were recorded and illustrated on a contour map.

[29] Reproduced from: https://www.aemo.com.au/-/media/Files/PDF/Wind_Turbine_Plant_Capabilities_Report.ashx

## 5.4 South Australian system resilience

AEMO identified a number of emerging challenges for South Australian power system resilience, including:

- Frequency stability.
- Transient and voltage stability.
- Poor system strength (focusing on voltage dip, generator fault ride-through, voltage management, power quality, and protection systems).
- Frequency regulation (following a separation event).

While all topics were analysed, frequency stability was used as the basis for evaluating the range of economic benefits from improving system resilience. Frequency stability was selected after AEMO found that rapid frequency fall led to the 28 September 2016 state-wide blackout in South Australia.[30]

The assessment of economic benefits that could be realised from improving South Australian power system resilience used a projection of South Australian inertia and interconnector flow to determine the possible RoCoF following a separation event.[31] This process is described in Section 5.2 of the NTNDP main report.

## 5.5 Tasmania new generation capacity

The Tasmanian electricity network is a small and relatively weak system that is currently facing challenges managing:

- RoCoF – Tasmanian RoCoF is managed using a constraint equation that limits Basslink import and increases local synchronous generation to limit RoCoF following a credible contingency. To facilitate the projected new wind generation, existing hydro generators may have to be operated in synchronous condenser mode to maintain the RoCoF limit in Tasmania. The Australian Energy Market Commission (AEMC) is currently reviewing a rule change to establish an Inertia Ancillary Services Market.[32]
- Voltage control at Georgetown – Georgetown can be at risk of a voltage collapse, during periods of high export, and following a credible contingency. Without additional reactive plant, this risk can be managed by limiting Basslink export, or voluntary generation re-dispatch within Tasmania. The projected new wind generation in Tasmania may be required to procure Voltage Control Ancillary Services (VCAS) or install sufficient reactive capability to mitigate this risk.
- Low fault level – Tasmania can have low fault levels under various operating conditions. The projected new wind generation may be required to install synchronous condensers or other plant that can offer fault level support. The AEMC is currently reviewing a rule change on managing power system fault levels .[33]

AEMO has assumed that new market mechanisms will be in place that can address the RoCoF, voltage control, and low fault level issues highlighted above.

Therefore, there are no further system security issues identified in Tasmania over the 20-year outlook period. Any new wind generation is assumed to be constrained only by thermal limitations and interconnector stability constraints.

[30] AEMO. *Update Report – Black System Event in South Australia on 28 September 2016*. Available at: https://www.aemo.com.au/-/media/Files/Media_Centre/2016/AEMO_19-October-2016_SA-UPDATE-REPORT.pdf.
[31] For this RoCoF assessment, the sudden interruption of 500 MW of generation is included in the contingency for instances where it would result in Heywood flow exceeding 900 MW.
[32] http://www.aemc.gov.au/Rule-Changes/Inertia-Ancillary-Service-Market#.
[33] http://www.aemc.gov.au/Rule-Changes/Managing-power-system-fault-levels.

# CHAPTER 6. REGULATION FREQUENCY CONTROL ANCILLARY SERVICES ASSESSMENT

At present, a minimum of 120 MW of lower regulation and 130 MW of raise regulation are enabled in each period, to manage variability and uncertainty within a dispatch interval in the NEM. These quantities were determined empirically, by operational experience. At present, there is no defined methodology for determining the amount of regulation FCAS required, from first principles. To project the future amount of regulation FCAS required, such a first-principles methodology is needed.

The NEM Mainland Frequency Operating Standards indicate that under normal conditions (when there is no contingency event or load event), the frequency must remain within 49.85 to 50.15 Hz, at least 99% of the time. This provides an indication that regulation FCAS should be sufficient to manage around 99% of supply-demand imbalance events, under normal conditions. On this basis, it is reasonable to expect that a 1% probability of exceedance (1% POE) measure, applied to the most significant sources of supply-demand imbalances, should broadly equate to the empirically determined regulation FCAS requirement.

At present, one major driver of regulation needs is forecast errors. The demand forecast cannot be perfect, and regulation FCAS is the primary mechanism for managing any residual errors. The 1%POE measure was applied to historical demand forecast errors, as indicated in Table 5, compared with the minimum regulation FCAS requirements, determined empirically. The table below shows that the 1% POE measure does give an approximate indication of the empirically determined regulation FCAS requirements, suggesting that it does provide a useful measure.

**Table 5 Comparison of 1% POE for demand forecast errors with empirically determined regulation requirements**

| Region | 1%POE of demand forecast error (5 min) (MW) | | | | Minimum Regulation Raise (MW) | Minimum Regulation Lower (MW) |
|---|---|---|---|---|---|---|
| | 2012 | 2013 | 2014 | 2015 | | |
| NEM | 187 | 186 | 187 | 194 | 130 | 120 |
| Queensland | 124 | 129 | 130 | 136 | 110 | 110 |
| South Australia | 42 | 41 | 44 | 45 | 70 (prior to 2015–16)<br>35 (from 2015–16) | 70 (prior to 2015–16)<br>35 (from 2015–16) |
| Tasmania | 32 | 32 | 31 | 29 | 50 | 50 |

The 1% POE measure was therefore applied to the five-minute change in generation for the potential sources of growing system variability and uncertainty – wind generation, utility-scale PV, and rooftop PV.

Generation data for each technology was aggregated in different ways, producing different installed capacities. For each aggregation, the total generation was calculated in each five-minute interval, and the 1% POE value for the change in five-minute generation calculated.

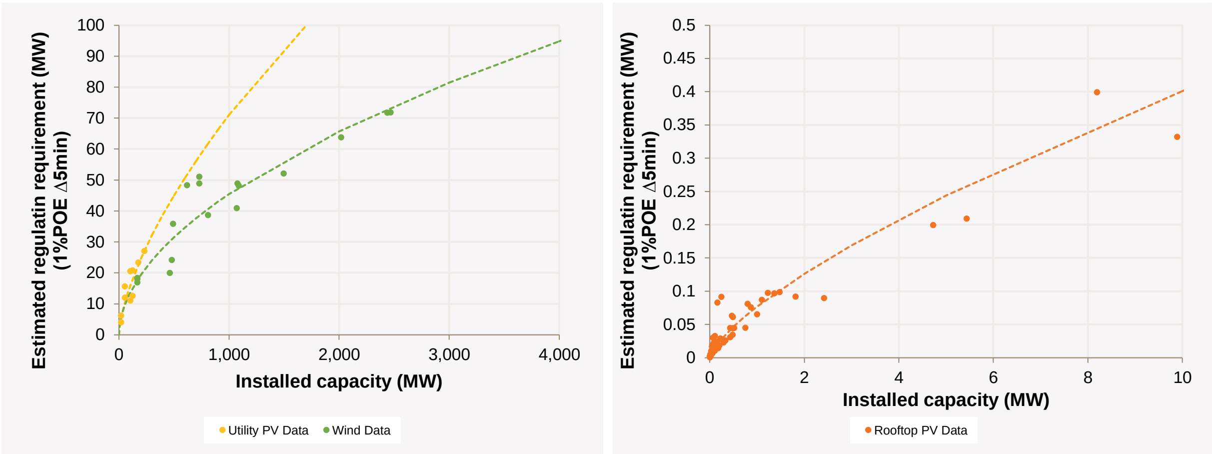
For wind and utility-scale PV, generation data from 2014–15 and 2015–16 was used. For rooftop PV, the data from individual systems was collected from PVoutput.org for 2015–16, and aggregated by the first two postcode digits, and region. The installed capacity of rooftop PV was averaged over the year.

Figure 7 shows the 1% POE of the five-minute change in generation, for each technology, as a function of installed capacity. Each data point represents a different aggregation of the units considered, for a different year, producing a different installed capacity. Based on the analysis discussed above, the 1% POE measure, applied to the five-minute change in generation, is considered to be a reasonable measure of the regulation FCAS required to manage the variability from that source.

Figure 7 illustrates that all three technologies show a diminishing increase in the regulation requirement, as the installed capacity grows. This is due to the increasing amount of geographic diversity, as the installed capacity gets larger and more renewable generation is built across NEM regions. This has been fitted with a power relationship for each technology, as indicated by the dashed lines.

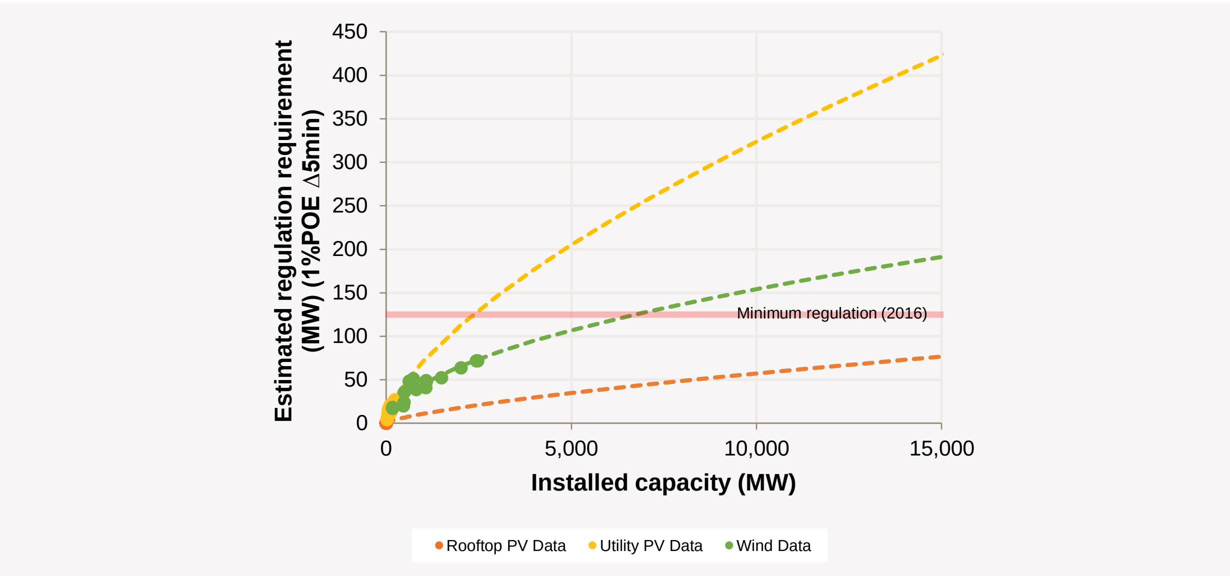
Note that there is very little data available for utility-scale PV, since there are very few plant installed in the NEM at present (only Nyngan (102 MW), Moree (55 MW), Broken Hill (53 MW), and Royalla (21 MW)). This means there is little data on which to base a forward projection of variability, and the results should be interpreted as indicative only. The quantification of this relationship for utility-scale PV will improve as the amount of historical data available grows over time.

**Figure 7 Estimated regulation required as a function of installed capacity for wind, utility-scale PV and rooftop PV**




Based on the power relationships illustrated in Figure 7, the amount of variability anticipated from each technology in future, with larger installed capacities, can be projected. This is illustrated in Figure 8.

**Figure 8 Projected regulation requirement**



It is evident that utility-scale PV is the most significant contributor to variability, with its anticipated regulation needs exceeding the minimum regulation FCAS enablement at approximately 2–3 GW installed capacity. In contrast, rooftop PV makes a relatively minimal contribution to variability, and remains below the minimum regulation FCAS enablement even with more than 15 GW installed. Wind generation is in the middle, exceeding the minimum regulation FCAS enablement at approximately 6–8 GW installed capacity.

These relationships were combined with the projected installed capacities of each technology (summarised in the following section) to calculate the future regulation FCAS requirements in each year, as presented in section 4.2 of the main NTNDP report.

## Projection of installed capacities

The projection of future regulation FCAS requirements is directly dependent on the projection of the future installed capacities of variable technologies. Table 6 summarises the modelling outcomes for the installed capacities of wind, utility-scale PV, and rooftop PV, from the Neutral scenario, which have been applied for these regulation FCAS projections.

**Table 6 Projected renewable generation installed capacity – Neutral scenario Base Case (MW)**

| Technology | Region | 2016–17 | 2021–22 | 2026–27 | 2035–36 |
|---|---|---|---|---|---|
| **Large-scale PV** | **NEM** | **211** | **1,248** | **1,900** | **13,350** |
| | NSW | 211 | 231 | 231 | 6,097 |
| | QLD | 0 | 311 | 311 | 3,441 |
| | SA | 0 | 0 | 0 | 1,106 |
| | VIC | 0 | 706 | 1,358 | 2,705 |
| | TAS | 0 | 0 | 0 | 0 |
| **Rooftop PV** | **NEM** | **4,939** | **8,565** | **12,636** | **19,050** |
| | NSW | 1,278 | 2,355 | 3,494 | 5,513 |
| | QLD | 1,737 | 2,817 | 4,063 | 6,066 |
| | SA | 718 | 1,115 | 1,549 | 1,942 |
| | VIC | 1,094 | 2,069 | 3,202 | 5,004 |
| | TAS | 113 | 209 | 327 | 526 |
| **Wind** | **NEM** | **3,689** | **8,463** | **11,953** | **13,238** |
| | NSW | 609 | 1,662 | 3,030 | 3,030 |
| | QLD | 0 | 279 | 354 | 354 |
| | SA | 1,607 | 3,037 | 3,037 | 3,037 |
| | VIC | 1,166 | 2,858 | 4,635 | 5,781 |
| | TAS | 307 | 627 | 898 | 1,037 |

# CHAPTER 7. NSCAS

Network Support and Control Ancillary Services (NSCAS) are a non-market ancillary service that may be procured by AEMO or TNSPs to maintain power system security and reliability, and to maintain or increase the power transfer capability of the transmission network.

NSCAS requirements are assessed based on a Quantity Procedure[34] which was developed in consultation with NEM market participants.

A high level overview of the steps taken to assess NSCAS gaps is given below:

- Prepare load flow study cases considering both maximum and minimum regional demand, and only committed generation or transmission network changes, for a five-year outlook horizon (from 2016–17 to 2020–21).
- Identify potential reactive power shortfalls.
- Identify potential over voltages.
- Identify potential thermal overloads.
- Identify system inertia or network strength shortfalls.
- Identify binding constraints[35] that have a market impact of over $50,000 annually, and identify if procuring NSCAS will result in a net market benefit.

All constraints that result in a high market impact are reported in the NTNDP, even if it does not require any NSCAS.

[34] AEMO. Network support and control ancillary services procedures and guidelines. Available: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Network-support-and-control-ancillary-services-procedures-and-guidelines.

[35] Excluding any constraints associated with frequency control ancillary services.

# APPENDIX A. NTNDP DATABASE

**Table 7 NTNDP assumptions database**

| Report | Date available | Description |
|---|---|---|
| 2015 Australian Power Generation and Technology Report | 11 Aug 2016 | This document provides information on power generation technology costs that are applied in the 2016 Planning Studies. |
| 2016 Coal Cost Data (Wood Mackenzie) | 11 Aug 2016 | This dataset presents the assumed coal price inputs into AEMO's time-sequential database. |
| 2016 Coal Cost Report (Wood Mackenzie) | 11 Aug 2016 | This document provides an overview of the assumed coal price inputs in 2016 Planning Studies. |
| 2016 Emissions Factor Assumptions Data (ACIL Allen) | 11 Aug 2016 | This dataset presents the assumed emissions factors used in AEMO's planning publications. |
| 2016 Emissions Factor Assumptions Update (ACIL Allen) | 11 Aug 2016 | This document provides the methodology and results from ACIL Allen's review of generator emissions data. |
| 2016 Generation and Transmission outlooks | 12 Dec 2016 | The generation outlook provides a view of the generation required to meet expected operational demand and consumption across the NEM over the next 20 years. The transmission outlook uses the generation outlook to provide a strategic view of the efficient development of the transmission grid over the next 20 years. Separate spreadsheets have been provided for each scenario examined in the 2016 NTNDP. |
| 2016 NTNDP Database Input Data Traces | 23 Dec 2016 | This dataset presents the assumed operational demand, PV, and wind generation traces for the modelling horizon. For variable generation traces, the dataset includes traces by generation technology, per planning zone. |
| 2016 Planning Studies - Additional Modelling Data and Assumptions Summary | 12 Dec 2016 | A spreadsheet containing a broad range of modelling data and input assumptions that were applied in the 2016 Planning Studies. |
| Annual Planning Reports summary | 12 Dec 2016 | A consolidated summary of TNSP projects listed in their 2016 Annual Planning Reports, and how they relate to the 2016 NTNDP. |
| February 2016 Gas Pricing Consultancy Databook (Core Energy Group) | 18 Jun 2016 | This document provides wholesale gas price inputs into AEMO's time-sequential database for the 2016 Planning Studies. |
| Fuel and Technology Cost Review – Data (ACIL Allen) | 12 Jun 2014 | Some of the properties for existing generators shown in this report are used in the 2016 NTNDP, unless they are included in the 2016 *Planning Studies - Additional Modelling Data and Assumptions* summary, which take priority. |
| Market Modelling Methodology and Input Assumptions | 23 Dec 2016 | This document provides an overview of the modelling methodologies and assumptions employed for the AEMO's 2016 planning reports, including NTNDP, ESOO, Gas Statement of Opportunities (GSOO), and VAPR. |
| National Electricity Forecast Report | 18 Jun 2016 | The NEFR provides AEMO's independent electricity consumption forecasts, developed on a consistent basis over the next 10 years for the five National Electricity Market (NEM) regions (New South Wales (including ACT), Queensland, South Australia, Tasmania, and Victoria). |

# GLOSSARY

This document uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified.

| Term | Definition |
|---|---|
| **active power** | Also known as electrical power. A measure of the instantaneous rate at which electrical energy is consumed, generated or transmitted. In large electric power systems it is measured in megawatts (MW) or 1,000,000 watts. |
| **ancillary services** | Services used by AEMO that are essential for:<br>• Managing power system security.<br>• Facilitating orderly trading.<br>• Ensuring electricity supplies are of an acceptable quality.<br>This includes services used to control frequency, voltage, network loading and system restart processes, which would not otherwise be voluntarily provided by market participants on the basis of energy prices alone.<br>Ancillary services may be obtained by AEMO through either market or non-market arrangements. |
| **annual planning report** | An annual report providing forecasts of gas or electricity (or both) supply, capacity, and demand, and other planning information. |
| **augmentation** | The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline. |
| **capacity for reliability** | The allocated installed capacity required to meet a region's minimum reserve level (MRL). When met, sufficient supplies are available to the region to meet the Reliability Standard.<br>Capacity for reliability = 10% probability of exceedance (POE) scheduled and semi-scheduled maximum demand + minimum reserve level – committed demand-side participation. |
| **capacity limited** | A generating unit whose power output is limited. |
| **committed project** | Committed transmission projects include new transmission developments below $5 million that are published in the TNSPs' Annual Planning Reports, or those over $5 million that have completed a Regulatory Investment Test.<br>Committed generation projects include all new generation developments that meet all five criteria specified by AEMO for a committed project. |
| **connection point (electricity)** | The agreed point of supply established between network service provider(s) and another registered participant, non-registered customer or franchise customer. |
| **constraint equation** | The mathematical expression of a physical system limitation or requirement that must be considered by the central dispatch algorithm when determining the optimum economic dispatch outcome.<br>See also network constraint equation. |
| **contingency** | An event affecting the power system that is likely to involve an electricity generating unit's or transmission element's failure or removal from service. |
| **consumer** | A person or organisation who engages in the activity of purchasing electricity supplied through a transmission or distribution system to a connection point. |
| **credible contingency** | Any outage that is reasonably likely to occur. Examples include the outage of a single electricity transmission line, transformer, generating unit, or reactive plant, through one or two phase faults. |
| **customer** | See consumer. |
| **demand** | See electricity demand. |
| **demand-side management** | The act of administering electricity demand-side participants) possibly through a demand-side response aggregator). |
| **demand-side participation** | The situation where consumers vary their electricity consumption in response to a change in market conditions, such as the spot price. |
| **distribution network** | A network which is not a transmission network. |
| **electrical energy** | Energy can be calculated as the average electrical power over a time period, multiplied by the length of the time period. |

| Term | Definition |
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| | Measured on a sent-out basis, it includes energy consumed by the consumer load, and distribution and transmission losses.<br>In large electric power systems, electrical energy is measured in gigawatt hours (GWh) or 1,000 megawatt hours (MWh). |
| **electrical power** | Electrical power is a measure of the instantaneous rate at which electrical energy is consumed, generated or transmitted. In large electric power systems it is measured in megawatts (MW) or 1,000,000 watts.<br>Also known as active power. |
| **electricity demand** | The electrical power requirement met by generating units. The Electricity Statement of Opportunities (ESOO) reports demand on a generator-terminal basis, which includes:<br>• The electrical power consumed by the consumer load.<br>• Distribution and transmission losses.<br>• Power station transformer losses and auxiliary loads.<br>• The ESOO reports demand as half-hourly averages. |
| **embedded generating unit** | A generating unit connected within a distribution network and not having direct access to the transmission network. |
| **embedded generator** | A generator who owns, operates or controls an embedded generating unit. |
| **energy** | See electrical energy. |
| **generating system** | A system comprising one or more generating units that includes auxiliary or reactive plant that is located on the generator's side of the connection point. |
| **generating unit** | The actual generator of electricity and all the related equipment essential to its functioning as a single entity. |
| **generation** | The production of electrical power by converting another form of energy in a generating unit. |
| **generation capacity** | The amount (in megawatts (MW)) of electricity that a generating unit can produce under nominated conditions.<br>The capacity of a generating unit may vary due to a range of factors. For example, the capacity of many thermal generating units is higher in winter than in summer. |
| **generation expansion plan** | A plan developed using a special algorithm that models the extent of new entry generation development based on certain economic assumptions. |
| **generator** | A person who engages in the activity of owning, controlling or operating a generating system that is connected to, or who otherwise supplies electricity to, a transmission or distribution system and who is registered by AEMO as a generator under Chapter 2 (of the NER) and, for the purposes of Chapter 5 (of the NER), the term includes a person who is required to, or intends to register in that capacity. |
| **impedance** | Electrical impedance represents how much opposition a conductor poses to the flow of electricity. |
| **inertia** | Produced by synchronous generators, inertia dampens the impact of changes in power system frequency, resulting in a more stable system. Power systems with low inertia experience faster changes in system frequency following a disturbance, such as the trip of a generator. |
| **installed capacity** | Refers to generating capacity (in megawatts (MW)) in the following context:<br>• A single generating unit.<br>• A number of generating units of a particular type or in a particular area.<br>• All of the generating units in a region. |
| **interconnector** | A transmission line or group of transmission lines that connects the transmission networks in adjacent regions. |
| **interconnector flow** | The quantity of electricity in MW being transmitted by an interconnector. |
| **Large-scale Renewable Energy Target (LRET)** | A federal government target that 33,000 GWh of large scale generation must come from renewable energy sources by 2020. |
| **limitation (electricity)** | Any limitation on the operation of the transmission system that will give rise to unserved energy (USE) or to generation re-dispatch costs. |
| **load** | A connection point or defined set of connection points at which electrical power is delivered to a person or to another networks or the amount of electrical power delivered at a defined instant at a connection pint, or aggregated over a defined set of connection points. |

| Term | Definition |
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| **maximum demand** | The highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, or year) either at a connection point, or simultaneously at a defined set of connection points. |
| **National Electricity Law** | The National Electricity Law (NEL) is a schedule to the National Electricity (South Australia) Act 1996, which is applied in other participating jurisdictions by application acts. The NEL sets out some of the key high-level elements of the electricity regulatory framework, such as the functions and powers of NEM institutions, including AEMO, the AEMC, and the AER. |
| **National Electricity Market (NEM)** | The wholesale exchange of electricity operated by AEMO under the NER. |
| **National Electricity Rules (NER)** | The National Electricity Rules (NER) describes the day-to-day operations of the NEM and the framework for network regulations. See also National Electricity Law. |
| **national transmission flow path** | That portion of a transmission network or transmission networks used to transport significant amounts of electricity between generation centres and load centres. Generally refers to lines of nominal voltage of 220kV and above. |
| **national transmission grid** | See national transmission flow paths. |
| **National Transmission Network Development Plan (NTNDP)** | An annual report to be produced by AEMO that replaces the existing National Transmission Statement (NTS) from December 2010.<br>Having a 20-year outlook, the NTNDP will identify transmission and generation development opportunities for a range of market development scenarios, consistent with addressing reliability needs and maximising net market benefits, while appropriately considering non-network options. |
| **National Transmission Planner** | AEMO acting in the performance of National Transmission Planner functions. |
| **National Transmission Planner (NTP) functions** | Functions described in section 49(2) of the National Electricity Law. |
| **net market benefit** | Refers to market benefits of an augmentation option minus the augmentation cost. The market benefit of an augmentation is defined in the regulatory investment test for transmission developed by the Australian Energy Regulator. |
| **network** | The apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity to consumers (whether wholesale or retail) excluding any connection assets. In relation to a network service provider, a network owned, operated or controlled by that network service provider. |
| **network capability** | The capability of the network or part of the network to transfer electricity from one location to another. |
| **network congestion** | When a transmission network cannot accommodate the dispatch of the least-cost combination of available generation to meet demand. |
| **network constraint equation** | A constraint equation deriving from a network limit equation. Network constraint equations mathematically describe transmission network technical capabilities in a form suitable for consideration in the central dispatch process. See also 'constraint equation'. |
| **network limit** | Defines the power system's secure operating range. Network limits also take into account equipment/network element ratings. |
| **network limitation** | Network limitation describes network limits that cause frequently binding network constraint equations, and can represent major sources of network congestion. See also network congestion. |
| **network service** | Transmission service or distribution service associated with the conveyance, and controlling the conveyance, of electricity through the network. |
| **network service provider (NSP)** | A person who engages in the activity of owning, controlling or operating a transmission or distribution system and who is registered by AEMO as a network service provider under Chapter 2 (of the NER). |
| **non-credible contingency** | Any outage for which the probability of occurrence is considered very low. For example, the coincident outages of many transmission lines and transformers, for different reasons, in different parts of the electricity transmission network. |
| **non-network option** | An option intended to relieve a limitation without modifying or installing network elements. Typically, non-network options involved demand-side participation (including post contingent load relief) and new generation on the load side for the limitation. |
| **power** | See 'electrical power'. |
| **power station** | In relation to a generator, a facility in which any of that generator's generating units are located. |

| Term | Definition |
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| power system | The National Electricity Market’s (NEM) entire electricity infrastructure (including associated generation, transmission, and distribution networks) for the supply of electricity, operated as an integrated arrangement. |
| power system reliability | The ability of the power system to supply adequate power to satisfy customer demand, allowing for credible generation and transmission network contingencies. |
| power system security | The safe scheduling, operation, and control of the power system on a continuous basis in accordance with the principles set out in clause 4.2.6 (of the NER). |
| reactive energy | A measure, in varhour (varh), of the alternating exchange of stored energy in inductors and capacitors, which is the time-integral of the product of voltage and the out-of-phase component of current flow across a connection point. |
| reactive power | The rate at which reactive energy is transferred. Reactive power, which is different to active power, is a necessary component of alternating current electricity.<br>In large power systems it is measured in MVAr (1,000,000 volt-amperes reactive). It is predominantly consumed in the creation of magnetic fields in motors and transformers and produced by plant such as:<br>• Alternating current generators.<br>• Capacitors, including the capacitive effect of parallel transmission wires.<br>• Synchronous condensers.<br>Management of reactive power is necessary to ensure network voltage levels remains within required limits, which is in turn essential for maintaining power system security and reliability. |
| region | An area determined by the AEMC in accordance with Chapter 2A (of the NER), being an area served by a particular part of the transmission network containing one or more major load centres of generation centres or both. |
| regulatory investment test for transmission (RIT-T) | The test developed and published by the AER in accordance with clause 5.6.5B, including amendments.<br>The test is to identify the most cost-effect option for supplying electricity to a particular part of the network. It may compare a range of alternative projects, including, but not limited to, new generation capacity, new or expanded interconnection capability, and transmission network augmentation within a region, or a combination of these. |
| reliability | The probability that plant, equipment, a system, or a device, will perform adequately for the period of time intended, under the operating conditions encountered. Also, the expression of a recognised degree of confidence in the certainty of an event or action occurring when expected. |
| Reliability and Emergency Reserve Trader (RERT) | The actions taken by AEMO in accordance with clause 3.20 (of the NER) to ensure reliability of supply by negotiating and entering into contracts to secure the availability of reserves under reserve contracts. These actions may be taken when:<br>• Reserve margins are forecast to fall below minimum reserve levels (MRLs), and<br>• A market response appears unlikely. |
| rooftop photovoltaic (PV) | Includes both residential and commercial photovoltaic installations that are typically installed on consumers’ rooftops. |
| scenario | A consistent set of assumptions used to develop forecasts of demand, transmission, and supply. |
| scheduling | The process of scheduling nominations and increment/decrement offers, which AEMO is required to carry out in accordance with the NGR, for the purpose of balancing gas flows in the transmission system and maintaining the security of the transmission system. |
| security | Security of supply is a measure of the power system's capacity to continue operating within defined technical limits even in the event of the disconnection of a major power system element such as an interconnector or large generator. |
| substation | A facility at which two or more lines are switched for operational purposes. May include one or more transformers so that some connected lines operate at different nominal voltages to others. |
| supply | The delivery of electricity. |
| synchronous condenser | Synchronous condensers are synchronous machines that are specially built to supply only reactive power. The rotating mass of synchronous condensers will contribute to the total inertia of the network from its stored kinetic energy. |
| trading interval | A 30 minute period ending on the hour (EST) or on the half hour and, where identified by a time, means the 30 minute period ending at that time. |

| Term | Definition |
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| **transmission network** | A network within any participating jurisdiction operating at nominal voltages of 220 kV and above plus:<br>• Any part of a network operating at nominal voltages between 66 kV and 220 kV that operates in parallel to and provides support to the higher voltage transmission network.<br>• Any part of a network operating at nominal voltages between 66 kV and 220 kV that is not referred to in paragraph (a) but is deemed by the Australian Energy Regulator (AER) to be part of the transmission network. |
| **voltage instability** | An inability to maintain voltage levels within a desired operating range. For example, in a 3-phase system, voltage instability can lead to all three phases dropping to unacceptable levels or even collapsing entirely. |