2012

NATIONAL TRANSMISSION NETWORK DEVELOPMENT PLAN

For the National Electricity Market

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EXECUTIVE SUMMARY

The 2012 National Transmission Network Development Plan (NTNDP) shows less transmission investment is required compared to previous estimates and there is a clear opportunity to achieve integration and efficiency from this investment.

The 2012 report reflects changes in the energy environment since the 2010 and 2011 NTNDPs including lower electricity demand and energy forecasts and higher projected gas costs. The NTNDP takes a least-cost approach to the development of the power system and reflects AEMO's best estimate of economic and policy outlooks.

$4 billion in transmission investment to meet demand

Lower forecast demand growth has resulted in a revised estimate in 2012 of $4 billion over twenty years. Previous NTNDP modelling estimated required investment of $7 billion in the main transmission networks over the same time frame.

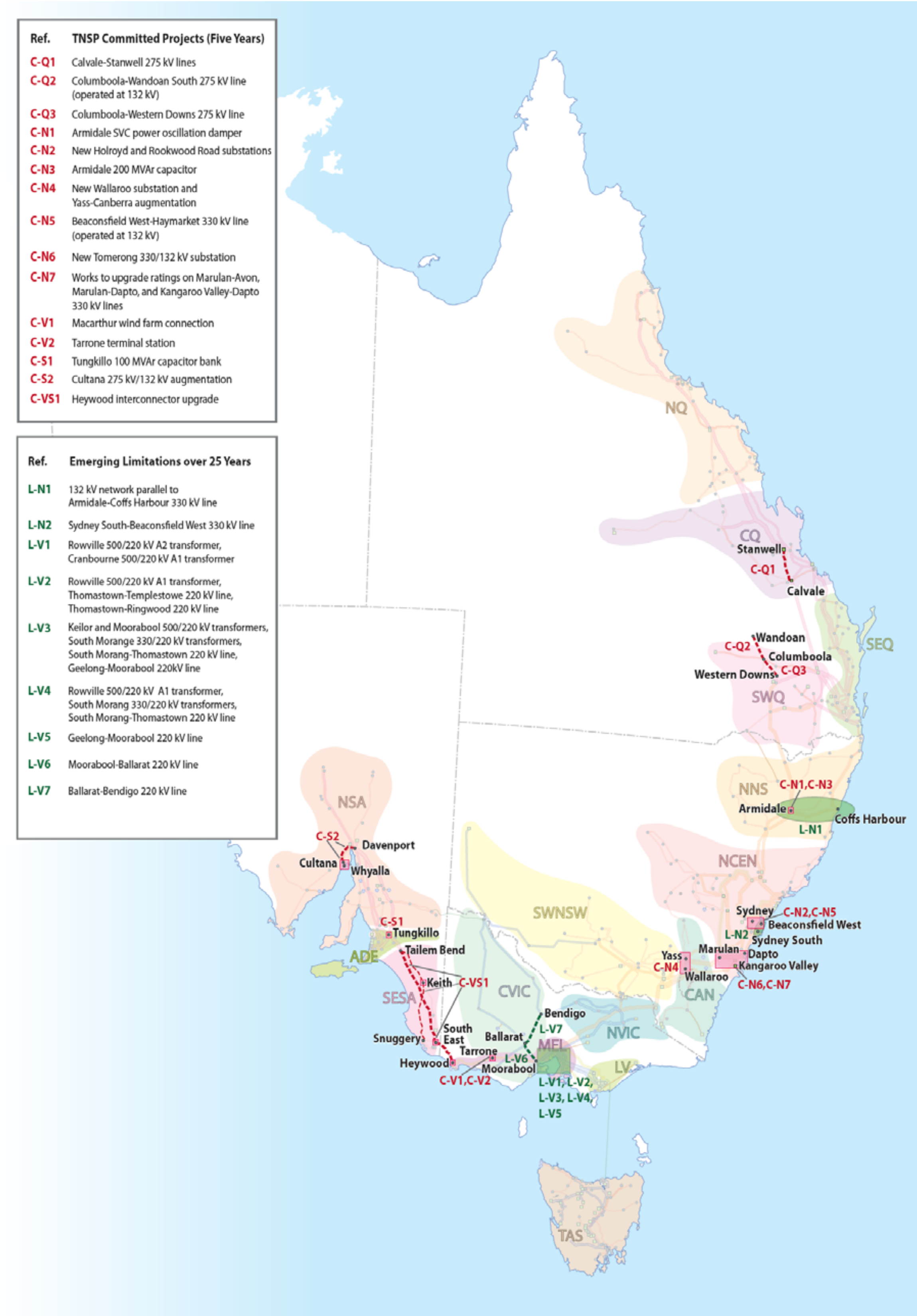
In addition to main transmission network augmentation, further investment will also be needed to replace old assets and augment transmission networks.

Other findings from the 2012 NTNDP modelling for transmission investment:

- Most main transmission network limitations are due to demand growth in major load centres. Some limitations, however, are driven by changed power flow patterns resulting from new generation and possible generation retirement.
- There is generally sufficient capability in the main transmission network for new generation to connect at locations which allow for growth avoiding the need for significant new transmission investment.

Figure 1 provides a map of the National Electricity Market (NEM) showing committed main transmission projects, and emerging limitations for the least-cost development of the power system over the outlook period.

Figure 1 — Committed TNSP main transmission projects over five years and emerging limitations over 25 years



New generation investment outlook

To develop an efficient national electricity network, the NTNDP's least-cost expansion planning locates new generation to minimise the total cost of new generation and transmission, while still meeting reliability standards.

Previous NTNDP modelling estimated required generation investment of $65 billion over the next 20 years. Lower forecast demand growth, however, has resulted in a revised estimate in 2012 of $26 billion.

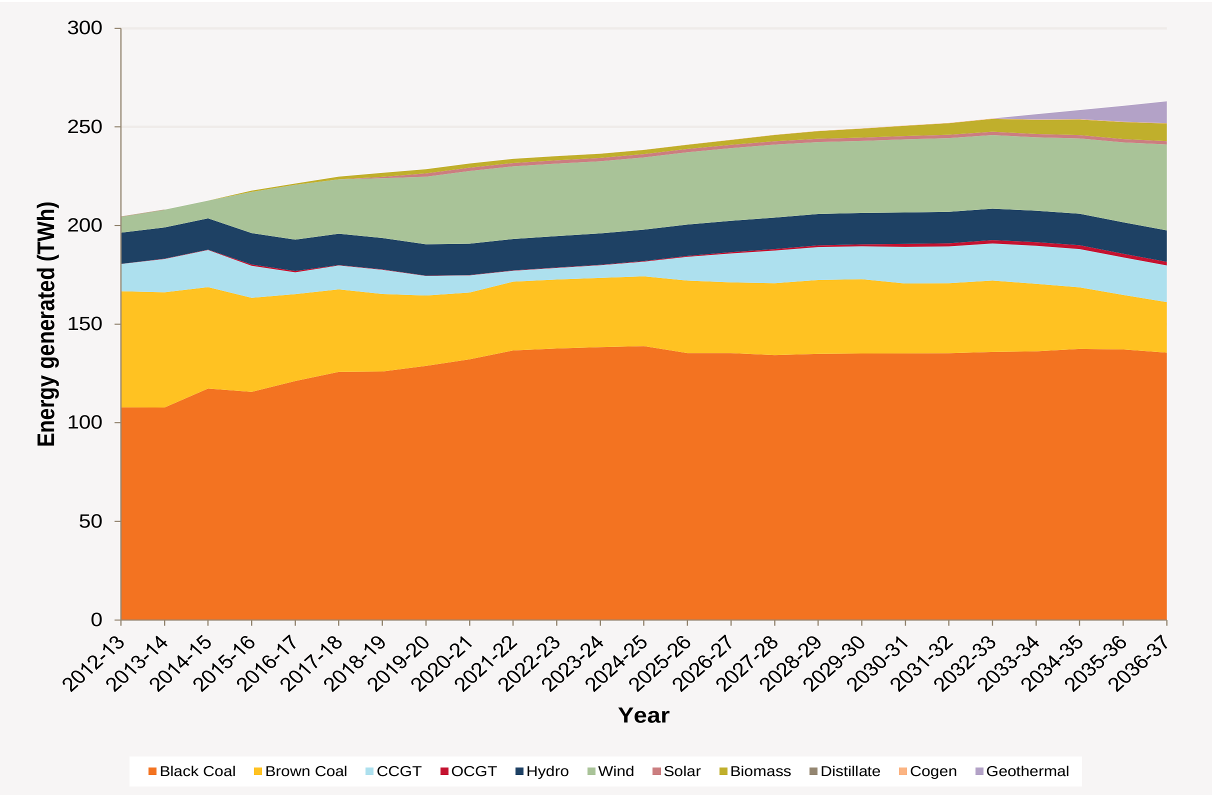
Key findings from the 2012 NTNDP modelling for generation investment involve the following:

- Eastern and South Eastern Australia will still rely on coal-fired generation during the outlook period, and new generation investment until 2020 (particularly wind generation) will primarily be driven by the Large-scale Renewable Energy Target (LRET).
- The carbon price, new renewable generation resulting from the LRET, a changing fuel mix and lower energy growth will change the operation and output of different types of electricity generation.
- Least-cost modelling, assuming Treasury's core carbon price projections, retires or mothballs 4,300 MW of brown and black coal-fired generation, which constitutes 16% of the current coal-fired installed capacity, over the outlook period, with the remaining coal-fired generation maintaining its competitiveness.
- There is less need for combined cycle gas turbine (CCGT) generation, which requires a higher carbon price or lower gas fuel prices than modelled to compete with coal.

  There is a need for additional generation to meet peak demand, however, and this will largely be met by open cycle gas turbine (OCGT) generation, which provides reliable generation reserves in an environment of significant levels of intermittent generation (such as wind) and reduced coal-fired generation.
- Greenhouse gas emissions from electricity generation in Eastern Australia will largely persist at current levels, before decreasing at the end of the outlook period.

Figure 2 shows the projected energy generated by technology over the outlook period.

Figure 2 — Energy generation by technology



Network Support and Control Ancillary Service outlook

The 2012 NTNDP incorporates a suite of documents which have been published on the AEMO website including a 2012 Network Support and Control Ancillary Service (NSCAS) assessment report.

The report shows the only gap for maintaining security is identified in New South Wales, requiring up to 800 MVAr of absorbing reactive power for the next five years, consistent with last year's assessment. Two potential NSCAS gaps for increasing power transfer capability to maximise net economic benefit are also identified.

Well-developed transmission network essential for market integration

The Australian energy landscape has changed following the introduction of a carbon price, the impact of gas prices and increased investment in renewable technologies. The efficient integration of different energy sources and technologies will become increasingly important in the electricity and gas markets.

A well-developed transmission network is a key to meeting the National Electricity Objective of efficient investment in, and efficient operation and use of, electricity services for the long term interests of electricity consumers.

Slowing electricity demand growth and likely future economic and policy conditions suggest there will be less need for additional capacity on single interconnectors within the outlook period. An exception is the upgrade of the Heywood interconnector between South Australia and Victoria, which is currently in the final stages of a Regulatory Investment Test.

As the national planner, AEMO is committed to enhancing market integration where this is economically justified, and has been exploring more coordinated upgrades of multiple interconnectors. The NEMLink concept was one option examined by previous NTNDP modelling. It does not appear viable under current market conditions.

In 2012 AEMO published an Economic Planning Study which looked at the benefits of a cost benefit approach to network investment with the aim of providing a better service-price balance for customers.

The report available on AEMO's website shows network costs could be significantly reduced if an economic planning approach was adopted across the NEM.

AEMO will continue to monitor economic and policy environments and explore alternative scenarios and opportunities to support further market integration.

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CHAPTER 1 - INTRODUCTION

1.1 Introduction

The National Transmission Network Development Plan's (NTNDP) overall objective is to facilitate the development of an efficient national electricity network that considers potential transmission and generation investments. The NTNDP provides an independent strategic plan offering nationally consistent information about transmission capabilities, congestion, and investment options for a range of plausible market development scenarios.

In 2010, the NTNDP provided an independent strategic plan for the National Electricity Market (NEM) transmission network, which delivered a comprehensive review of electricity transmission development needs for the next 20 years.

Rather than requiring a yearly update of a strategic plan, AEMO believes it more efficient to update the plan in response to changes in the economic and policy environment that drives the plan.

In response to stakeholder feedback, the 2011 NTNDP built on the work completed in 2010 by providing additional information relating to the 2010 results, and new or improved ways for transmission planners and the industry generally to approach the issues the 2010 NTNDP identified.

As there have now been significant changes in the input conditions, the 2012 NTNDP provides a new strategic 25-year plan for the NEM transmission network, replacing the 2010 plan. Overall, the NTNDP aims to support optimal asset investments in an environment with lower energy consumption growth, increasing costs, and scrutiny of network investment following high-profile reviews.

AEMO has extended the outlook period to 25 years to provide the flexibility of not needing to update the strategic plan every year while still maintaining at least a 20-year future view.

1.2 Background to the NTNDP

The NTNDP is one of a collection of key planning publications that AEMO issues annually. Together with these publications (listed in Section 1.6), the NTNDP aims to provide the energy market with a comprehensive body of information to assist investors with understanding the issues facing the NEM, and the way development of the transmission network is likely to evolve under two scenarios.

Developing optimum development options and opportunities

The need to maintain competitive neutrality drives AEMO to explore and effectively communicate development options that deliver optimum benefits, whether they involve generation, transmission, demand-side or non-network responses, or other electricity industry sectors. To achieve this, the NTNDP seeks to influence transmission investment in a number of different ways:

- Providing a national focus on market benefits and transmission augmentations to support an efficient power system.
- Proposing a range of plausible future scenarios and exploring their electricity supply industry impacts, with an emphasis on identifying national transmission network limitations under those scenarios, and providing a consistent plan that identifies their transmission network needs.
- Identifying network needs early to increase the time available to identify non-network options, including demand-side and generation options.

2012 NTNDP least-cost expansion planning

The 2012 NTNDP's least-cost expansion planning locates new generation to minimise the total cost of new generation and transmission, while still meeting reliability standards.

Generation investments in the NEM, however, are made in a market context without central planning, while shared transmission investments are centrally planned by AEMO and the transmission network service providers (TNSP).[1]

Attempting to model the commercial decisions of investors over a 25-year timeframe is complex and can produce volatile results, requiring assumptions that are very likely to change over that timeframe. Critical assumptions include the following:

- The structure of the supply-side (generation) industry may well change, with future mergers or break-ups affecting the level of competition and pricing outcomes, which will in turn affect investment decisions.
- Market rules may change, with the existing rules that recover shared transmission costs from customers potentially changing under proposals being considered by the Australian Energy Market Commission. If changes are made that internalise transmission costs, this will favour generators located closer to loads.

As a result, in its least-cost modelling AEMO assumes that the competition and regulatory environment will develop to support construction of the most efficient total power system over time, including both transmission and generation. This assumes that material market failures will be resolved.

1.3 Scenario modelling and the NTNDP

The NTNDP considers two scenarios:

- The Planning scenario represents AEMO's best estimate of how the future will develop.
- The Slow Rate of Change scenario describes a world characterised by lower economic growth, low commodity prices, and a carbon price that dips effectively to zero after an initial three-year fixed-price period.

For more information about the scenarios used for the NTNDP, and the way they relate to the scenarios used in AEMO's other energy planning studies, see Chapter 5.

1.4 Responses to emerging issues

Price increases and falling electricity demand growth

Historically, the NEM experienced general increases in annual energy and maximum demand. Recently, however, annual energy growth has declined or stopped, depending on location, and future growth rate expectations are generally being revised downwards. Maximum demand is also growing less quickly.

Reasons for this change include changes in economic outlook, significant recent rooftop solar photovoltaic installations, which reduce the energy taken from the power system, and changes in customer behaviour in response to highly publicised electricity price increases (including the use of more energy-efficient devices). Significant price increases have also driven scrutiny of network investment and how further price increases can be contained by improving the efficiency of investment. The changing drivers of energy demand are addressed in AEMO's National Electricity Forecasting Report (NEFR) published in June 2012.[2]

Network limitations and potential solutions considered in the 2012 NTNDP reflect this changing environment (involving an overall decrease in annual energy and maximum demand growth), and the NTNDP's least-cost expansion plan modelling results provide AEMO's view of how the NEM's generation and transmission might be most efficiently developed.

1 When generation investments are committed, AEMO and TNSP transmission planning takes them into account.

2 AEMO, Available http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012. Viewed 4 December 2012.

1.5 The NEM transmission network

Currently, the NEM transmission network supports the provision of power to most of Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania, and South Australia, and has the following key features:

- The network supplies 19 million residents and approximately 200,000 gigawatt hours (GWh) of energy to both businesses and households each year, meeting maximum demand of approximately 36,000 MW.
- Extending over 5,000 kilometres from Far North Queensland to Tasmania and west to Adelaide and Port Augusta with approximately 40,000 kilometres of transmission lines and cables, the network is one of the longest alternating current (AC) systems in the world.
- Comprising strong regional transmission networks connected with modest cross-border transmission capability, the network is long and linear compared to Europe and North America, where power systems are generally more strongly meshed.
- Due to the large distances and resulting high capital costs of new transmission investment, the network is potentially costly to upgrade.

Figure 1-1 shows a map of the NEM transmission network.

Figure 1-1 — The National Electricity Market transmission network

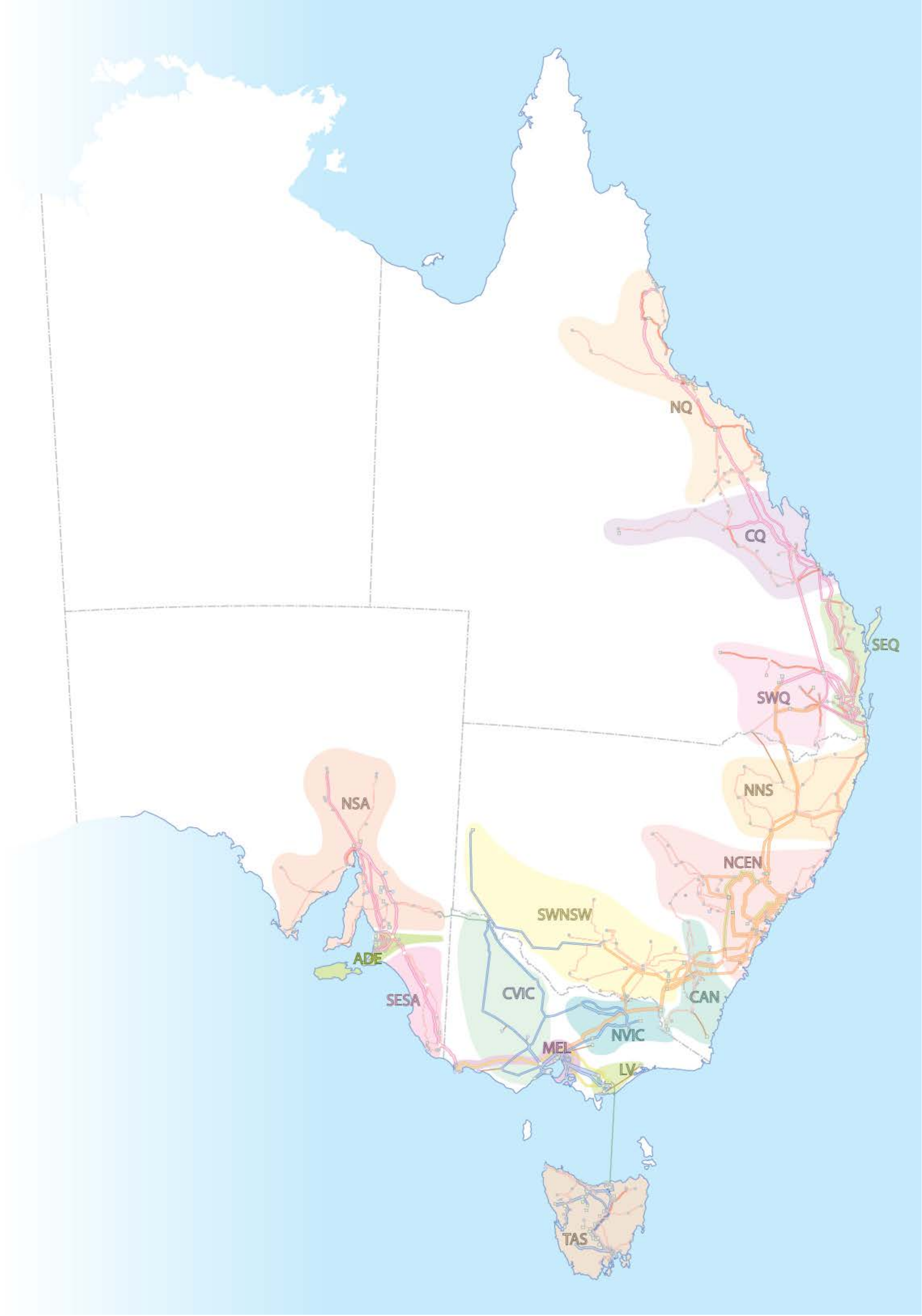


Table 1-1 lists the NTNDP zones and their abbreviations.

Table 1-1 — NTNDP zone abbreviations

NTNDP zone	Zone abbreviation
North Queensland	NQ
Central Queensland	CQ
South West Queensland	SWQ
South East Queensland	SEQ
Northern New South Wales	NNS
Central New South Wales	NCEN
Canberra	CAN
South West New South Wales	SWNSW
Latrobe Valley	LV
Melbourne	MEL
Country Victoria	CVIC
Northern Victoria	NVIC
Adelaide	ADE
Northern South Australia	NSA
South East South Australia	SESA
Tasmania	TAS

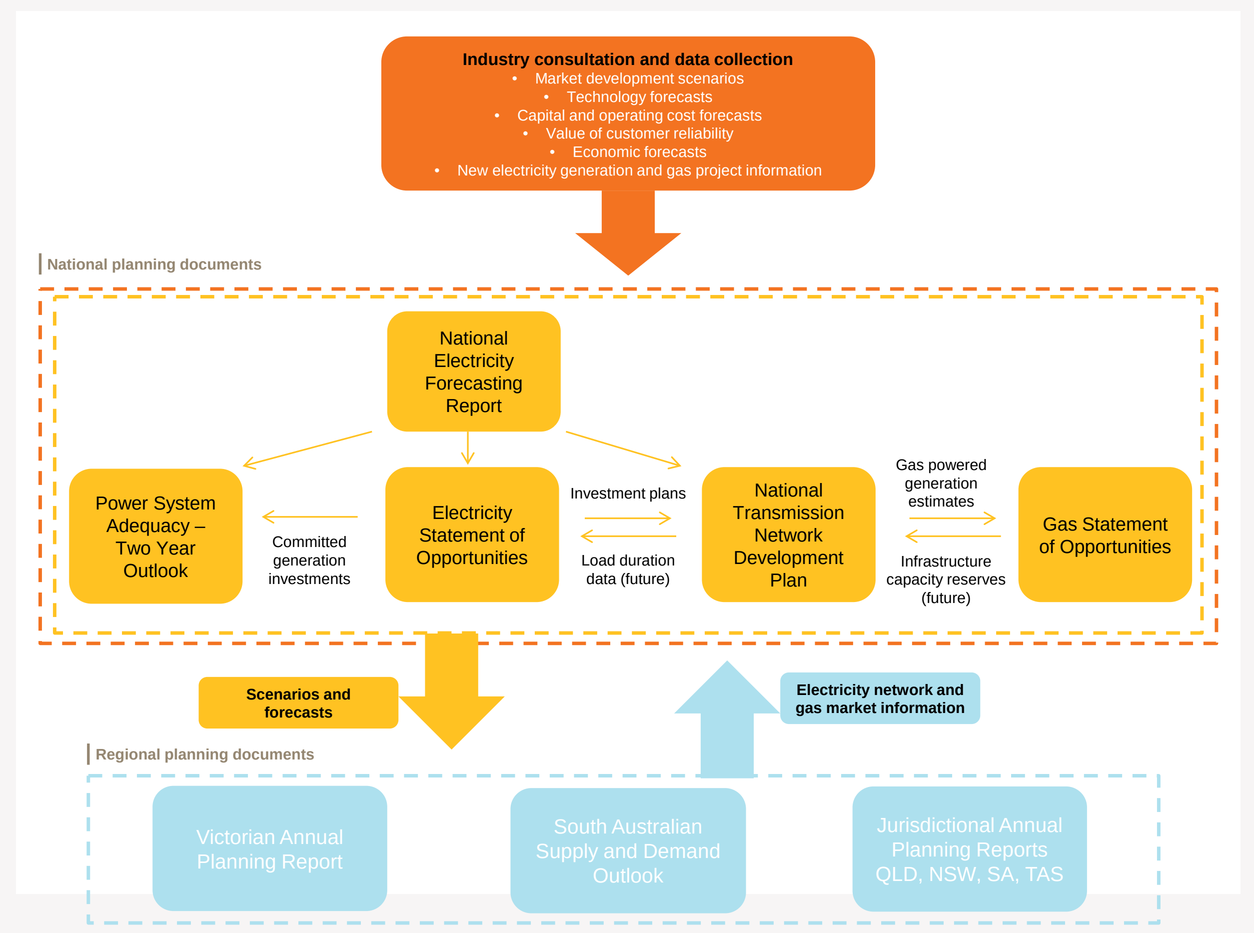
1.6 The NTNDP in the energy planning context

AEMO publishes several other national energy planning reports including the National Electricity Forecast Report (NEFR), Electricity Statement of Opportunities (ESOO), and Gas Statement of Opportunities (GSOO). The NEFR provides annual energy and maximum demand forecasts and the ESOO and GSOO investigate supply-side reliability and provide information about energy resources affecting Eastern and South Eastern Australia.

Reports that focus on specific regions include the electricity annual planning reports (APRs) published by AEMO for Victoria and by the jurisdictional planning bodies (JPBs) for Queensland, New South Wales, South Australia and Tasmania. AEMO also publishes a range of reports as part of its South Australian Advisory Functions, including the South Australian Electricity Report (SAER), which address the current state and future development of South Australian electricity supplies, complementing the South Australian JPB's APR.

Figure 1-2 shows how the NTNDP links with other energy planning reports.

Figure 1-2 — Energy planning reports and the NTNDP



1.7 Content and structure of the 2012 NTNDP

Chapter 2, Results summary and scenario comparison, provides a summary of AEMO's view of a program for efficient development of the NEM transmission network, comparing Planning scenario and Slow Rate of Change scenario results.

Chapter 3, National transmission outlook, provides AEMO's view of a program for efficient development of the NEM transmission network under the Planning scenario, which represents AEMO's central estimate of how the future will develop, including generation development and retirement.

Chapter 4, Future trends, relates the 2012 NTNDP results to trends in the energy industry environment and indicates how AEMO will monitor and address future trends.

Chapter 5, Scenarios, key inputs and modelling approach, provides information about the scenarios used to develop the NTNDP and the key inputs and approach used for the modelling and analysis.

Appendix A, Slow rate of change scenario results, provides AEMO's view of a program for efficient development of the NEM transmission network under this scenario (including generation development and retirement), which describes a world characterised by lower economic growth, with low commodity prices.

Measures and abbreviations provides the units of measure and abbreviations used throughout the NTNDP.

Glossary and list of company names provides a glossary of terms and a list of the companies referred to throughout the NTNDP.

For detailed NTNDP modelling results (including spread sheets, charts and tables) see the NTNDP supplementary information page.[3] The modelling results outlined include the following:

- Transmission committed projects and emerging limitations.
- Generation expansion (installed capacity and generation output).
- Carbon dioxide equivalent emissions.

For input data and assumptions see the NTNDP assumptions and input information page.[4]

Additional information that forms part of the NTNDP includes the following:

- The 2012 Network Support and Control Ancillary Services (NSCAS) assessment report, which provides a five-year forecast of NSCAS gaps and their trigger and tender dates (where applicable), and reports on the NSCAS acquired by AEMO in 2011–12.[5]
- A consolidated summary of the augmentations proposed by each JPB in their 2012 APRs and how they relate to the NTNDP.[6]

[3] AEMO. Available http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Detailed-Results. Viewed 11 December 2012.

[4] AEMO. Available http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Assumptions-and-Inputs. Viewed 11 December 2012.

[5] AEMO. Available http://aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Network-Support-and-Control-Ancillary-Services-Assessment-2012. Viewed 11 December 2012.

[6] AEMO. Available http://www.aemo.com.au/~/media/Files/Other/ntndp/2012_APR_Transmission_Project_Information.ashx. Viewed 11 December 2012.

Supporting information

This section provides links to other information about National Electricity Market transmission planning.

Information source	Website address
NTNDP Supplementary Information Page	http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Detailed-Results
NTNDP Assumptions and Input Information Page	http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Assumptions-and-Inputs
National Energy Forecasting Report	http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012
Generator Information Page	http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information
Historical Market Information Page	http://www.aemo.com.au/Electricity/Planning/Related-Information/Historical-Market-Information-Report
2012 Power System Adequacy – Two Year Outlook	http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Power-System-Adequacy
MT PASA	http://www.aemo.com.au/Electricity/Data/Market-Management-System-MMS/Projection-Assessment
Energy Adequacy Assessment Projection (EAAP)	http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/EAAP
Economic Outlook Information Paper	http://www.aemo.com.au/Reports-and-Documents/Information-Papers/Economic-Outlook-Information-Paper-National-Electricity-Forecasting
Rooftop PV Information Paper	http://www.aemo.com.au/Reports-and-Documents/Information-Papers/Rooftop-PV-Information-Paper-National-Electricity-Forecasting
Wind Contribution to Peak Demand	http://www.aemo.com.au/Electricity/Planning/Related-Information/Wind-Contribution-to--Peak-Demand
Gas Reserve Update	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Reserve-Update
2011–12 NEM Demand Review Information Paper	http://www.aemo.com.au/Electricity/Planning/Forecasting/Information-Papers-2012
Introduction to the Australian NEM	http://www.aemo.com.au/About-the-Industry/Energy-Markets/National-Electricity-Market
Joining the NEM Guide	http://www.aemo.com.au/About-the-Industry/Registration
Maps and Network Diagrams	http://www.aemo.com.au/Electricity/Planning/Related-Information/Maps-and-Diagrams
Annual NEM Constraint Report	http://www.aemo.com.au/Electricity/Market-Operations/Dispatch/Annual-NEM-Constraint-Report

CHAPTER 2 - RESULTS SUMMARY AND SCENARIO COMPARISON

Summary

This chapter summarises the outcomes of optimised generation and transmission modelling under the Planning scenario over a 25-year outlook period, providing a view of future power system requirements that focus on generation and transmission development that accounts for the Australian Treasury's core policy scenario carbon price. It also compares the Planning scenario results with results from the Slow Rate of Change scenario, which was modelled as a sensitivity reflecting slower economic growth and the absence of a carbon price after an initial three-year carbon price period.

To develop new generation assets and augment the shared transmission network across the National Electricity Market (NEM), investment of approximately $51 billion is required under the Planning scenario and $27 billion under the Slow Rate of Change scenario (investment required for the first 20 years is $30 billion and $26 billion, respectively, compared with approximately $72 billion under the 2010 NTNDP Decentralised World scenario[1]).

Key transmission findings include the following:

- After the Heywood interconnector upgrade, currently at the final stage of a regulatory investment test for transmission, further upgrades involving individual interconnector augmentations are not required because of low projected demand growth. On the basis of delivering net market benefits, the need for further increases in power transfer capability between regions does not emerge for the outlook period.
- Under the least-cost expansion plan, demand growth in each NTNDP zone is largely met by new generation in the same zone resulting in less need for intra-regional transmission augmentations.

  As a result, the need for significant transmission augmentation can be avoided if new generation development occurs according to the least-cost expansion plan.[2]

Key generation findings include the following:

- Renewable generation (mostly wind generation driven by the Large-scale Renewable Energy Target (LRET)) dominates the new generation mix until 2020.
- Post 2020, the generation mix has three key features:
  - Increased output predominantly from existing gas powered generation (GPG) to meet total annual energy.
  - New peaking generation involving open cycle gas turbines (OCGT) for capacity to meet maximum demand.
  - New renewable generation driven by a carbon price.
- Generation retirement or mothballing removes approximately 16% of existing black coal-fired generating capacity from the power system resulting in a need for new peaking generation (involving OCGTs) to provide sufficient reserve margins for supply reliability.

Slow Rate of Change (sensitivity)

Results from the Slow Rate of Change scenario analysis are generally consistent with the Planning scenario, while demand growth and carbon price are the key drivers for the differences, which include the following:

1 The 2010 NTNDP examined the outcomes of optimised generation and transmission modelling over a 20-year outlook period.

2 Additional transmission will still be needed to replace aging assets, as will augmentations in the lower voltage transmission and distribution networks to meet local load growth. Local transmission issues associated with new generation connections will also need to be addressed. These needs are outside the scope of the NTNDP.

- The scenario's lower demand growth requires less new generation.
- The scenario's demand growth after 2020 is predominantly met by increased output from existing coal-fired generation.
- The majority of retired or mothballed generation is black coal-fired. Under the Planning scenario both black and brown coal-fired generation is retired or mothballed.

This chapter provides a NEM-wide focus. For results involving specific zones see Chapter 3 (Planning scenario) and Appendix A (Slow Rate of Change scenario). For detailed results spreadsheets see the NTNDP supplementary information page.[3]

2.1 Capital investment summary

This section summarises the generation and shared transmission network investment requirements identified under the Planning scenario and provides a comparison with the Slow Rate of Change scenario.

Based on AEMO's modelling, to develop new generation assets and augment the shared transmission network across the NEM, investment of approximately $51 billion is required under the Planning scenario and $27 billion under the Slow Rate of Change scenario.

These estimated investment levels represent capital costs only, and do not include tax or borrowing costs.

2.1.1 Scenario results comparison

Table 2-1 compares capital investment under the two scenarios.

Table 2-1 — Scenario investment comparison

	Planning scenario ($ billion)	Slow Rate of Change scenario ($ billion)
Total transmission investment	5.2	4.0
Total generation investment	45.6	22.5
Total investment	**50.8**	**26.5**

Table 2-2 compares the capital investment against the 2010 NTNDP's Decentralised World scenario.[4] This comparison is based on the investment over the first 20 years because the 2010 NTNDP used a 20-year outlook period.

3 AEMO. Available http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Detailed-Results. Viewed 11 December 2012.

4 The 2010 NTNDP examined the outcomes of optimised generation and transmission modelling over a 20-year outlook period.

Table 2-2 — Comparison of investment over 20 years against the 2010 NTNDP's Decentralised World scenario

	Planning scenario ($ billion)	Slow Rate of Change scenario ($ billion)	2010 NTNDP's Decentralised World ($ billion)
Total transmission investment	4.4	3.8	7.4
Total generation investment	25.7	21.7	64.6
Total investment	**30.1**	**25.5**	**72.0**

2.1.2 Transmission investment

Total new transmission asset investment is $5.2 billion under the Planning scenario and $4.0 billion under the Slow Rate of Change scenario. This includes investment involving the main transmission network and connecting new generation to the nearest transmission connection point (assuming standard connection configurations). It does not include works to address localised needs associated with new generation connections.

Investment will still be needed to replace aging assets, to address non-thermal related issues and to address local transmission needs driven by local load growth.

2.1.3 Generation investment

The main difference between the scenarios relates to generation investment. There are three key drivers in the final generation investment outcomes:

- Demand projections.
- The Large-scale Renewable Energy Target.
- Other factors (such as the carbon price, fuel costs, technology costs and capital costs).

Demand projections

The 2012 demand projections require a low level of new entry generation to meet the need for additional capacity. At the end of the outlook period, the total installed new generation capacity under the Planning scenario is approximately 20,000 MW.[5]

Large-scale Renewable Energy Target

The LRET scheme is the prime driver of renewable generation until 2020. Wind generation is the main technology implemented from the start of the outlook period until 2020, with other technologies like solar and biomass beginning to appear later on towards 2020. Investment in wind generation amounts to $18 billion by 2020 under the Planning scenario and approximately $14 billion under the Slow Rate of Change scenario.

Other factors

Under the Planning scenario, carbon price-driven renewable generation investment occurs post 2020. An increase in biomass generation is seen from 2026–27, with wind and geothermal generation becoming economic without the LRET scheme towards the end of the outlook period (post 2033–34).

The type of new generation investment is also influenced by factors such as technology costs, capital costs, and fuel costs, which determine the new generation mix by considering trade-offs between capital and operational costs.

[5] Total installed new generation capacity is approximately 15,000 MW over the first 20 years of the 2012 NTNDP Planning scenario, and approximately 34,000 MW over the 20-year outlook period of the 2010 NTNDP Decentralised World scenario.

2.2 Transmission development in the NEM

Following the Heywood interconnector upgrade (which the least cost expansion plan modelled as a committed project[6]), further inter-regional interconnectors are not augmented in the least-cost expansion plan modelling under the Planning scenario within the outlook period. Due to interconnector augmentation costs being expected to outweigh the market benefits from increased power transfer capabilities between regions, no need is identified for further inter-regional power transfer capability increases.

Even though the current modelling does not show an economic justification for interconnector augmentation, an economic case may exist if the modelling could capture the full market benefits associated with the full range of intermittent renewable generation outputs.

The impact of wind generation

The NTNDP modelling focuses on determining the least-cost expansion plan for meeting NEM energy requirements. The intermittency of wind generation has not been fully captured in the modelling. As a result, there may be some market benefits (such as benefits associated with upgrading the inter-regional transmission network) that are not fully captured in the analysis, the examination of which will form part of more detailed investigations, including RIT-Ts and AEMO's future national transmission planning work.

Transmission network outcomes

Under the Planning scenario, there are only a few limitations on the main transmission network[7] within the zones and on connections between neighbouring zones during the outlook period. This is mainly because of lower electricity demand than seen in previous NTNDPs.

Demand growth in each zone is largely met by new generation in the same zone. This reflects the least-cost expansion plan modelling approach, which locates new generation to minimise overall generation and transmission investment, resulting in less need for transmission augmentations across the NEM. If future generation development differs from the least-cost expansion plan, however, then other limitations may occur on the main transmission network, potentially requiring reinforcement of the transmission network within and between the zones.

In addition to committed transmission projects and identified transmission network needs, transmission investment will still be required to address three issues:

- Aging assets.
- Local transmission issues driven by new generation connections.
- Transmission needs in the lower voltage and radial transmission and distribution networks driven by local load growth.

Figure 2-1 shows the main transmission network and Figure 2-2 shows new generation development in the NEM under the Planning scenario by the end of the outlook period. Figure 2-1 also shows areas in the NEM where limitations arise as part of the least-cost expansion and the new generation technologies in each zone. This transmission needs assessment builds on transmission network service provider (TNSP) committed main transmission network projects. Figure 2-3 and Figure 2-4 show the equivalent under the Slow Rate of Change scenario.

Table 2-3 lists committed main transmission network projects across the NEM (identified in Figure 2-1 and Figure 2-3 by the prefix C).

6 AEMO. Available http://www.aemo.com.au/~/media/Files/Other/planning/Heywood_Interconnector_Upgrade_RIT_T_PADR_Forum_Presentation.ashx. Viewed 5 November 2012.

7 Generally 220 kV and above.

Table 2-4 lists the transmission network development needs identified over the outlook period under the Planning and the Slow Rate of Change scenarios (identified in Figure 2-1 and Figure 2-3 by the prefix L).

Slow Rate of Change scenario differences

Additional transmission needs driven by either new generation or modelled retirements arise in the CQ and NCEN zones under the Slow Rate of Change scenario. Transmission needs under the Slow Rate of Change scenario generally appear around the same time. Four limitations identified in the NCEN, MEL and CVIC zones[8] occur during similar time periods under both the scenarios. Two limitations[9] arise under the Slow Rate of Change scenario that do not arise under the Planning scenario.

[8] Identified as L-N2, L-V1, L-V6 and L-V7.

[9] Identified as L-Q1 and L-N3.

Figure 2-1 — Main transmission network development in the NEM by 2036–37 (Planning scenario)

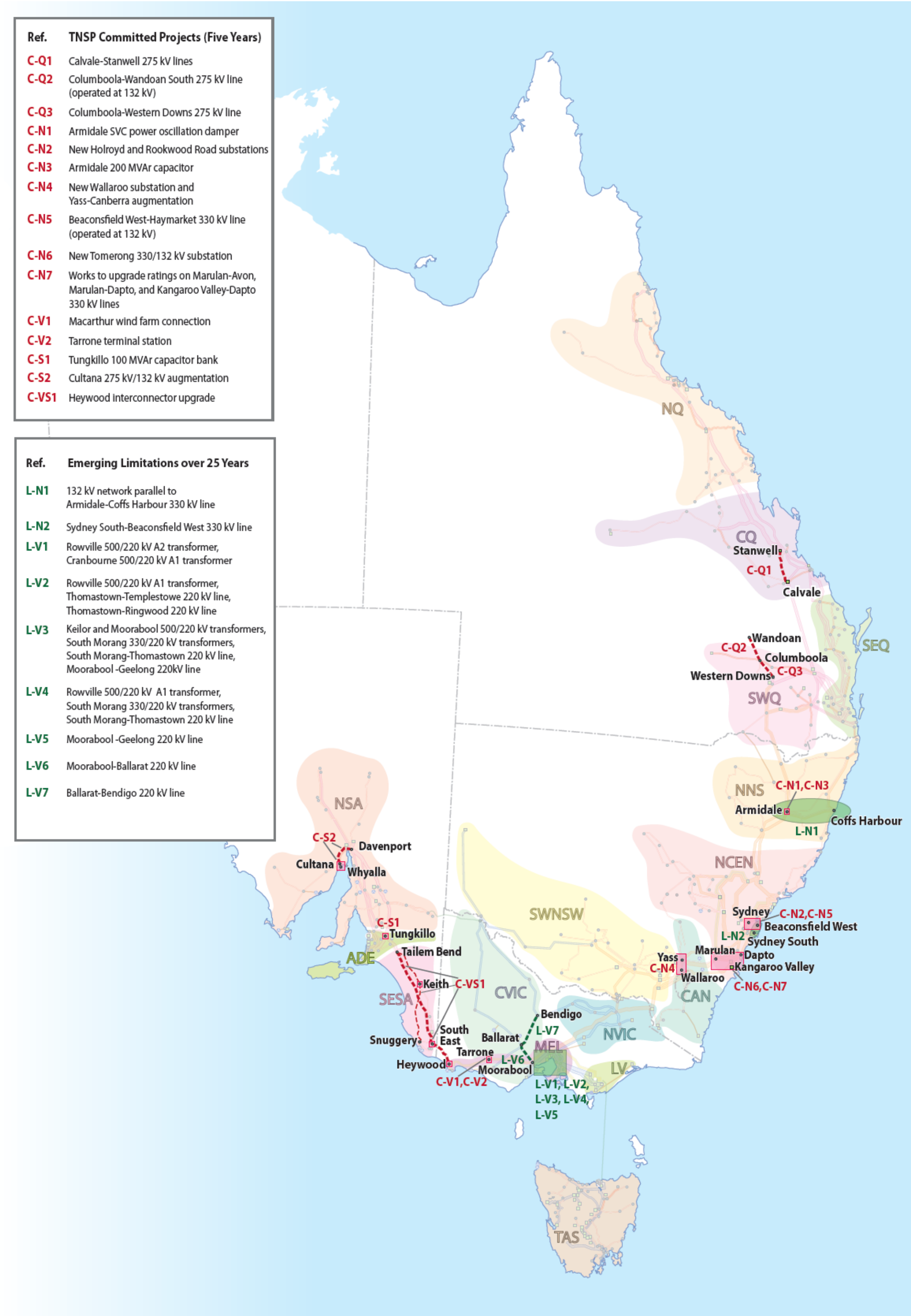


Figure 2-2 —New generation development in the NEM by 2036–37 (Planning scenario)

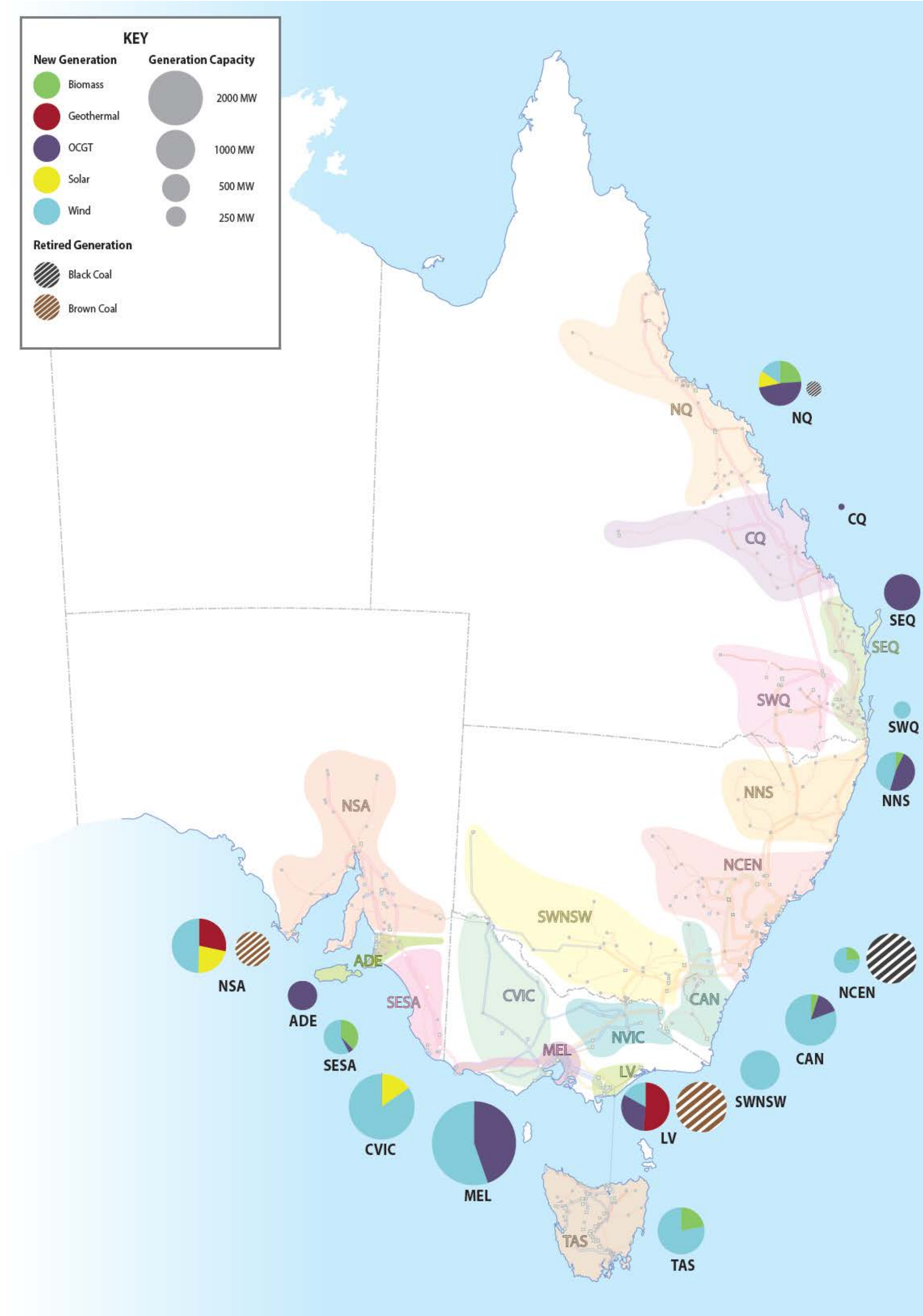
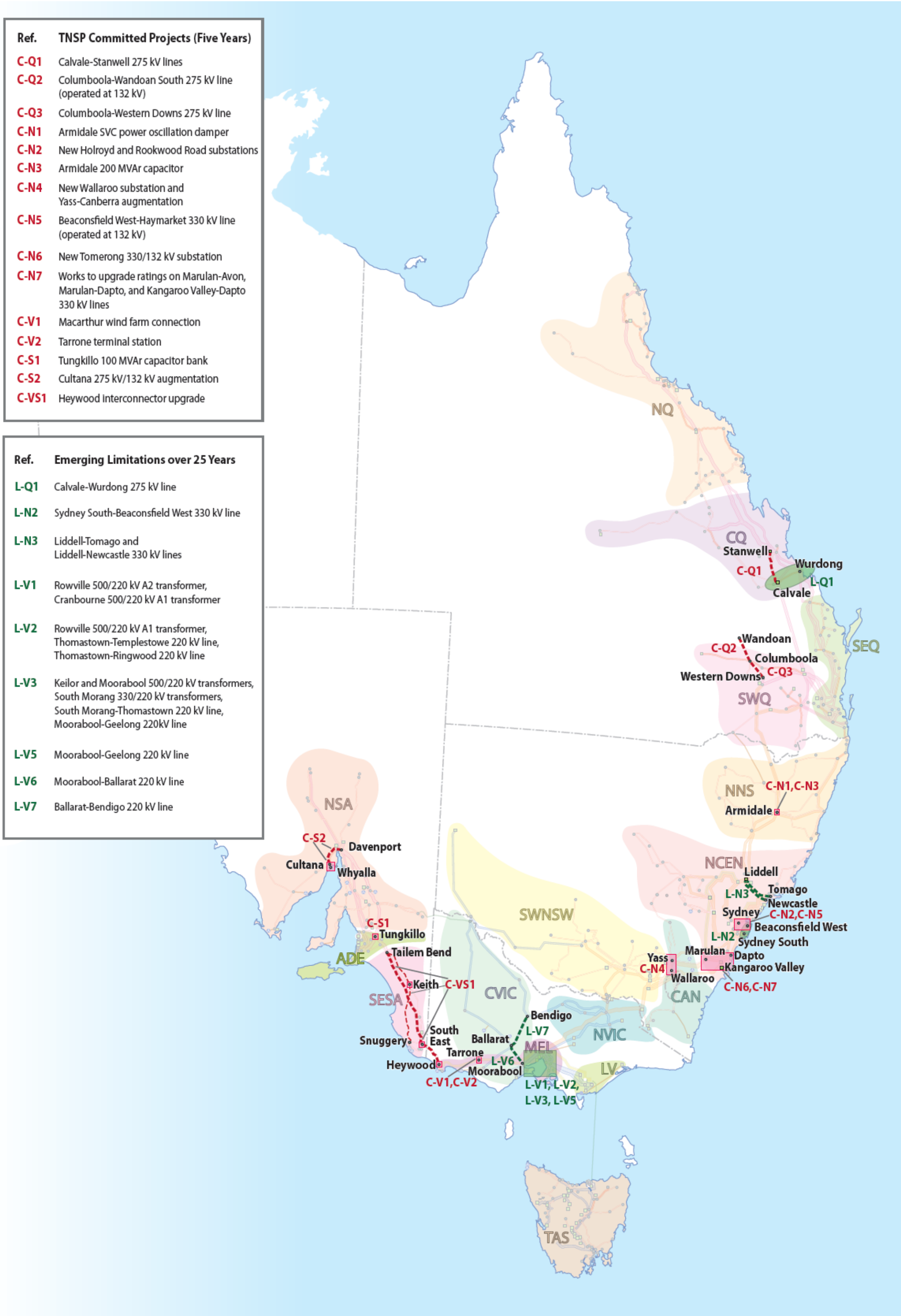


Figure 2-3 — Main transmission network development in the NEM by 2036–37 (Slow Rate of Change scenario)



Ref.	TNSP Committed Projects (Five Years)
C-Q1	Calvale-Stanwell 275 kV lines
C-Q2	Columboola-Wandoan South 275 kV line (operated at 132 kV)
C-Q3	Columboola-Western Downs 275 kV line
C-N1	Armidale SVC power oscillation damper
C-N2	New Holroyd and Rookwood Road substations
C-N3	Armidale 200 MVAr capacitor
C-N4	New Wallaroo substation and Yass-Canberra augmentation
C-N5	Beaconsfield West-Haymarket 330 kV line (operated at 132 kV)
C-N6	New Tomerong 330/132 kV substation
C-N7	Works to upgrade ratings on Marulan-Avon, Marulan-Dapto, and Kangaroo Valley-Dapto 330 kV lines
C-V1	Macarthur wind farm connection
C-V2	Tarrone terminal station
C-S1	Tungkillo 100 MVAr capacitor bank
C-S2	Cultana 275 kV/132 kV augmentation
C-VS1	Heywood interconnector upgrade

Ref.	Emerging Limitations over 25 Years
L-Q1	Calvale-Wurdong 275 kV line
L-N2	Sydney South-Beaconsfield West 330 kV line
L-N3	Liddell-Tomago and Liddell-Newcastle 330 kV lines
L-V1	Rowville 500/220 kV A2 transformer, Cranbourne 500/220 kV A1 transformer
L-V2	Rowville 500/220 kV A1 transformer, Thomastown-Templestowe 220 kV line, Thomastown-Ringwood 220 kV line
L-V3	Keilor and Moorabool 500/220 kV transformers, South Morang 330/220 kV transformers, South Morang-Thomastown 220 kV line, Moorabool-Geelong 220kV line
L-V5	Moorabool-Geelong 220 kV line
L-V6	Moorabool-Ballarat 220 kV line
L-V7	Ballarat-Bendigo 220 kV line

Figure 2-4 — New generation development in the NEM by 2036–37 (Slow Rate of Change scenario)

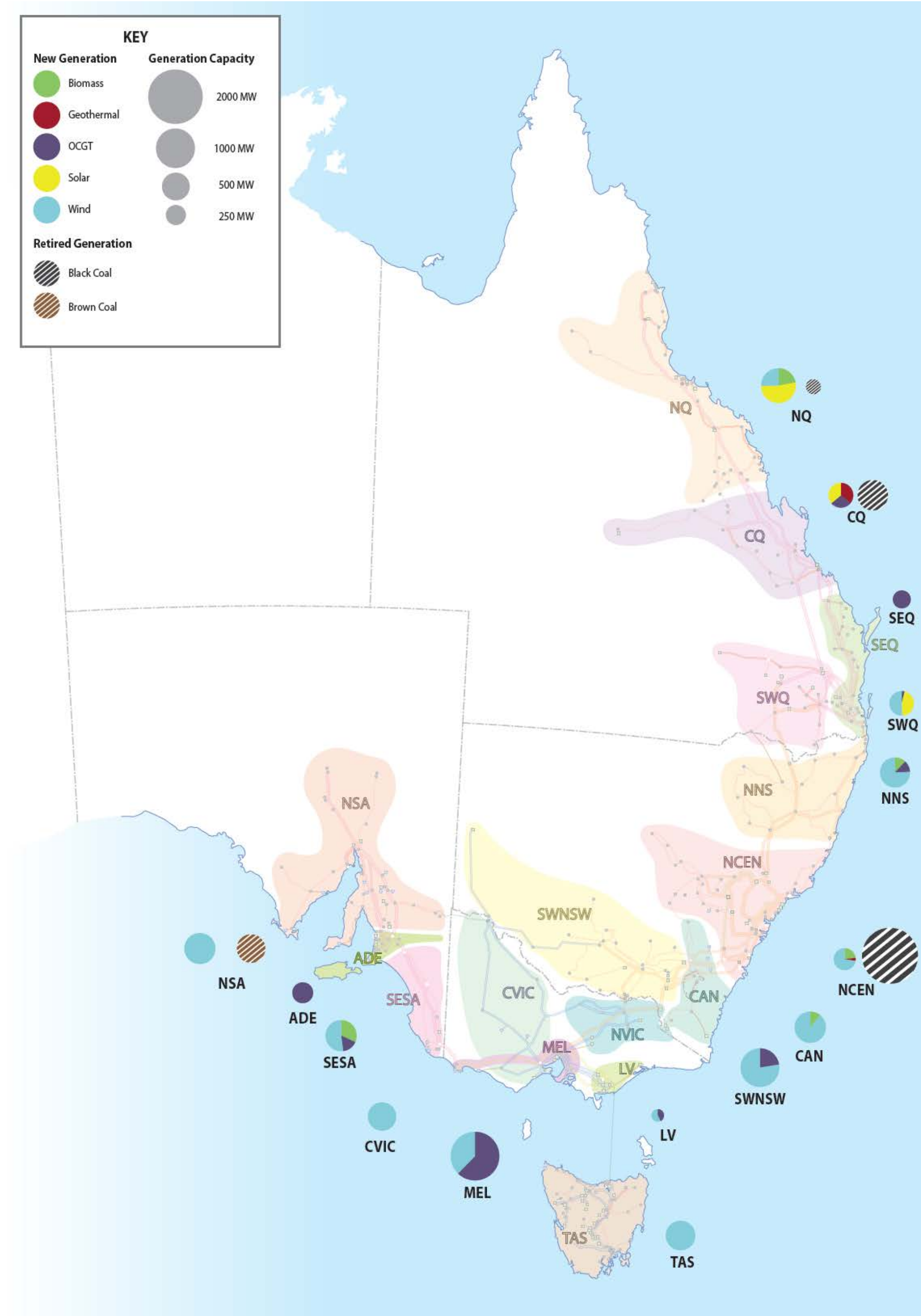


Table 2-3 — Committed main transmission network projects across the NEM

Reference	Region	Zone	Project	Anticipated timing
C-Q1	Queensland	CQ	The Calvale–Stanwell 275 kV double circuit line.	Summer 2013–14
C-Q2	Queensland	SWQ	The Columboola–Wandoan South 275 kV line (operating at 132 kV).[a]	Winter 2013
C-Q3	Queensland	SWQ	The Columboola–Western Downs 275 kV line.[a]	Winter 2014
C-N1	New South Wales	NNS	An Armidale SVC power oscillation damper.	2012
C-N2	New South Wales	NCEN	Establishment and connection of the Holroyd and Rookwood Road Substations.	2013–14
C-N3	New South Wales	NNS	A 200 MVAr capacitor at Armidale.	2013
C-N4	New South Wales	CAN	Establishment of the Wallaroo Substation and Yass/Canberra line rearrangements.	2018
C-N5	New South Wales	NCEN	Beaconsfield West–Haymarket 330 kV cable (operated at 132 kV).	2012–13
C-N6	New South Wales	NCEN	Establishment and connection of a new Tomerong 330/132 kV substation to supply the Nowra area.	2015
C-N7	New South Wales	NCEN	Line ratings increased on the Marulan–Avon, Marulan–Dapto and Kangaroo Valley–Dapto 330 kV lines.	2015
C-V1	Victoria	MEL	Macarthur Wind Farm connection, involving 420 MW at the 500 kV Tarrone Terminal Station.[b]	December 2012 (wind farm fully in service)
C-V2	Victoria	MEL	Tarrone Terminal Station cut into the existing Moorabool–Heywood 500 kV No.1 line approximately 65 kilometres from Heywood.	Completed
C-S1	South Australia	ADE	A Tungkillo 275 kV 100 MVAr capacitor bank.	2012
C-S2	South Australia	NSA	A Cultana 275 kV augmentation.	2014
C-VS1	Victoria and South Australia	MEL–SESA	The incremental augmentation of the Victoria to South Australia interconnector (Heywood)[c]: Scope of work in Victoria: • A third 370 MVA 500/275 kV transformer and bus tie at Heywood. Scope of work in South Australia: • 275 kV series compensation. • Reconfiguration and decommissioning of the 132 kV network.	2016

a. For information about pre-requisite augmentations currently being implemented by Powerlink Queensland see Chapter 3.

b. Wind generation is currently being progressively added to the power system.

c. AEMO and ElectraNet are undertaking a joint Regulatory Investment Test for Transmission (RIT-T) application to investigate increasing the interconnector's capability, and realising market benefits from relieving congestion on the Heywood interconnector. The RIT-T consultation for this upgrade was initiated by the Project Specification Consultation Report (PSCR) in October 2011. The Project Assessment Draft Report (PADR) was published in the middle of September 2012. In the NTNDP analysis, the currently preferred option was assumed to be proceeding. Available http://www.aemo.com.au/~/media/Files/Other/planning/Heywood_Interconnector_Upgrade_RIT_T_PADR_Forum_Presentation.ashx.

Table 2-4 — Transmission needs across the NEM under the Planning and Slow Rate of Change scenarios

Reference	Region	Zone	Planning timing	Slow Rate of Change timing	Observed limitation	Network needs
L-Q1[a]	Queensland	CQ	Does not arise.	2012–13 to 2016–17.	Overload of a Calvale–Wurdong 275 kV circuit for an outage of the Gladstone–Wurdong 275 kV circuit.	Reinforce the transmission network connecting Calvale and Gladstone to Stanwell and Bouldercombe.
L-N1	New South Wales	NNS	2017–18 to 2021–22.	Does not arise.	Overload of the 132 kV network supplying north coast demand centres for an outage of the Armidale–Coffs Harbour 330 kV line.	Reinforce the connection between the inland 330 kV transmission network and the north coast demand centres.
L-N2	New South Wales	NCEN	2012–13 to 2016–17.	2012–13 to 2016–17.	Overload of the Sydney South–Beaconsfield West 330 kV line for an outage of the Sydney South–Haymarket 330 kV line.	A new supply to the Beaconsfield West Substation from another 330 kV supply point.
L-N3	New South Wales	NCEN	Does not arise.	2012–13 to 2016–17.	Overload of a Liddell–Tomago 330 kV line or a Liddell–Newcastle 330 kV line, for an outage of a parallel line.	Reinforce the transmission network connecting Liddell to the Newcastle area.
L-V1	Victoria	MEL	2012–13 to 2016–17.	2012–13 to 2016–17.	Overload of the Rowville 500/220 kV A2 transformer for an outage of the Cranbourne 500/220 kV A1 transformer (and vice versa).	An additional 500/220 kV transformer in the Eastern Metropolitan Melbourne area.
L-V2	Victoria	MEL	2017–18 to 2021–22.	2022–23 to 2026–27.	Overload of the Rowville 500/220 kV A1 transformer for system normal conditions, and overload of the Thomastown–Templestowe and Thomastown–Ringwood 220 kV circuits for an outage of the Rowville 500/220 kV A1 transformer.	An additional 500/220 kV transformer in the Eastern Metropolitan Melbourne area, and connection of the Rowville–Templestowe 220 kV circuit at Ringwood.

Reference	Region	Zone	Planning timing	Slow Rate of Change timing	Observed limitation	Network needs
L-V3	Victoria	MEL	2022–23 to 2026–27.	2032–33 to 2036–37.	Overload of a Keilor 500/220 kV transformer for an outage of the parallel transformer or a Moorabool 500/220 kV transformer, and overload of a South Morang 330/220 kV transformer and a South Morang–Thomastown 220 kV circuit for an outage of the parallel transformer/circuit, and overload of a Moorabool–Geelong 220 kV circuit for an outage of the parallel circuit.	An additional 500/220 kV transformer in the Western Metropolitan Melbourne area.
L-V4	Victoria	MEL	2027–28 to 2031–32.	Does not arise.	Overload of the Rowville 500/220 kV A1 transformer for an outage of the parallel transformer (and vice versa), and overload of a South Morang 330/220 kV transformer and a South Morang–Thomastown 220 kV circuit for an outage of the parallel transformer/circuit.	An additional 500/220 kV transformer in the Eastern Metropolitan Melbourne area.
L-V5	Victoria	MEL	2027–28 to 2031–32.	2032–33 to 2036–37.	Overload of a Moorabool–Geelong 220 kV circuit for an outage of the parallel circuit.	Additional transmission capability from Moorabool to Geelong.
L-V6	Victoria	CVIC	2012–13 to 2016–17.	2012–13 to 2016–17.	Overload of the Moorabool–Ballarat 220 kV No.1 circuit for an outage of the Moorabool–Ballarat 220 kV No.2 circuit.	Additional transmission capability from Moorabool to Ballarat.
L-V7	Victoria	CVIC	2012–13 to 2016–17.	2012–13 to 2016–17.	Overload of the Ballarat–Bendigo 220 kV circuit for an outage of the Bendigo–Shepparton 220 kV circuit.	Additional transmission capability from Ballarat to Bendigo.

a. Unavailability of more than three Gladstone generating units may cause overloads on some circuits on the network connecting Calvale and Gladstone to Stanwell and Bouldercombe.

2.3 Generation development in the NEM

Figure 2-5 and Figure 2-6 show NEM installed capacity and energy generated (respectively) by technology under the Planning scenario, enabling the following observations:

- Based on an economic assessment, the least-cost expansion plan modelling retires or mothballs approximately 4,300 MW (approximately 16%) of existing black and brown coal-fired generation, largely in the first five years.
- Combined black and brown coal-fired generation is fairly stable throughout the outlook period, with reduced brown coal-fired generation balanced by increased output from existing black coal-fired generation. Coal remains the dominant fuel and by the end of the outlook period, combined black and brown coal-fired generation still accounts for more than half of the energy produced.
- Results show that renewable generation (mostly LRET-driven wind generation, and with some solar and biomass generation) dominates the new generation mix until 2020.
- No new wind generation is built after completion of the LRET (in 2020) until 2030–31, when wind generation becomes economic without the LRET scheme.
- As energy continues to grow after 2020, existing generation (mainly GPG and coal-fired generation) increases its output.

  Coal-fired generation increases its output until 2024–25 then remains. As the carbon price increases, coal-fired generation levels remain relatively unchanged until 2032–33, before decreasing due to new renewable generation towards the end of the outlook period.

  GPG output grows steadily, starting from 2024–25 until the end of the outlook period.
- Biomass, wind and geothermal generation become economic without the LRET towards the end of the outlook period.
- Installed OCGT capacity grows slowly at first, increasing towards the end of the outlook period, and driven by increasing energy from intermittent renewable energy sources that require the maintenance of dispatchable reserves for reliability. Over the outlook period, OCGT provides peaking capacity while its actual annual energy production remains relatively low.

Figure 2-5 — Total NEM installed capacity by technology under the Planning scenario

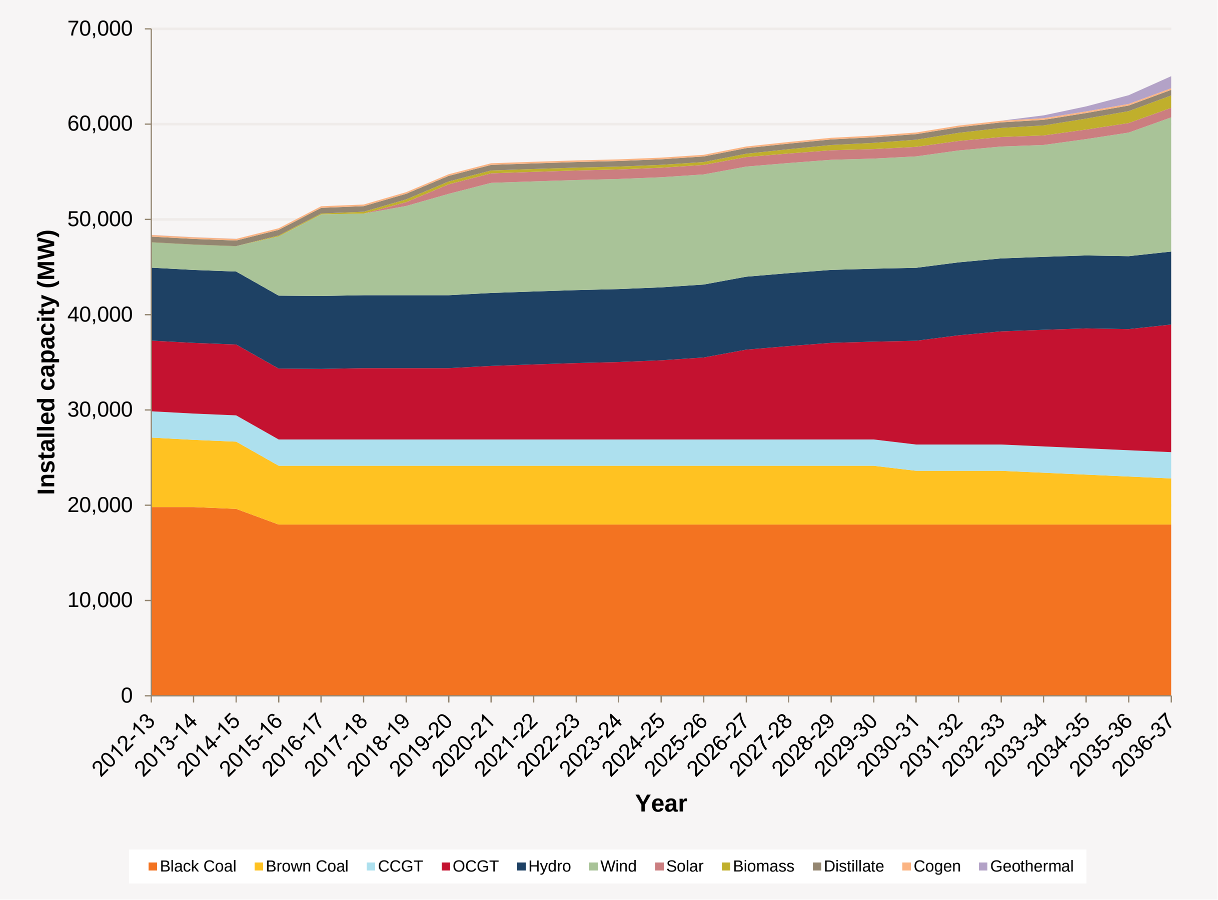
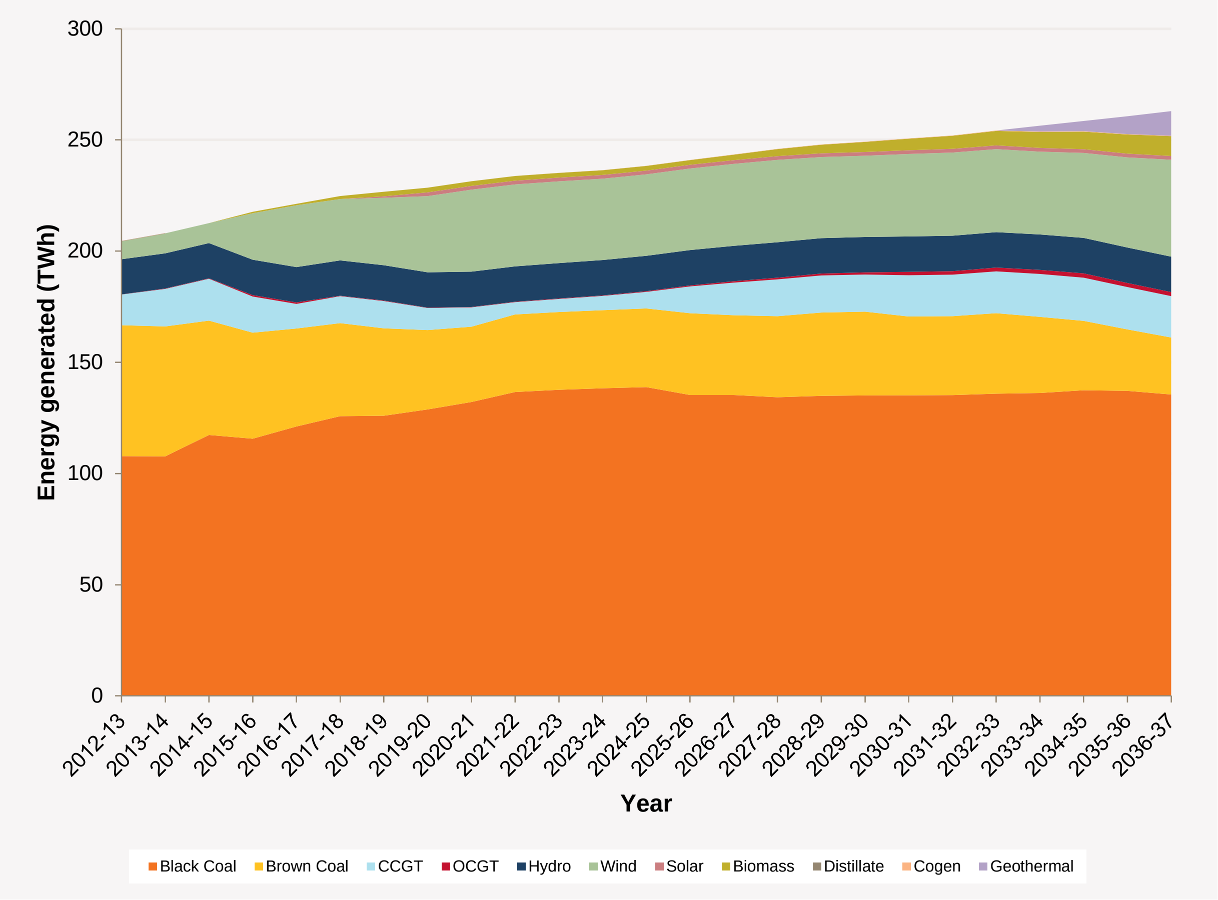


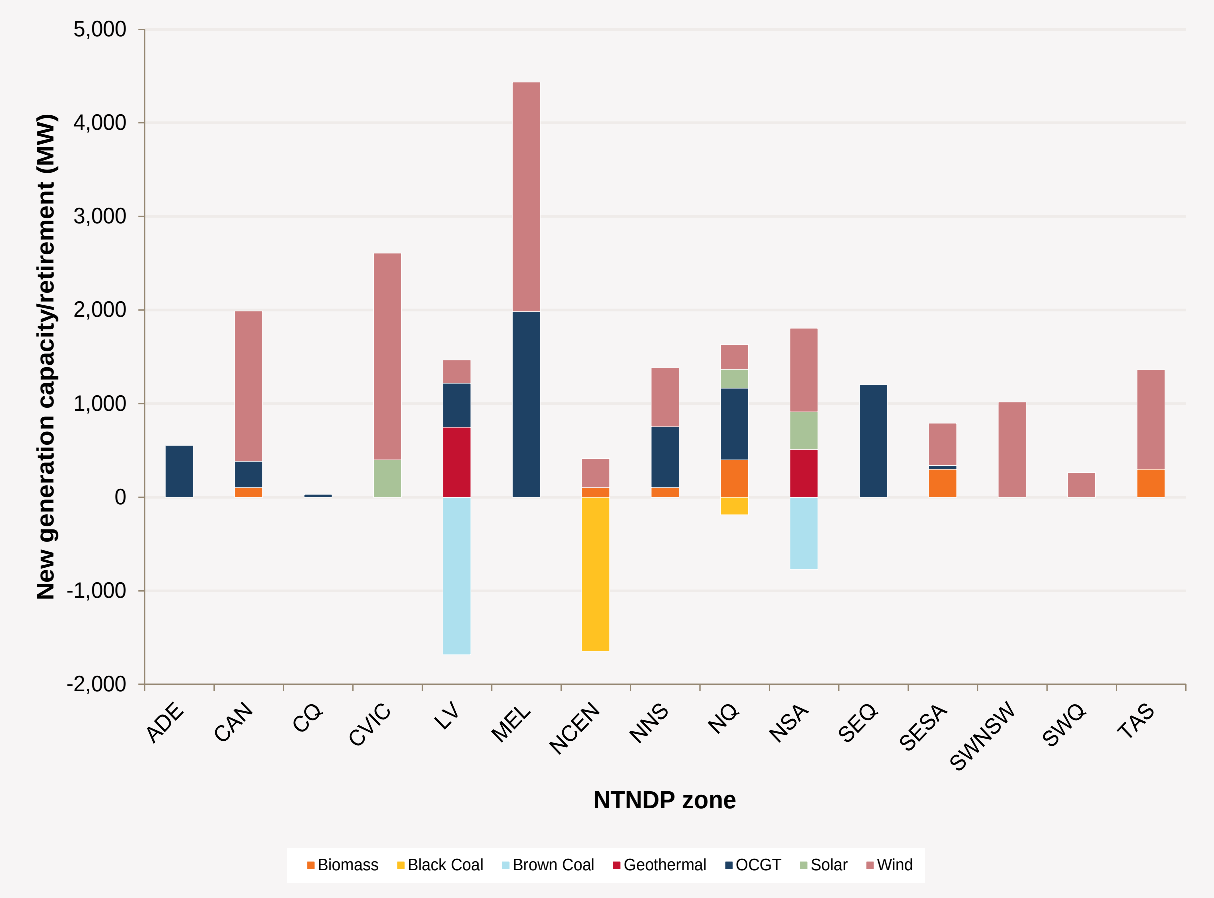
Figure 2-6 — Total NEM generated energy by technology under the Planning scenario



Generation development – NEM-wide overview by technology under the Planning scenario

Figure 2-7 shows the NEM's new generation capacity and retirements at the end of the outlook period by technology under the Planning scenario.

Figure 2-7 — Total NEM new generation capacity and retirements by 2036–37 by technology under the Planning scenario



2.3.2 New generation outcomes compared with the Slow Rate of Change scenario

Slow Rate of Change scenario assumptions differ from the Planning scenario in the following key ways:

- Lower annual energy and maximum demand growth.
- Higher growth in gas prices.
- A carbon price reflecting the Australian Treasury's core policy scenario for the first three years, and (zero) 0 dollars per tonne carbon dioxide equivalent ($ /t CO_2-e) emmissions from then onwards.

For more information see Chapter 5, Section 5.1.

Differences in generation development under the Slow Rate of Change scenario include the following:

- Significant new renewable generation is not built after the LRET ends in 2020. Without a carbon price, large-scale renewable generation does not become economically viable.
- As energy continues to grow after 2020, energy needs are largely met by increased output from existing generation (mainly coal-fired).

- The least-cost expansion plan modelling retires or mothballs approximately 4,700 MW (approximately 17%) of existing coal-fired generation (mainly black coal). Under the Planning scenario, black and brown coal-fired generation amounting to 4,300 MW (approximately 16%) is retired or mothballed.

The LRET is achieved under both the Planning and Slow Rate of Change scenarios. For more information about LRET modelling see the 2012 NTNDP Assumptions and Inputs.[10]

Figure 2-8 shows the NEM's new generation capacity at the end of the 25-year outlook period under the Slow Rate of Change scenario (with new generation capacity under the Planning scenario shown for comparison).

Figure 2-8 — Total new generation capacity and retirements by 2036–37 under the Planning and Slow Rate of Change scenarios

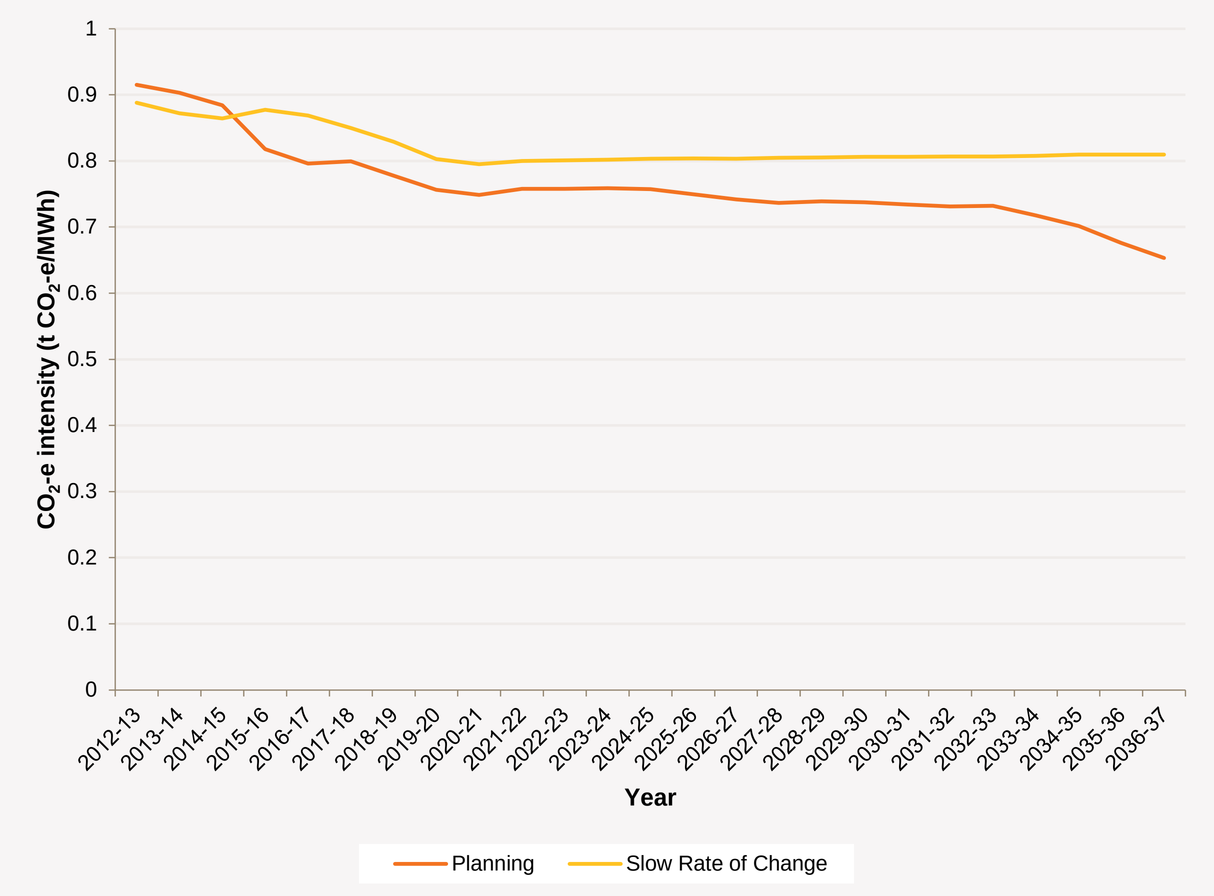
[10] AEMO. Available http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Assumptions-and-Inputs. Viewed 11 December 2012.

2.3.3 Carbon dioxide equivalent emissions

Figure 2-9 and Figure 2-10 show the total NEM CO_2-e emissions intensity and carbon emission quantities (respectively) under the Planning and Slow Rate of Change scenarios, enabling the following observations:

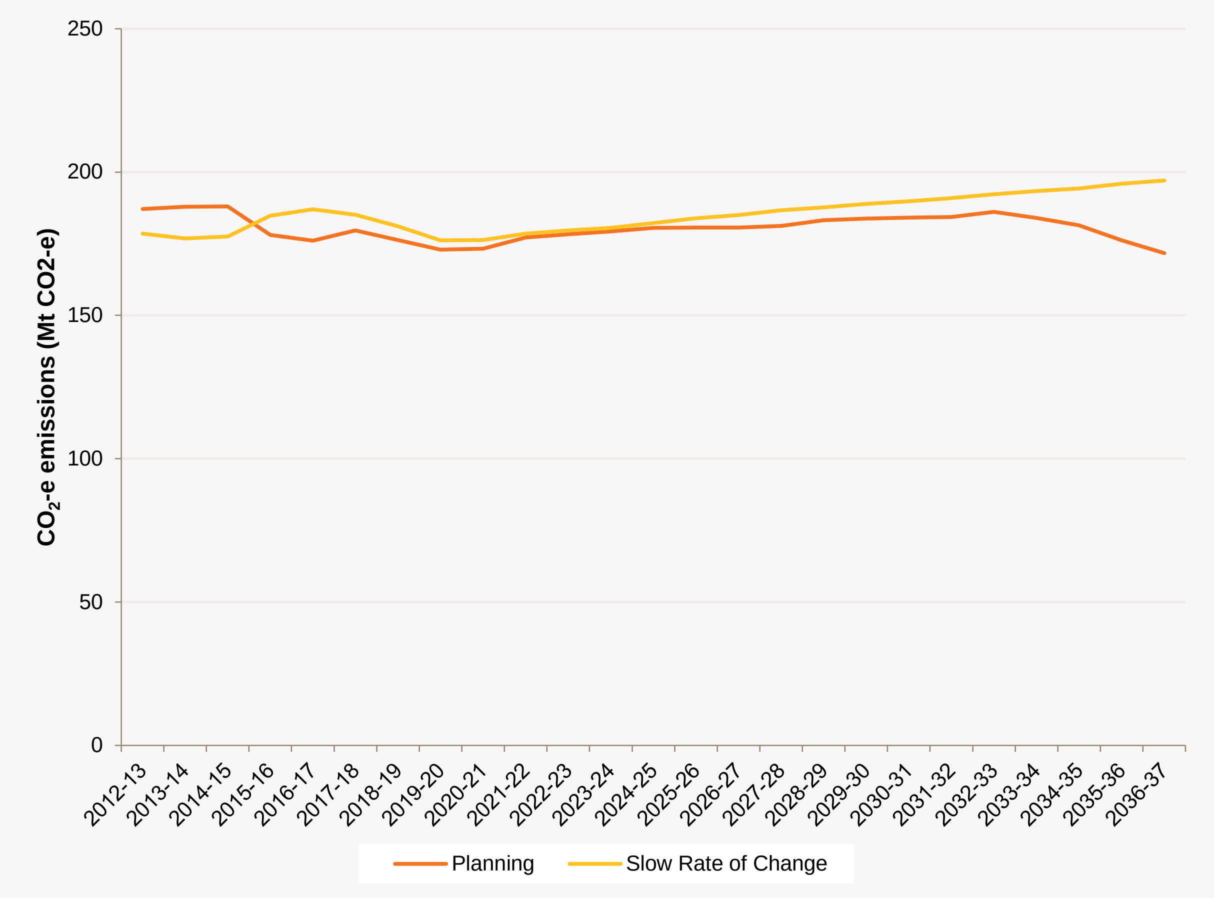
- Presently, the annual simulated CO_2-e intensity in tonnes of CO_2-e emissions per megawatt hour (t CO_2-e/MWh) averaged across the NEM is close to 0.9 t CO_2-e/MWh.
- CO_2-e emissions intensity falls around 2013–14 under both scenarios due to LRET-driven renewable generation. It then remains constant until the end of the outlook period under the Slow Rate of Change scenario, while the Planning scenario sees a further fall towards the end of the outlook period due to carbon price-driven renewable generation.
- Under both scenarios, CO_2-e emissions remain reasonably constant over the outlook period (consistent with Australian Treasury modelling outcomes published in the Clean Energy Future Plan).[11]

Figure 2-9 — Total NEM CO_2-e intensity under the Planning and Slow Rate of Change scenarios



[11] Australian Government. Available http://www.cleanenergyfuture.gov.au/clean-energy-future/securing-a-clean-energy-future/. Viewed 2 November 2012.

Figure 2-10 — Carbon emissions under the Planning and Slow Rate of Change scenarios



2.3.4 Comparison with the 2010 NTNDP

The 2010 NTNDP[12] considered a least-cost generation and transmission expansion plan for the NEM, and examined five future market development scenarios (with significantly varied results). The high and medium growth scenarios located a large amount of new generation throughout the NEM. The maximum total installed capacity of new generation for any 2010 scenario exceeded 50,000 MW, and there was a NEM-wide need for significant transmission investment.

The 2012 Planning scenario has a significantly lower rate of demand and energy growth (for more information see Chapter 5, Section 5.3), which is reflected in total installed capacity of new generation of approximately 20,000 MW[13], resulting in different transmission augmentation outcomes, and signalling the need for less NEM-wide transmission development.

The other significant difference between the 2010 scenarios and 2012 Planning scenario involves the location of GPG base load generation (notionally combined cycle gas turbines (CCGT)). In the 2010 NTNDP modelling outcomes, large-scale CCGT generation was built across the NEM. However, GPG base load generation does not appear under the 2012 Planning scenario due to lower demand growth combined with a high gas price outlook.

[12] The 2011 NTNDP involved a detailed examination of the results from 2010, and so did not contain a new scenario-based generation and transmission expansion assessment.

[13] Total new generation capacity is approximately 15,000 MW over the first 20 years of the Planning scenario outlook period.

2.4 Generation comparison by zone

This section compares the generation outcomes under the Planning and Slow Rate of Change scenarios for each NTNDP zone.

2.4.1 North Queensland (NQ)

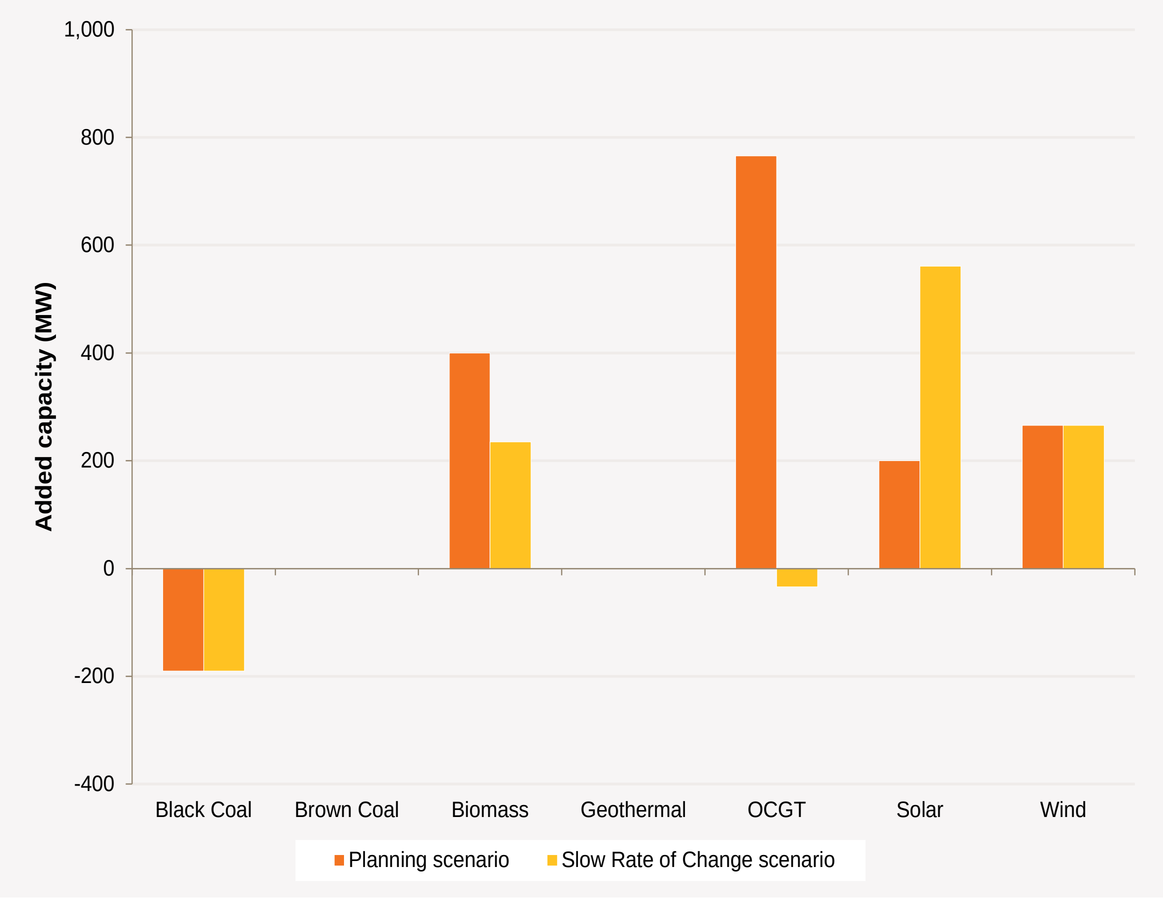
Table 2-5 lists the existing generation[14] and modelled new generation and retirements in the zone under the scenarios. Figure 2-11 shows the total new generation/retirements in the zone by 2036–37.

Table 2-5 — Existing installed capacity and modelled new generation/retirements (cumulative) for North Queensland (NQ)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)									
		2016–17		2021–22		2026–27		2031–32		2036–37	
		P	SRC	P	SRC	P	SRC	P	SRC	P	SRC
Biomass	**0**	0	68	0	222	0	222	251	222	400	235
CCGT	**244**	0	0	0	0	0	0	0	0	0	0
OCGT	**34**	-34	-34	-34	-34	-34	-34	32	-34	766	-34
Distillate	**424**	0	0	0	0	0	0	0	0	0	0
Coal	**190**	-190	-190	-190	-190	-190	-190	-190	-190	-190	-190
Wind	**0**	0	266	0	266	0	266	0	266	266	266
Hydro	**154**	0	0	0	0	0	0	0	0	0	0
Solar	**0**	0	0	200	561	200	561	200	561	200	561

[14] Includes scheduled generation, semi-scheduled generation and non-scheduled wind generation greater than 30 MW.

Figure 2-11 — Total new generation capacity/retirements in NQ by 2036–37



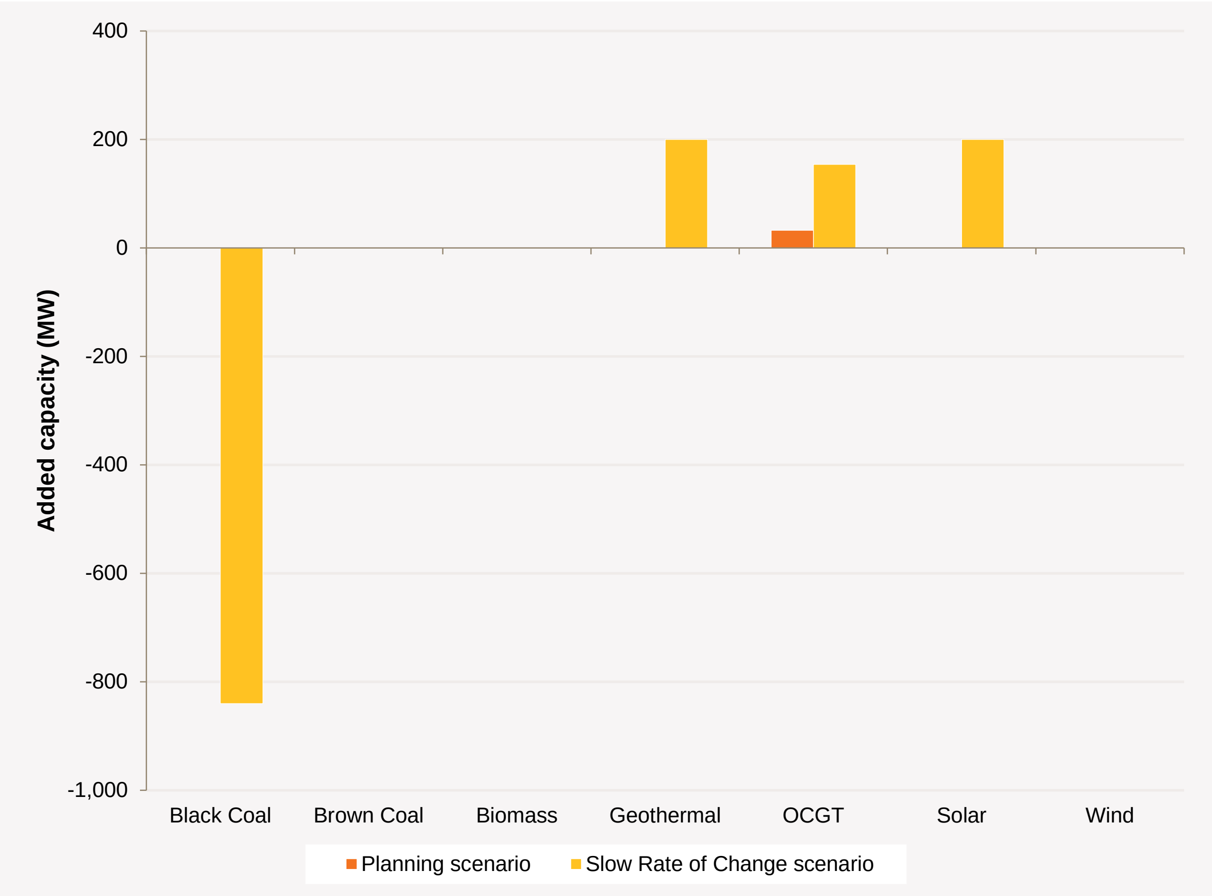
2.4.2 Central Queensland (CQ)

Table 2-6 lists the existing generation[15] and modelled new generation and retirements in the zone under the scenarios. Figure 2-12 shows the total new generation/retirements in the zone by 2036–37.

Table 2-6 — Existing installed capacity and modelled new generation/retirements (cumulative) for Central Queensland (CQ)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)									
		2016–17		2021–22		2026–27		2031–32		2036–37	
		P	SRC	P	SRC	P	SRC	P	SRC	P	SRC
Geothermal	**0**	0	0	0	200	0	200	0	200	0	200
CCGT	**55**	0	0	0	0	0	0	0	0	0	0
OCGT	**0**	0	0	0	0	0	0	0	109	32	154
Coal	**4,790**	0	-840	0	-840	0	-840	0	-840	0	-840
Solar	**0**	0	0	0	200	0	200	0	200	0	200

Figure 2-12 — Total new generation capacity/retirements in CQ by 2036–37



15 See note 14.

2.4.3 South West Queensland (SWQ)

Table 2-7 lists the existing generation[16] and modelled new generation and retirements in the zone under the scenarios. Figure 2-13 shows total new generation/retirements in the zone by 2036–37.

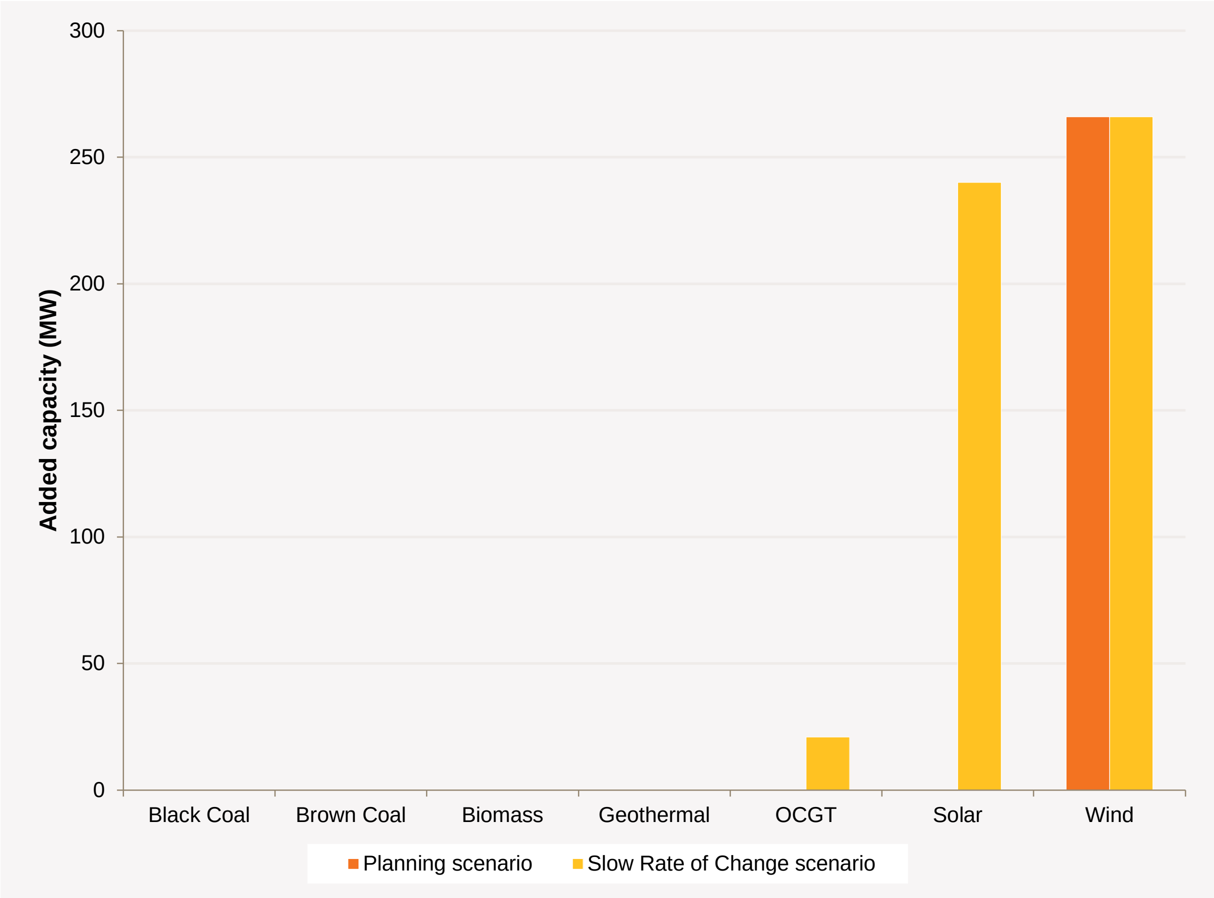
Table 2-7 — Existing installed capacity and modelled new generation/retirements (cumulative) for South West Queensland (SWQ)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)									
		2016–17		2021–22		2026–27		2031–32		2036–37	
		P	SRC	P	SRC	P	SRC	P	SRC	P	SRC
CCGT	**788**	0	0	0	0	0	0	0	0	0	0
OCGT	**1,385**	0	0	0	0	0	0	0	21	0	21
Coal	**3,450**[a]	0	0	0	0	0	0	0	0	0	0
Wind	**0**	0	266	266	266	266	266	266	266	266	266
Solar	**0**	0	0	0	239	0	239	0	239	0	239

a. This number includes two Tarong Power Station generating units totalling 700 MW that will be unavailable for at least two years.

16 See note 14.

Figure 2-13 — Total new generation capacity/retirements in SWQ by 2036–37



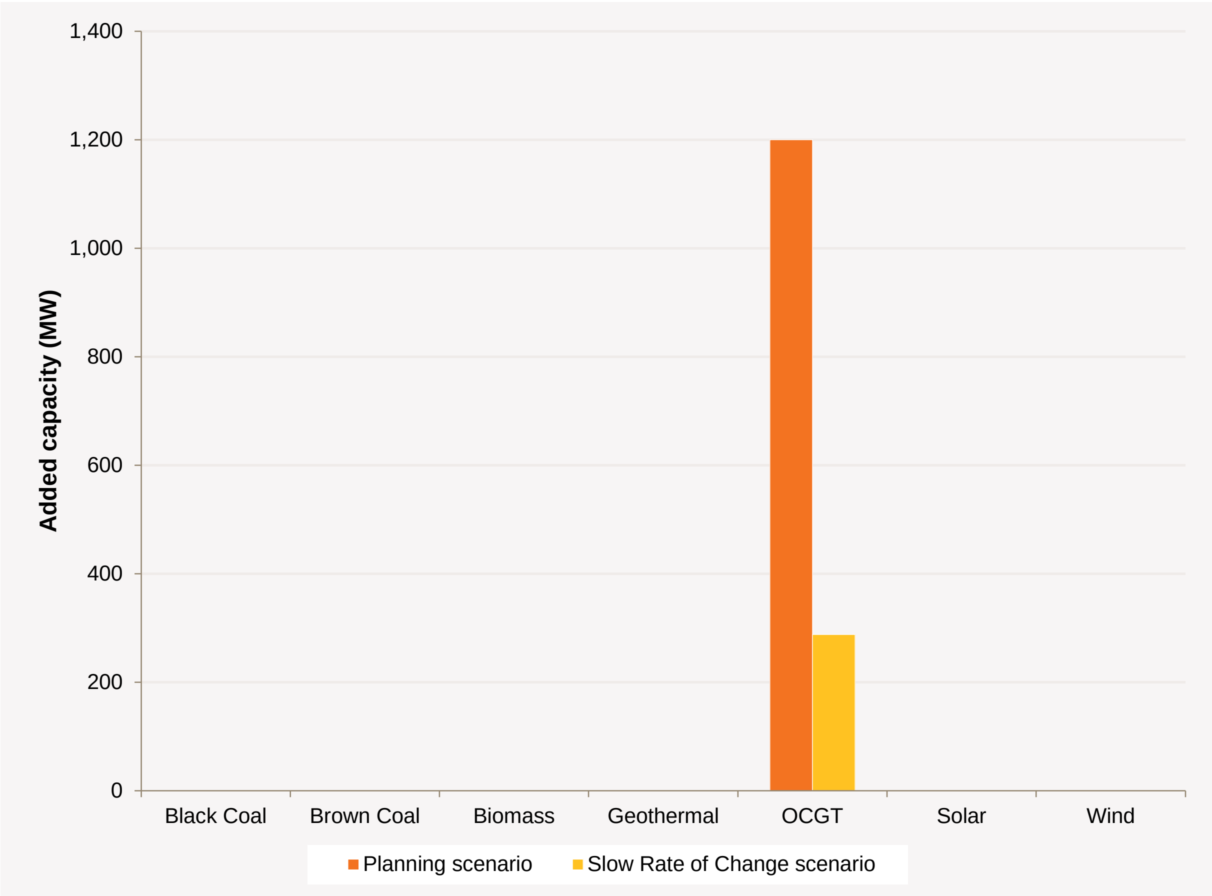
2.4.4 South East Queensland (SEQ)

Table 2-8 lists the existing generation[17] and modelled new generation and retirements in the zone under the scenarios. Figure 2-14 shows total new generation/retirements in the zone by 2036–37.

Table 2-8 — Existing installed capacity and modelled new generation/retirements (cumulative) for South East Queensland (SEQ)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)									
		2016–17		2021–22		2026–27		2031–32		2036–37	
		P	SRC	P	SRC	P	SRC	P	SRC	P	SRC
CCGT	**385**	0	0	0	0	0	0	0	0	0	0
OCGT	**0**	0	0	0	0	600	0	1,200	12	1,200	288
Hydro	**500**	0	0	0	0	0	0	0	0	0	0

Figure 2-14 — Total new generation capacity/retirements in SEQ by 2036–37



[17] See note 14.

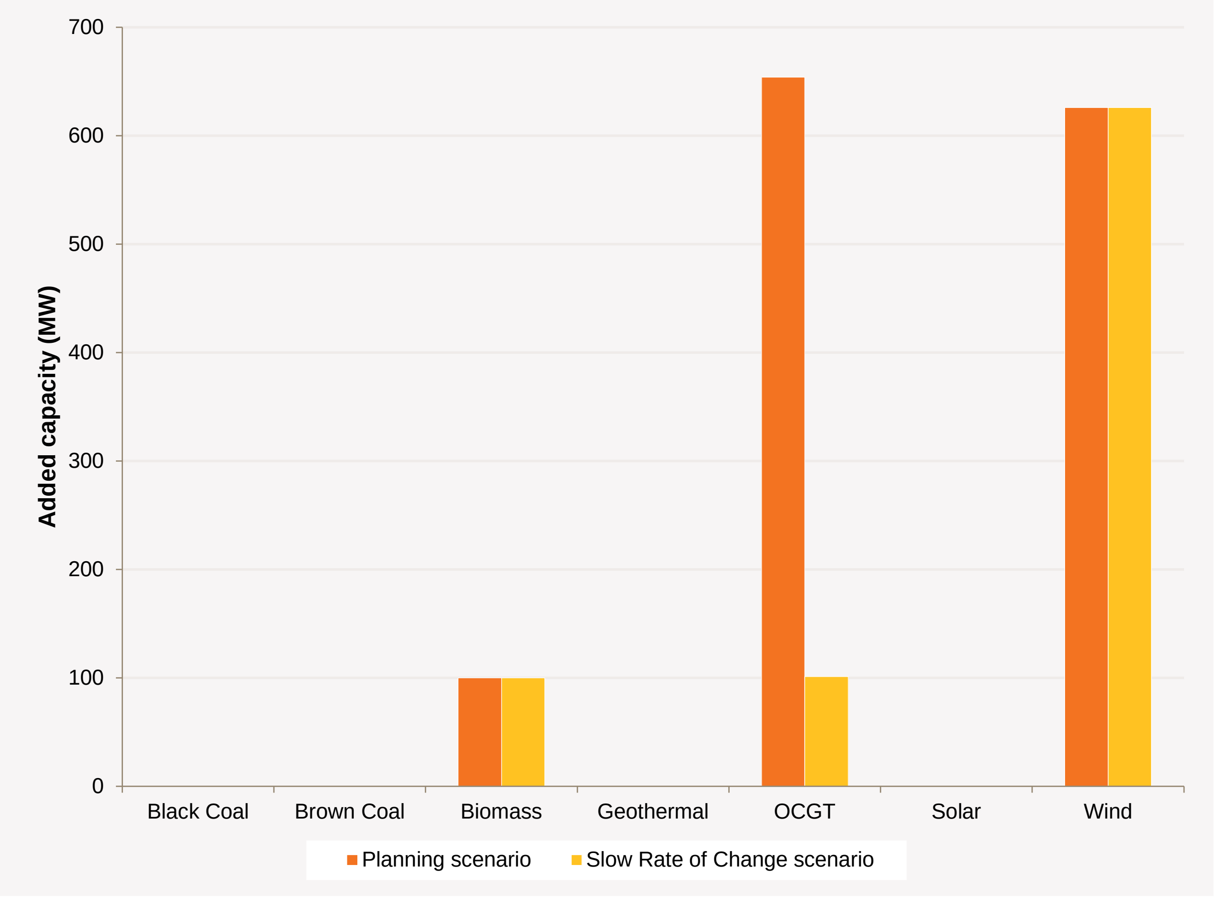
2.4.5 Northern New South Wales (NNS)

Table 2-9 lists the existing generation[18] and modelled new generation and retirements in the zone under the scenarios. Figure 2-15 shows total new generation/retirements in the zone by 2036–37.

Table 2-9 — Existing installed capacity and modelled new generation/retirements (cumulative) for Northern New South Wales (NNS)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)									
		2016–17		2021–22		2026–27		2031–32		2036–37	
		P	SRC	P	SRC	P	SRC	P	SRC	P	SRC
Biomass	0	0	17	0	100	0	100	100	100	100	100
OCGT	0	0	0	0	0	0	0	212	101	654	101
Wind	0	313	355	313	626	313	626	313	626	626	626

Figure 2-15 — Total new generation capacity/retirements in NNS by 2036–37



[18] See note 14.

2.4.6 Central New South Wales (NCEN)

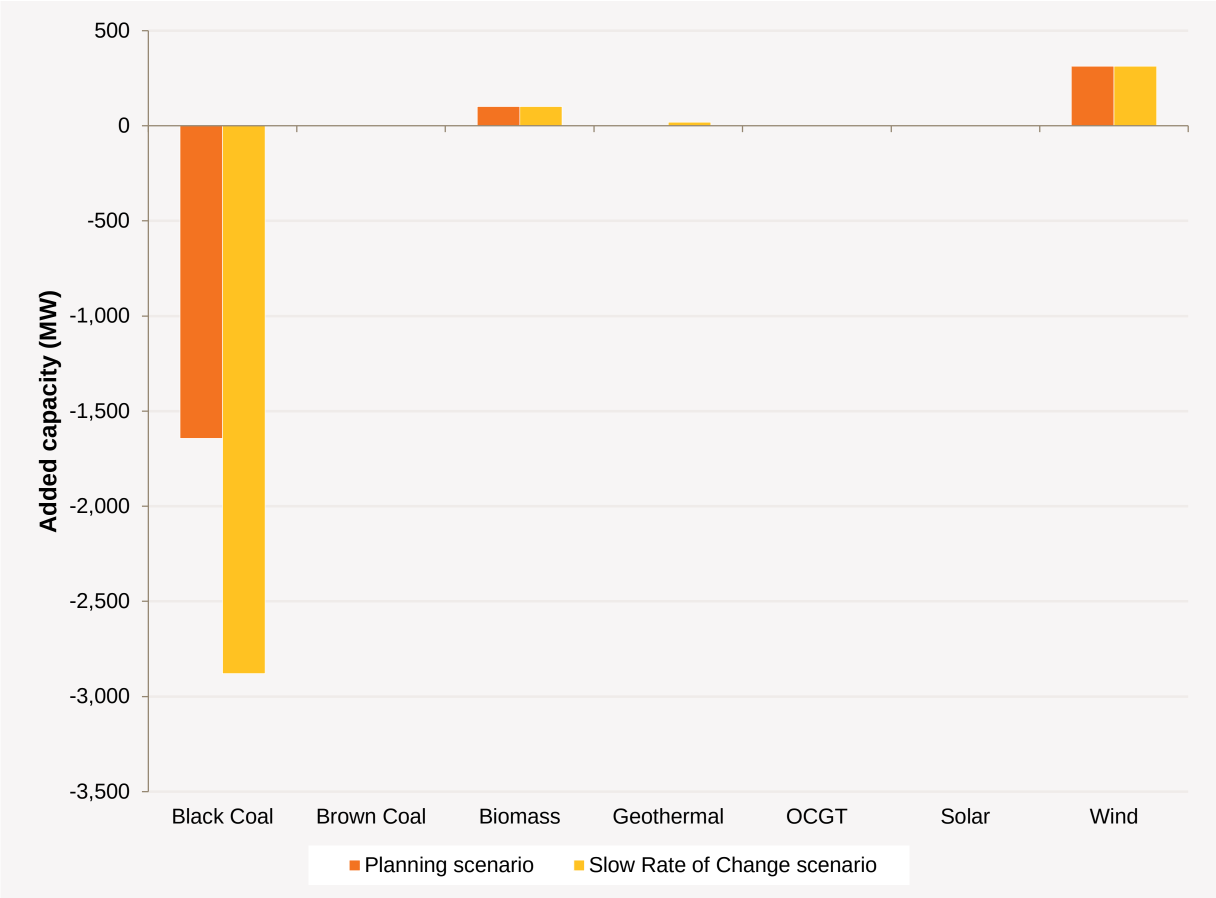
Table 2-10 lists the existing generation[19] and modelled new generation and retirements in the zone under the scenarios. Figure 2-16 shows total new generation/retirements in the zone by 2036–37.

Table 2-10 — Existing installed capacity and modelled new generation/retirements (cumulative) for New South Wales (NCEN)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)									
		2016–17		2021–22		2026–27		2031–32		2036–37	
		P	SRC	P	SRC	P	SRC	P	SRC	P	SRC
Biomass	**0**	0	100	0	100	51	100	100	100	100	100
Geothermal	**0**	0	0	0	19	0	19	0	19	0	19
CCGT	**420**	0	0	0	0	0	0	0	0	0	0
OCGT	**724**	0	0	0	0	0	0	0	0	0	0
Cogen	**171**	0	0	0	0	0	0	0	0	0	0
Distillate	**25**	0	0	0	0	0	0	0	0	0	0
Coal	**11,384**	-1,644	-2,880	-1,644	-2,880	-1,644	-2,880	-1,644	-2,880	-1,644	-2,880
Wind	**0**	0	313	313	313	313	313	313	313	313	313
Hydro	**240**	0	0	0	0	0	0	0	0	0	0

19 See note 14.

Figure 2-16 — Total new generation capacity/retirements in NCEN by 2036–37



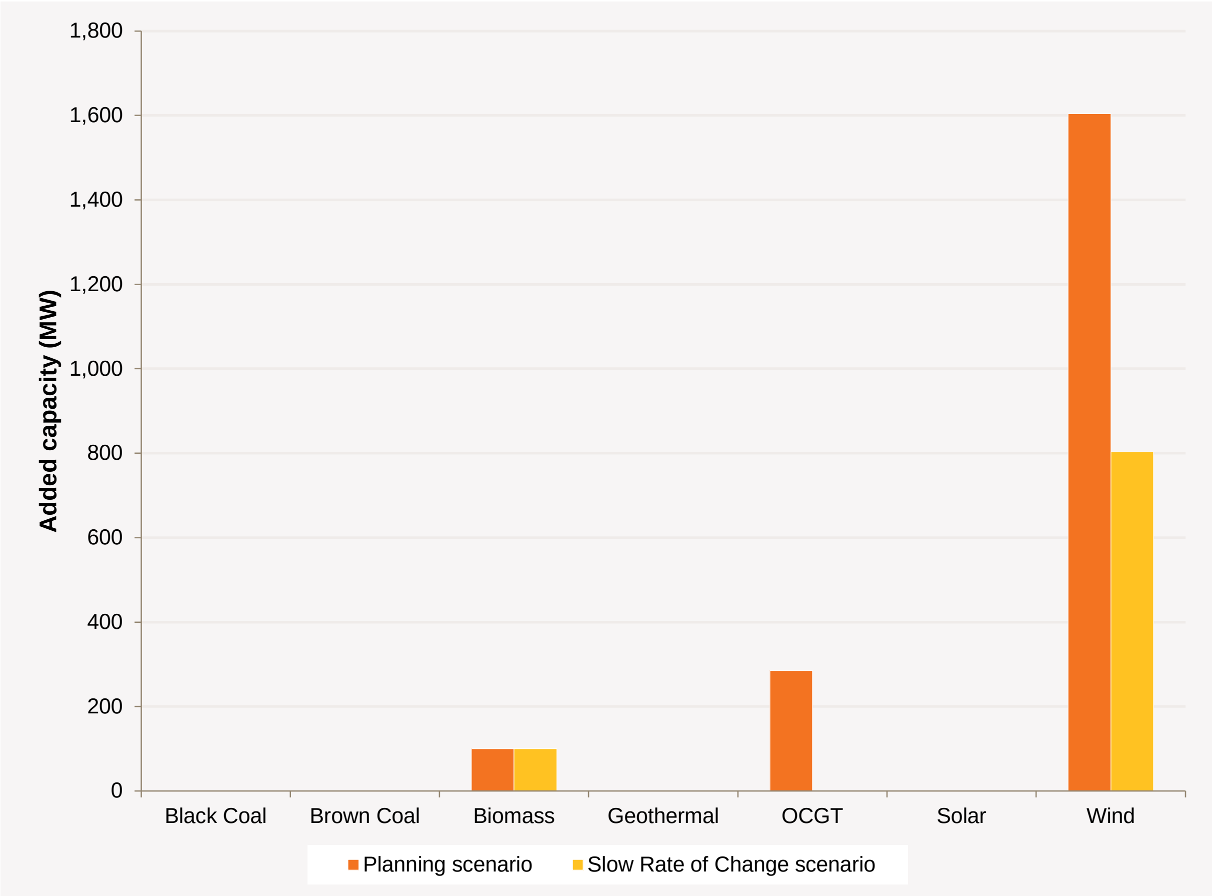
2.4.7 Canberra (CAN)

Table 2-11 lists the existing generation[20] and modelled new generation and retirements in the zone under the scenarios. Figure 2-17 shows total new generation/retirements in the zone by 2036–37.

Table 2-11 — Existing installed capacity and modelled new generation/retirements (cumulative) for Canberra (CAN)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)									
		2016–17		2021–22		2026–27		2031–32		2036–37	
		P	SRC	P	SRC	P	SRC	P	SRC	P	SRC
Biomass	**0**	0	100	0	100	0	100	100	100	100	100
OCGT	**0**	0	0	0	0	19	0	19	0	285	0
Wind	**266**	802	802	802	803	802	803	802	803	1,604	803
Hydro	**60**	0	0	0	0	0	0	0	0	0	0

Figure 2-17 — Total new generation capacity/retirements in CAN by 2036–37



[20] See note 14.

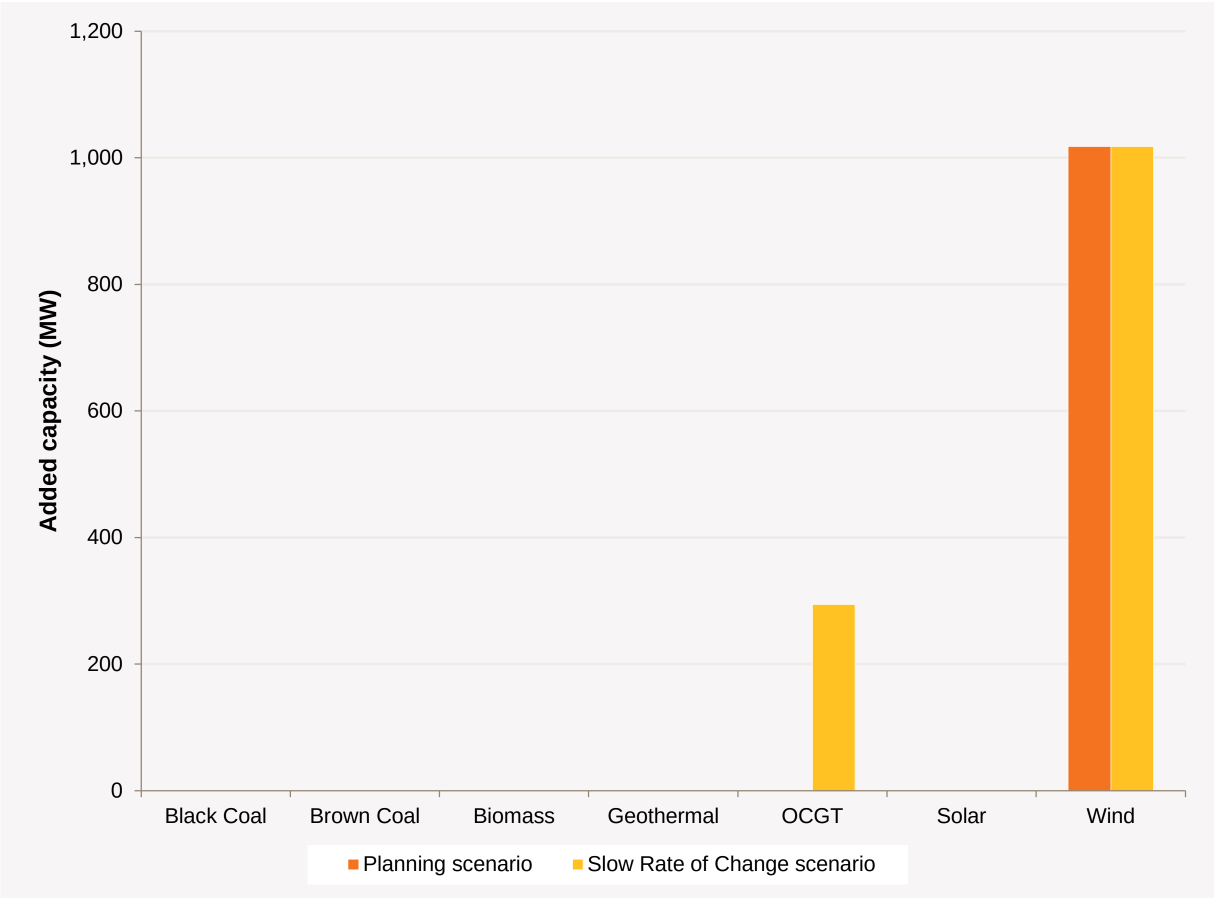
2.4.8 South West New South Wales (SWNSW)

Table 2-12 lists the existing generation[21] and modelled new generation and retirements in the zone under the scenarios. Figure 2-18 shows total new generation/retirements in the zone by 2036–37.

Table 2-12 — Existing installed capacity and modelled new generation/retirements (cumulative) for South West New South Wales (SWNSW)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)									
		2016–17		2021–22		2026–27		2031–32		2036–37	
		P	SRC	P	SRC	P	SRC	P	SRC	P	SRC
OCGT	**664**	0	0	0	0	0	0	0	99	0	294
Wind	**0**	509	1,018	689	1,018	689	1,018	689	1,018	1,018	1,018
Hydro	**2,319**	0	0	0	0	0	0	0	0	0	0

Figure 2-18 — Total new generation capacity/retirements in SWNSW by 2036–37



[21] See note 14.

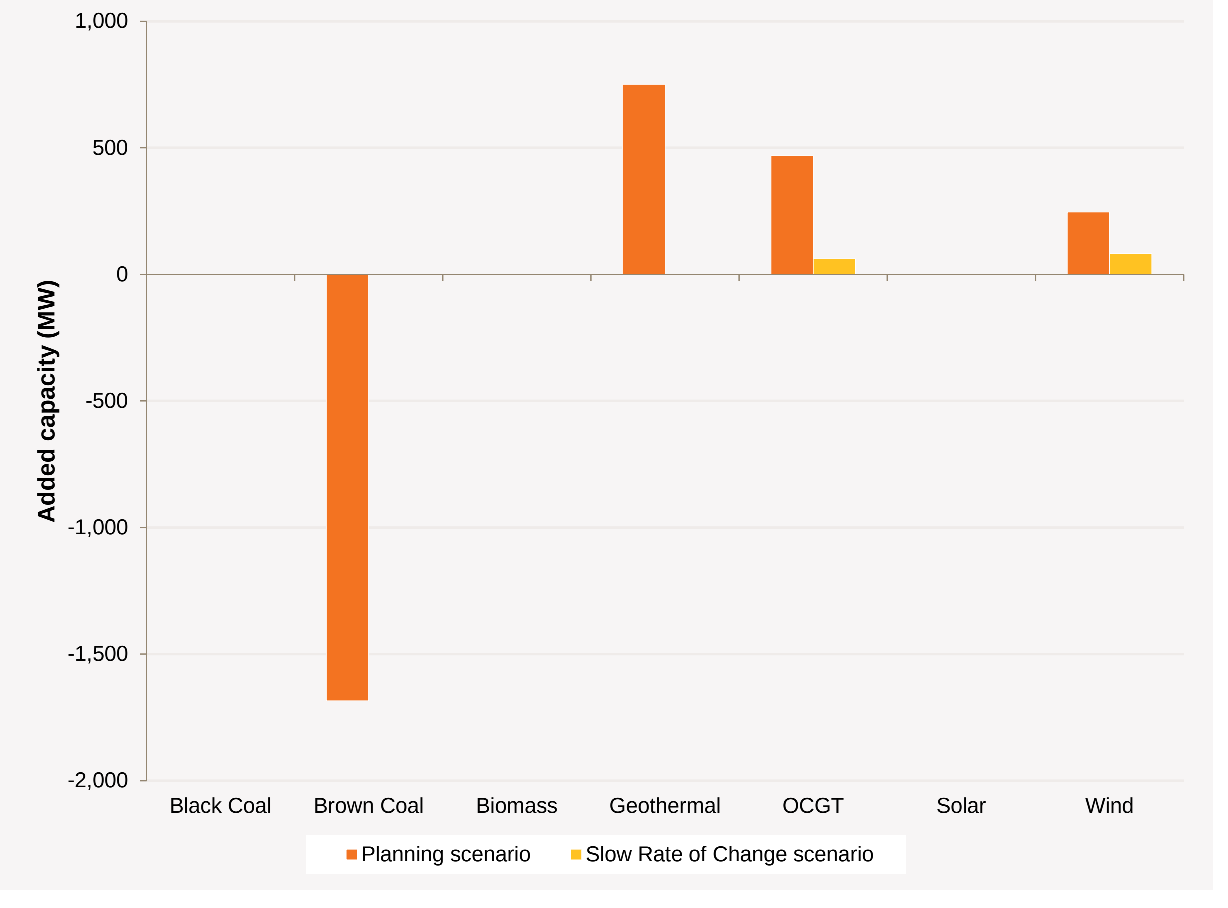
2.4.9 Latrobe Valley (LV)

Table 2-13 lists the existing generation[22] and modelled new generation and retirements in the zone under the scenarios. Figure 2-19 shows total new generation/retirements in the zone by 2036–37.

Table 2-13 — Existing installed capacity and modelled new generation/retirements (cumulative) for Latrobe Valley (LV)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)									
		2016–17		2021–22		2026–27		2031–32		2036–37	
		P	SRC	P	SRC	P	SRC	P	SRC	P	SRC
Geothermal	**0**	0	0	0	0	0	0	0	0	750	0
OCGT	**834**	0	0	469	0	469	61	469	61	469	61
Coal	**6,374**	-884	0	-884	0	-884	0	-884	0	-1,684	0
Wind	**30**	82	0	164	82	164	82	164	82	246	82

Figure 2-19 — Total new generation capacity/retirements in LV by 2036–37



22 See note 14.

2.4.10 Melbourne (MEL)

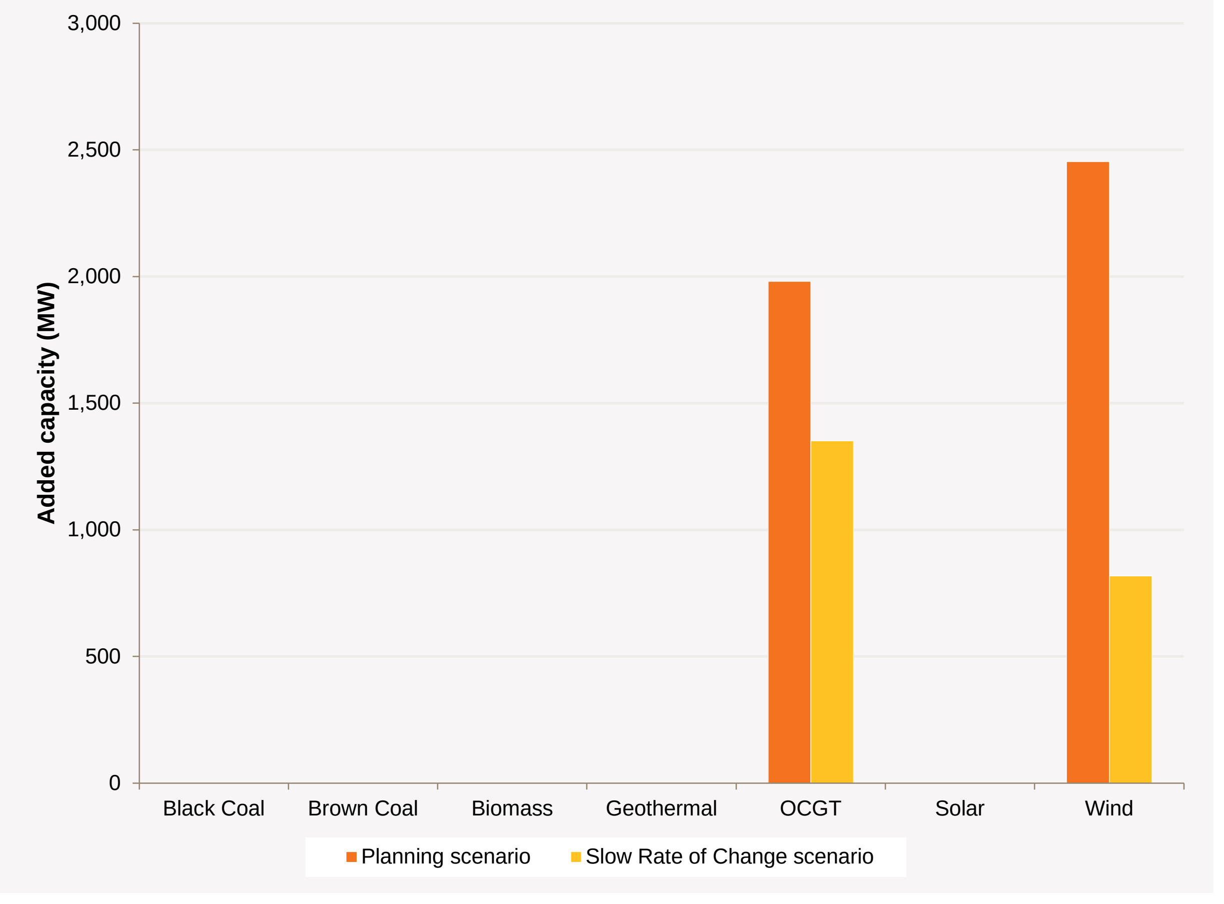
Table 2-14 lists the existing generation[23] and modelled new generation and retirements in the zone under the scenarios. Figure 2-20 shows total new generation/retirements in the zone by 2036–37.

Table 2-14 — Existing installed capacity and modelled new generation/retirements (cumulative) for Melbourne (MEL)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)									
		2016–17		2021–22		2026–27		2031–32		2036–37	
		P	SRC	P	SRC	P	SRC	P	SRC	P	SRC
OCGT	1,538	0	0	0	0	932	210	1,541	884	1,981	1,351
Wind	552[a]	1,636	485	2,454	818	2,454	818	2,454	818	2,454	818

a. Includes the committed Macarthur Wind Farm.

Figure 2-20 — Total new generation capacity/retirements in MEL by 2036–37



23 See note 14.

2.4.11 Country Victoria (CVIC)

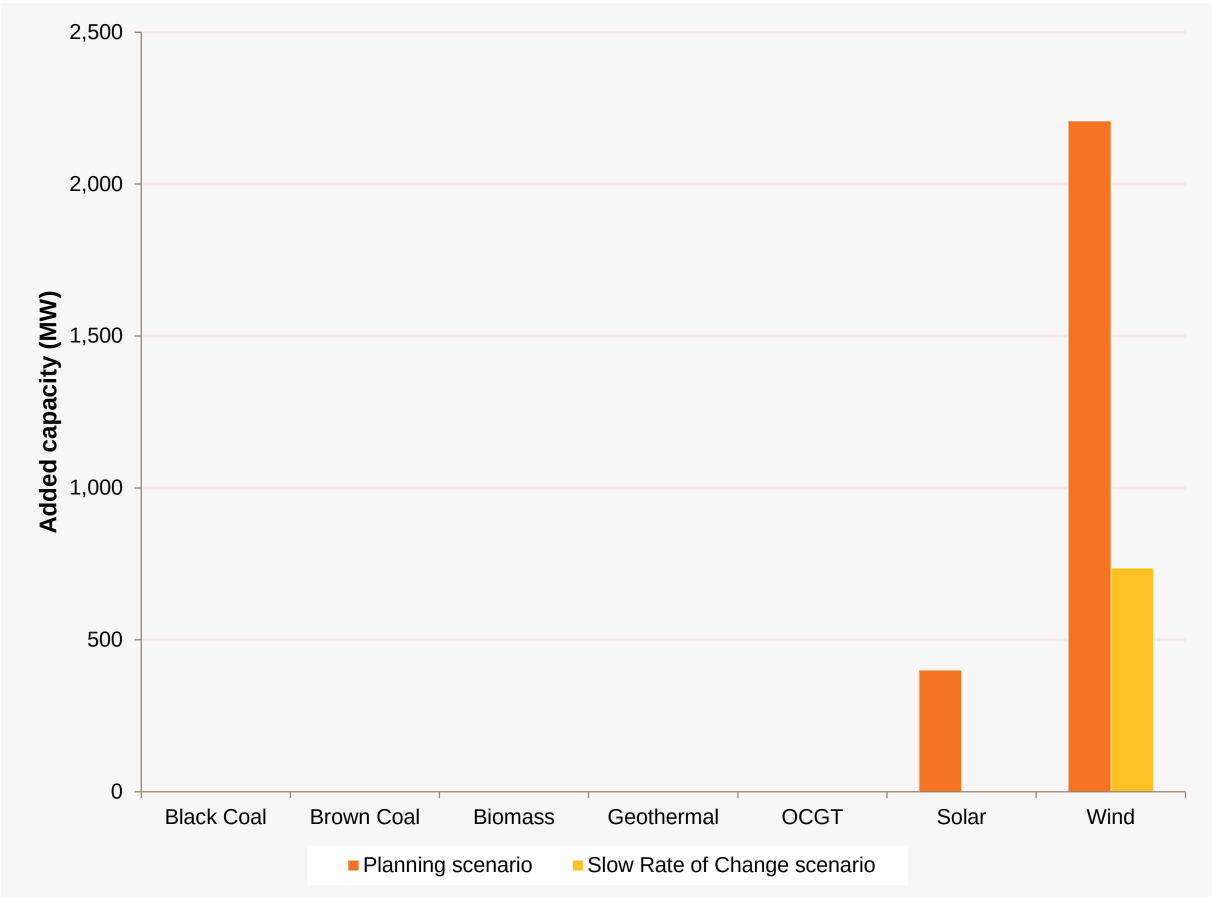
Table 2-15 lists the existing generation[24] and modelled new generation and retirements in the zone under the scenarios. Figure 2-11 Figure 2-21 shows total new generation/retirements in the zone by 2036–37.

Table 2-15 — Existing installed capacity and modelled new generation/retirements (cumulative) for Country Victoria (CVIC)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)									
		2016–17		2021–22		2026–27		2031–32		2036–37	
		P	SRC	P	SRC	P	SRC	P	SRC	P	SRC
Wind	312	873	0	1,472	736	1,472	736	1,658	736	2,208	736
Solar	0	0	0	400	0	400	0	400	0	400	0
Coal	150[a]	0	0	0	0	0	0	0	0	0	0

a. Non-scheduled Anglesea generation of 150 MW is included in the analysis

Figure 2-21 — Total new generation capacity/retirements in CVIC by 2036–37



[24] See note 14.

2.4.12 Northern Victoria (NVIC)

Table 2-16 lists the existing generation[25] and modelled new generation and retirements in the zone under the scenarios. No new generation is modelled in the zone under either scenario.

Table 2-16 — Existing installed capacity and modelled new generation/retirements (cumulative) for Northern Victoria (NVIC)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)									
		2016–17		2021–22		2026–27		2031–32		2036–37	
		P	SRC	P	SRC	P	SRC	P	SRC	P	SRC
Hydro	2,211	0	0	0	0	0	0	0	0	0	0

2.4.13 Adelaide (ADE)

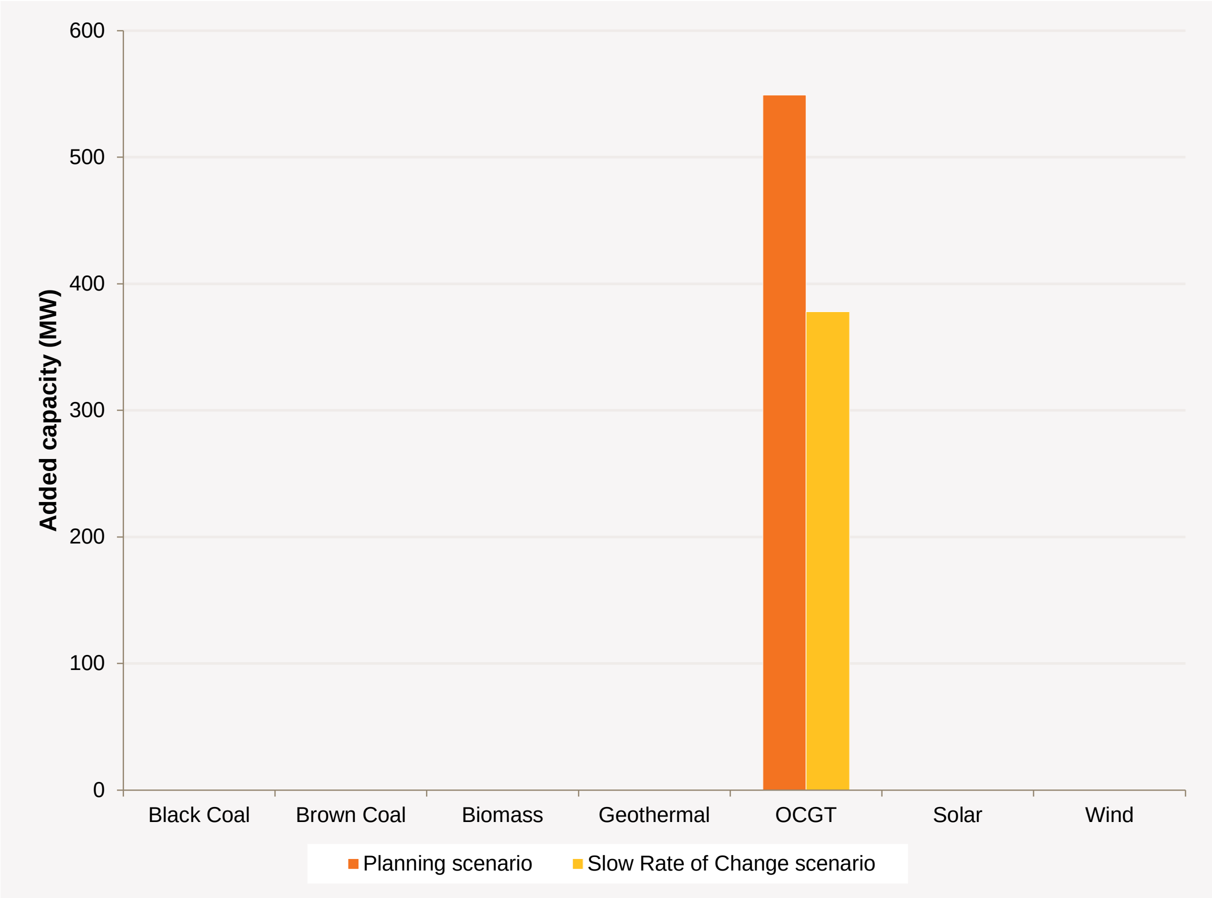
Table 2-17 lists the existing generation[26] and modelled new generation and retirements in the zone under the scenarios. Figure 2-22 shows the total new generation/retirements in the zone by 2036–37.

Table 2-17 — Existing installed capacity and modelled new generation/retirements (cumulative) for Adelaide (ADE)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)									
		2016–17		2021–22		2026–27		2031–32		2036–37	
		P	SRC	P	SRC	P	SRC	P	SRC	P	SRC
CCGT	658	0	0	0	0	0	0	0	0	0	0
Gas/steam sub-critical	1,280	0	0	0	0	0	0	0	0	0	0
OCGT	380	21	0	21	0	21	191	549	378	549	378
Wind	35	0	0	0	0	0	0	0	0	0	0

25 See note 14.
26 See note 14.

Figure 2-22 — Total new generation capacity/retirements in ADE by 2036–37



2.4.14 Northern South Australia (NSA)

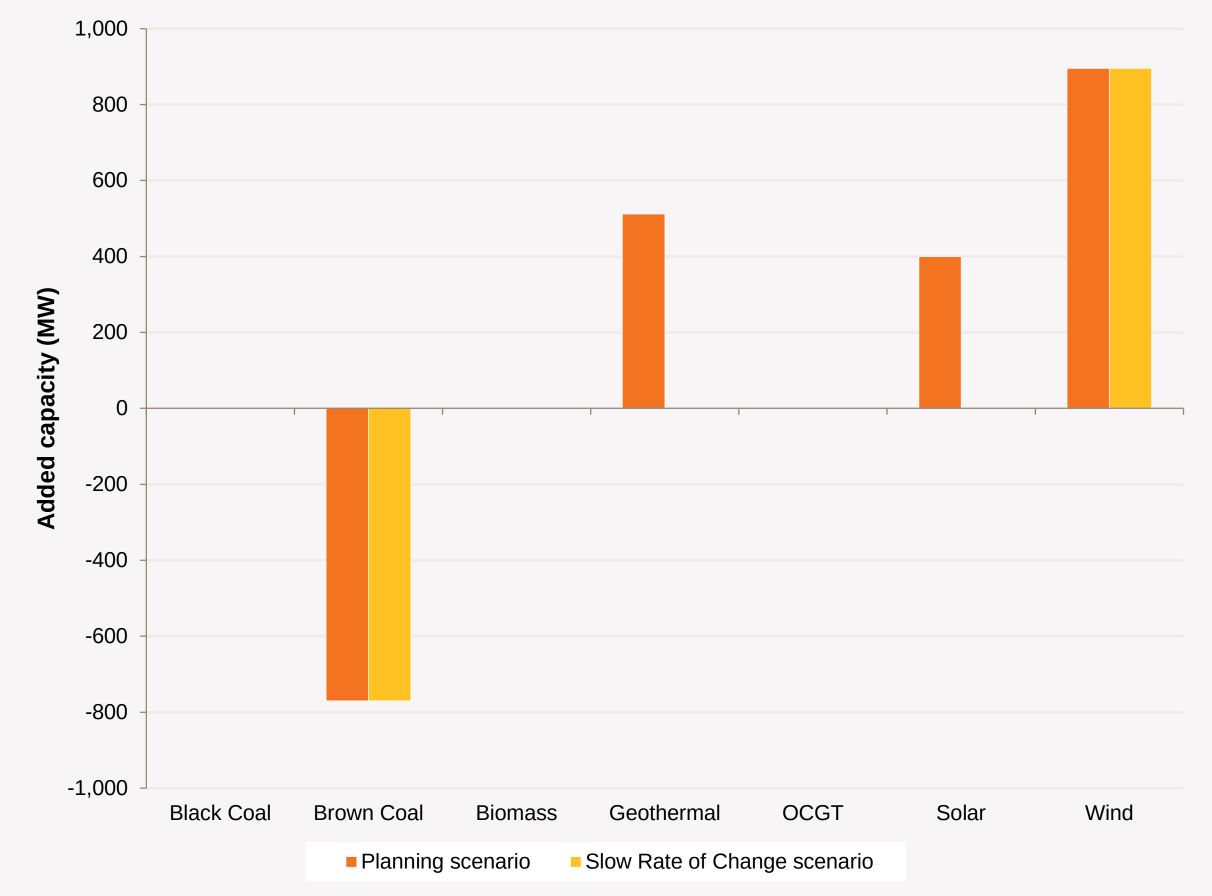
Table 2-18 lists the existing generation[27] and modelled new generation and retirements in the zone under the scenarios. Figure 2-23 shows total new generation/retirements in the zone by 2036–37.

Table 2-18 — Existing installed capacity and modelled new generation/retirements (cumulative) for Northern South Australia (NSA)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)									
		2016–17		2021–22		2026–27		2031–32		2036–37	
		P	SRC	P	SRC	P	SRC	P	SRC	P	SRC
Geothermal	**0**	0	0	0	0	0	0	0	0	512	0
OCGT	**318**	0	0	0	0	0	0	0	0	0	0
Distillate	**74**	0	0	0	0	0	0	0	0	0	0
Coal	**770**	-240	-505	-240	-505	-240	-505	-770	-770	-770	-770
Wind	**844**	895	895	895	895	895	895	895	895	895	895
Solar	**0**	0	0	400	0	400	0	400	0	400	0

[27] See note 14.

Figure 2-23 — Total new generation capacity/retirements in NSA by 2036–37



2.4.15 South East South Australia (SESA)

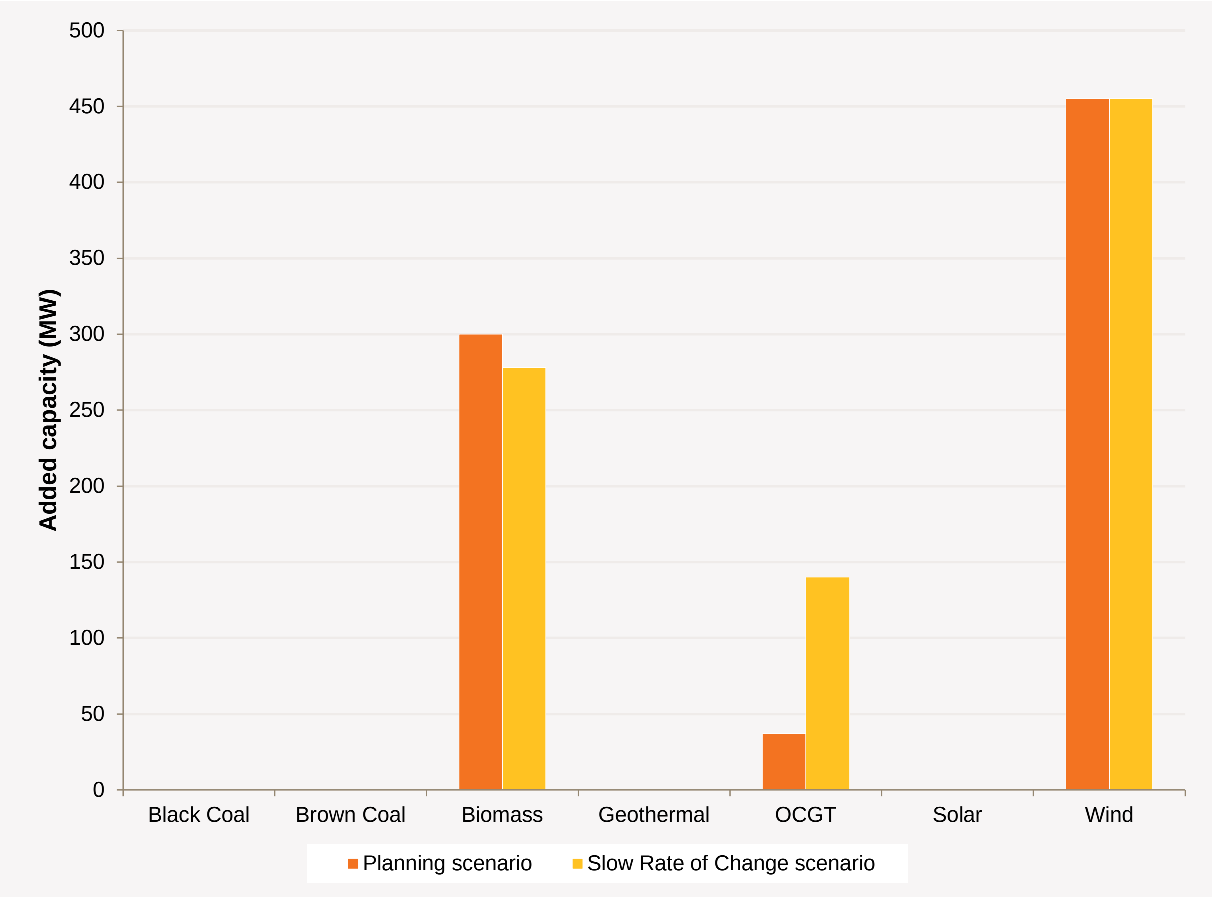
Table 2-19 lists the existing generation[28] and modelled new generation and retirements in the zone under the scenarios. Figure 2-24 shows total new generation/retirements in the zone by 2036–37.

Table 2-19 — Existing installed capacity and modelled new generation/retirements (cumulative) for South East South Australia (SESA)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)									
		2016–17		2021–22		2026–27		2031–32		2036–37	
		P	SRC	P	SRC	P	SRC	P	SRC	P	SRC
Biomass	**0**	92	115	300	278	300	278	300	278	300	278
OCGT	**80**	0	0	0	0	0	11	22	62	37	140
Distillate	**63**	0	0	0	0	0	0	0	0	0	0
Wind	**325**	455	455	455	455	455	455	455	455	455	455

28 See note 14.

Figure 2-24 — Total new generation capacity/retirements in SESA by 2036–37



2.4.16 Tasmania (TAS)

Table 2-20 lists the existing generation[29] and modelled new generation and retirements in the zone under the scenarios. Figure 2-25 shows total new generation/retirements in the zone by 2036–37.

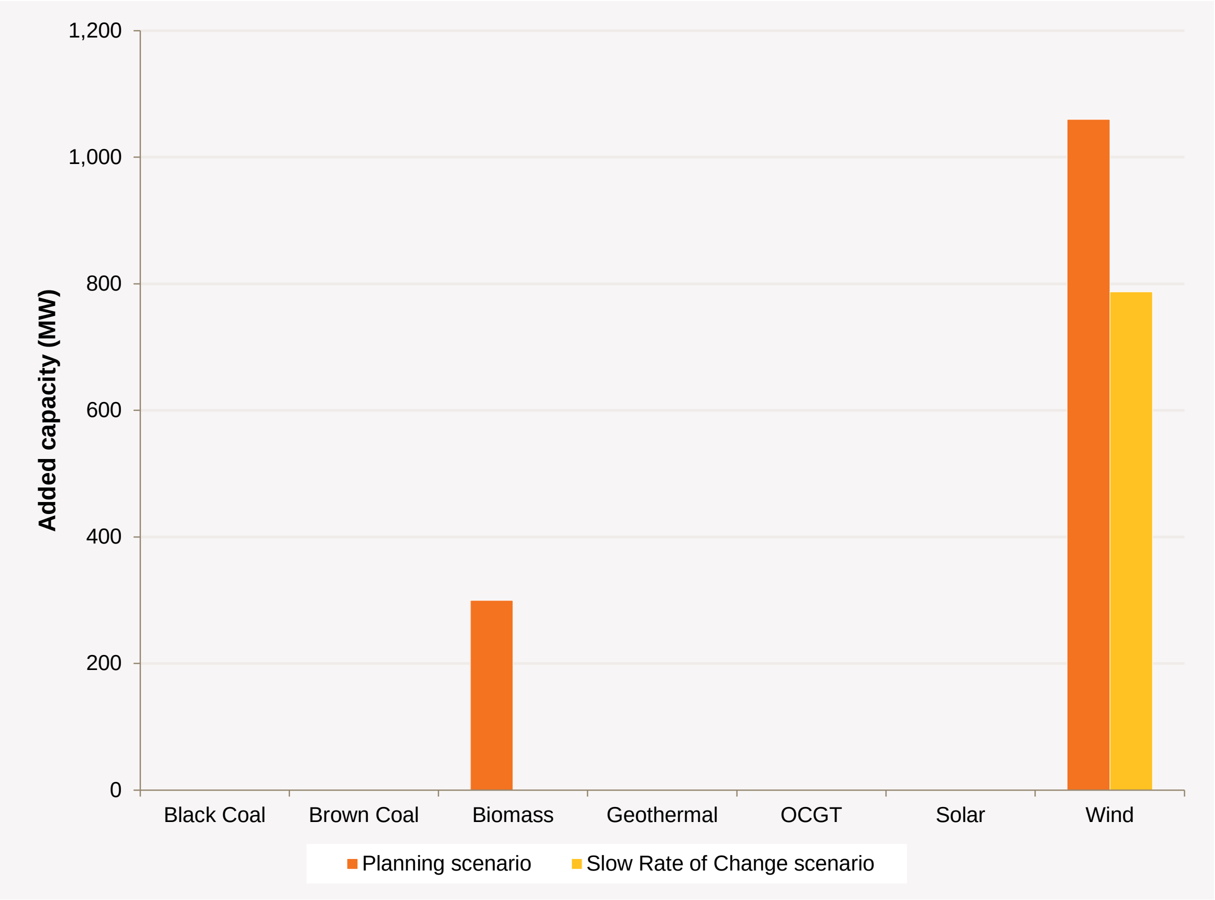
Table 2-20 — Existing installed capacity and modelled new generation/retirements (cumulative) for Tasmania (TAS)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)									
		2016–17		2021–22		2026–27		2031–32		2036–37	
		P	SRC	P	SRC	P	SRC	P	SRC	P	SRC
Biomass	**0**	0	0	0	0	0	0	0	0	300	0
CCGT	**208**	0	0	0	0	0	0	0	0	0	0
OCGT	**178**	0	0	0	0	0	0	0	0	0	0
Wind	**308**[a]	330	330	1,060	787	1,060	787	1,060	787	1,060	787
Hydro	**2,170**	0	0	0	0	0	0	0	0	0	0

a. Includes the committed Musselroe Wind Farm.

[29] See note 14.

Figure 2-25 — Total new generation capacity/retirements in TAS by 2036–37



CHAPTER 3 - NATIONAL TRANSMISSION OUTLOOK

Summary

This chapter presents the outcomes of the optimised generation and transmission modelling by zone under the Planning scenario over the NTNDP's 25-year outlook period. It also provides an alternative to the NEM-wide view of future power system requirements (see Chapter 2) by focussing on the impact the Planning scenario has on generation and transmission development in each NTNDP zone.

The main transmission network limitations identified in the 2012 NTNDP include the following:

- The Northern New South Wales (NNS) zone may experience main transmission network[1] limitations involving the capability of the 132 kV supply in the period from 2017–18 to 2021–22.
- The Central New South Wales (NCEN) zone may experience an emerging main transmission network limitation involving supply to the Sydney Metropolitan Area, requiring network reinforcement within five years (in the period from 2012–13 to 2016–17).

  TransGrid has also identified this limitation and is proposing to reinforce the 330 kV transmission supplying the Sydney Metropolitan Area (for more information see TransGrid's 2012 Annual Planning Report).[2]
- The Melbourne (MEL) zone may experience main transmission network limitations in the period from 2012–13 to 2031–32 involving the following:
  - The transformers at Rowville, Cranbourne, Keilor and South Morang.
  - A number of 220 kV circuits including Thomastown–Templestowe, Thomastown–Ringwood, South Morang–Thomastown, and Moorabool–Geelong.
- The Country Victoria (CVIC) zone may experience limitations on the Moorabool–Ballarat 220 kV No. 1 circuit and the Ballarat–Bendigo 220 kV circuit within five years (in the period from 2012–13 to 2016–17).

No other main transmission network limitations in the NEM were identified under the Planning scenario based on the key assumption that new generation development follows the least-cost expansion plan.

3.1 Introduction

3.1.1 The context of the analysis

The transmission development analysis focuses on assessing the adequacy of the main transmission network to reliably support major power transfers between NEM generation and demand centres, and identifying potential network needs when there is insufficient transmission network capability. This analysis is based on the key assumption that new generation development follows the least-cost expansion plan.

Modelling of committed projects

All committed projects are accounted for by the power system modelling and the committed main transmission network projects are listed in Chapter 2, Section 2.3.

For the complete list of committed main transmission projects and transmission needs under the Planning scenario, see the supplementary information page.[3]

1 Generally 220 kV and above.

2 TransGrid. Available http://www.transgrid.com.au/network/np/Documents/TRAN_219219_Annual_Planning_Report_2012_FA_web.pdf. Viewed 14 November 2012.

Transmission network adequacy assessment exclusions

The assessment of transmission network adequacy does not include the following:

- Transmission augmentations that may be required if future generation development does not follow the least-cost expansion plan. Information about these augmentations is still provided, however, to examine possible transmission impacts (where relevant).
- Intra-regional transmission augmentations driven by economic justification to deliver net market benefits.
- Transmission augmentations based on TNSPs applying different planning criteria (for information about the NTNDP planning criteria see Chapter 5, Section 5.6.1).
- Ongoing local transmission needs in each zone (for more information see Section 3.18).
- The need for local or regional transmission augmentations driven by regional or local demand growth, consideration of coincident maximum demands of individual zones, or the appearance of new or contracted loads.
- The need for additional transmission to replace aged assets.

3.2 North Queensland (NQ)

The NQ zone is a net importer of energy as this zone's demand exceeds the locally installed generation.

The zone relies heavily on power flows from the Central Queensland (CQ) zone via the Broadsound–Nebo 275 kV main transmission network. The transmission network north of Nebo is part of the NQ zone.

3.2.1 Committed main transmission projects

There are no committed projects in the NQ zone affecting the main transmission network.

3.2.2 Transmission needs

There are no limitations involving the main transmission network in the NQ zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no NQ zone transmission network development needs identified under the Planning scenario.

Other considerations

As demand growth exceeds new generation, the zone continues to rely on generation from the CQ, South West Queensland (SWQ), and South East Queensland (SEQ) zones during the first 20 years of the outlook period. The zone becomes a net exporter of energy towards the end of the outlook period due to more new generation in the NQ zone that reverses power flows, which are currently from CQ to NQ. With the least-cost expansion plan's modelled generation, transmission limitations on supply to the NQ zone from the CQ zone do not appear under the Planning scenario.

Under some conditions, existing NQ zone generation (including relatively high-cost liquid-fuelled generating units) may be required to supply local load. The NTNDP analysis has not considered the potential market benefits, however, of any transmission augmentations to reduce the reliance on high-cost generation. For example, under certain generation dispatch scenarios, an emerging limitation on transmission from the CQ to the NQ zone arises during 2017–18 to 2021–22 and 2022–23 to 2026–27 due to insufficient transmission capability north of the Stanwell area.

Even though generation re-dispatch will eliminate this limitation, the potential market benefits of transmission augmentation will still need to be assessed. This limitation does not arise after 2026–27, however, due to new generation appearing in the NQ zone from that year on.

[3] AEMO. Available http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Detailed-Results. Viewed 11 December 2012.

If actual NQ zone generation development differs from least-cost expansion plan patterns, the NQ zone will have to rely on power transfers from zones to the south. Depending on the location and amount of new generation development, the transmission system between the southerly zones and the NQ zone may need reinforcement. For example, if a large amount of new generation in NQ is located south of Calvale, transmission network limitations arise on the main transmission network connecting Calvale and Gladstone to Stanwell and Bouldercombe.

3.2.3 Generation expansion

Non-renewable

New open cycle gas turbine (OCGT) generation totalling 800 MW is built in the NQ zone towards the end of the outlook period.

Renewable

Wind generation in the NQ zone is assumed to contribute 9.2% of its installed capacity to the maximum demand in the Queensland region, and new wind generation is built at the end of the outlook period.

Under the Planning scenario:

- Biomass plant located in the NQ zone is built during the periods from 2027–28 to 2031–32 and 2032–33 to 2036–37.
- Solar thermal plant located in the NQ zone is built during the period from 2017–18 to 2021–22.

Retirements

Modelling identified approximately 190 MW of coal-fired generation retiring from 2014–15, and 34 MW of OCGT generation retiring from 2016–17.

Table 3-1 lists the existing generation[4] and modelled new generation and retirements in the zone.

Table 3-1 — Existing installed capacity and modelled new generation/retirements (cumulative) for North Queensland (NQ)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
Biomass	**0**	0	0	0	251	400
CCGT	**244**	0	0	0	0	0
OCGT	**34**	-34	-34	-34	32	766
Distillate	**424**	0	0	0	0	0
Coal	**190**	-190	-190	-190	-190	-190
Wind	**0**	0	0	0	0	266
Hydro	**154**	0	0	0	0	0
Solar	**0**	0	200	200	200	200

3.3 Central Queensland (CQ)

The CQ zone connects the NQ zone in the north to the SEQ and SWQ zones in the south.

4 Includes scheduled and semi-scheduled generation, and non-scheduled wind generation larger than 30 MW.

Demand is lower than the installed generation capacity in the CQ zone. As a result, the CQ zone is a net exporter of energy to the NQ and SEQ zones.

The CQ zone is connected to the NQ zone via the main transmission network between Broadsound and Nebo and to the SEQ and SWQ zones via the main transmission network south of Calvale, Gladstone and Wurdong.

3.3.1 Committed main transmission projects

Transmission needs in the CQ zone build on Powerlink Queensland's committed main transmission network projects, which include building a new 275 kV double circuit line between Calvale and Stanwell to increase the power transfer capability between the CQ and NQ zones.

3.3.2 Transmission needs

There are no limitations involving the main transmission network in the CQ zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no CQ zone transmission network development needs identified under the Planning scenario.

Other considerations

The CQ zone continues to be a net exporter of energy throughout the outlook period under the Planning scenario, which models a minimum amount of new generation in this zone of up to 32 MW.

The least-cost expansion plan analysis does not support major augmentations between CQ and the other zones. A need for augmentation may emerge, however, if actual CQ generation development differs from least-cost expansion plan patterns (depending on the location and amount).

For example, under the Planning scenario new generation in the NQ zone lowers the dependency of NQ zone demand on generation from southern zones. If new generation is not built, however, then the NQ zone will rely on supply from the south, resulting in increased power flows from CQ to NQ that may require reinforcement of the transmission network between these zones (for more information see Section 3.2.2)

3.3.3 Generation expansion

Non-renewable

Up to 32 MW of new OCGT generation is located in the CQ zone towards the end of the outlook period.

Renewable

No renewable generation is built in the CQ zone.

Retirements

There are no retirements modelled in the CQ zone.

Table 3-2 lists the existing generation[5] and modelled new generation and retirements in the zone under the Planning scenario.

Table 3-2 — Existing installed capacity and modelled new generation/retirements (cumulative) for Central Queensland (CQ)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
CCGT	55	0	0	0	0	0

5 See note 4.

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
OCGT	**0**	0	0	0	0	32
Coal	**4,790**	0	0	0	0	0

3.4 South West Queensland (SWQ)

The SWQ zone has the highest installed capacity in the Queensland region. With installed generation far exceeding the local demand, the SWQ zone is a net exporter of power.

The SWQ zone is connected to neighbouring zones via the following circuits:

- The CQ zone to the north via the Tarong–Calvale 275 kV transmission circuits.
- The SEQ zone to the east via the 275 kV transmission circuits from Tarong and Middle Ridge.
- The NNS zone in New South Wales via the Queensland–New South Wales (QNI) interconnector, which is a corridor for power flows between Queensland and New South Wales.

3.4.1 Committed main transmission projects

Transmission needs in the SWQ zone build on Powerlink Queensland's committed main transmission network projects, which include two new 275 kV double circuit lines:

- From Columboola to Wandoan South (initially operating at 132 kV) to increase power transfer capability to the Surat Basin's north-west.
- From Columboola to Western Downs to increase power transfer capability to the Surat Basin's north west.

The modelling also includes a number of recently commissioned and committed works implemented by Powerlink Queensland that are required to be complete before the two 275 kV double circuit projects. These works include establishing two new 275 kV substations at Western Downs and at Halys, splitting the 275 kV bus at the Braemar Substation, and constructing a new 275 kV transmission line from the Western Downs Substation to the Halys Substation. The existing 275 kV transmission line between Braemar Substation and Kogan Creek Power Station is also rearranged to connect the Western Downs and Braemar Substations. All of these works are planned to be completed by summer 2013–14.

3.4.2 Transmission needs

There are no limitations involving the main transmission network in the SWQ zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no SWQ zone transmission network development needs identified under the Planning scenario.

Other considerations

Transmission augmentation is not required in the SWQ zone because there is little new generation. As SEQ zone demand growth is mainly met by new generation in the zone, any increased demand is less dependent on increased power flows from the SWQ zone, which defers the need for further reinforcement of the transmission network within SWQ and between SEQ and SWQ.

There is also no need for augmentation between the SWQ and CQ zones. There is a surplus of generation in Central and North Queensland throughout the outlook period, and power flows between these two areas are typically southerly during peak demand periods. Additionally, new generation in the CQ and NQ zones does not result in significant power flows towards the southern zones, avoiding the need for any significant augmentation throughout the outlook period.

Various augmentation options to upgrade the power transfer capability between the Northern New South Wales (NNS) and SWQ zones (the Queensland–New South Wales (QNI) interconnector) were considered by assessing the net market benefits using least-cost expansion plan modelling. These options are driven by the ability for New South Wales to export energy to Queensland during high demand periods (given Queensland has the highest energy and demand growth among the regions), while allowing Queensland to export energy to New South Wales during lower demand periods.

None of the QNI interconnector upgrade options occur in the least cost modelling under the Planning scenario, and the need for increased power transfer capability between Queensland and New South Wales does not arise because the augmentation cost outweighs the market benefits.

If actual SWQ generation development differs from the least-cost expansion plan patterns, however, future transmission reinforcement may be required to address any thermal, voltage stability, and transient stability limitations.

For example, if 1,200 MW of new generation currently modelled in SEQ is located in SWQ, then depending on the location and amount of new generation, increased power transfers from SWQ to SEQ will reach the existing limits, requiring reinforcement of the transmission network within SWQ and between the zones.

3.4.3 Generation expansion

Non-renewable

No non-renewable generation is built in the SWQ zone.

Renewable

The SWQ zone has up to 266 MW of new wind generation appearing during the period from 2017–18 to 2021–22, which is assumed to contribute 9.2% of its installed capacity to the maximum demand in the Queensland region.

Retirements

The least-cost expansion plan has no retirements modelled in the SWQ zone. However, two units of the Tarong Power Station will not be available for service for at least two years[6] (which is accounted for by the transmission analysis).

Table 3-3 lists the existing generation[7] and modelled new generation and retirements in the zone under the Planning scenario.

[6] Stanwell Corporation has announced plans to withdraw two generating units from service at the Tarong Power Station in October and December 2012 for at least two years or until wholesale electricity demand improves (http://www.stanwell.com/Files/Stanwell_Media_Release_-_Stanwell_to_withdraw_Tarong_Power_Station_units_from_service_-_11_October_2012.PDF).

[7] See note 4.

Table 3-3 — Existing installed capacity and modelled new generation/retirements (cumulative) for South West Queensland (SWQ)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
CCGT	**788**	0	0	0	0	0
OCGT	**1,385**	0	0	0	0	0
Coal	**3,450**[a]	0	0	0	0	0
Wind	**0**	0	266	266	266	266

a. This number includes two Tarong Power Station generating units totalling 700 MW that will be unavailable for at least two years.

3.5 South East Queensland (SEQ)

The SEQ zone is a major load centre that includes the wider Brisbane area, Sunshine Coast, and Gold Coast. With local demand exceeding installed generation, the SEQ zone is a net importer, mainly from the CQ and SWQ zones.

The SEQ zone is connected to the CQ zone via the transmission system from Gin-Gin to Wurdong and Gladstone, and to the SWQ zone via the transmission circuits from Tarong and Middleridge. It is also connected to the NNS zone in New South Wales via the Terranora interconnector, and acts as a partial corridor for power flows between Queensland and New South Wales.

3.5.1 Committed main transmission projects

There are no committed projects affecting the main transmission network in this zone. Powerlink Queensland's other committed projects within the zone, however, are included in the power system modelling.

3.5.2 Transmission needs

There are no limitations involving the main transmission network in the SEQ zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no SEQ zone transmission network development needs identified under the Planning scenario.

Other considerations

The modelling of new entry generation in the SEQ zone is influenced by SEQ zone fuel cost assumptions (which are comparable to the SWQ zone), and the proximity to the load centre, which provides advantages to least-cost expansion plan development. Other factors, however, possibly limit the amount of generation that may be expected in the SEQ zone, such as air quality and noise level restrictions, and the relatively high cost of land.

Following advice from Powerlink Queensland, the NTNDP accounts for these environmental restrictions in two ways:

- By placing an upper limit (1,200 MW) on the allowable generation capacity.
- By restricting the type of new generation in this zone.

The 1,200 MW upper limit is reached under the Planning scenario, because the assumed fuel costs are comparable to other zones and new generation near the wider Brisbane area, Sunshine Coast, and Gold Coast load centres requires less transmission network investment. The demand growth in the area also balances the additional capacity from new generation development. This defers transmission augmentations that would otherwise be required to enable increasing power flows from the neighbouring CQ and SWQ zones.

If actual SEQ generation development differs from least-cost expansion plan patterns, future transmission reinforcement may be required to address any thermal, voltage stability, and transient stability limitations.

For example, if new generation is built in the SWQ zone rather than in the SEQ zone, then increased power flows from SWQ to SEQ may require reinforcement of the transmission network between the two zones (for more information see Section 3.4.2).

3.5.3 Generation expansion

Non-renewable

There is up to 1,200 MW of new OCGT generation located in the SEQ zone under the Planning scenario, which is installed prior to any other generation type. A total build restriction of 1,200 MW for conventional generation is applied to the SEQ zone based on advice from Powerlink Queensland relating to likely licensing and environmental restrictions.

Renewable

No new renewable generation is built in the SEQ zone.

Retirements

There are no retirements modelled in the SEQ zone.

Table 3-4 lists the existing generation[8] and modelled new generation and retirements in the zone under the Planning scenario.

Table 3-4 — Existing installed capacity and modelled new generation/retirements (cumulative) for South East Queensland (SEQ)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
CCGT	**385**	0	0	0	0	0
OCGT	**0**	0	0	600	1,200	1,200
Hydro	**500**	0	0	0	0	0

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3.6 Northern New South Wales (NNS)

The NNS zone connects the rest of New South Wales to Queensland via the Terranora and QNI[9] interconnectors. With no existing major generation sources, the NNS zone is a net importer and a corridor for power flows between Queensland and New South Wales.

The NNS zone includes the significant demand centres of Coffs Harbour, Tamworth, Lismore, and Terranora. There is currently no major source of generation within the zone.

3.6.1 Committed main transmission projects

Transmission needs in the NNS zone build on TransGrid's committed main transmission network projects, which include the following:

[8] See note 4.

[9] The Dumaresq–Bulli Creek 330 kV lines.

- Installation of a power oscillation damper on the Armidale SVC to increase the QNI interconnector's power transfer capability (in the Queensland to New South Wales direction).
- A new 200 MVAr capacitor at the Armidale Substation to increase the QNI interconnector's power transfer capability (in the New South Wales to Queensland direction).

3.6.2 Transmission needs

The NNS zone has little established generation, and includes major demand centres at Coffs Harbour, Tamworth, Lismore, and Terranora. The load growth in these areas, along with the expected load growth in the mid-north coast area, is expected to exceed the capability of the supplying 132 kV network in the period from 2017–18 to 2021–22, with one possible solution being to build a new 330 kV line from Dumaresq to Lismore.

A significant amount of new OCGT and wind generation is modelled towards the end of the outlook period, which the existing transmission network will be able to accommodate.

Other considerations

The NNS zone transmission network comprises multiple flow paths where 132 kV lines operate in parallel to 330 kV lines. As a result, 330 kV network power flows, including the QNI interconnector, can be limited by the 132 kV network's capability. As demand in the NNS zone grows and as 132 kV network limitations increase, strengthening or removing some of the 132 kV networks that run in parallel to the 330 kV network may result in positive net market benefits, providing economic justification.

None of the QNI interconnector upgrade options occur in the least-cost expansion plan modelling under the Planning scenario within the outlook period, and the need for increased power transfer capability between Queensland and New South Wales does not arise, because the augmentation cost outweighs the market benefits.

Table 3-5 lists NNS zone transmission network development needs identified under the Planning scenario.

Table 3-5 — NNS zone transmission development needs

Timing	Observed limitation	Network needs	Comments
2012–13 to 2016–17	None.	None.	None.
2017–18 to- 2021–22	Overload of the 132 kV transmission network supplying the north coast area demand centres for an outage of the Armidale–Coffs Harbour 330 kV line.	Reinforce the connection between the inland 330 kV transmission network and the north coast demand centres.	One possible solution is a 330 kV line from Dumaresq to Lismore.[a]
2022–23 to 2026–27	None.	None.	None.
2027–28 to 2031–32	None.	None.	None.
2032–33 to 2036–37	None.	None.	None.

a. In 2009, TransGrid and Country Energy [Essential Energy] published the final report in the regulatory test "Development of Electricity Supply to the NSW Far North Coast". The report recommended a 330 kV line from Dumaresq to Lismore to supply the north coast demand centres. Since publication, TransGrid has received proposals to provide non-network support to the region. This along with revised demand forecasts has led TransGrid to reassess the need for the project through a Regulatory Investment Test for Transmission (RIT-T).

3.6.3 Generation expansion

Non-renewable

Under the Planning scenario, OCGT generation of approximately 200 MW is built in the zone by 2031–32, increasing to 654 MW by 2036–37.

Renewable

Wind generation is built from the beginning of the outlook period and biomass plant is built from 2027–28 to 2031–32, with an assumed contribution of 2.2% of its installed capacity to the maximum demand in the New South Wales region.

Retirements

There are no retirements modelled in the NNS zone.

Table 3-6 lists the existing generation[10] and modelled new generation and retirements in the zone under the Planning scenario.

Table 3-6 — Existing installed capacity and modelled new generation/retirements (cumulative) for Northern New South Wales (NNS)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
Biomass	**0**	0	0	0	100	100
OCGT	**0**	0	0	0	212	654
Wind	**0**	313	313	313	313	626

3.7 Central New South Wales (NCEN)

The NCEN zone contains most of the New South Wales region's demand, involving the major load centres of Newcastle, Sydney, and Wollongong, which comprise approximately 75% of the region's demand at the time of maximum demand. The NCEN zone also has most of the region's generation capacity (including all its coal-fired generation).

At times of high demand, the NCEN zone is a net importer, with power being supplied from Queensland via the NNS zone in the north, and from the SWNSW zone and Victoria in the south via the CAN zone.

The NCEN transmission network is highly meshed and comprises 500 kV, 330 kV and 132 kV elements.

3.7.1 Committed main transmission projects

Transmission needs in the NCEN zone build on TransGrid's committed main transmission network projects, which include the following:

- The establishment of the new 330 kV Holroyd Substation and 330 kV Rookwood Road Substation in the Sydney Metropolitan Area.
- A new 330 kV cable (operated at 132 kV) between the Haymarket and Beaconsfield West Substations in the Sydney Metropolitan Area.
- Establishment and connection of a new Tomerong 330/132 kV substation to supply the Nowra area.
- Line rating increases on the Marulan–Avon, Marulan–Dapto and Kangaroo Valley–Dapto 330 kV lines.

3.7.2 Transmission needs

In the NCEN zone, demand growth is larger than generation growth throughout the outlook period under the Planning scenario, making the zone a net importer during peak demand periods.

[10] See note 4.

An emerging limitation arises in supplying the Sydney Metropolitan Area, and studies indicate that the supply to Beaconsfield West will need to be reinforced within five years. TransGrid has also identified problems with the 330 kV Sydney South–Beaconsfield West cable that may require its rating to be reduced under certain conditions, and is proposing to reinforce the 330 kV transmission supplying the Sydney Metropolitan Area. A Rookwood Road-Beaconsfield West 330 kV cable is the currently preferred option by TransGrid (for more information see TransGrid's 2012 Annual Planning Report).[11]

Other considerations

The location of any generation retirement is likely to significantly impact future transmission needs, and retirements occur in the Lake Macquarie area under the Planning scenario. If the retiring generation had been in the Newcastle area, then transmission limitations will probably arise on the 330 kV lines between the Hunter Valley and Newcastle. Similarly, if Wallerawang generation is retired, then transmission limitations will probably arise on the Mt Piper–Wallerawang 330 kV lines.

Table 3-7 lists NCEN zone transmission network development needs identified under the Planning scenario.

Table 3-7 — NCEN transmission development needs

Timing	Observed limitation	Network needs	Comments
2012–13 to 2016–17	Overload of the Sydney South–Beaconsfield West 330 kV line for an outage of the Sydney South–Haymarket 330 kV line	A new supply to the Beaconsfield West Substation from another 330 kV supply point.	In its 2012 APR, TransGrid noted that the most likely route for a new 330 kV line is from the new Rookwood Road Substation.
2017–18 to 2021–22	None.	None.	None.
2022–23 to 2026–27	None.	None.	None.
2027–28 to 2031–32	None.	None.	None.
2032–33 to 2036–37	None.	None.	None.

3.7.3 Generation expansion

Non-renewable

No new non-renewable generation is built in the NCEN zone under the Planning scenario.

Renewable

There is approximately 313 MW of new wind generation in the NCEN zone under the Planning scenario during the period from 2017–18 to 2021–22, with an assumed contribution of 2.2% of its installed capacity to the maximum demand in the New South Wales region.

Under the Planning scenario, 51 MW of biomass generation is located in the NCEN zone by 2026–27, increasing to 100 MW by 2031–32.

Retirements

The Munmorah Power Station ceased operation in July 2012. Modelling identified approximately 1,644 MW of coal-fired generation retiring during the period from 2012–13 to 2016–17 under the Planning scenario.

Table 3-8 lists the existing generation[12] and modelled new generation and retirements in the zone under the Planning scenario.

[11] TransGrid. Available http://www.transgrid.com.au/network/np/Documents/TRAN_219219_Annual_Planning_Report_2012_FA_web.pdf. Viewed 14 November 2012.

[12] See note 4.

Table 3-8 — Existing installed capacity and modelled new generation/retirements (cumulative) for Central New South Wales (NCEN)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
Biomass	**0**	0	0	51	100	100
CCGT	**420**	0	0	0	0	0
OCGT	**724**	0	0	0	0	0
Cogen	**171**	0	0	0	0	0
Distillate	**25**	0	0	0	0	0
Coal	**11,384**	-1,644	-1,644	-1,644	-1,644	-1,644
Wind	**0**	0	313	313	313	313
Hydro	**240**	0	0	0	0	0

3.8 Canberra (CAN)

The CAN zone is a net importer of power and a major power corridor connecting the SWNSW and NCEN zones. During peak demand periods in New South Wales, power generally flows north from SWNSW to CAN and from CAN to NCEN.

3.8.1 Committed main transmission projects

Transmission needs in the CAN zone build on TransGrid's committed main transmission network projects, which include establishing and connecting a new Williamsdale 330/132 kV substation to supply the southern part of the Australian Capital Territory.

3.8.2 Transmission needs

There are no limitations involving the main transmission network in the CAN zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no CAN zone transmission network development needs identified under the Planning scenario.

Other considerations

New wind generation of approximately 1,600 MW (largely in the Yass area) does not require major transmission augmentation. However, it is necessary to reduce generation in the SWNSW zone (or possibly Victoria) to avoid limitations on the transmission lines between CAN and NCEN at times of peak demand. Augmentation may also be required to accommodate this level of wind generation if the wind farms within the CAN zone are not optimally located (connected to areas of low capacity in the transmission network or overly concentrated in one area of the zone).

Interest has been expressed in locating new GPG in the north of the CAN zone (and the southern part of the NCEN zone). However, the majority of the GPG is located in the NNS zone under the Planning scenario. If significant amounts of GPG were to be built in the CAN zone, SWNSW zone, or the southern part of the NCEN zone, transmission limitations arise on the 330 kV network between the Yass/Canberra area and the Sydney Metropolitan Area.

3.8.3 Generation expansion

Non-renewable

New OCGT generation is built in the CAN zone under the Planning scenario, increasing from 19 MW during the period from 2022–23 to 2026–27, to 285 MW during the period from 2032–33 to 2036–37.

Renewable

Wind generation in the CAN zone is built under the Planning scenario from the beginning of the outlook period, with an assumed contribution of 2.2% of its installed capacity to the maximum demand in the New South Wales region.

Biomass plant located in the CAN zone is built during the period from 2027–28 to 2031–32.

Retirements

There are no retirements modelled in the CAN zone.

Table 3-9 lists the existing generation[13] and modelled new generation and retirements in the zone under the Planning scenario.

Table 3-9 — Existing installed capacity and modelled new generation/retirements (cumulative) for Canberra (CAN)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
Biomass	**0**	0	0	0	100	100
OCGT	**0**	0	0	19	19	285
Wind	**266**	802	802	802	802	1604
Hydro	**60**	0	0	0	0	0

3.9 South West New South Wales (SWNSW)

The SWNSW zone connects the rest of the New South Wales region to the Victorian region via the Lower and Upper Tumut–Murray 330 kV lines, the Jindera–Wodonga 330 kV line, and the Buronga–Redcliffs 220 kV line.

The SWNSW zone contains a large amount of hydroelectric generation. Although there is some demand within this zone, it is a net exporter of power to New South Wales load centres during times of peak demand.

3.9.1 Committed main transmission projects

There are no committed projects in the SWNSW zone affecting the main transmission network.

3.9.2 Transmission needs

There are no limitations involving the main transmission network in the SWNSW zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no SWNSW zone transmission network development needs identified under the Planning scenario.

13 See note 4.

Other considerations

The Victoria to New South Wales interconnector is not augmented in the least cost modelling under the Planning Scenario, because the augmentation cost exceeds any market benefits gained from the increased power transfer capability.

New wind generation of approximately 1,000 MW does not require any major transmission augmentation in the SWNSW zone if the wind farms are optimally located (not connected to areas of low capacity transmission network and not overly concentrated in one area of the zone). However, the addition of significant amounts of wind generation to the SWNSW zone may lead to network limitations in the Country Victoria (CVIC) zone (for more information see section 3.12.2).

The existing SWNSW transmission network is expected to be able to meet demand growth under the Planning scenario.

3.9.3 Generation expansion

Non-renewable

No non-renewable generation is built in the SWNSW zone.

Renewable

A significant amount of wind generation is built in the SWNSW zone under the Planning scenario, with 509 MW by 2016–17, 689 MW by 2021–22, and 1,018 MW by 2036–37, with an assumed contribution of 2.2% of its installed capacity to the maximum demand in the New South Wales region.

Retirements

There are no retirements modelled in the SWNSW zone.

Table 3-10 lists the existing generation[14] and modelled new generation and retirements in the zone under the Planning scenario.

Table 3-10 — Existing installed capacity and modelled new generation/retirements (cumulative) for South West New South Wales (SWNSW)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
OCGT	**664**	0	0	0	0	0
Wind	**0**	509	689	689	689	1,018
Hydro	**2,319**	0	0	0	0	0

3.10 Latrobe Valley (LV)

The LV zone is a major exporter of energy, principally to Melbourne and Geelong, and also to Regional Victoria and Tasmania.

Within the zone, the 500 kV transmission network connects Hazelwood to South Morang, Cranbourne, and Rowville, and the 220 kV transmission network connects Hazelwood and Yallourn to Rowville.

The zone itself connects to the Melbourne (MEL) zone via its 500 kV and 220 kV transmission networks and to TAS via the Basslink interconnector.

14 See note 4.

3.10.1 Committed main transmission projects

There are no committed projects in the LV zone affecting the main transmission network.

3.10.2 Transmission needs

There are no limitations involving the main transmission network in the LV zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no LV zone transmission network development needs identified under the Planning scenario.

Other considerations

The LV zone continues to be a net exporter of energy throughout the outlook period.

New generation (coupled with moderate demand growth) in the zone is slightly less than modelled retirements, which retires approximately 26% of brown coal-fired generation under the Planning scenario, most of which is replaced by new OCGT and geothermal generation. Consistent with a least-cost development, it is assumed that new generation will be in the same location as retired brown coal generation or connected to the Hazelwood 500 kV terminal station. This enables the existing transmission network to accommodate the new generation with minimal (or no) new transmission.

A second HVDC link, increasing Victoria to Tasmania interconnector capability, is not built under the Planning Scenario for the outlook period. This is due to the cost of the project outweighing the market benefits gained from increased power transfer capability between the two regions. The analysis is based on additional new wind generation of 1,000 MW in Tasmania with the existing Victoria to Tasmania interconnector and 1,700 MW with a second Victoria to Tasmania interconnector.

The existing 500 kV transmission network capability between the LV and MEL zones is adequate to accommodate the modelled new generation in the LV zone, even if the modelled retirements do not occur.

3.10.3 Generation expansion

Non-renewable

New OCGT generation is built in the LV zone under the Planning scenario, with an installed capacity of 469 MW being built during the period from 2017–18 to 2021–22.

Renewable

Wind generation in the LV zone is assumed to contribute 6.5% of its installed capacity to the maximum demand in the Victorian region. Under the Planning scenario, wind generation is built from the beginning of the outlook period and geothermal generation towards the end of the outlook period.

Retirements

The least-cost expansion plan modelling shows the LV zone has the highest level of retirement of existing plant under the Planning scenario, identifying up to 1,684 MW of coal-fired generation retiring during the outlook period.

Approximately 884 MW of coal-fired generation retires from 2015–16. The remaining generation (approximately 800 MW) retires during the period from 2032–33 to 2036–37.

Table 3-11 lists the existing generation[15] and modelled new generation and retirements in the zone under the Planning scenario.

[15] See note 4.

Table 3-11 — Existing installed capacity and modelled new generation/retirements (cumulative) for Latrobe Valley (LV)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
Geothermal	**0**	0	0	0	0	750
OCGT	**834**	0	469	469	469	469
Coal	**6,374**	-884	-884	-884	-884	-1,684
Wind	**30**	82	164	164	164	246

3.11 Melbourne (MEL)

The MEL zone transmission network comprises 220 kV, 275 kV, 330 kV and 500 kV transmission linking the LV, CVIC, NVIC and SESA zones. This zone has approximately 1,500 MW of OCGT generation, and transports power to and from South Australia and New South Wales. The zone is a net importer of energy, as the Melbourne and Geelong Greater Metropolitan Area is the largest load centre in Victoria, and is projected to remain Victoria's dominant load centre.

3.11.1 Committed main transmission projects

The MEL zone's development needs include connecting the Macarthur Wind Farm (capacity 420 MW) by establishing a 500 kV terminal station at Tarrone with connection to the Moorabool–Heywood–Portland 500 kV No.1 line. Tarrone Terminal Station has been commissioned and Macarthur Wind Farm is scheduled to be fully in service by December 2012.[16]

There are a number of other committed projects related to connections, which are not directly related to the main transmission network.

3.11.2 Transmission needs

Load growth in the Melbourne and Geelong Greater Metropolitan Area and a large amount of new generation connected to the 500 kV network drive the need to strengthen the 500/220 kV transformation capability. Four new 500/220 kV transformers have been identified in the zone to meet the increased load growth, and remove the overload on the existing 500/220 kV and 330/220 kV transformers.

Limitations have also been identified on the 220 kV circuits from Thomastown to Ringwood, Thomastown to Templestowe and South Morang to Thomastown during a single transmission element outage. Possible solutions involve the new transformers and connection of the Rowville–Templestowe 220 kV circuit at Ringwood.

An emerging limitation has also been observed on the 220 kV circuits from Moorabool to Geelong during the parallel transmission circuit outage. Possible solutions involve uprating the existing Moorabool–Geelong 220 kV circuits or adding a new Moorabool–Geelong 220 kV circuit.

Other considerations

Emerging network limitations may also arise on a number of radially connected 220 kV circuits (Rowville–Springvale, Springvale–Heatherton and Rowville–Malvern). The timing of these limitations depends on connection point load forecasts and load transfers to nearby terminal stations.

[16] AEMO. Available http://www.aemo.com.au/~/media/Files/Other/planning/2012_Victorian_Annual_Planning_Report.ashx. Chapter 3, Section 3.1.1. Viewed 31 October 2012.

New wind generation of up to 2,454 MW is modelled in this zone, giving rise to network limitations on the existing 500 kV transmission network along the South West Corridor. High imports from South Australia combined with moderate levels of OCGT generation also contribute to this limitation. Generation rescheduling was modelled to remove the network limitations in the least-cost expansion plan. However, additional 500 kV transmission augmentation between Moorabool and Heywood is an alternative potential solution.

Table 3-12 lists the MEL zone transmission network development needs identified under the Planning scenario.

Table 3-12 — MEL transmission development needs

Timing	Observed limitation	Network needs	Comments
2012–13 to 2016–17	Overload of the Rowville 500/220 kV A2 transformer for an outage of the Cranbourne 500/220 kV A1 transformer (and vice versa).	An additional 500/220 kV transformer in the Eastern Metropolitan Melbourne area.	One possible solution is an additional 1,000 MVA 500/220 kV transformer at Cranbourne or Rowville. For more information see AEMO's 2012 Victorian APR.[a]
2017–18 to 2021–22	Overload of the Rowville 500/220 kV A1 transformer under system normal conditions, and overload of the Thomastown–Templestowe and Thomastown–Ringwood 220 kV circuits for an outage of the Rowville 500/220 kV A1 transformer.	An additional 500/220 kV transformer in the Eastern Metropolitan Melbourne area and connection of the Rowville–Templestowe 220 kV circuit at Ringwood.	One possible solution is an additional 1,000 MVA 500/220 kV transformer at Rowville, Ringwood or Templestowe, and connection of the Rowville–Templestowe 220 kV circuit at Ringwood. For more information see AEMO's 2012 Victorian APR.[a]
2022–23 to 2026–27	Overload of a Keilor 500/220 kV transformer for an outage of the parallel transformer or a Moorabool 500/220 kV transformer, and overload of a South Morang 330/220 kV transformer and a South Morang–Thomastown 220 kV circuit for an outage of the parallel transformer/circuit, and overload of a Moorabool–Geelong 220 kV circuit for an outage of the parallel circuit.	An additional 500/220 kV in the Western Metropolitan Melbourne area.	One possible solution is an additional 500/220 kV transformer at Keilor.
2027–28 to 2031–32	Overload of the Rowville 500/220 kV A1 transformer for an outage of the parallel transformer (and vice versa), and overload of a South Morang 330/220 kV transformer and a South Morang–Thomastown 220 kV circuit for an outage of the parallel transformer/circuit.	An additional 500/220 kV transformer in the Eastern Metropolitan Melbourne area.	One possible solution is an additional 1,000 MVA 500/220 kV transformer at Rowville, Ringwood, Templestowe or South Morang.
2027–28 to 2031–32	Overload of a Moorabool–Geelong 220 kV circuit for an outage of the parallel circuit.	An additional 220 kV capability from Moorabool to Geelong.	None.
2032–33 to 2036–37	None.	None.	None.

a. AEMO. Available http://www.aemo.com.au/~/media/Files/Other/planning/2012_Victorian_Annual_Planning_Report.ashx. Chapter 3. Viewed 31 October 2012.

3.11.3 Generation expansion

Non-renewable

New OCGT generation is built in the MEL zone under the Planning scenario. New generation in the MEL zone's South West Corridor increases from 932 MW during the period from 2022–23 to 2026–27 to 1,775 MW towards the end of the outlook period. In the Greater Melbourne Metropolitan Area, 206 MW of new OCGT generation is built towards the end of the outlook period (totalling 1,981 MW in the MEL zone).

Renewable

The MEL zone wind generation is assumed to contribute 6.5% of its installed capacity to maximum demand in the Victorian region. Wind generation is built in the MEL zone under the Planning scenario from the beginning of the outlook period.

Retirements

There are no retirements modelled in the MEL zone.

Table 3-13 lists the existing generation[17] and modelled new generation and retirements in the zone under the Planning scenario.

Table 3-13 — Existing installed capacity and modelled new generation/retirements (cumulative) for Melbourne (MEL)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
OCGT	**1,538**	0	0	932	1,541	1,981
Wind	**552**[a]	1,636	2,454	2,454	2,454	2,454

a. Includes Macarthur Wind Farm generation of 420 MW.

3.12 Country Victoria (CVIC)

The CVIC zone is electrically connected to the neighbouring NSA zone in South Australia via Murraylink, and to the SWNSW zone in New South Wales via Red Cliffs/Buronga. This zone also links to the MEL and Northern Victoria (NVIC) zones and has 312 MW of installed wind generation.

The transmission network in this zone, while delivering supply to the load centres in CVIC, also transfers power to South Australia and New South Wales.

3.12.1 Committed main transmission projects

There are no committed projects in the CVIC zone affecting the main transmission network. The power system modelling includes other committed projects that are related to connection augmentation in this zone.

3.12.2 Transmission needs

Network limitations on the Moorabool–Ballarat 220 kV No. 1 circuit and the Ballarat–Bendigo 220 kV circuit were observed during the period from 2012–13 to 2016–17. However, these limitations were not observed after this point, as 400 MW of solar power generation is located in the CVIC zone. Approximately 270 MW of the total solar generation installed in the zone was modelled as available for the summer peak demand period.

17 See note 4.

The least-cost expansion plan distributes the 2,208 MW of new wind generation at Ballarat, Bendigo, Horsham, Terang and Red Cliffs to minimise major transmission network augmentation in the CVIC zone. Nevertheless, limitations on the Moorabool–Ballarat 220 kV No.1 circuit were observed at times of high wind generation and moderate demand during the period from 2017–18 to 2022–23.

Other considerations

If a high proportion of the new wind generation is built at Horsham, Terang or Red Cliffs, additional network limitations would emerge. The following network limitations were observed with high wind generation during moderate demand periods:

- Overload of the Terang–Ballarat 220 kV circuit on outage of the Terang–Moorabool 220 kV circuit.
- Overload of the Ballarat–Waubra–Horsham 220 kV circuit on outage of the Red Cliffs–Wemen–Kerang 220 kV circuit.
- Overload of the Red Cliffs–Wemen–Kerang 220 kV circuit on outage of the Ballarat–Waubra–Horsham 220 kV circuit.

Table 3-14 lists CVIC zone transmission network development needs identified under the Planning scenario.

Table 3-14 — CVIC transmission development needs

Timing	Observed limitation	Network needs	Comments
2012–13 to 2016–17	Overload of the Moorabool–Ballarat 220 kV No.1 circuit for an outage of the Moorabool–Ballarat 220 kV No.2 circuit.	An additional 220 kV capability from Moorabool to Ballarat.	The timing is subject to the location, size and timing of proposed wind and solar generation.
2012–13 to 2016–17	Overload of the Ballarat–Bendigo 220 kV circuit for an outage of the Bendigo–Shepparton 220 kV circuit.	An additional 220 kV capability from Ballarat to Bendigo.	The timing is subject to the location, size and timing of proposed wind and solar generation.
2017–18 to 2021–22	None.	None.	None.
2022–23 to 2026–27	None.	None.	None.
2027–28 to 2031–32	None.	None.	None.
2032–33 to 2036–37	None.	None.	None.

3.12.3 Generation expansion

Non-renewable

No new non-renewable generation is built in the CVIC zone under the Planning scenario.

Renewable

CVIC zone wind generation is assumed to contribute 6.5% of its installed capacity to the maximum demand in the Victorian region. Similarly to the MEL zone, high levels of new wind generation are built from the beginning of the outlook period. Modelled generation in the CVIC zone also includes solar generation of approximately 400 MW during the period from 2017–18 to 2021–22.

Retirements

There are no retirements modelled in the CVIC zone.

Table 3-15 lists the existing generation[18] and modelled new generation and retirements in the zone under the Planning scenario.

Table 3-15 — Existing installed capacity and modelled new generation/retirements (cumulative) for Country Victoria (CVIC)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
Wind	**312**	873	1,472	1,472	1,658	2,208
Solar	**0**	0	400	400	400	400
Coal	**150**[a]	0	0	0	0	0

a. Non-scheduled Anglesea generation of 150 MW is included in the analysis.

3.13 Northern Victoria (NVIC)

The NVIC zone includes connections to the MEL and CVIC zones, and major interconnectors between Victoria and New South Wales.

The zone has hydroelectric generation installed capacity of 2,211 MW, and provides electrical transmission for the Kiewa, Dartmouth, Eildon, and Murray hydroelectric schemes.

3.13.1 Committed main transmission projects

There are no committed projects in the NVIC zone affecting the main transmission network.

3.13.2 Transmission needs

There are no limitations involving the main transmission network in the NVIC zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no NVIC zone transmission network development needs identified under the Planning scenario.

Other considerations

A transmission network limitation arises on the Dederang–Mount Beauty 220 kV line during periods of high hydroelectric generation. Generation re-scheduling might remove this limitation.

3.13.3 Generation expansion

Non-renewable

No non-renewable generation is built in the NVIC zone for the outlook period.

Renewable

No new renewable generation is built in the NVIC zone for the outlook period.

Retirements

There are no retirements modelled in the NVIC zone.

Table 3-16 lists the existing generation[19] and modelled new generation and retirements in the zone under the Planning scenario.

[18] See note 4.

Table 3-16 — Existing installed capacity and modelled new generation/retirements (cumulative) for Northern Victoria (NVIC)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
Hydro	2,211	0	0	0	0	0

3.14 Adelaide (ADE)

The ADE zone, which covers the Adelaide Metropolitan Area and Eastern Hills, is South Australia's major load and generation centre, accounting for approximately 70% of the region's total demand and approximately 60% to 70% of the region's total non-wind generation.

The ADE zone is connected to the NSA zone via four 275 kV circuits and one 132 kV circuit, and the SESA zone via two 275 kV circuits and one 132 kV circuit.

At times of peak demand, ADE needs to import power to meet demand in the zone. During off-peak conditions, ADE may export power, depending on system load and generation dispatch.

3.14.1 Committed main transmission projects

The ADE zone's transmission needs build on ElectraNet's committed main transmission network projects, which include a Tungkillo 275 kV 100 MVAr capacitor bank to maintain adequate reactive power margins. ElectraNet's other committed projects within the zone, however, are included in the power system modelling.

3.14.2 Transmission needs

There are no limitations involving the main transmission network in the ADE zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no ADE zone transmission network development needs identified under the Planning scenario.

Other considerations

Future transmission augmentation needs will be driven by the location of new OCGT. For example, the NTNDP analysis assumed that all new generation in the ADE zone (up to 549 MW) will be located in the vicinity of Torrens Island. Based on this assumption, main transmission network limitations do not emerge for the outlook period.

Alternatively, if new generation in the ADE zone is located in the vicinity of Tepko (near Tungkillo, approximately 40 kilometres east of Adelaide), transmission network augmentations will be required to strengthen the 275 kV transmission network between Tailem Bend and Tungkillo. This augmentation facilitates increased power transfers from new generation and from Victoria to the Adelaide Metropolitan Area.

3.14.3 Generation expansion

Non-renewable

New OCGT generation is built in the ADE zone under the Planning scenario. New generation capacity increases from 21 MW during the period from 2012–13 to 2016–17 to 549 MW during the period from 2027–28 to 2036–37.

Renewable

No renewable generation is built in the ADE zone for the outlook period.

[19] See note 4.

Retirements

There are no retirements modelled in the ADE zone.

Table 3-17 lists the existing generation[20] and modelled new generation and retirements in the zone under the Planning scenario.

Table 3-17 — Existing installed capacity and modelled new generation/retirements (cumulative) for Adelaide (ADE)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
CCGT	**658**	0	0	0	0	0
Gas/steam sub-critical	**1,280**	0	0	0	0	0
OCGT	**380**	21	21	21	549	549
Wind	**35**	0	0	0	0	0

3.15 Northern South Australia (NSA)

The NSA zone, which covers the Mid-North, Upper North, Eyre Peninsula and Riverland areas, accounts for approximately 20% of the region's total demand. The zone is connected to the ADE zone via four 275 kV circuits and one 132 kV circuit, and to Victoria via Murraylink (between Monash in the Riverland area of South Australia and Red Cliffs in CVIC).

3.15.1 Committed main transmission projects

The NSA zone's transmission needs build on ElectraNet's committed main transmission network projects, which include the Cultana 275 kV and 132 kV transmission network reinforcements to meet Eyre Peninsula demand growth. ElectraNet's other committed projects within the zone are also included in the power system modelling.

3.15.2 Transmission needs

There are no limitations involving the main transmission network in the NSA zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no NSA zone transmission network development needs identified under the Planning scenario.

Other considerations

Throughout the outlook period, the NSA zone continues to be a net power importer at the time of the 10% probability of exceedence (POE) summer maximum demand in South Australia, even though the NSA zone accounts for approximately 30% of South Australia's total non-wind generation under the Planning scenario. This can be attributed to the high cost of OCGT generation in this zone, demand growth, and the low coincidence factor between solar generation and South Australia's 10% POE summer maximum demand.

New wind generation of approximately 895 MW modelled by the least-cost expansion plan at Snowtown[21], Lincoln Gap, Hornsdale, and Mt Cone does not require major main transmission network augmentation.

[20] See note 4.

Transmission needs do arise, however, depending on the penetration levels and concentration of wind generation within the zone. For example, a 600 MW wind farm development on the Yorke Peninsula will require augmentation of the main transmission network for power transfers to the ADE zone.

3.15.3 Generation expansion

Non-renewable

No non-renewable generation is built in the NSA zone under the Planning scenario for the outlook period.

Renewable

The NSA zone wind generation is assumed to contribute 8.3% of its installed capacity to maximum demand in the South Australian region. Wind generation of approximately 895 MW, solar generation of approximately 400 MW, and geothermal generation of approximately 512 MW are built in the NSA zone.

Retirements

The modelling identifies up to 770 MW of coal-fired generation for retirement during the outlook period, with approximately 240 MW retiring during the period from 2012–13 to 2016–17, and the remaining 530 MW during the period from 2027–28 to 2031–32.

Table 3-18 lists the existing generation[22] and modelled new generation and retirements in the zone under the Planning scenario.

Table 3-18 — Existing installed capacity and modelled new generation/retirements (cumulative) for Northern South Australia (NSA)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
Geothermal	**0**	0	0	0	0	512
OCGT	**318**	0	0	0	0	0
Distillate	**74**	0	0	0	0	0
Coal	**770**	-240	-240	-240	-770	-770
Wind	**844**	895	895	895	895	895
Solar	**0**	0	400	400	400	400

3.16 South East South Australia (SESA)

The transmission and sub-transmission network in SESA comprises a 275 kV transmission network linking Victoria to the east (the Heywood interconnector) and the ADE zone to the north-west, and a parallel 132 kV sub-transmission network.

The SESA transmission and sub-transmission networks have two major roles:

- Supplying the loads in the SESA zone.
- Power transfers with Victoria.

21 The 2012 NTNDP modelled the Snowtown Stage 2 Wind Farm as a potential project (consistent with the information available at the time of modelling input preparation). The Snowtown Stage 2 Wind Farm was confirmed as a committed project in September 2012.

22 See note 4.

As the 275 kV transmission network and the 132 kV sub-transmission network operate in parallel, transmission and sub-transmission network power flows in the SESA zone depend on a combination of three areas involving inter-regional power transfers, local demand, and local generation. As a result, close coordination of 132 kV and 275 kV transmission network augmentations is required in response to development in these areas.

3.16.1 Committed main transmission projects

There are no committed projects in the SESA zone affecting the main transmission network.[23] ElectraNet's other committed projects within the zone, however, are included in the power system modelling.

3.16.2 Transmission needs

There are no limitations involving the main transmission network in the SESA zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no SESA zone transmission network development needs identified under the Planning scenario.

Other considerations

The Heywood interconnector upgrade project[24] (assumed to be committed in the NTNDP analysis) defers the need for further upgrades of the Victoria to South Australia interconnector for the outlook period. This is due to the cost of further interconnector augmentation outweighing any market benefits gained from increased power transfer capability between the two regions.

Emerging main transmission network limitations within the SESA zone do not arise during the outlook period due to a number of network augmentations to be implemented as part of the Heywood interconnector upgrade project.

The existing 132 kV network in SESA has very limited capability to accommodate new generation connections. As a result, large-scale generation is modelled as directly connected to the 275 kV transmission network at a future 275 kV injection point at Krongart, which is close to the existing 275/132 kV South East Substation and connected to the existing Tailem Bend–South East 275 kV circuits. If generation connects to the lower voltage networks, however, then depending on the capacity of the generation, augmentation may be required.

3.16.3 Generation expansion

Non-renewable

A small amount of new OCGT generation is built in the SESA zone under the Planning scenario towards the end of the outlook period.

Renewable

The SESA zone wind generation is assumed to contribute 8.3% of its installed capacity to maximum demand in the South Australian region. New wind generation of approximately 455 MW is built at the start of the outlook period.

Biomass generation of up to 300 MW is also built in the SESA zone.

Retirements

There are no retirements modelled in the SESA zone.

[23] AEMO and ElectraNet are undertaking a joint Regulatory Investment Test for Transmission (RIT-T) application to investigate increasing the interconnector's capability to realise market benefits from relieving congestion on the Heywood interconnector. The RIT-T consultation was initiated by the Project Specification Consultation Report (PSCR) in October 2011. The Project Assessment Draft Report (PADR) was published in September 2012. In the NTNDP analysis, the currently preferred option was assumed to be built and was modelled as a committed project. Available http://www.aemo.com.au/~/media/Files/Other/planning/Heywood_Interconnector_Upgrade_RIT_T_PADR_Forum_Presentation.ashx. Viewed 7 November 2012.

[24] AEMO. Available http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission-RITTs/Heywood-Interconnector-RIT-T. Viewed 31 October 2012.

Table 3-19 lists the existing generation[25] and modelled new generation and retirements in the zone under the Planning scenario.

Table 3-19 — Existing installed capacity and modelled new generation/retirements (cumulative) for South East South Australia (SESA)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
Biomass	**0**	92	300	300	300	300
OCGT	**80**	0	0	0	22	37
Distillate	**63**	0	0	0	0	0
Wind	**325**	455	455	455	455	455

3.17 Tasmania (TAS)

Hydroelectric generation predominates in the TAS zone (81% of the total installed capacity), and is geographically dispersed across the region, with GPG connected in the George Town area, and wind generation connected at Woolnorth in the north-west (at Burnie).

The zone's transmission network comprises 220 kV transmission lines between the north and south, and spurs for the connection of major power stations. The 220 kV transmission network, with supporting 110 kV transmission circuits, connects power stations and major load centres.

An HVDC link between George Town in Northern Tasmania and Loy Yang in South East Victoria connects this zone to the NEM.

3.17.1 Committed main transmission projects

There are no committed projects in the TAS zone affecting the main transmission network. Transend's other committed projects (including the Musselroe Wind Farm connection) within the zone, however, are included in the power system modelling.

3.17.2 Transmission needs

There are no limitations involving the main transmission network in the TAS zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no TAS zone transmission network development needs identified under the Planning scenario.

Other considerations

A second HVDC link, increasing Victoria to Tasmania interconnector capability, is not built under the Planning Scenario for the outlook period. This is due to the cost of the project outweighing the market benefits gained from increased power transfer capability between the two regions. The analysis is based on additional new wind generation of 1,000 MW in TAS with the existing Victoria to Tasmania interconnector and 1,700 MW with a second Victoria to Tasmania interconnector.

New wind generation of 1,060 MW is modelled at Burnie, Farrell, Waddamana and George Town. Limitations potentially arise on the Farrell–Sheffield and Sheffield–George Town 220 kV lines during periods of high wind

[25] See note 4.

generation and moderate local demand, combined with maximum export levels from Tasmania to Victoria. These limitations can be eliminated via existing special protection schemes and generation re-scheduling in the zone.

Depending on the location and amount of wind generation, the Burnie–Sheffield and Sheffield–Palmerston 220 kV lines may experience limitations. Lower voltage network augmentation requirements may also arise due to local demand growth, for example, with limitations relating to the Sheffield and Hadspen 220/110 kV transformers during an outage of the other transformer.

The least-cost expansion plan results assume that inertia is available from existing synchronous generation in Tasmania.

3.17.3 Generation expansion

Non-renewable

No non-renewable generation is built in the TAS zone under the Planning scenario.

Renewable

TAS has the highest quality wind resources available in the NEM, with high levels of wind generation during non-peak demand periods, and an assumed contribution of 2.9% of its installed capacity to the maximum demand in the Tasmanian region. The least-cost expansion models 330 MW of new wind generation in the period 2016–17, increasing to 1,060 MW during the period from 2021–22 to the end of the outlook period.

The least-cost expansion also models biomass generation of 300 MW towards the end of the outlook period.

Retirements

There are no retirements modelled in the TAS zone.

Table 3-20 lists the existing generation[26] and modelled new generation and retirements in the zone under the Planning scenario.

Table 3-20 — Existing installed capacity and modelled new generation/retirements (cumulative) for Tasmania (TAS)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
Biomass	**0**	0	0	0	0	300
CCGT	**208**	0	0	0	0	0
OCGT	**178**	0	0	0	0	0
Wind	**308**[a]	330	1,060	1,060	1,060	1,060
Hydro	**2,170**	0	0	0	0	0

a. Includes Musselroe Wind Farm generation of 168 MW.

3.18 Other transmission network needs

In addition to the main transmission network needs identified in this chapter, there are a series of ongoing local transmission needs:

26 See note 4.

- Connecting new generation to the existing main transmission network by expanding existing substations or establishing new connection facilities (or both).
- Replacing aged transmission assets.
- Meeting local demand growth, which at some connection points may exceed the growth of the region's maximum demand (the basis for the NTNDP analysis).
- Delivering net market benefits through intra-regional transmission (for example, to alleviate congestion and enable the dispatch of lower cost plant).

  The NTNDP does not identify a network limitation if demand can be met through generation redispatch, and net market benefits may result from reducing redispatch occurrence and volume.

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CHAPTER 4 - FUTURE TRENDS

Summary

This chapter relates the 2012 NTNDP results to trends in the energy industry and indicates how AEMO intends to monitor and address future trends.

2012 NTNDP results

The 2012 NTNDP shows that less National Electricity Market (NEM) generation and transmission investment is needed over the next 25 years compared to previous estimates, and there is an opportunity to achieve better integration and more efficiency from the investment that is needed.

Scenario modelling based on current policies and expectations of future demand provided the following results:

- Generation can be located in such a way as to avoid the need for substantial augmentations to the main transmission network to achieve an overall economic development of the NEM.
- Until 2020, most new generation is driven by meeting the Large-scale Renewable Energy Target (LRET), the majority of which is wind generation.
- Coal-fired generation retirement or mothballing (largely driven by the LRET rather than the carbon price) will remove capacity from the power system resulting in a need for new peaking generation (mainly open cycle gas turbines) from 2020 to maintain sufficient reserves for reliable supply.
- As energy consumption continues to grow post-2020, existing generation (mainly coal- and gas-fired) will increase its output.

Greater market integration

The 2012 analysis shows reduced economic benefits for large-scale interconnector development, based on two sources of benefits involving reserve sharing and production costs (fuel and carbon emissions cost differences). These benefits are now relatively small due to lower forecast demand growth, resulting in low reserve sharing benefits, and due to very similar fuel costs between regions.

The 2012 NTNDP also does not identify a relative advantage from the remote location of large-scale renewable generation, when compared to locating it closer to load centres and the existing transmission network.

4.1 Introduction

The 2012 National Transmission Network Development Plan (NTNDP) reflects changes in the energy environment since the 2010 and 2011 NTNDPs, including lower electricity demand and energy forecasts, and higher projected gas costs.

The 2010 NTNDP explored several scenarios that include a wide range of possible future conditions, including high, medium and low future electricity demand. In 2012, AEMO examined changes to these assumptions by focusing on the new medium and low demand and energy projections, as these represent areas well outside the 2010 NTNDP scenarios.

The scenario basis

The results from the 2012 NTNDP analysis derive from two scenarios developed by AEMO in conjunction with an industry reference group:

- The Planning scenario is AEMO's central estimate of future economic and policy trends.
- The Slow Rate of Change scenario combines lower economic growth with a carbon price that essentially drops to zero after the fixed price period for the first three years.

The LRET is assumed to continue under both scenarios.

The results have been scenario dependent, and AEMO will continue to monitor trends in the economic and policy environments and will refresh the base scenario modelling if required. Specifically, much of the projected generation is expected to be driven by the LRET, which is currently being reviewed. Changes are also occurring to the emissions trading arrangements.

Additionally, AEMO is considering the value of modelling additional scenarios in 2013 (for example, a higher growth scenario that explores outcomes if demand growth exceeds current expectations).

AEMO will be seeking stakeholder feedback from this via a consultation in January 2013.

Greater market integration

As the national planner, AEMO previously investigated the benefits of a significant increase in power transfer capability across the NEM, involving a conceptual project referred to as NEMLink (although this was just one potential augmentation concept).

This study originally showed that increasing the capability of multiple interconnectors potentially provides benefits that exceed the sum of the benefits from augmenting individual interconnectors. The identified benefits, however, were insufficient to justify the concept's cost.

The 2012 analysis shows reduced economic benefits for large-scale interconnector development, based on two sources of benefits involving reserve sharing and production costs (fuel and carbon emission cost differences). These benefits are now relatively small due to lower forecast demand growth, resulting in low reserve sharing benefits, and due to very similar fuel costs between regions. The 2012 NTNDP also does not identify a relative advantage from the remote location of large-scale renewable generation, when compared to locating it closer to load centres and the existing transmission network.

There are other sources of benefits (for example, competition benefits, option value and benefits related to reducing curtailment of intermittent generation due to network congestion) that were not included fully or at all in the 2012 study. AEMO is currently conducting a competition benefits study, the results of which will be published in 2013. AEMO is also conducting further studies into the integration of intermittent generation.

AEMO continues to support increasing market integration where this is economically justified. Although the large-scale augmentation concept previously studied is not viable in the current market environment, AEMO will continue to monitor and respond to economic and policy conditions for opportunities to improve market integration. AEMO will also continue to monitor studies that consider additional benefits and will review the modelling approach to ensure all material benefits are addressed.

CHAPTER 5 - SCENARIOS, KEY INPUTS AND MODELLING APPROACH

Summary

This chapter presents information about the scenarios used to develop the 2012 NTNDP and the key inputs and approach used for the modelling and analysis.

The Australian energy industry's future development is uncertain and subject to a number of global and local drivers including economic growth, technological development, fuel availability and price, and carbon emission and renewable energy policy. As a result, the NTNDP considers two scenarios:

- The Planning scenario represents AEMO's central (rather than high or low) estimate of future development, given the available information and anticipated changes.
- The Slow Rate of Change scenario describes a world characterised by lower economic growth, with low commodity prices and a carbon price that effectively drops to zero after an initial three-year fixed-price period. This scenario has been modelled to investigate how sensitive the results are to carbon price and demand growth assumptions.

Key inputs into the modelling and analysis include the following:

- Regional economic and population growth projections.
- Regional electricity demand traces (based on annual energy and maximum demand projections), representing the demand placed on generating units for the 25-year outlook period.
- Future generation fuel cost estimates.
- New generation technology capital and running costs.
- Current network capability and future network augmentation costs.
- Policy drivers.

Two key changes were made to the scenarios analysed in 2012 based on stakeholder responses to the 2010 NTNDP:

- Five scenarios were considered in 2010 with two carbon prices each, making up 10 sets of results. Unlike in 2012, the 2010 scenarios did not include a 'planning' scenario, and instead comprised five different views of the future, with a carbon price sensitivity in each case.
- The 2010 scenarios addressed zero, low, medium and high carbon price assumptions. Following the release of Australian Treasury carbon price modelling, the 2012 scenarios use the Australian Treasury core and high carbon prices, or a zero carbon price. As in 2010, significant uncertainty remains about future carbon prices.

The modelling approach comprises a combination of least-cost expansion modelling, transmission network power flow studies, time sequential market simulations, and gas supply-demand modelling.

5.1 NTNDP scenarios

This section describes the scenarios created to enable a study of the National Electricity Market (NEM) transmission network over the next 25 years. Each scenario describes the Australian stationary energy sector in 2037, and explores a series of credible outcomes given a series of uncertainties including carbon prices beyond the fixed-price period, and energy and maximum demand projections driven by demographic and economic changes.

The scenarios also make assumptions about economic, technological, and social outcomes that lead to diverse inputs to energy market modelling, and provide supply, delivery, and consumption impacts for key inputs that include the following:

- Growth in demand (and its location).
- Supply-side and demand-side responses to carbon policy.
- Distribution-connected generation responses to carbon policy.

Six scenarios were developed, two of which were selected for detailed modelling in the 2012 NTNDP: the Planning scenario and the Slow Rate of Change scenario.

The Planning scenario has the following characteristics:

- Based on AEMO's best estimate of the future direction of the major drivers.
- Designed to include any policy or other changes that can be predicted with reasonable certainty.
- Designed as a central growth scenario.
- Includes currently legislated carbon policies, based on the Australian Treasury core scenario.
- Currently estimated rates of development of new technologies.

The Slow Rate of Change scenario has the following characteristics:

- Lower growth.
- A carbon price of effectively zero after the first three years.
- Slowed development of new technologies.

The Slow Rate of Change scenario has been modelled to investigate how sensitive the results are to carbon price and demand growth assumptions.

Table 5-1 and Table 5-2 list the drivers for each scenario (economic and greenhouse, and fuel and technology, respectively).

Table 5-1 — Scenario drivers, economic and greenhouse

Scenario	Economic				Greenhouse			
	Economic growth	Commodity prices	Productivity growth	Population growth	Reduction target (below 2000 levels)	Carbon price	National Renewable Energy Target scheme	Green Power sales
Planning	National economic growth continues at currently predicted levels. Global recovery continues with ongoing growth in the demand for Australian commodities, particularly resources.	Medium.	Medium.	Medium.	5% reduction by 2020, 80% reduction by 2050.	Treasury core scenario, starting at 23 \$/t CO_2-e on 1 July 2012.	LRET[a] remains in place to 2036–37 with no significant changes from the two-yearly reviews. SRES[b] remains in place to 2030 with currently announced reductions to the STC[c] multiplier[d].	No growth.
Slow Rate of Change	Lower.	Low.	Low.	Low.	Zero reduction by 2020, 80% reduction by 2050.	Treasury core scenario for first three years, then 0 \$/t CO_2-e.	Remains in place (as Planning scenario).	No growth.

a. Large-scale Renewable Energy Target.

b. Small-scale Renewable Energy Scheme.

c. Small-scale Technology Certificates.

d. Also referred to as the Federal Solar Credits rebate Renewable Energy Certificate (REC) (STC) multiplier.

Table 5-2 — Scenario drivers, fuel and technology

Scenario	Fuel		Technology		
	International coal prices (\$/tonne)	LNG east coast production	Global technology R&D support	Distributed generation penetration	Electric vehicles penetration
Planning	Medium.	Medium.	Moderate.	Moderate.	Moderate.
Slow Rate of Change	Low.	Low.	Moderate.	Weak.	Weak.

5.2 Scenario descriptions

5.2.1 Planning scenario

The Planning scenario represents a central estimate of future development given all the available information. The other scenarios are designed to provide outlying views of the future around this central scenario. The key drivers for the changes to the energy industry supply and demand mix are identified and quantified (where possible).

In developing the Planning scenario, the current world is taken as the starting point and future changes are considered.

The Planning scenario is not designed to be a pure business-as-usual scenario as it attempts to identify future signposts for change and the most likely direction that the market will take.

For the 2012 Planning scenario, a carbon price and the national Renewable Energy Target (RET) scheme[1] legislation were identified as potential signposts for future change.

The Australian carbon price

The Australian carbon price started on 1 July 2012 and is designed to achieve a reduction in Australian carbon dioxide equivalent (CO_2-e) emissions of 5% below 2000 levels by 2020, and an 80% reduction in emissions below 2000 levels by 2050.

The first three years of the carbon price have legislated fixed prices for emissions. Following this period, emissions permits will be auctioned and traded and the price set by the market. Liable entities will have the ability to import up to 50% from approved emission units.

The Australian Government announced in August 2012 that Australia and the European Union (EU) will be linking their emissions trading systems. From 1 July 2015, Australian businesses will be able to use EU allowances to help meet liabilities under the Australian scheme. The Australian and EU schemes are to be fully linked before 1 July 2018.

To facilitate the link, the Australian carbon price floor of 15 \$/t CO_2-e emissions from 1 July 2015 will not be implemented. Also, while businesses in Australia will still be able to meet up to 50% of their liabilities through purchasing eligible international units, only 12.5% of their liabilities will be able to be met by Kyoto units.[2]

Modelling by the Australian Treasury in 2011 produced a forward price estimate for the price of permits. The Treasury core forward price projections correspond to the 5% cuts, although they were produced prior to the August 2012 changes to the scheme and falls in international carbon prices. While the current EU carbon price is low, the market has been volatile. As a result, the carbon price assumptions in the Planning scenario have not been changed, and were considered to remain a valid basis for generation and transmission modelling for the NEM.

The Australian Government has indicated that it will consider tighter targets if other major emitting countries commit to substantial emissions cuts, and has further committed to a long-term target to cut CO_2-e emissions by 80% below 2000 levels by 2050.

There is bi-partisan support for a 5% cut in emissions below 2000 levels by 2020, although the carbon price as a mechanism for delivering this is not universally supported. Since the target is bi-partisan, from a modelling perspective it is still appropriate to apply a carbon price under either policy in order to achieve the emissions target (even if the application is indirect).

[1] Comprising the Large-scale Renewable Energy Target (LRET) and Small-scale Renewable Energy Scheme (SRES).

[2] Assigned Amount Units (AAUs) under the Kyoto Protocol. Each unit represents an allowance to emit one metric tonne of carbon dioxide equivalent greenhouse gases.

National Renewable Energy Target scheme

The national RET scheme is subject to two-yearly reviews. The first review commenced in June 2012 and is expected to report to the Australian Government by 31 December 2013. While many aspects of the legislation will be considered, no major changes are currently anticipated.

Green Power sales continue at the current flat path.

5.2.2 Slow Rate of Change scenario

The Slow Rate of Change scenario reflects a lower rate of economic growth, both domestically and internationally. The United States of America's economy remains weak, there are defaults by EU member states that cause a new credit freeze, and growth in the Chinese economy is slowing.

Low international economic growth leads to low commodity prices for both rural and non-rural commodities, with serious impacts on the Australian economy.

World credit risk premiums are high with a low level of capital liquidity that constrains investment, particularly in new technologies, including low carbon and renewable energy technologies.

There is minimal response to climate change from the rest of the world and Australia is able to meet its international emission targets with minimal effort, primarily through reduced economic growth. In Australia, the carbon price effectively drops to zero after the first three years of a fixed price.

The low levels of economic growth and the low demand for Australia's resources have reduced the requirements for additional skilled labour and as a result immigration levels are low. The strained economy has also driven birth rates to historically low levels.

Research and development in new low emission generation technologies is slow. Even in technologies with research and development funding, low demand growth slows the rate at which they are deployed.

Opinion on renewable energy is divided, with some of the more commercial renewable technologies facing increasing obstruction and insufficient investment (which would otherwise reduce costs as the technology matures).

Low international growth implies a lower fuel price trajectory as a result of lower demand. However, resource companies see benefit in not commercialising some resources, therefore maintaining high gas prices despite low economic growth.

There is little demand-side response, as few residential or commercial consumers can afford to invest in small-scale renewable energy options. The poor economy makes the higher up-front costs of plug-in electric vehicles unattractive. The uptake is low and the impact on the electricity demand profiles is minimal.

Like the Planning scenario, no major changes to the national RET scheme are anticipated.

5.3 Key inputs

This section provides a high-level description of the key inputs used in the NTNDP generation and transmission expansion modelling.

5.3.1 Annual energy and maximum demand forecasts

The NTNDP analysis relies on regional demand traces, which are based on annual energy and maximum demand projections, to represent the demand placed on generating units for the 25-year outlook period.

Regional projections provided as part of AEMO's 2012 National Electricity Forecasting Report (NEFR) were developed for the six scenarios from which the 2012 NTNDP demand projections were developed.

For information about the regional annual energy and maximum demand projection spread sheets for each scenario see the 2012 NTNDP Assumptions and Inputs webpage.[3]

5.3.2 Generation inputs

Information about the key operational parameters of current generating units and future generation projects derives from a number of sources[4], and includes the following:

- Committed projects.
- Generating unit capacities.
- Hydroelectric models and water storage assumptions.

For more information see the AEMO Generation Information webpage[5] and the 2012 NTNDP Assumptions and Inputs webpage.[6]

AEMO contracted Worley Parsons to provide fuel cost projections for natural gas, brown coal, and bituminous (black) coal for new entry generating units, and estimates of the costs and other parameters for a range of new generation technologies.

Worley Parsons contracted ACIL Tasman to develop the fuel cost projections. The ACIL Tasman report is available from the AEMO website.[7]

The Worley Parsons report[8], which is also available from the AEMO website, evaluates several new technologies and includes the following information for each:

- Capital costs.
- Fixed and variable operating and maintenance costs.
- Regional annual build limits.
- Thermal efficiency factors.
- Emissions factors.

5.3.3 Network inputs

Network information is required to model generating unit dispatch and generation and transmission expansion. Key inputs include the following:

- Network constraint equations (developed by AEMO).
- Intra-regional loss factors for existing and committed generation (developed by AEMO).
- Committed transmission augmentations and non-network projects (provided by the transmission network service providers (TNSPs)).
- Potential (non-committed) transmission augmentations and non-network projects (developed by AEMO and the TNSPs).
- Transmission project cost estimates (developed by AEMO and the TNSPs).

[3] AEMO. Available http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Assumptions-and-Inputs. Viewed 11 December 2012.

[4] Including AEMO's analysis, consultants, generators, and potential generation investors.

[5] AEMO. Available http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information. Viewed 15 November 2012.

[6] AEMO. Available http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Assumptions-and-Inputs. Viewed 11 December 2012.

[7] ACIL Tasman. "Fuel cost projections". Available http://www.aemo.com.au/~/media/Files/Other/planning/ACIL_Tasman_Fuel_Cost_%20Projections_2012.ashx. Viewed 15 November 2012.

[8] WorleyParsons. "Cost of Construction New Generation Technology". Available http://www.aemo.com.au/~/media/Files/Other/planning/WorleyParsons_Cost_of_Construction_New_Generation_Technology_2012%20pdf.ashx. Viewed 15 November 2012.

- Interconnector loss factor equations.
- Existing interconnector transfer capability.
- Interconnector upgrade options.

5.3.4 Other modelling inputs

Other modelling input assumptions include the following:

- A CO_2-e price trajectory.
- An LRET trajectory (including Green Power sales assumptions).
- Scaling factors used to convert maximum demand from a generator-terminal to a sent-out basis.
- Regional demand profiles at hourly resolution.
- Profiles of intermittent wind and solar generation at hourly resolution.
- The level of committed demand-side participation (DSP) available at different regional reference node prices.

5.4 Scenario development

In 2012, AEMO developed six planning scenarios for the purposes of energy planning, with each scenario reflecting different levels of economic growth, industrial energy demand, rooftop PV penetration, energy efficiency, and small non-scheduled generation.[9]

Table 5-3 lists the six planning scenarios developed in 2012, indicating the scenarios used to develop the NTNDP generation and transmission expansion (for more information about the scenarios see the 2012 Scenarios Descriptions report[10]).

Table 5-3 — Scenarios developed for the 2012 NTNDP

2012 AEMO scenario	2012 NTNDP reference
Scenario 1 - Fast Rate of Change	-
Scenario 2 - Fast World Recovery	-
Scenario 3 - Planning	Planning
Scenario 4 – Decentralised World	-
Scenario 5 - Slow Rate of Change	Slow Rate of Change
Scenario 6 - Slow Growth	-

Designed as a central growth scenario, the Planning scenario includes currently legislated carbon policies, and is based on the Australian Treasury's core scenario[11], as well as currently estimated rates of new technology development.

9 Possible future scenarios for the Australian stationary energy sector were first developed in conjunction with the Department of Resources Energy and Tourism (DRET) and an industry working group in 2009, and further refined in 2010.

10 AEMO. “2012 Scenarios Descriptions”. Available http://www.aemo.com.au/~/media/Files/Other/planning/2012_Scenarios_Descriptions.ashx. Viewed 15 November 2012.

The Slow Rate of Change scenario reflects a lower rate of economic growth, which enables Australia to meet its international emissions targets with minimal effort. Under this scenario the Australian carbon price effectively drops to zero after the three-year fixed-price period.

Two scenarios were selected from the six 2012 AEMO scenarios, following stakeholder feedback that the NTNDP should address fewer scenarios than in 2010. Addressing two scenarios enables AEMO to incorporate the 2012 NEFR outcomes in the NTNDP, within the time and resource constraints.

The Planning and Slow Rate of Change scenarios were selected as offering the highest value to stakeholders. The Planning scenario was selected in response to stakeholder feedback in favour of a central scenario, and the Slow Rate of Change scenario was selected to test the impact of a carbon price that effectively drops to zero. To ensure consistency between AEMO's planning documents and studies, these scenarios have also been considered when developing the 2012 Victorian Annual Planning Report (VAPR), South Australian Electricity Report (SAER), Electricity Statement of Opportunities (ESOO), and Gas Statement of Opportunities (GSOO).

5.5 Comparing the 2010 and 2012 NTNDP scenarios

Several key changes were made to the scenarios analysed in 2012 based on stakeholder responses to the 2010 NTNDP.

2010 scenarios

The 2010 NTNDP's five scenarios each included two carbon prices, producing 10 sets of results. These scenarios represent five different views of the future, with a carbon price sensitivity in each case, variously addressing zero, low, medium and high carbon price assumptions.

2012 scenarios

The 2012 NTNDP's two scenarios (representing two of the six scenarios that were developed) include a scenario representing a best estimate of the future (the Planning scenario), and a scenario to investigate a sensitivity to reductions in the carbon price and economic growth assumptions (the Slow Rate of Change scenario). For more information about the scenarios see Section 5.2.

Other than the Planning scenario, the other five scenarios developed by AEMO in 2012 address alternative possible futures and examine how sensitive the generation and transmission expansion modelling results are to key assumptions (primarily carbon prices and economic growth).

Following release of Australian Treasury carbon price modelling in 2011, four of the six 2012 scenarios use the Australian Treasury core carbon prices, with one scenario using the Australian Treasury high carbon prices, and another a zero carbon price. For information about the core and high carbon prices, see the Australian Treasury website.[12]

Similarities between the 2010 and 2012 scenarios

Table 5-4 summarises the relationship between the 2010 and 2012 scenarios.

Table 5-4 — 2010 and 2012 scenario comparison

2010 scenarios and sensitivities	Equivalent scenarios for 2012
Fast Rate of Change, high carbon price	Scenario 1 - Fast Rate of Change.
Fast Rate of Change, medium carbon price (sensitivity)	Scenario 2 - Fast World Recovery.

[11] The Australian Government's Treasury and the Department of Climate Change and Energy Efficiency modelled the potential economic impacts of reducing emissions over the medium and long term, proposed in the 'Strong Growth, Low Pollution, Modelling a Carbon Price' report released on 10 July 2011. Available http://archive.treasury.gov.au/carbonpricemodelling/content/default.asp. Viewed 15 November 2012.

[12] Australian Treasury. Available http://archive.treasury.gov.au/carbonpricemodelling/content/report/09chapter5.asp. Viewed 15 November 2012.

2010 scenarios and sensitivities	Equivalent scenarios for 2012
Uncertain World, low carbon price	No similar scenario.
Uncertain World, zero carbon price (sensitivity)	No similar scenario.
Decentralised World, medium carbon price	Scenario 3 - Planning.[a] Scenario 4 - Decentralised World.
Decentralised World, high carbon price (sensitivity)	No similar scenario.
Oil Shock and Adaptation, medium carbon price	No similar scenario.
Oil Shock and Adaptation, low carbon price (sensitivity)	No similar scenario.
Slow Rate of Change, low carbon price	Scenario 5 - Slow Rate of Change.[a]
Slow Rate of Change, zero carbon price (sensitivity)	Scenario 6 - Slow Growth.[b]

a. Scenario used to develop the 2012 NTNDP.

b. This scenario applies Australian Treasury's core carbon price instead of a zero carbon price.

5.5.1 Comparison of key inputs

There are significant differences between the key inputs for 2010 and 2012, in particular due to changes in the annual energy and maximum demand projections, and assumed gas and carbon prices.

Figure 5-1 shows that the annual energy projections used in the 2012 modelling are significantly lower than the 2010 assumptions, which reduces the need for new generating capacity. This figure shows the range of annual energy projections in the five 2010 NTNDP scenarios as well as a projection for the 2010 Decentralised World scenario, which is used in this section as a reference scenario for comparison with the 2012 Planning scenario.

Figure 5-2 shows that the 2012 gas price assumptions are at the high end of the range of assumptions for 2010. Higher gas prices mean that gas powered generation (GPG) is less able to compete with wind and coal-fired generation, particularly under low carbon prices.

Figure 5-3 shows that the 2012 Planning scenario's carbon prices are close to the 2010 low carbon price projection, although increasing later in the outlook period towards the 2010 medium carbon price projection. The 2010 NTNDP Decentralised World scenario used the 2010 medium carbon price projection.

Compared with 2010, lower carbon prices for 2012 contribute to reduced levels of new, low-emissions generation, and increased use of high-emissions coal-fired generation.

Figure 5-1 — Annual energy assumptions

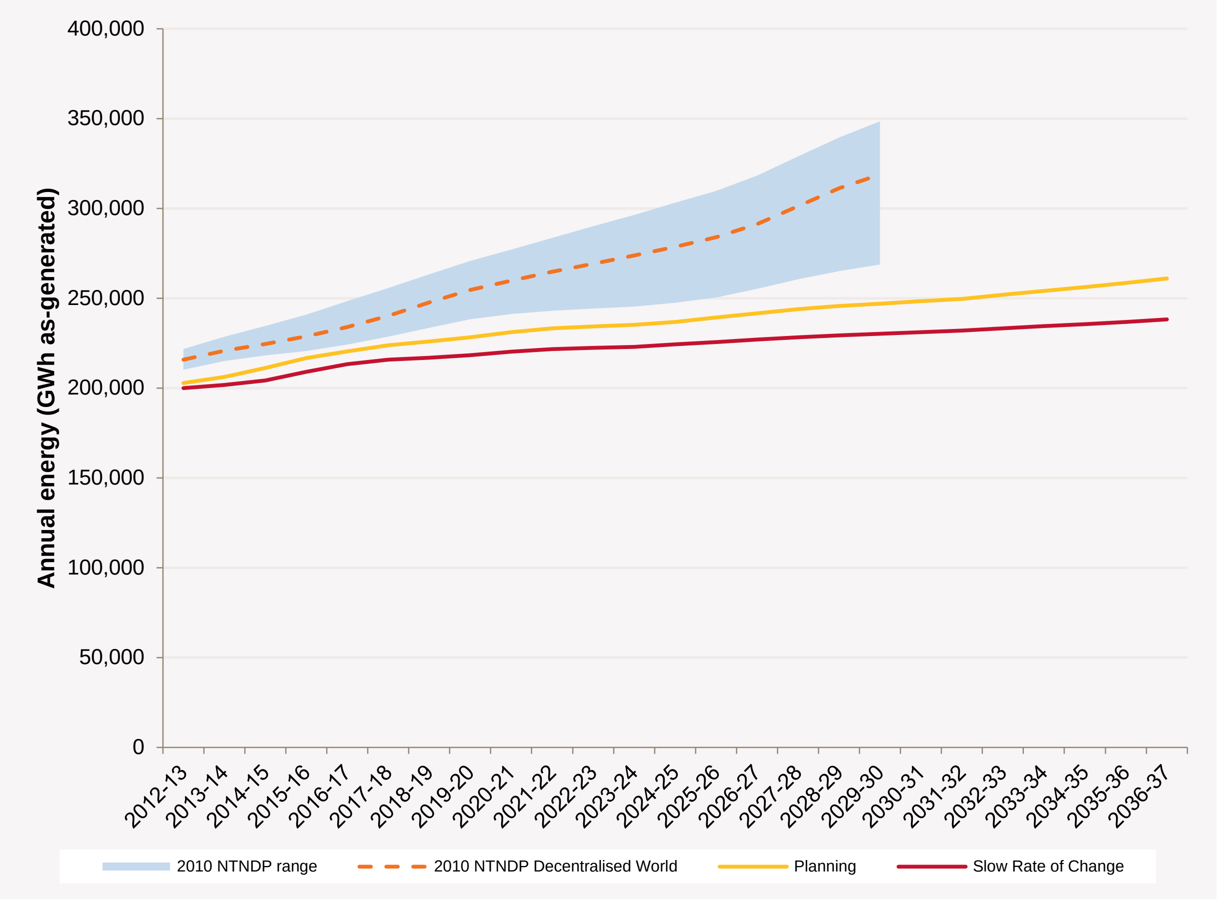


Figure 5-2 — Gas price assumptions

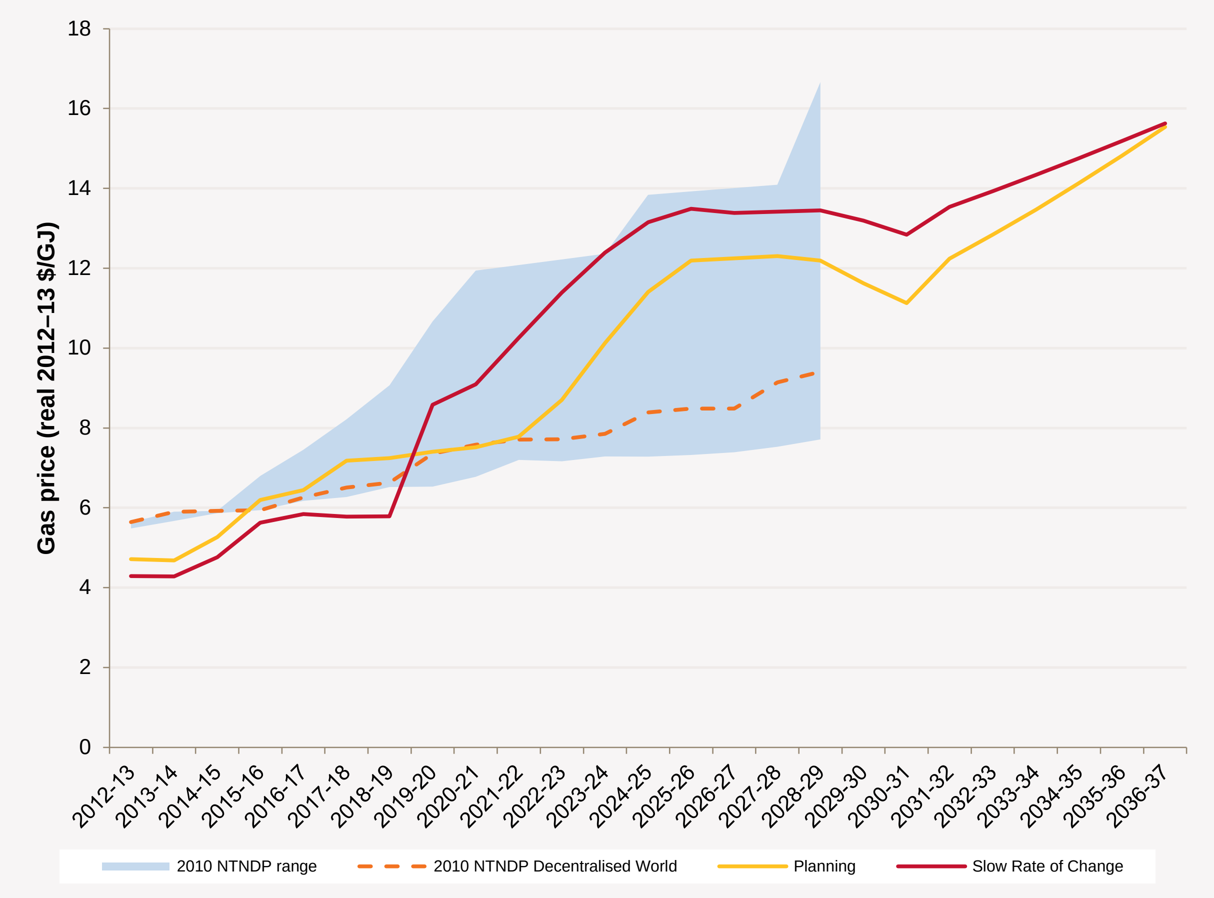
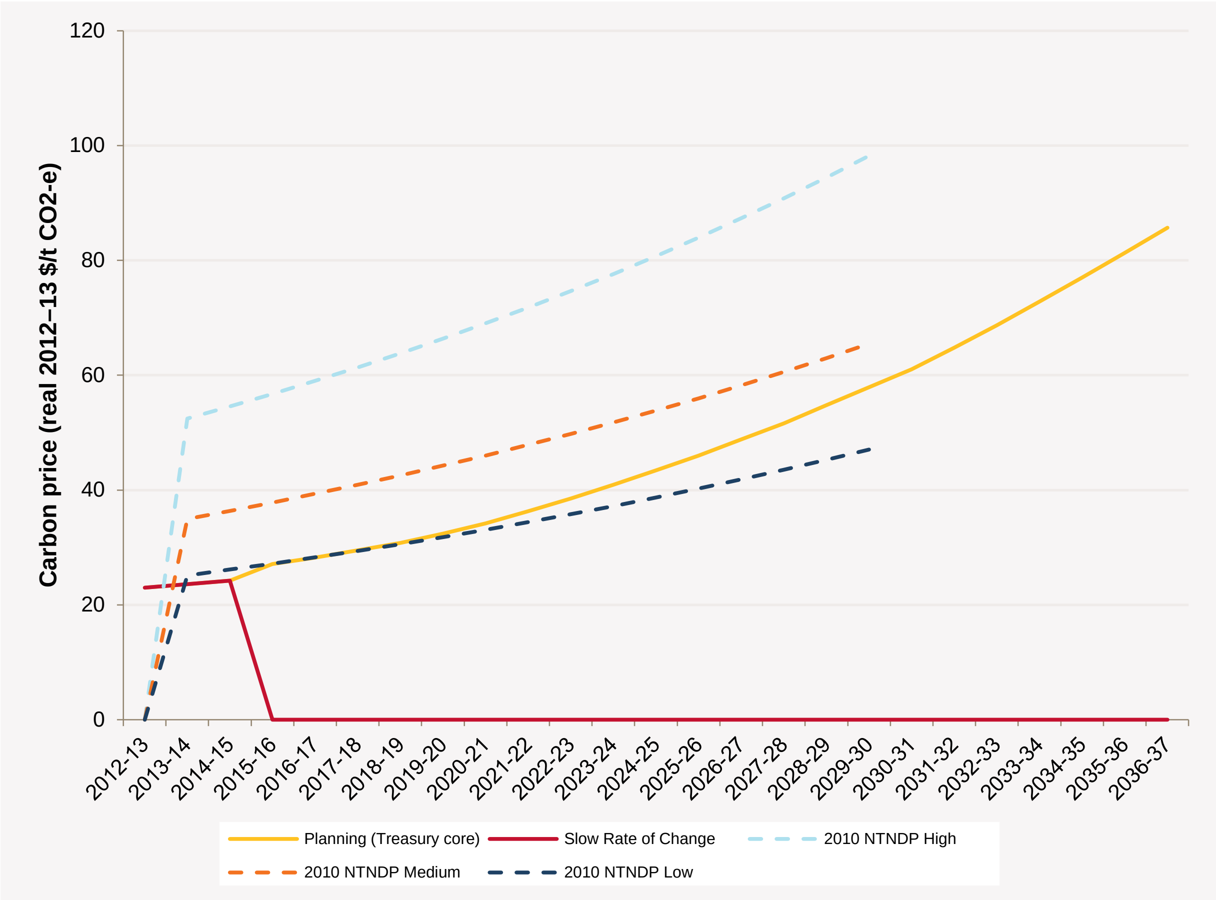


Figure 5-3 — Carbon price assumptions



5.6 Modelling approach

The 2012 NTNDP modelling framework comprises a combination of least-cost expansion models, transmission network power flow studies, gas supply-demand balance models, and time-sequential market simulations.

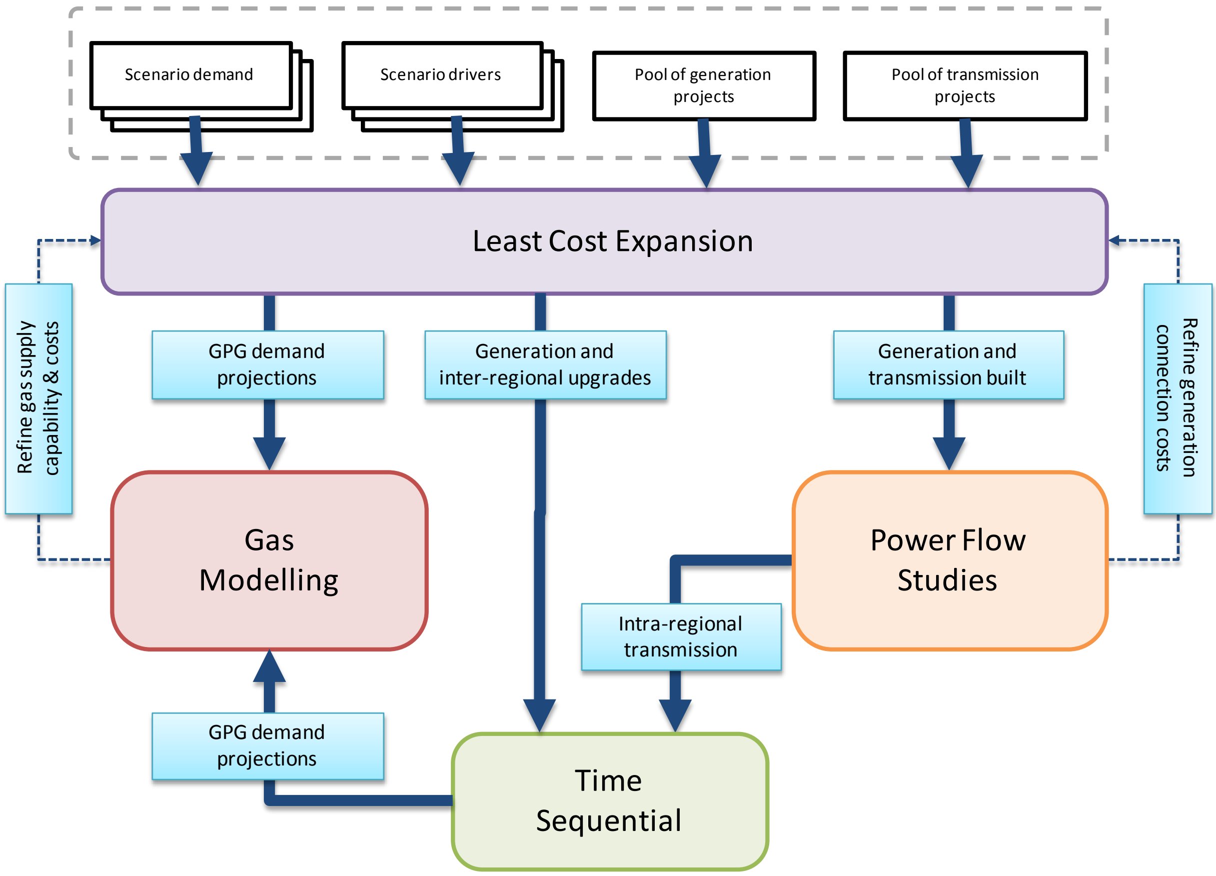
Figure 5-4 shows the relationships and data flows between these modelling activities. In particular, the 2012 NTNDP uses these activities iteratively to ensure feasible and economically justifiable results:

- The least-cost expansion models produce a co-optimised expansion plan considering generation and interregional network options, which minimises overall capital and operating costs (subject to meeting reliability requirements).
- The transmission network power flow studies identify intra-regional network augmentation required to maintain reliability of supply under the assumed load growth and generation expansion results. The cost of the intra-regional network augmentations is used to refine the least cost expansion modelling assumptions so that further simulations account for these costs, and the model can choose to keep the same generation expansion or alter it to reduce total expansion costs.
- The gas supply-demand balance models add additional constraints on the location and timing of GPG developments, taking account of gas reserves and gas network limitations.

- The time-sequential market simulations provide an input into the gas modelling.

For a detailed description of the process used to develop the optimised generation and transmission plan, see the methodology document published on the AEMO website.[13]

Figure 5-4 — Modelling approach overview



5.6.1 Scope of transmission developments considered by the NTNDP

Taking a long-term NEM-wide view, the NTNDP focuses on the main transmission network's[14] ability to reliably support major power transfers between generation and demand centres in the NEM. AEMO confined the scope of this analysis to transmission network thermal limitations arising during diversified regional peak demands.

System conditions

Load flow analysis was carried out to assess the transmission network adequacy for conditions matching regional 10% probability of exceedence (POE) maximum demand, which were based on AEMO's 2012 NEFR.[15] Economic dispatch of NEM-wide generation was used to meet the 10% POE maximum demand. This involved modelling the economic dispatch of generation in a given region and inter-regional transfers to meet the 10% POE maximum demand in that region and corresponding demand in other regions.

[13] AEMO. "2012 Modelling Methodology and Assumptions". Available http://www.aemo.com.au/~/media/Files/Other/planning/2418-0002%20pdf.ashx. Viewed 15 November 2012.

[14] This generally refers to lines of nominal voltage of 220 kV and above.

[15] AEMO. "National Electricity Forecasting Report for the National Electricity Market (NEM) 2012". Available http://www.aemo.com.au/~/media/Files/Other/forecasting/2012%20National%20Electricity%20Forecasting%20Report.ashx. Viewed 15 November 2012.

Each point of connection was represented with diversified load at the time of AEMO's 10% POE maximum demand at a region-wide level. Individual connection points can experience a local load higher than the load at the time of the regional maximum demand. The 2012 NTNDP, however, did not assess local transmission network adequacy to meet localised peak demand at times outside the 10% POE regional maximum demand.

Although the network adequacy was assessed assuming wind power generation at historical levels of contribution during maximum demand[16], higher wind power generation can occur. To identify main transmission network limitations to accommodate high wind power generation, additional load flow studies were undertaken with 80% of wind power generation and moderate demand levels.

Planning criteria

AEMO undertook power system simulation studies and monitored the loading of main transmission lines and transformers under the following conditions:

- System intact (pre-contingency, when all other equipment is in service).
- A potential single credible contingency (N-0-1 criterion).[17]

The monitored transmission lines and transformers form part of the main transmission network supporting major NEM power transfers, although in some cases the monitoring was extended to lower voltages, particularly in areas where the transmission network at lower voltage levels was parallel to the main transmission network at voltage levels of 220 kV and above.

Network limitations were identified by comparing network loadings of monitored transmission lines and transformers against their summer continuous ratings. Winter continuous ratings were also considered for Tasmania because Tasmania experiences its 10% POE maximum demand in winter.

Short-term ratings, generation rescheduling and the application of existing control schemes were also taken into account to manage observed limitations. To identify a co-optimised generation and transmission plan, further investigations were carried out to check whether the limitations can be eliminated by the economic relocation of new generation (whether additional generation costs at the alternative location were outweighed by the costs of the avoided transmission).

The identification of network limitations did not consider the unavailability of generation plant combined with transmission plant outages.

Network limitations and congestion points

The 2012 NTNDP describes potential network limitations and congestion points in the main transmission network, rather than focusing on the augmentations (network or non-network) required to relieve them. To enable modelling to proceed beyond the first network limitation identified, however, AEMO does model the possible augmentation options to address the observed limitation. These modelled augmentations are indicative only.[18]

Suitable augmentations depend on a range of factors, such as the condition of existing assets, planning permits, land and easement requirements, voltage support, fault levels, and lower voltage network development. Many of these factors are beyond the scope of the 2012 NTNDP's long-term analysis (and are most appropriately addressed by detailed investigation closer to the time they are required).

The National Electricity Rules (NER) also define a process for analysing potential alternative solutions (including non-network alternatives), and selection via the Regulatory Investment Test for Transmission (RIT-T) and an associated consultation process. Until a solution has undergone this process it cannot be considered certain.

[16] AEMO. "2012 Modelling Methodology and Assumptions". Available http://www.aemo.com.au/~/media/Files/Other/planning/2418-0002%20pdf.ashx. Viewed 15 November 2012.

[17] Where 'N' refers to the total number of plant, '0' refers to no prior outage, and '1' refers to a potential unplanned outage of one plant.

[18] In addition to augmentations to address limitations identified in the NTNDP, investment will be required to replace aged assets and also to address more localised supply issues, voltage support, and fault levels.

5.7 Supporting information

This section provides links to other information about the NTNDP scenarios, inputs and modelling.

Information source	Website address
2012 Scenarios Descriptions	http://www.aemo.com.au/~/media/Files/Other/planning/2012_Scenarios_Descriptions.ashx
2012 Modelling Methodology and Assumptions	http://www.aemo.com.au/~/media/Files/Other/planning/2418-0002%20pdf.ashx
2012 Modelling Assumptions and Data	http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Assumptions-and-Inputs/ http://www.aemo.com.au/~/media/Files/Other/planning/Modelling_Assumptions_and_Data_2012_rev.ashx
Cost of Construction New Generation Technology, Worley Parsons	http://www.aemo.com.au/~/media/Files/Other/planning/WorleyParsons_Cost_of_Construction_New_Generation_Technology_2012%20pdf.ashx
Fuel Cost Projections, ACIL Tasman	http://www.aemo.com.au/~/media/Files/Other/planning/ACIL_Tasman_Fuel_Cost_%20Projections_2012.ashx http://www.aemo.com.au/~/media/Files/Other/planning/ACIL_Tasman_Wholesale_Fuel_Cost_Projections%20xlsx.ashx
2012 National Electricity Forecasting Report	http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012 http://www.aemo.com.au/Electricity/Planning/Forecasting/Forecasting-Data-2012

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APPENDIX A - SLOW RATE OF CHANGE SCENARIO RESULTS

Summary

This appendix presents the outcomes of the optimised generation and transmission modelling by zone under the Slow Rate of Change scenario over the NTNDP's 25-year outlook period. It also provides an alternative to the NEM-wide view of future power system requirements (see Chapter 2) by focussing on the impact the Slow Rate of Change scenario has on generation and transmission development in each NTNDP zone.

The main transmission network limitations identified in the 2012 NTNDP include the following:

- The Central Queensland (CQ) zone may experience a main transmission network limitation involving the Calvale–Wurdong 275 kV circuit due to the unavailability of full generation from Gladstone (or some Gladstone generating units).
- The Central New South Wales (NCEN) zone may experience an emerging main transmission network limitation involving supply to the Sydney Metropolitan Area, requiring network reinforcement within five years (in the period from 2012–13 to 2016–17).

  TransGrid has also identified this limitation and is proposing to reinforce the 330 kV transmission supplying the Sydney Metropolitan Area (for more information see TransGrid's 2012 Annual Planning Report).[1]

  Coal-fired generation retiring from 2016–17 in the NCEN zone, if assumed to comprise the Eraring and Munmorah Power Stations, results in limitations on the 330 kV lines connecting the Hunter Valley to the Newcastle area, which will require reinforcement.
- The Melbourne (MEL) zone may experience main transmission network limitations progressively in the period from 2012–13 to 2031–32 involving the following:
  - The transformers at Rowville, Cranbourne, Keilor and South Morang.
  - A number of 220 kV circuits including Thomastown–Templestowe, Thomastown–Ringwood, South Morang–Thomastown, and Moorabool–Geelong.
- The Country Victoria (CVIC) zone may experience limitations on the Moorabool–Ballarat 220 kV No. 1 circuit and the Ballarat–Bendigo 220 kV circuit within five years (in the period from 2012–13 to 2016–17).

No other main transmission network limitations in the NEM were identified under the Slow Rate of Change scenario based on the key assumption that new generation development follows the least-cost expansion plan.

A.1 Introduction

A.1.1 Context of the analysis

For information about the context of the analysis see Chapter 3, Section 3.1.1.

For more detailed results see the supplementary information page.[2]

1 TransGrid. Available http://www.transgrid.com.au/network/np/Documents/TRAN_219219_Annual_Planning_Report_2012_FA_web.pdf. Viewed 14 November 2012.

2 AEMO Available http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Detailed-Results. Viewed 11 December 2012.

A.2 North Queensland (NQ)

For a description of the NQ zone see Chapter 3, Section 3.2.

A.2.1 Committed main transmission projects

For information about the committed main transmission projects see Chapter 3, Section 3.2.1.

A.2.2 Transmission needs

There are no limitations involving the main transmission network in the NQ zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no NQ zone transmission network development needs identified under the Slow Rate of Change scenario.

A.2.3 Generation expansion

Non-renewable

No non-renewable generation is built in the NQ zone under the Slow Rate of Change scenario.

Renewable

A small amount of wind generation, which is assumed to contribute 9.2% of its installed capacity to the maximum demand in the Queensland region, is built from the beginning of the outlook period.

Biomass plant located in the zone is built from the beginning of the outlook period.

Solar thermal plant located in the zone is built during the period from 2017–18 to 2021–22.

Retirements

Modelling identified approximately 190 MW of coal-fired generation retiring from 2014–15, and 34 MW of OCGT generation retiring from 2016–17.

Table A-1 lists the existing generation[3] and modelled new generation and retirements in the zone under the Slow Rate of Change scenario.

Table A-1 — Existing installed capacity and modelled new generation/retirements (cumulative) for North Queensland (NQ)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
Biomass	0	68	222	222	222	235
CCGT	244	0	0	0	0	0
OCGT	34	-34	-34	-34	-34	-34
Distillate	424	0	0	0	0	0
Coal	190	-190	-190	-190	-190	-190
Wind	0	266	266	266	266	266
Hydro	154	0	0	0	0	0
Solar	0	0	561	561	561	561

[3] Includes scheduled and semi-scheduled generation, and non-scheduled wind generation greater than or equal to 30 MW.

A.3 Central Queensland (CQ)

For a description of the CQ zone see Chapter 3, Section 3.3.

A.3.1 Committed main transmission projects

For information about the committed main transmission projects see Chapter 3, Section 3.3.1.

A.3.2 Transmission needs

The CQ zone continues to be a net exporter of energy throughout the outlook period under the Slow Rate of Change scenario, and retired capacity outweighs new generation.

Coal-fired generation retiring from 2015–16 in the CQ zone, if assumed to comprise three Gladstone generating units, results in a need to increase the transmission capability from Calvale to Wurdong as demand in the Wurdong area is no longer supported by full generation at Gladstone. As a result, thermal limitations may arise during the period from 2012–13 to 2016–17 due to the thermal overload of a Calvale–Wurdong 275 kV circuit on the outage of a Calliope River–Wurdong 275 kV circuit. This assumes that the remaining generation in the Gladstone area is available for service.

If any of the remaining generation in the Gladstone area is not in service, a number of thermal limitations will emerge on the main 275 kV transmission network connecting Calvale and Gladstone to Stanwell and Bouldercombe during various circuit outages. As a result, the scope of the required augmentation would be to increase the transmission capability between Calvale and Larcom Creek/Gladstone/Wurdong.

Other considerations

The least-cost expansion plan analysis does not support major augmentations between CQ and the other zones. An augmentation need may emerge, however, if actual CQ generation development differs from least cost expansion plan patterns (depending on the location and amount of new generation).

Table A-2 lists CQ zone transmission network development needs identified under the Slow Rate of Change scenario.

Table A-2 — CQ zone transmission development needs

Timing	Observed limitation	Network needs	Comments
2012–13 to 2016–17	Overload of a Calvale–Wurdong 275 kV circuit for an outage of the Calliope River –Wurdong 275 kV circuit.[a]	Reinforcement of the transmission network connecting Calvale and Gladstone to Stanwell and Bouldercombe.	A transmission need arises if the modelled retirements involve Gladstone generating units.
2017–18 to 2021–22	None.	None.	None.
2022–23 to 2026–27	None.	None.	None.
2027–28 to 2031–32	None.	None.	None.
2032–33 to 2036–37	None.	None.	None.

a. Unavailability of more than three Gladstone generating units may cause overloads on some circuits connecting Calvale and Gladstone to Stanwell and Bouldercombe.

A.3.3 Generation expansion

Non-renewable

The Slow Rate of Change scenario models 109 MW of new OCGT generation during the period from 2027–28 to 2031–32 and an additional 45 MW during the period from 2032–33 to 2036–37.

Renewable

New solar and geothermal generation is built during the period 2017–18 to 2021–22.

Retirements

Approximately 840 MW of coal-fired generation is modelled to retire from 2015–16.

Table A-3 lists the existing generation[4] and modelled new generation and retirements in the zone under the Slow Rate of Change scenario.

Table A-3 — Existing installed capacity and modelled new generation/retirements (cumulative) for Central Queensland (CQ)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
Geothermal	**0**	0	200	200	200	200
CCGT	**55**	0	0	0	0	0
OCGT	**0**	0	0	0	109	154
Coal	**4,790**	-840	-840	-840	-840	-840
Solar	**0**	0	200	200	200	200

A.4 South West Queensland (SWQ)

For a description of the SWQ zone see Chapter 3, Section 3.4.

A.4.1 Committed main transmission projects

For information about the committed main transmission projects see Chapter 3, Section 3.4.1.

A.4.2 Transmission needs

There are no limitations involving the main transmission network in the SWQ zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no SWQ zone transmission network development needs identified under the Slow Rate of Change scenario.

Other considerations

Transmission augmentation is not required in the SWQ zone because there is little new generation. As SEQ zone demand growth is mainly met by new generation in the zone, any increased demand is less dependent on increased power flows from the SWQ zone, which defers the need for further reinforcement of the transmission network within SWQ and between SEQ and SWQ.

There is also no need for augmentation between the SWQ and CQ zones. There is a surplus of generation in Central and North Queensland throughout the outlook period, and power flows between these two areas are typically southerly during peak demand. Additionally, new generation in the CQ and NQ zones does not result in significant power flows towards the southern zones, avoiding the need for any significant augmentation throughout the outlook period.

None of the QNI interconnector upgrade options occur in the least cost modelling under the Slow Rate of Change scenario within the outlook period, and the need for increased power transfer capability between Queensland and New South Wales does not arise because the augmentation cost is expected to outweigh the market benefits.

[4] See note 3.

If actual SWQ generation development differs from least cost expansion plan patterns, future transmission reinforcement may be required to address any thermal, voltage stability, and transient stability limitations.

A.4.3 Generation expansion

Non-renewable

A small amount of new OCGT generation is built during the period from 2027–28 to 2031–32.

Renewable

New wind generation is built almost from the beginning of the outlook period and is assumed to contribute 9.2% of its installed capacity to the maximum demand in the Queensland region.

Retirements

There are no retirements modelled in the SWQ zone. However, two units of the Tarong Power Station will not be available for service for at least two years[5] (which is accounted for by the transmission analysis).

Table A-4 lists the existing generation[6] and modelled new generation and retirements in the zone under the Slow Rate of Change scenario.

Table A-4 — Existing installed capacity and modelled new generation/retirements (cumulative) for South West Queensland (SWQ)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
CCGT	**788**	0	0	0	0	0
OCGT	**1,385**	0	0	0	21	21
Coal	**3,450**[a]	0	0	0	0	0
Wind	**0**	266	266	266	266	266
Solar	**0**	0	239	239	239	239

a. This number includes two Tarong Power Station generating units totalling 700 MW that will be unavailable for at least two years.

A.5 South East Queensland (SEQ)

For a description of the SEQ zone see Chapter 3, Section 3.5.

A.5.1 Committed main transmission projects

For information about the committed main transmission projects see Chapter 3, Section 3.5.1.

A.5.2 Transmission needs

There are no limitations involving the main transmission network in the SEQ zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

5 Stanwell Corporation has announced plans to withdraw two generating units from service at the Tarong Power Station in October and December 2012 for at least two years or until wholesale electricity demand improves (http://www.stanwell.com/Files/Stanwell_Media_Release_-_Stanwell_to_withdraw_Tarong_Power_Station_units_from_service_-_11_October_2012.PDF).

6 See note 3.

As a result, there are no SEQ zone transmission network development needs identified under the Slow Rate of Change scenario.

If actual SEQ generation development differs from least-cost expansion plan patterns, future transmission reinforcement may be required to address any thermal, voltage stability, and transient stability limitations.

A.5.3 Generation expansion

Non-renewable

Up to 288 MW of new OCGT generation is built in the SEQ zone towards the end of the outlook period.

Renewable

No renewable generation is built in the SEQ zone throughout the outlook period.

Retirements

There are no retirements modelled in the SEQ zone.

Table A-5 lists the existing generation[7] and modelled new generation and retirements in the zone under the Slow Rate of Change scenario.

Table A-5 — Existing installed capacity and modelled new generation/retirements (cumulative) for South East Queensland (SEQ)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
CCGT	**385**	0	0	0	0	0
OCGT	**0**	0	0	0	12	288
Hydro	**500**	0	0	0	0	0

A.6 Northern New South Wales (NNS)

For a description of the NNS zone see Chapter 3, Section 3.6.

A.6.1 Committed main transmission projects

For information about the committed main transmission projects see Chapter 3, Section 3.6.1.

A.6.2 Transmission needs

There are no limitations involving the main transmission network in the NNS zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no NNS zone transmission network development needs identified under the Slow Rate of Change scenario.

Other considerations

The NNS zone transmission network comprises multiple flow paths where 132 kV lines operate in parallel with 330 kV lines. As a result, 330 kV network power flows, including the QNI interconnector, can be limited by the 132 kV network's capability. As demand in the NNS zone grows and as 132 kV network limitations increase, strengthening

[7] See note 3.

or removing some of the 132 kV networks that run in parallel with the 330 kV network may result in positive net market benefits for economic justification.

The need for increased power transfer capability between Queensland and New South Wales does not arise, because the augmentation cost is expected to outweigh the market benefits.

A.6.3 Generation expansion

Non-renewable

New OCGT generation is built in the NNS zone during the period from 2027–28 to 2031–32.

Renewable

Wind and Biomass generation is built from the beginning of the outlook period. The NNS zone wind generation is assumed to contribute 2.2% of its installed capacity to the maximum demand in the New South Wales region.

Retirements

There are no retirements modelled in the NNS zone.

Table A-6 lists the existing generation[8] and modelled new generation and retirements in the zone under the Slow Rate of Change scenario.

Table A-6 — Existing installed capacity and modelled new generation/retirements (cumulative) for Northern New South Wales (NNS)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
Biomass	**0**	17	100	100	100	100
OCGT	**0**	0	0	0	101	101
Wind	**0**	355	626	626	626	626

A.7 Central New South Wales (NCEN)

For a description of the NCEN zone see Chapter 3, Section 3.7.

A.7.1 Committed main transmission projects

For information about the committed main transmission projects see Chapter 3, Section 3.7.1.

A.7.2 Transmission needs

In the NCEN zone, demand growth is faster than generation growth throughout the outlook period under the Slow Rate of Change scenario, making the zone a net importer during peak demand periods.

An emerging limitation arises in supplying the Sydney Metropolitan Area, and studies indicate that the supply to Beaconsfield West will need to be reinforced within five years. TransGrid has also identified problems with the 330 kV Sydney South–Beaconsfield West line that may require its rating to be reduced under certain conditions, and is proposing to reinforce the 330 kV transmission supplying the Sydney Metropolitan Area. A Rookwood Road–

8 See note 3.

Beaconsfield West 330 kV line is TransGrid's preferred option (for more information see TransGrid's 2012 Annual Planning Report).[9]

Coal-fired generation retiring from 2016–17 in the NCEN zone, if assumed to comprise the Eraring and Munmorah Power Stations, results in limitations on the 330 kV lines connecting the Hunter Valley to the Newcastle area, which will require reinforcement.

Table A-7 lists NCEN zone transmission network development needs identified under the Slow Rate of Change scenario.

Table A-7 — NCEN transmission development needs

Timing	Observed limitation	Network needs	Comments
2012–13 to 2016–17	Overload of the Liddell–Tomago and Liddell–Newcastle 330 kV lines for an outage of a parallel line.	Reinforcement of the transmission flow paths between Liddell and the Newcastle area.	None.
2012–13 to 2016–17	Overload of the Sydney South–Beaconsfield West 330 kV cable for an outage of the Sydney South–Haymarket 330 kV cable.	A new supply to the Beaconsfield West Substation from another 330 kV supply point.	None.
2017–18 to 2021–22	None.	None.	None.
2022–23 to 2026–27	None.	None.	None.
2027–28 to 2031–32	None.	None.	None.
2032–33 to 2036–37	None.	None.	None.

A.7.3 Generation expansion

Non-renewable

No non-renewable generation is built in the NCEN zone under the Slow Rate of Change scenario.

Renewable

Both biomass and wind generation are built in the NCEN zone from the beginning of the outlook period, and geothermal generation is built during the period from 2017–18 to 2021–22. Wind generation is assumed to contribute 2.2% of its installed capacity to the maximum demand in the New South Wales region.

Retirements

Modelling identified approximately 2,880 MW of coal-fired generation retiring during the period from 2012–13 to 2016–17 under the Slow Rate of Change scenario.

Table A-8 lists the existing generation[10] and modelled new generation and retirements in the zone under the Slow Rate of Change scenario.

9 TransGrid. Available http://www.transgrid.com.au/network/np/Documents/TRAN_219219_Annual_Planning_Report_2012_FA_web.pdf. Viewed 14 November 2012.

10 See note 3.

Table A-8 — Existing installed capacity and modelled new generation/retirements (cumulative) for New South Wales (NCEN)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
Biomass	**0**	100	100	100	100	100
Geothermal	**0**	0	19	19	19	19
CCGT	**420**	0	0	0	0	0
OCGT	**724**	0	0	0	0	0
Cogen	**171**	0	0	0	0	0
Distillate	**25**	0	0	0	0	0
Coal	**11,384**	-2,880	-2,880	-2,880	-2,880	-2,880
Wind	**0**	313	313	313	313	313
Hydro	**240**	0	0	0	0	0

A.8 Canberra (CAN)

For a description of the CAN zone see Chapter 3, Section 3.8.

A.8.1 Committed main transmission projects

For information about the committed main transmission projects see Chapter 3, Section 3.8.1.

A.8.2 Transmission needs

There are no limitations involving the main transmission network in the CAN zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no CAN zone transmission network development needs identified under the Slow Rate of Change scenario.

Other considerations

Interest has been expressed in locating new GPG in the north of the CAN zone (and the southern part of the NCEN zone). However, the majority of the GPG is located in the NNS zone under the Slow Rate of Change scenario. If significant amounts of GPG were to be built in the CAN zone, SWNSW zone, or the southern part of the NCEN zone, transmission limitations arise on the 330 kV network between the Yass/Canberra area and the Sydney Metropolitan Area.

A.8.3 Generation expansion

Non-renewable

No new non-renewable generation is built in the CAN zone under the Slow Rate of Change scenario.

Renewable

Wind and biomass generation are built in the CAN zone from the beginning of the outlook period. The CAN zone wind generation is assumed to contribute 2.2% of its installed capacity to the maximum demand in the New South Wales region.

Retirements

There are no retirements modelled in the CAN zone.

Table A-9 lists the existing generation[11] and modelled new generation and retirements in the zone under the Slow Rate of Change scenario.

Table A-9 — Existing installed capacity and modelled new generation/retirements (cumulative) for Canberra (CAN)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
Biomass	**0**	100	100	100	100	100
Wind	**266**	802	803	803	803	803
Hydro	**60**	0	0	0	0	0

A.9 South West New South Wales (SWNSW)

For a description of the SWNSW zone see Chapter 3, Section 3.9.

A.9.1 Committed main transmission projects

For information about the committed main transmission projects see Chapter 3, Section 3.9.1.

A.9.2 Transmission needs

There are no limitations involving the main transmission network in the SWNSW zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no SWNSW zone transmission network development needs identified under the Slow Rate of Change scenario.

Other considerations

The Victoria to New South Wales interconnector is not augmented in the least cost modelling under the Slow Rate of Change Scenario, because the augmentation cost is expected to outweigh any market benefits gained from the increased power transfer capability.

New wind generation of approximately 1,000 MW does not require any major transmission augmentation in the SWNSW zone if the wind farms are optimally located (not connected to areas of low capacity in the transmission network or overly concentrated in one area of the zone).

A.9.3 Generation expansion

Non-renewable

Some new OCGT generation is built in the SWNSW zone towards the end of the outlook period under the Slow Rate of Change scenario, and the amount installed varies from 99 MW during the period from 2027–28 to 2031–32, to 294 MW during the period from 2032–33 to 2036–37.

Renewable

Wind generation is built in the SWNSW zone from the beginning of the outlook period under the Slow Rate of Change scenario. The SWNSW zone wind generation is assumed to contribute 2.2% of its installed capacity to the maximum demand in the New South Wales region.

[11] See note 3.

Retirements

There are no retirements modelled in the SWNSW zone.

Table A-10 lists the existing generation[12] and modelled new generation and retirements in the zone under the Slow Rate of Change scenario.

Table A-10 — Existing installed capacity and modelled new generation/retirements (cumulative) for South West New South Wales (SWNSW)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
OCGT	664	0	0	0	99	294
Wind	0	1,018	1,018	1,018	1,018	1,018
Hydro	2,319	0	0	0	0	0

A.10 Latrobe Valley (LV)

For a description of the LV zone see Chapter 3, Section 3.10.

A.10.1 Committed main transmission projects

For information about the committed main transmission projects see Chapter 3, Section 3.10.1.

A.10.2 Transmission needs

There are no limitations involving the main transmission network or connections to neighbouring zones for the outlook period if new generation is located according to the least cost expansion plan.

As a result, there are no LV zone transmission network development needs identified under the Slow Rate of Change scenario.

A.10.3 Generation expansion

Non-renewable

New OCGT generation with an installed capacity of 61 MW is built under the Slow Rate of Change scenario during the period from 2022–23 to 2026–27.

Renewable

LV zone wind generation is assumed to contribute 6.5% of its installed capacity to the maximum demand in the Victorian region. Under the Slow Rate of Change scenario, wind generation is built in the LV zone during the period from 2017–18 to 2021–22.

Retirements

There are no retirements modelled in the LV zone.

Table A-11 lists the existing generation[13] and modelled new generation and retirements in the zone under the Slow Rate of Change scenario.

[12] See note 3.
[13] See note 3.

Table A-11 — Existing installed capacity and modelled new generation/retirements (cumulative) for Latrobe Valley (LV)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
OCGT	**834**	0	0	61	61	61
Coal	**6,374**	0	0	0	0	0
Wind	**30**	0	82	82	82	82

A.11 Melbourne (MEL)

For a description of the MEL zone see Chapter 3, Section 3.11.

A.11.1 Committed main transmission projects

For information about the committed main transmission projects see Chapter 3, Section 3.11.1.

A.11.2 Transmission needs

Load growth in the Melbourne and Geelong Greater Metropolitan Area and a significant amount of new generation connected to the 500 kV network drive the need to strengthen the 500/220 kV transformation capability. Three new 500/220 kV transformers have been identified in the zone to meet the increased load growth, and remove the overload on the existing 500/220 kV and 330/220 kV transformers.

Limitations have been identified on the 220 kV transmission circuits from Thomastown to Ringwood, Thomastown to Templestowe and South Morang to Thomastown during a single transmission element outage. Possible solutions involve the new transformers and connection of Rowville–Templestowe 220 kV circuit at Ringwood.

An emerging limitation has also been observed on the 220 kV transmission circuits from Moorabool to Geelong during the parallel transmission circuit outage. Possible solutions involve uprating the existing Moorabool–Geelong 220 kV circuits or adding a new Moorabool–Geelong 220 kV circuit.

Other considerations

Emerging network limitations may also arise on a number of radially connected 220 kV circuits (Rowville–Springvale, Springvale–Heatherton and Rowville–Malvern). The timing of these limitations depends on connection point load forecasts and load transfers to nearby terminal stations.

High levels of new wind generation are modelled in this zone, giving rise to network limitations on the existing 500 kV transmission network along the South West Corridor. High imports from South Australia combined with moderate levels of OCGT generation also contribute to this limitation. Generation rescheduling was modelled to remove the network limitations in the least cost expansion plan. However, additional 500 kV transmission augmentation between Moorabool and Heywood is an alternative potential solution if economically justified to deliver positive net market benefits from reducing the need to redespatch generation.

Table A-12 lists the MEL zone transmission network development needs identified under the Slow Rate of Change scenario.

Table A-12 — MEL transmission development needs

Timing	Observed limitation	Network needs	Comments
2012–13 to 2016–17	Overload of the Rowville 500/220 kV A2 transformer for an outage of the Cranbourne 500/220 kV A1 transformer (and vice versa).	An additional 500/220 kV transformer in the Eastern Metropolitan Melbourne area.	One possible solution is an additional 1,000 MVA 500/220 kV transformer at Cranbourne or Rowville. For more information see AEMO's 2012 Victorian APR.[a]
2017–18 to 2021–22	None.	None.	None.
2022–23 to 2026–27	Overload of the Rowville 500/220 kV A1 transformer under system normal conditions, and overload of the Thomastown–Templestowe and Thomastown–Ringwood 220 kV circuits for an outage of the Rowville 500/220 kV A1 transformer.	An additional 500/220 kV transformer in the Eastern Metropolitan Melbourne area and connection of the Rowville–Templestowe 220 kV circuit at Ringwood.	One possible solution is an additional 1,000 MVA 500/220 kV transformer at Rowville, Ringwood or Templestowe, and connection of the Rowville–Templestowe 220 kV circuit at Ringwood. For more information see AEMO's 2012 Victorian APR[a].
2027–28 to 2031–32	None.	None.	None.
2032–33 to 2036–37	Overload of a Keilor 500/220 kV transformer for an outage of the parallel transformer or a Moorabool 500/220 kV transformer, and overload of a South Morang 330/220 kV transformer and a South Morang–Thomastown 220 kV circuit for an outage of the parallel transformer/circuit, and overload of a Moorabool–Geelong 220 kV circuit for an outage of the parallel circuit.	An additional 500/220 kV in the Western Metropolitan Melbourne area.	One possible solution is an additional 500/220 kV transformer at Keilor. For more information see AEMO's 2012 Victorian APR.[a]
2032–33 to 2036–37	Overload of a Moorabool–Geelong 220 kV circuit for an outage of the parallel circuit.	An additional 220 kV capability from Moorabool to Geelong.	A new transformer at Keilor (but not at Moorabool) defers overload of a Moorabool–Geelong 220 kV circuit by a few years.

a. AEMO. Available http://www.aemo.com.au/~/media/Files/Other/planning/2012_Victorian_Annual_Planning_Report.ashx. Viewed 2 November 2012.

A.11.3 Generation expansion

Non-renewable

New OCGT generation is built in the South West Corridor of the MEL zone in the period from 2022–23 to 2026–27 onwards under the Slow Rate of Change scenario.

Renewable

Wind generation in the MEL zone is assumed to contribute 6.5% of its installed capacity to the maximum demand in the Victorian region. Wind generation is built in the MEL zone under the Slow Rate of Change scenario from the beginning of the outlook period.

Retirements

There are no retirements modelled in the MEL zone.

Table A-13 lists the existing generation[14] and modelled new generation and retirements in the zone under the Slow Rate of Change scenario.

Table A-13 — Existing installed capacity and modelled new generation/retirements (cumulative) for Melbourne (MEL)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
OCGT	**1,538**	0	0	210	884	1,351
Wind	**552**[a]	485	818	818	818	818

a. Includes Macarthur Wind Farm generation of 420 MW.

A.12 Country Victoria (CVIC)

For a description of the CVIC zone see Chapter 3, Section 3.12.

A.12.1 Committed main transmission projects

For information about the committed main transmission projects see Chapter 3, Section 3.12.1.

A.12.2 Transmission needs

As demand growth exceeds new generation, the zone continues to rely on generation from the MEL, NVIC and SWNSW zones.

Network limitations on the Moorabool–Ballarat 220 kV No.1 line on an outage of the Moorabool–Ballarat 220 kV No.2 line arise during 2012–13 to 2016–17. Another emerging limitation is identified on the Ballarat–Bendigo 220 kV circuit on an outage of the Bendigo–Shepparton 220 kV circuit during the same period.

Table A-14 lists the CVIC zone transmission network development needs identified under the Slow Rate of Change scenario.

Table A-14 — CVIC transmission development needs

Timing	Observed limitation	Network needs	Comments
2012–13 to 2016–17	Overload of the Moorabool–Ballarat 220 kV No.1 circuit for an outage of the Moorabool–Ballarat 220 kV No.2 circuit.	An additional 220 kV capability from Moorabool to Ballarat.	For more information see Chapter 3 of AEMO's 2012 Victorian APR.[a]
2012-2013 to 2016–17	Overload of the Ballarat–Bendigo 220 kV circuit for an outage of the Bendigo–Shepparton 220 kV circuit.	An additional 220 kV power transfer capability between Ballarat and Bendigo.	A possible solution is to uprate the Ballarat–Bendigo 220 kV circuit. For more information see Chapter 3 of AEMO's 2012 Victorian APR.[a]
2017–18 to 2021–22	None.	None.	None.
2022–23 to 2026–27	None.	None.	None.
2027–28 to 2031–32	None.	None.	None.

14 See note 3.

Timing	Observed limitation	Network needs	Comments
2032–33 to 2036–37	None.	None.	None.

a. AEMO. Available http://www.aemo.com.au/~/media/Files/Other/planning/2012_Victorian_Annual_Planning_Report.ashx. Viewed 2 November 2012.

A.12.3 Generation expansion

Non-renewable

No new non-renewable generation is built in the CVIC zone under the Slow Rate of Change scenario.

Renewable

New wind generation is built during the period from 2017–18 to 2021–22 under the Slow Rate of Change scenario and is assumed to contribute 6.5% of its installed capacity to the maximum demand in the Victorian region.

Retirements

There are no retirements modelled in the CVIC zone.

Table A-15 lists the existing generation[15] and modelled new generation and retirements in the zone under the Slow Rate of Change scenario.

Table A-15 — Existing installed capacity and modelled new generation/retirements (cumulative) for Country Victoria (CVIC)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
Wind	**312**	0	736	736	736	736
Coal	**150**[a]	0	0	0	0	0

a. Non-scheduled Anglesea generation of 150 MW is included in the analysis

A.13 Northern Victoria (NVIC)

For a description of the NVIC zone see Chapter 3, Section 3.13.

A.13.1 Committed main transmission projects

For information about the committed main transmission projects see Chapter 3, Section 3.13.1.

A.13.2 Transmission needs

There are no limitations involving the main transmission network in the NVIC zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no NVIC zone transmission network development needs identified under the Slow Rate of Change scenario.

Other considerations

A transmission network limitation arises on the Dederang–Mount Beauty 220 kV line during periods of high hydroelectric generation. Generation re-scheduling might remove this limitation.

15 See note 3.

A.13.3 Generation expansion

Non-renewable

No non-renewable generation is built in the NVIC zone for the outlook period.

Renewable

No renewable generation is built in the NVIC zone for the outlook period.

Retirements

There are no retirements modelled in the NVIC zone.

Table A-16 lists the existing generation[16] and modelled new generation and retirements in the zone under the Slow Rate of Change scenario.

Table A-16 — Existing installed capacity and modelled new generation/retirements (cumulative) for Northern Victoria (NVIC)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
Hydro	2,211	0	0	0	0	0

A.14 Adelaide (ADE)

For a description of the ADE zone see Chapter 3, Section 3.14.

A.14.1 Committed main transmission projects

For information about the committed main transmission projects see Chapter 3, Section 3.14.1.

A.14.2 Transmission needs

There are no limitations involving the main transmission network in the ADE zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no ADE zone transmission network development needs identified under the Slow Rate of Change scenario.

Other considerations

Future transmission augmentation needs will be driven by the location of new OCGT. For example, the NTNDP analysis assumed that all new generation in the ADE zone (up to 378 MW) will be located in the vicinity of Torrens Island. Based on this assumption, main transmission network limitations do not emerge for the outlook period.

Alternatively, if new generation in the ADE zone is located in the vicinity of Tepko (near Tungkillo, approximately 40 kilometres east of Adelaide), local transmission network augmentations will be required to strengthen the 275 kV transmission network between Tailem Bend and Tungkillo. This augmentation facilitates increased power transfers from new generation and from Victoria to the Adelaide Metropolitan Area.

[16] See note 3.

A.14.3 Generation expansion

Non-renewable

New OCGT generation is built in the ADE zone during the period from 2022–23 to 2026–27 (approximately 200 MW), increasing to close to 400 MW later in the outlook period.

Renewable

No renewable generation is built in the ADE zone throughout the outlook period. Existing wind generation in the ADE zone is assumed to contribute 8.3% of its installed capacity to the maximum demand in the South Australian region.

Retirements

No retirements are modelled in the ADE zone.

Table A-17 lists the existing generation[17] and modelled new generation and retirements in the zone under the Slow Rate of Change scenario.

Table A-17 — Existing installed capacity and modelled new generation/retirements (cumulative) for Adelaide (ADE)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
CCGT	**658**	0	0	0	0	0
Gas/steam sub-critical	**1,280**	0	0	0	0	0
OCGT	**380**	0	0	191	378	378
Wind	**35**	0	0	0	0	0

A.15 Northern South Australia (NSA)

For a description of the NSA zone see Chapter 3, Section 3.15.

A.15.1 Committed main transmission projects

For information about the committed main transmission projects see Chapter 3, Section 3.15.1.

A.15.2 Transmission needs

There are no limitations involving the main transmission network in the NSA zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no NSA zone transmission network development needs identified under the Slow Rate of Change scenario.

Other considerations

The NSA zone imports more power than under the Planning scenario for the outlook period. This is largely driven by plant retirements and lack of new non-wind generation within the zone. The analysis shows that the existing

[17] See note 3.

275 kV main transmission system is able to support additional imports to the NSA zone from the ADE zone under the Slow Rate of Change scenario.

New wind generation of approximately 895 MW modelled by the least cost expansion plan at Snowtown[18], Lincoln Gap, Hornsdale, and Mt Cone does not require major main transmission network augmentation.

Transmission needs arise depending on the penetration levels and concentration of wind generation within the zone. For example, a 600 MW wind farm development on the Yorke Peninsula will require augmentation of the main transmission network for power transfers to the ADE zone.

A.15.3 Generation expansion

Non-renewable

No non-renewable generation is built in the NSA zone.

Renewable

Approximately 895 MW of new wind generation is built in the NSA zone. The NSA zone wind generation is assumed to contribute 8.3% of its installed capacity to the maximum demand in the South Australian region.

Retirements

The modelling identifies up to 770 MW of coal-fired generation for retirement during the outlook period, with approximately 505 MW retiring by 2016–17, and the remaining 265 MW by 2031–32.

Table A-18 lists the existing generation[19] and modelled new generation and retirements in the zone under the Slow Rate of Change scenario.

Table A-18 — Existing installed capacity and modelled new generation/retirements (cumulative) for Northern South Australia (NSA)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
OCGT	**318**	0	0	0	0	0
Distillate	**74**	0	0	0	0	0
Coal	**770**	-505	-505	-505	-770	-770
Wind	**844**	895	895	895	895	895

A.16 South East South Australia (SESA)

For a description of the SESA zone see Chapter 3, Section 3.16.

A.16.1 Committed main transmission projects

For information about the committed main transmission projects see Chapter 3, Section 3.16.1.

18 The 2012 NTNDP modelled the Snowtown Stage 2 Wind Farm as a potential project (consistent with the information available at the time of modelling inputs preparation). Snowtown Stage 2 Wind Farm was confirmed to be a committed project in September 2012.

19 See note 3.

A.16.2 Transmission needs

There are no limitations involving the main transmission network in the SESA zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no SESA zone transmission network development needs identified under the Slow Rate of Change scenario.

Other considerations

The Heywood interconnector upgrade project[20, 21] (assumed to be committed in the NTNDP analysis) defers the need for further upgrades of the Victoria to South Australia interconnector for the outlook period. This is due to the cost of further interconnector augmentation expecting to outweigh any market benefits gained from increased power transfer capability between the two regions.

Emerging main transmission network limitations within the SESA zone do not arise during the outlook period due to a number of network augmentations to be implemented as part of the Heywood interconnector upgrade project.

The existing 132 kV network in SESA has very limited capability to accommodate new generation connections. As a result, large-scale generation is modelled as directly connected to the 275 kV transmission network at a future 275 kV injection point at Krongart, which is close to the existing 275/132 kV South East Substation and connected to the existing Tailem Bend–South East 275 kV circuits.

A.16.3 Generation expansion

Non-renewable

A small amount of new OCGT generation is built in the SESA zone under the Slow Rate of Change scenario during the period from 2022–23 to 2026–27 (increasing to 140 MW towards the end of the outlook period).

Renewable

Wind generation of approximately 455 MW is built in the SESA zone throughout the outlook period. Biomass generation of approximately 278 MW is also built. The SESA zone wind generation is assumed to contribute 8.3% of its installed capacity to the maximum demand in the South Australian region.

Retirements

There are no retirements modelled in the SESA zone.

Table A-19 lists the existing generation[22] and modelled new generation and retirements in the zone under the Slow Rate of Change scenario.

Table A-19 — Existing installed capacity and modelled new generation/retirements (cumulative) for South East South Australia (SESA)

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
Biomass	0	115	278	278	278	278

[20] AEMO and ElectraNet are undertaking a joint Regulatory Investment Test for Transmission (RIT-T) application to investigate increasing the interconnector's capability to realise market benefits from relieving congestion on the Heywood interconnector. The RIT-T consultation was initiated by the Project Specification Consultation Report (PSCR) in October 2011. The Project Assessment Draft Report (PADR) was published in September 2012. The NTNDP analysis assumed the currently preferred option was proceeding.

[21] AEMO. Available http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission-RITTs/Heywood-Interconnector-RIT-T. Viewed 31 October 2012.

[22] See note 3.

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
OCGT	**80**	0	0	11	62	140
Distillate	**63**	0	0	0	0	0
Wind	**325**	455	455	455	455	455

A.17 Tasmania (TAS)

For a description of the TAS zone see Chapter 3, Section 3.17.

A.17.1 Committed main transmission projects

For information about the committed main transmission projects see Chapter 3, Section 3.17.1.

A.17.2 Transmission needs

There are no limitations involving the main transmission network in the TAS zone or connections to neighbouring zones for the outlook period if new generation is located according to the least-cost expansion plan.

As a result, there are no TAS zone transmission network development needs identified under the Slow Rate of Change scenario.

Other considerations

A second HVDC link, increasing Victoria to Tasmania interconnector capability, is not built under the Slow Rate of Change Scenario for the outlook period. This is due to the cost of the project expecting to outweigh any market benefits gained from increased power transfer capability between the two regions.

New wind generation of 787 MW is modelled at Burnie, Farrell, Waddamana and George Town. Limitations potentially arise on the Farrell–Sheffield and Sheffield–George Town 220 kV lines during periods of high wind generation and moderate local demand, combined with maximum export levels from Tasmania to Victoria. These limitations can be eliminated via existing special protection schemes and generation re-scheduling in the zone.

Depending on the location and amount of wind generation, the Burnie–Sheffield and Sheffield–Palmerston 220 kV lines may experience limitations. Lower voltage network augmentation requirements may also arise due to local demand growth, for example, with limitations relating to the Sheffield and Hadspen 220/110 kV transformers during an outage of the other transformer.

There is a concern that increased penetration of wind generation will displace existing synchronous generation leading to potential stability issues. The least-cost expansion plan results assume that inertia is available from existing synchronous generation in Tasmania, for example by operating in synchronous condenser mode.

A.17.3 Generation expansion

Non-renewable

No new non-renewable generation is built in the TAS zone.

Renewable

TAS has high levels of wind generation during non-peak demand periods, although assumed contribution during peak demand periods is 2.9% of installed capacity. Wind generation is built in the TAS zone from the beginning of the outlook period.

Retirements

There are no retirements modelled in the TAS zone.

Table A-20 lists the existing generation[23] and modelled new generation and retirements in the zone under the Slow Rate of Change scenario.

Table A-20 — Existing installed capacity and modelled new generation/retirements (cumulative) for Tasmania

Generation type	Existing installed capacity (MW)	Modelled new generation capacity/retirements (MW)				
		2016–17	2021–22	2026–27	2031–32	2036–37
CCGT	**208**	0	0	0	0	0
OCGT	**178**	0	0	0	0	0
Wind	**308**[a]	330	787	787	787	787
Hydro	**2,170**	0	0	0	0	0

a. Includes Musselroe Wind Farm generation of 168 MW.

A.18 Other transmission network needs

For more information about transmission network needs in addition to those identified in this chapter, see Chapter 3, Section 3.18.

23 See note 3.

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The purpose of this publication is to provide an independent strategic view of the efficient development of the National Electricity Market (NEM) national transmission network over at least a 20 year planning horizon.

AEMO publishes the National Transmission Network Development Plan in accordance with clause 5.6A.2 of the National Electricity Rules. This publication has been prepared by AEMO using information available at 1 November 2012, unless otherwise specified. Information made available after 1 November 2012 may have been included in this publication where practical.

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MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
GW	Gigawatts
GWh	Gigawatt hours
kV	Kilovolts
kW	Kilowatts
kWh	Kilowatt hours
Mt	Megatonnes
MVA	Megavolt amperes
MVAr	Megavolt amperes reactive
MW	Megawatts
MWh	Megawatt hours
t/MWh	Tonnes per megawatt hour
TWh	Terawatt hours
$	Australian dollars
$/GJ	Australian dollars gigajoule
$/MWh	Australian dollars per megawatt hour
$/t	Australian dollars per tonne

Abbreviations

Abbreviation	Expanded Name
AC	Alternating current
ADE	Adelaide zone
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APR	Annual Planning Report
CAN	Canberra zone
CCGT	Combined cycle gas turbine (a type of GPG)
CO_2-e	Carbon dioxide equivalent
CQ	Central Queensland zone
CVIC	Country Victoria zone
DRET	Department of Resources, Energy and Tourism
DSP	Demand-side participation
EAAP	Energy Adequacy Assessment Projection
EDT	Eastern Daylight-saving Time (see also EST)
ESOO	Electricity Statement of Opportunities
EST	Eastern Standard Time (see also EDT)
EU	European Union
GPG	Gas powered generation
GSOO	Gas Statement of Opportunities
HVDC	High voltage direct current
JPB	Jurisdictional planning body
LNG	Liquefied Natural Gas
LRET	Large-scale Renewable Energy Target
LRMC	Long-run marginal cost
LV	Latrobe Valley zone
MD	Maximum demand
MEL	Melbourne zone
MLF	Marginal loss factor
MRL	Minimum Reserve Level
MT PASA	Medium-term Projected Assessment of System Adequacy
NCEN	Central New South Wales zone

Abbreviation	Expanded Name
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NNS	Northern New South Wales zone
NQ	North Queensland zone
NSA	Northern South Australia zone
NSCAS	Network support and control ancillary services
NTNDP	National Transmission Network Development Plan
NVIC	Northern Victoria zone
OCGT	Open cycle gas turbine (a type of GPG)
PASA	Projected Assessment of System Adequacy
POE	Probability of exceedence
PSA	Power System Adequacy – Two Year Outlook
PV	Present value
REC	Renewable Energy Certificate
RET	Renewable Energy Target - national Renewable Energy Target scheme
RIT-T	Regulatory Investment Test for Transmission
SEQ	South East Queensland zone
SESA	South East South Australia zone
SRES	Small-scale Renewable Energy Scheme
SRMC	Short-run marginal cost
STC	Small-scale Technology Certificates
SVC	Static VAr compensator
SWNSW	South West New South Wales zone
SWQ	South West Queensland zone
TAS	Tasmania zone
TNSP	Transmission network service provider
USE	Unserved energy
VCR	Value of Customer Reliability

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GLOSSARY AND LIST OF COMPANY NAMES

Glossary

Many of the listed terms are already defined in the National Electricity Rules (NER), version 53[1] . For ease of reference, these terms are highlighted in blue. Some terms, although defined in the NER, have been clarified, and these terms are highlighted in green.

Term	Definition
Active power	See electrical power.
Advanced proposal	A proposed generation project that meets at least three and shows progress on two of the five criteria specified by AEMO for a committed project. See also 'proposed project' and 'publicly announced proposal'.
Ancillary services	Services used by AEMO that are essential for: • managing power system security • facilitating orderly trading, and • ensuring electricity supplies are of an acceptable quality. 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. 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.
As-generated	A measure of demand or energy (in megawatts (MW) and megawatt hours (MWh), respectively) at the terminals of a generating system. This measure includes consumer load, transmission and distribution losses, and generator auxiliary loads.
Augmentation	The process of upgrading the capacity or service potential of transmission infrastructure.
Base load generating system	A generating system designed to run almost constantly at near maximum capacity levels, usually at lower cost than intermediate or peaking generating systems.
Capacity factor	The output of generating units or systems, averaged over time, expressed as a percentage of rated or maximum output.
Central dispatch	The process managed by AEMO for the dispatch of scheduled generating units, semi-scheduled generating units, scheduled loads, scheduled network services and market ancillary services in accordance with Rule 3.8.
Cogeneration (Cogen.)	The simultaneous generation of both electricity and useful heat.
Committed project	A committed project is any new generation development or non-regulated transmission development that meets all five criteria specified by AEMO for a committed project (see Chapter 2, Section 2.4.1 of the Electricity Statement of Opportunities (ESOO) for more information).
Connection point (electricity)	The agreed point of supply established between network service provider(s) and another registered participant, non-registered customer or franchise customer.

[1] AEMC. Available **http://www.aemc.gov.au/rules.php**. Viewed 5 December 2012.

Term	Definition
Constrained	A limitation on the capability of a network, load, or a generating unit such that it is unacceptable to either transfer, consume or generate the level of electrical power that would occur if the limitation was removed.
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.
Contingency event	An event affecting the power system, such as the failure or unplanned removal from operational service of a generating unit or transmission network element.
Credible contingency event	A contingency event AEMO considers reasonably possible, given the circumstances in the power system.
Customer (electricity)	A person who engages in the activity of purchasing electricity supplied through a transmission or distribution system to a connection point, and is registered by AEMO as a Customer under Chapter 2 [of the NER].
Demand	See electricity demand.
Demand diversity	Refers to both intra and inter-regional demand diversity: • 'Intra-regional' recognises that the maximum demands at each connection point within a region might not occur at the same time, and the sum of the connection point maximum demands will exceed the regional maximum demand. • 'Inter-regional' recognises that the maximum demands of different regions may occur at different times, and the sum of the individual regional maximum demands will exceed the total National Electricity Market (NEM) maximum demand.
Demand-side participation (DSP)	The situation where customers 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.
Diversity	The lack of coincidence of peak demand across several sources of demand, such as residential, industrial, and gas powered generation.
Electrical energy	Energy can be calculated as the average electrical power over a time period, multiplied by the length of the time period. Measured on a sent-out basis, it includes energy consumed by the consumer load, and distribution and transmission losses. 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.
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 the following: • The electrical power consumed by the consumer load. • Distribution and transmission losses. • Power station transformer losses and auxiliary loads. The ESOO reports demand as half-hourly averages.
Energy	See 'electrical energy'.
Energy Adequacy Assessment Projection (EAAP)	A quarterly report, produced by AEMO, of projected energy availability for each region over a 24-month period for three different rainfall scenarios. The EAAP reports the impact of the projected energy availabilities on regional electrical supply reliability in terms of long-term unserved energy (USE).

Term	Definition
Flow path	Those elements of the electricity transmission networks used to transport significant amounts of electricity between generation centres and major load centres.
Forced outage	An unplanned outage of an electricity transmission network element (transmission line, transformer, generator, reactive plant, etc).
Frequency control ancillary services (FCAS)	Those ancillary services concerned with balancing, over short intervals (shorter than the dispatch interval), the power supplied by generating units and the power consumed by loads. This imbalance is managed by monitoring the power system frequency.
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. 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 centre	A geographically concentrated area containing a generating unit or generating units with significant combined generating capability.
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.
Generator auxiliary load	Load used to run a power station, including supplies to operate a coal mine (otherwise known as 'used in station load').
Generator-terminal basis	A measure of demand at the terminals of a generating unit. This measure covers the entire output of the generating unit (in megawatts (MW)): • Consumer load. • Transmission and distribution losses. • Generating unit auxiliary load. • Generator transformer losses.
Installed capacity	The generating capacity (in megawatts (MW)) of the following (for example): • A single generating unit. • A number of generating units of a particular type or in a particular area. • 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.
Interconnector power transfer capability	The power transfer capability (in megawatts (MW)) of a transmission network connecting two regions to transfer electricity between those regions.
Intermediate generating system	A generating system that adjusts its output as demand for electricity fluctuates throughout the day. These systems are typically in-between base load and peaking generation in terms of efficiency, speed of start-up and shutdown, construction cost, cost of electricity, and capacity factor.

Term	Definition
Intermittent	A description of a generating unit whose output is not readily predictable, including, without limitation, solar generators, wave turbine generators, wind turbine generators and hydro-generators without any material storage capability.
Jurisdictional planning body (JPB)	An entity nominated by the relevant Minister of the relevant participating jurisdiction as having transmission system planning responsibility (in that participating jurisdiction). There are five jurisdictional planning bodies: • Queensland – Powerlink Queensland. • New South Wales – TransGrid. • Victoria – AEMO. • South Australia – ElectraNet. • Tasmania – Transend Networks.
Large-scale Renewable Energy Target (LRET)	See 'national Renewable Energy Target scheme'.
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.
Liquid fuelled generation	Generation that utilises liquid fuel (usually in the form of distillate, kerosene or fuel oil) as its primary fuel source.
Liquefied Natural Gas	Natural gas that has been converted to liquid form for ease of storage or transport.
Load	A connection point or defined set of connection points at which electrical power is delivered to a person or to another network or the amount of electrical power delivered at a defined instant at a connection point, or aggregated over a defined set of connection points.
Load shedding	Reducing or disconnecting load from the power system.
Long-run marginal cost (LRMC)	A generator's long-run marginal cost (LRMC) describes the revenue required to exactly cover financing costs, and the fixed and variable operating and maintenance costs of the investment over the generating system's lifetime.
Loss factor	A multiplier used to describe the electrical energy loss for electricity used or transmitted.
Low reserve condition (LRC)	When the AEMO considers that a region's reserve margin (calculated under 10% probability of exceedence (POE) scheduled and semi-scheduled maximum demand conditions) for the period being assessed is below the minimum reserve level (MRL).
Marginal loss factor (MLF)	A multiplier used to describe the marginal electrical energy loss for electricity used or transmitted.
Market	Any of the markets or exchanges described in the NER, for so long as the market or exchange is conducted by AEMO.
Market ancillary services	The ancillary services required by AEMO as part of the spot market, which include the services listed in clause 3.11.2(a) of the NER. The prices of market ancillary services are established using the central dispatch process.
Market customer (electricity)	A Customer who has classified any of its loads as a market load and who is also registered by AEMO as a market customer under Chapter 2 [of the NER].
Market generating unit	A generating unit whose sent-out generation is not purchased in its entirety by the local retailer or by a customer located at the same connection point and which has been classified as such in accordance with Chapter 2 [of the NER].
Market generator	A generator who has classified at least one generating unit as a market generating unit in accordance with Chapter 2 [of the NER] and who is also registered by AEMO as a market generator under Chapter 2 [of the NER].

Term	Definition
Market load	A load that is settled through the spot market, and may also be classified as a scheduled load. Customers submit bids in relation to market loads to purchase electricity through the central dispatch process. They must be controllable according to dispatch instructions issued by AEMO.
Market network service provider (MNSP)	A network service provider who has classified any of its network services as a market network service in accordance with Chapter 2 [of the NER] and who is also registered by AEMO as a market network service provider under Chapter 2 [of the NER].
Market non-scheduled (MNS) generating unit	A generating unit with the following characteristics: • Sells energy into the energy spot market. • Is not scheduled by AEMO as part of central dispatch. • Has been classified as an MNS generating unit in accordance with Chapter 2 of the NER.
Market scheduled (MS) generating unit	A generating unit with the following characteristics: • Sells energy into the energy spot market. • Is scheduled by AEMO as part of central dispatch. • Has been classified as an MS generating unit in accordance with Chapter 2 of the NER.
Market participant (electricity)	A person who is registered by AEMO as a market generator, market customer or market network service provider under Chapter 2 [of the NER].
Maximum demand (MD)	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.
Medium-term Projected Assessment of System Adequacy (Medium-term PASA or MT PASA)	The medium term PASA covers the 24 month period commencing from the Sunday after the day of publication with a daily resolution.
Mothballed generation unit	A generating unit that is in storage and is currently unavailable, but may become available again in the future.
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 Market Dispatch Engine (NEMDE)	The software that calculates the optimum economic dispatch of the NEM every five minutes, subject to a number of constraint equations that reflect additional physical power system requirements. The software co-optimises the outcome of the energy spot market and the frequency control ancillary services (FCAS) market.
National Electricity Rules (NER)	The National Electricity Rules describes the day-to-day operations of the NEM and the framework for network regulations. See also 'National Electricity Law'.

Term	Definition
National Renewable Energy Target scheme	The national Renewable Energy Target (RET) scheme, which commenced in January 2010, aims to meet a renewable energy target of 20% by 2020. Like its predecessor, the Mandatory Renewable Energy Target (MRET), the national RET scheme requires electricity retailers to source a proportion of their electricity from renewable sources developed after 1997. The national RET scheme is currently structured in two parts: • Small-scale Renewable Energy Scheme (SRES), which is a fixed price, unlimited-quantity scheme available only to small-scale technologies (such as solar water heating) and is being implemented via Small-scale Technology Certificates (STC). • Large-scale Renewable Energy Target (LRET), which is being implemented via Large-scale Generation Certificates (LGC), and targets 41,000 GWh of renewable energy by 2020.
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 customers (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 support and control ancillary service (NSCAS)	A service with the capability to control the active power or reactive power flow into or out of a transmission network to address an NSCAS need.
Network limit	Defines the power system's secure operating range. Network limits also take into account equipment/network element ratings. See also 'ratings'.
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 limit equation	Describes the capability to transmit power through a particular portion of the network as a function of the following: • Generating unit outputs. • Interconnector flows. • Transmission equipment ratings. • Demand at one or more connection points. • Equipment status or operating mode. The set of all network limit equations fully describes a network's capability. AEMO translates network limit equations into network constraint equations for use in the central dispatch process. See also 'constraint equation'.
Network service provider	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].

Term	Definition
Non-credible contingency	Any planned or forced 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 involve demand-side participation (DSP) (including post contingent load relief) and new generation on the load side of the limitation.
Non-scheduled generating unit	A generating unit that is not scheduled by AEMO as part of the central dispatch process, and which has been classified as such in accordance with Chapter 2 [of the NER].
Normalised wind trace	Used in market stimulations to determine the maximum available wind farm generation capacity for each dispatch interval. Normalised wind traces were developed using two inputs: • Wind speed data from the Australian Bureau of Meteorology to produce wind speed traces. • Wind farm turbine characteristics (power curves) to convert wind speed traces into wind generation output availability traces.
Operating cost benefit	A benefit deriving from reduced fuel, operating and maintenance costs, indicating reduced operating costs.
Operational demand	That part of the electricity demand supplied by scheduled, semi-scheduled, and significant non-scheduled generating units. There are a number of significant non-scheduled generating units included in the definition of operational demand: • Cullerin Range Wind Farm (New South Wales). • Capital Wind Farm (New South Wales). • Yambuk Wind Farm (Victoria). • Portland Wind Farm (Victoria). • Challicum Hills Wind Farm (Victoria). • Waubra Wind Farm (Victoria). • Mount Millar Wind Farm (South Australia). • Cathedral Rocks Wind Farm (South Australia). • Starfish Hill Wind Farm (South Australia). • Wattle Point Wind Farm (South Australia). • Canunda Wind Farm (South Australia). • Lake Bonney Wind Farm (South Australia). • Woolnorth Wind Farm (Tasmania).
Peaking generating system	A generating system that typically runs only when demand (and spot market price) is high. These systems usually have lower efficiency, higher operating costs, and very fast start up and shutdown times compared with base load and intermediate systems.
Pipeline	A pipe or system of pipes for or incidental to the conveyance of gas and includes a part of such a pipe or system.
Planning criteria	Criteria intended to enable the jurisdictional planning bodies (JPBs) to discharge their obligations under the NER and relevant regional transmission planning standards. The JPBs must consider their planning criteria when assessing the need to increase network capability.
Planned outage	A controlled outage of a transmission element for maintenance and/or construction purposes, or due to anticipated failure of primary or secondary equipment for which there is greater than 24 hours notice.
Plant capacity	The maximum power output an item of electrical equipment is able to achieve for a given period.
Power	See ‘electrical power’.

Term	Definition
Power station	In relation to a generator, a facility in which any of that generator's generating units are located.
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].
Post-contingent	The timeframe after a power system contingency occurs.
Pre-contingent	The timeframe before a power system contingency occurs.
Present value (PV)	The value of a future cash flow expressed in today's dollars, and calculated using a particular discount rate. Present value calculations provide a means to meaningfully compare cash flows at different times.
Probability of exceedence (POE) maximum demand	The probability, as a percentage, that a maximum demand level will be met or exceeded (for example, due to weather conditions) in a particular period of time. For example, for a 10% POE maximum demand for any given season, there is a 10% probability that the corresponding 10% POE projected maximum demand level will be met or exceeded. This means that 10% POE projected maximum demand levels for a given season are expected to be met or exceeded, on average, 1 year in 10.
Projected Assessment of System Adequacy (PASA)	The PASA is a comprehensive program of information collection, analysis, and disclosure of medium term and short term power system security and reliability of supply prospects so that registered participants are properly informed to enable them to make decisions about supply, demand and outages of transmission networks in respect of periods up to 2 years in advance.
Proposed project	All generation project proposals that have come to AEMO's attention and are not committed. Proposed projects are further classified as either advanced proposals or publicly announced proposals.
Publicly announced proposal	A proposed generation project that has come to AEMO's attention, but cannot be classified as an advanced proposal.
Ratings	Describes an aspect of a network element's operating parameters, including categories like current-carrying capability, maximum voltage rating, and maximum fault level interrupting and withstand capability. Network elements must always be operated within their ratings. Network elements may have ratings that depend on time duration (such as short-term current-carrying capacity).
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. 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: • alternating current generators • capacitors, including the capacitive effect of parallel transmission wires, and • synchronous condensers. Management of reactive power is necessary to ensure network voltage levels remain within required limits, which is in turn essential for maintaining power system security and reliability.

Term	Definition
Regional reference node	The reference point (or designated reference node) for setting a region's spot price. The current regions and their reference nodes are: • Queensland - South Pine Substation 275 kV bus • New South Wales - Sydney West Substation 330 kV bus • Tasmania – George Town 220 kV bus • Victoria - Thomastown Terminal Station 66 kV bus, and • South Australia - Torrens Island Power Station 66 kV bus.
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 or generation centres or both.
Registered capacity	In relation to a generating unit, the nominal megawatt (MW) capacity of the generating unit registered with AEMO.
Registered participant	A person who is registered by AEMO in any one or more of the categories listed in clauses 2.2 to 2.7 [of the NER] (in the case of a person who is registered by AEMO as a trader, such a person is only a registered participant for the purposes referred to in clause 2.5A [of the NER]). However, as set out in clause 8.2.1(a1) [of the NER], for the purposes of some provisions of rule 8.2 [of the NER] only, AEMO connection applicants, metering providers and metering data providers who are not otherwise registered participants are also deemed to be registered participants.
Regulated interconnector	An interconnector which is referred to in clause 11.8.2 [of the NER] and is subject to transmission service regulation and pricing arrangements in Chapter 6A [of the NER].
Regulatory investment test for transmission (RIT-T)	The test developed and published by the AER in accordance with clause 5.6.5B, as in force from time to time, and includes amendments made in accordance with clause 5.6.5B.
Regulatory Test	The test promulgated by the AER to identify the most cost-effective option for supplying electricity to a particular part of the network. The test may also 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. After 1 August 2010, projects are assessed under the RIT-T (subject to transitional arrangements).
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 Panel	The panel established by the AEMC under section 38 of the National Electricity Law.
Reliability of supply	The likelihood of having sufficient capacity (generation or demand-side participation (DSP)) to meet demand. See also 'electricity demand'.
Reliability Standard	The power system reliability benchmark set by the Reliability Panel. The maximum permissible unserved energy (USE), or the maximum allowable level of electricity at risk of not being supplied to consumers, due to insufficient generation, bulk transmission or demand-side participation (DSP) capacity, is 0.002% of the annual energy consumption for the associated region, or regions, per financial year.
Renewable Energy Target (RET)	See 'National Renewable Energy Target scheme'.
Reserve	See 'reserve margin'.

Term	Definition
Reserve margin	The supply available to a region in excess of the scheduled and semi-scheduled demand. The supply available to a region includes generation capacity within the region, demand-side participation (DSP), and capacity available from other regions through interconnectors. A region's reserve margin is defined as the difference between the allocated installed capacity (plus any DSP), and the region's scheduled and semi-scheduled demand.
Scenario	A consistent set of assumptions used to develop forecasts of demand, transmission, and supply.
Scheduled demand	That part of the electricity demand supplied by scheduled generating units. Scheduled demand is measured on a generator-terminal basis. For a region, the measure includes the output of scheduled generating units within the region plus net imports (imports into the region minus exports from the region).
Scheduled generating unit	A generating unit that: • Has its output controlled through the central dispatch process. • Is classified as a scheduled generating unit in accordance with Chapter 2 of the NER.
Semi-scheduled generating unit	A generating unit with the following qualities: • Intermittent output. • A total capacity of 30 megawatts (MW) or greater. • May have its output limited to prevent the violation of network constraint equations.
Sent-out basis	A measure of demand or energy (in megawatts (MW) and megawatt hours (MWh), respectively) at the connection point between the generating system and the network. This measure includes consumer load and transmission and distribution losses.
Short run marginal cost (SRMC)	The increase in costs for an incremental increase in output. This includes the additional cost of fuel required, and non-fuel variable costs like maintenance, water, chemicals, ash disposal, etc.
Short-term Projected Assessment of System Adequacy (Short-term PASA or ST PASA)	The short term PASA covers the period of six trading days starting from the end of the trading day covered by the most recently published pre-dispatch schedule with a trading interval resolution.
Significant non-scheduled generating unit	Refers to the following: • All market non-scheduled (MNS) generating units. • All non-market non-scheduled (NMNS) generating units and generating units exempted from registration (with an aggregate capacity greater than 1 MW), for which AEMO and the jurisdictional planning bodies (JPBs) have sufficient data to enable the development of energy and maximum demand (MD) projections.
Small-scale Renewable Energy Scheme (SRES)	See 'National Renewable Energy Target scheme'.
Smart charging	Smart charging involves the bulk of charging occurring during off peak periods, normally late at night and early in the morning.
Spot market	Wholesale trading in electricity is conducted as a spot market. The spot market: • enables the matching of supply and demand • is a set of rules and procedures to determine price and production levels, and • is managed by AEMO. See also 'spot price'.

Term	Definition
Spot price	The price in a trading interval for one megawatt hour (MWh) of electricity at a regional reference node. Prices are calculated for each dispatch interval (five minutes) over the length of a trading interval (a 30-minute period). The six dispatch prices are averaged each half hour to determine the price for the trading interval.
Statement of Opportunities	The (gas or electricity) Statement of Opportunities published annually by AEMO.
Summer	Unless otherwise specified, refers to the period from 1 November to 31 March (for all regions except Tasmania), and from 1 December to 28 February (for Tasmania only).
Supply	The delivery of electricity.
System normal	The condition where no network elements are under maintenance or forced outage, and the network is operating in a normal configuration (according to day to day network operational practices).
Supply-demand outlook	The future state of supply's ability to meet projected demand.
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.
Transmission losses	Electrical energy losses incurred in transporting electrical energy through a transmission system.
Transmission network	A network within any participating jurisdiction operating at nominal voltages of 220 kV and above plus: • 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, • 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.
Transmission system (electricity)	A transmission network, together with the connection assets associated with the transmission network, which is connected to another transmission or distribution system.
Unserved energy (USE)	The amount of energy that cannot be supplied because there is insufficient generation capacity, demand-side participation (DSP), or network capability to meet demand. Under the provisions of the Reliability Standard, each region's annual USE can be no more than 0.002% of its annual energy consumption. Compliance is assessed by comparing the 10-year moving average annual USE for each region with the Reliability Standard. See also 'Reliability Standard'.
Value of Customer Reliability (VCR)	A measure of the cost of unserved energy used in Regulatory Test assessments for planned augmentations for the Victorian electricity transmission system. The VCR is determined through a customer survey approach that estimates direct end-user customer costs incurred from power interruptions at the sector and State levels.
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.
Winter	Unless otherwise specified, refers to the period from 1 June to 31 August (for all regions).

List of company names

Company	Full Company Name	ABN/ACN
ACIL Tasman	ACIL Tasman Pty Ltd	68 102 652 148
AEMC	Australian Energy Market Commission	49 236 270 144
AEMO	Australian Energy Market Operator	92 072 010 327
AER	Australian Energy Regulator (ABN provided for Australian Competition and Consumer Commission)	94 410 483 623
ElectraNet	Electranet Pty Ltd	41 094 482 416
ORER	Office of the Renewable Energy Regulator	68 574 011 917
Powerlink Queensland	Queensland Electricity Transmission Corporation Limited	82 078 849 233
SP AusNet	SP Australia Networks (Transmission) Ltd	48 116 124 362
Transend	Transend Networks Pty Ltd	57 082 586 892
TransGrid	TransGrid	19 622 755 774
WorleyParsons	WorleyParsons Ltd	61 001 279 812