NATIONAL TRANSMISSION NETWORK DEVELOPMENT PLAN

2010

AEMO
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Foreword

AEMO's National Transmission Network Development Plan (NTNDP) is an independent strategic plan for the National Electricity Market (NEM) transmission network.

It provides information for the energy industry, policy makers and investors to better understand, analyse, and discuss Australia's electricity transmission network needs over the next 20 years.

The National Transmission Network Development Plan:

- gives potential investors information about the NEM and its ongoing development, including where and when electricity transmission will be required
- highlights investment opportunities for the energy industry
- plays a key role in preparing the energy industry for future development by modelling the impacts of climate change policies on the NEM
- identifies how the national transmission network will need to evolve to cater for these changes, and
- enables electricity generators to see how the national transmission network may develop under various market development scenarios, to carry their power to the market and ultimately to consumers.

The NTNDP incorporates the transmission network service providers' (TNSPs) current network and committed development plans for the NEM. AEMO has worked closely with the TNSPs to include their views and commitments, which dominate the first five years of this plan in all modelled scenarios.

These projects represent approximately AUD2 billion of the TNSPs' broader five-year transmission capital investment of approximately AUD7.5 billion, which includes capital for asset replacement projects. AEMO has not questioned these projects and has taken this as the starting point for the NTNDP analysis.

In this plan, AEMO explores a wide range of scenarios to determine potential electricity transmission outcome impacts. The scenarios are based on several drivers, the two most prominent being demand growth and carbon price. AEMO's aim is to provide the energy industry with a comprehensive information source to enable dialogue and support the development of a responsive transmission network.

The future for both supply and demand over the next 20 years is linked to a number of uncertain outcomes. The forecast is for continued growth in electricity demand driven by a growing economy. Electricity generation will need to grow to meet this demand. It will also need to adapt to a future requiring reduced carbon intensity and increased energy efficiency.

Growth in the economy and increasing population are driving electricity demand in the NEM. By 2030, this expansion will see our energy consumption increase by 30% to 70% above today's levels.

Based on AEMO's scenario modelling, substantial investment is required for augmentation of the shared transmission network and development of new generation assets across the NEM. The majority of this investment is required in new generation assets.

In preparing the NTNDP, AEMO has used a new optimisation model that assesses market benefits and assists in guiding efficient investment. The model provides capacity to examine outcomes for multiple plausible scenarios.

AEMO will update the NTNDP scenarios each year as the Australian energy market develops, and will also work with the energy industry, governments, and stakeholders to continuously improve our modelling and analysis.

The NTNDP provides a NEM-wide view of where future generation could be clustered to make the best use of both renewable and non-renewable resources. The location of these generation clusters is an important outcome of the national planning process, allowing planners to develop efficient connecting transmission, and minimise overall costs to both customers and generators.

AEMO has also developed and modelled a concept referred to as NEMLink, which is a large-scale interconnection running from Queensland, through New South Wales and Victoria, to South Australia, with an additional direct current (DC) link to Tasmania. NEMLink would connect the existing and proposed 500 kV networks across the NEM.

NEMLink has the potential to substantially remove congestion in the NEM and deliver new options for generation investment and transmission development, while addressing the need for a truly national grid.

AEMO's NEMLink modelling demonstrates substantial benefits that warrant further exploration.

Following publication, AEMO will be working with TNSPs and other stakeholders to ensure that the conclusions of the NTNDP are taken into consideration. Regional planners should incorporate the findings in their annual planning reviews to enhance the national benefits arising from the NTNDP.

I am pleased to present AEMO’s first National Transmission Network Development Plan. I sincerely thank all our stakeholders for their invaluable input. I also acknowledge the foresight of the policymakers whose vision for energy planning helped to make this document a reality.

Yours sincerely

Matt Zema

Managing Director and Chief Executive Officer

Disclaimer

This publication has been prepared by the Australian Energy Market Operator Limited (AEMO) based on information provided by electricity industry participants. AEMO must publish the National Transmission Network Development Plan in order to comply with clause 5.6A.2 of the National Electricity Rules.

The purpose of this publication is to provide technical and market data regarding potential generation and transmission developments in the National Electricity Market (NEM).

Information in this publication does not amount to a recommendation in respect of any possible investment and does not purport to contain all of the information that a prospective investor or participant or potential participant in the NEM might require. The information contained in this publication might not be appropriate for all persons and it is not possible for AEMO to have regard to the investment objectives, financial situation, and particular needs of each person who reads or uses this publication. The information contained in this publication may contain errors or omissions, or might not prove to be correct.

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Key Findings

Introduction to the NTNDP

The National Transmission Network Development Plan (NTNDP) was developed by the Australian Energy Market Operator (AEMO) in collaboration with the electricity industry, governments, and key stakeholders. The NTNDP provides a transparent and independent resource for the energy industry, policy makers, and investors to better understand Australia's energy needs and transmission requirements for its eastern and south eastern States over the next 20 years. Ongoing engagement with transmission network service providers (TNSPs) also provided a good understanding of the committed and proposed projects in each region, enabling AEMO to provide an effective NTNDP.

The plan outlines the impact of increased demand for electricity from gas-powered generation. The trend towards greater reliance on gas is highlighted in AEMO's Gas Statement of Opportunities (GSOO) to ensure that AEMO's planning encompasses this new demand.

Investment in energy infrastructure is vital to the long-term provision of cost-effective, reliable power. Efficient investment in transmission means that market benefits outweigh the initial cost of investment and contribute to reducing the overall cost of electricity to consumers.

AEMO has considered the whole National Electricity Market (NEM) transmission system, which supports the provision of power to most of Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia, and Tasmania, including regions and interconnections, and the impacts on fuels for generation, such as gas.

The NTNDP addresses five scenarios in detail, ranging from a high economic growth, high carbon price scenario (Fast Rate of Change) to a low economic growth, low (or no) carbon price scenario (Slow Rate of Change). Two carbon price outcomes are examined in each scenario, providing 10 possible energy futures to plan for.

For a more comprehensive examination of the key findings, as well as other relevant background information, see the 2010 National Transmission Network Development Plan Executive Briefing (published separately).

Overall conclusions

The NTNDP scenario modelling and 20-year outlook broadly indicates the following:

- Large-scale interconnection could deliver significant operating benefits to the NEM.
- Extensive investment in renewable energy technologies is driven by climate change policy, and occurs at sites where the renewable resources are located closer to the transmission network.
- The Large-scale Renewable Energy Target (LRET) is materially achieved in all scenarios except those with no carbon price.

- There is a strong move to both peaking and base load gas-powered generation. The peaking capacity can potentially occur at various locations around the NEM without major transmission network augmentation. However, in some scenarios, base load gas-powered generation is clustered in areas with plentiful gas, and necessitates significant augmentation.

The NTNDP scenarios

The NTNDP examines the future through five market development scenarios, developed in conjunction with a stakeholder reference group. The scenarios consider whether new generation investment will be in the form of larger, centralised power stations or smaller, distributed generation close to load centres. The scenarios outline a range of plausible outcomes for key issues and policy settings facing the energy industry and investors, and account for the impact of a basic carbon price and an alternative carbon price (sensitivity)

Table 1 summarises the scenario drivers and emissions targets.

Table 1 Scenario drivers and emission targets

Scenario	Economic growth	Population growth	Global carbon policy	Centralised supply-side response	Decentralised supply-side response	Demand-side response	Emission targets below 2000 levels
Fast Rate of Change	High	High	Strong	Strong	Strong	Strong	-25%[3] (sensitivity -15%[2])
Uncertain World	High	High	Weak	Strong	Weak	Weak	-5%[1] (sensitivity no carbon price)
Decentralised World	Medium	Medium	Strong	Weak	Strong	Strong	-15%[2] (sensitivity -25%[3])
Oil Shock and Adaptation	Low	Medium	Moderate	Moderate (renewable)	Weak	Weak	-15%[2] (sensitivity -5%[1])
Slow Rate of Change	Low (mixed)	Low	Weak	moderate	Weak	Weak	-5%[1] (sensitivity no carbon price)

1. The -5% carbon emissions target (low carbon price) is associated with a carbon price trajectory from AUD0 to AUD44 per tonne CO2-e.
2. The -15% carbon emissions target (medium carbon price) is associated with a carbon price trajectory from AUD0 to AUD62 per tonne CO2-e.
3. The -25% carbon emissions target (high carbon price) is associated with a carbon price trajectory from AUD0 to AUD93 per tonne CO2-e.

Summary of results

The NTNDP comprehensively assesses transmission requirements under each scenario for the NEM power system as a whole. This approach includes consistency checks of the regional transmission plans developed by the TNSPs. Outcomes were also tested with the various State-based, jurisdictional planning bodies to confirm feasibility and consistency with local planning requirements.

NEM-wide results are presented by scenario as well as by geographical area (zone).

The NTNDP also provides results for a high-capacity backbone study (NEMLink), an assessment of Network Support and Control Ancillary Services (NSCAS) requirements, and a NEM-wide view of where future generation can be clustered to make the best use of both renewable and non-renewable resources.

Results by scenario

The modelling results vary significantly across the range of scenarios considered, and the range of results is best demonstrated by the following three scenarios.

The Slow Rate of Change, low carbon price scenario (SC-L), which assumes low economic growth, shows the least change compared to other scenarios:

- There are only moderate levels of new generation (gas, wind, and geothermal) and moderate generation retirements.
- Some transmission network investment is indicated, including reinforcement of the existing network from Northern New South Wales to the major load centres of Sydney, Wollongong, and Newcastle.
- For this scenario, the zero carbon price sensitivity (SC-0) shows less new generation and retirement, less transmission network investment, and network reinforcement from Northern New South Wales to the major New South Wales load centres is not required.

The Decentralised World, medium carbon price scenario (DW-M), which assumes medium economic growth, shows moderate change compared to other scenarios:

- There are high levels of new conventional gas and wind generation, moderate levels of new geothermal generation, and high generation retirements.
- Extensive reinforcement of the existing transmission network is required to deliver gas-powered generation to the major load centres.
- For this scenario, the high carbon price sensitivity (DW-H) shows significant brown and black coal generation retirement (the highest of all the scenarios and carbon price sensitivities), though this does not significantly alter the required transmission investment.

The Fast Rate of Change, high carbon price scenario (FC-H), which assumes high economic growth, shows the most change compared to other scenarios:

- There is significant new base load gas and coal generation (making use of carbon capture and sequestration (CCS) technology), as well as new generation from renewable resources. There are also moderate generation retirements.
- Extensive reinforcement of the existing transmission network is required to deliver new gas and coal-fired generation (from existing generation centres) and new renewable generation (in other locations) to the major load centres.
- For this scenario, the generation fleet does not change significantly under the medium carbon price sensitivity (FC-M), and the required transmission investment is unaltered.

AEMO's modelling indicates that a moderate to high carbon price will result in significant levels of generation retirement in Victoria's Latrobe Valley, with subsequent replacement by gas-powered generation. This is expected to have a significant impact on Victorian gas reserves, which AEMO is further exploring in the GSOO. There will also be some retirement of older and less efficient black coal generation in Queensland and New South Wales.

The LRET scheme is the prime driver of renewable generation over the next 10 years under all scenarios. Wind power is the main generation technology implemented in the short term, with other technologies, like geothermal and solar thermal generation, beginning to appear towards the end of the decade.

Augmentation of the Queensland-New South Wales (QNI) interconnector proceeds in five out of ten of the scenarios and their sensitivities, while in two of the scenarios an incremental upgrade of the Victoria-South Australia (Heywood) interconnector proceeds in the final years of the 20-year outlook period. This outcome reflects the least-cost modelling approach, where fuel costs and renewable potentials differ only marginally between the regions, and regional generation capacity requirements are explicitly modelled.

Based on AEMO's scenario modelling, between AUD40 billion and AUD130 billion in investment is required to augment the shared transmission network and develop new generation assets across the NEM to meet demand over the next 20 years.

Results by geographical area

Queensland has the highest energy and maximum demand (MD) growth, and the highest levels of new installed generation capacity in every scenario, leading to supply limitations to the major load centres in the South East Queensland (SEQ) zone. Significant multiple projects in the SEQ and South West Queensland (SWQ) zones are required under all scenarios to address these limitations.

In New South Wales, many scenarios underscore the need for augmentation to complete the main 500 kV transmission ring that circles and supports the major load centres of Sydney, Wollongong, and Newcastle.

In Victoria, the transmission network in the Country Victoria (CVIC) zone requires augmentation to meet demand growth, high exports from Victoria to South Australia via Murraylink during peak summer demand, and to accommodate new generation investments. Multiple significant transmission projects are seen under all scenarios.

Despite only modest energy and MD growth in Victoria, multiple significant projects to bring more power from South-West Victoria and the Latrobe Valley to the Melbourne Metropolitan Area, are seen under all scenarios in the Melbourne (MEL) zone.

In South Australia, investment will be required to reinforce the supply to central Adelaide to meet demand growth. Investment will also be required to establish significant amounts of wind generation.

Tasmania has the lowest existing and forecast energy and MD, resulting in less need for demand-driven transmission network investment. Modelling also shows high levels of new wind generation in the central, north-eastern, and north-western areas of Tasmania, leading to multiple significant transmission network projects under all scenarios, bringing more power to load centres.

The NTNDP provides detailed lists of the transmission network developments the modelling and analysis identified over the 20-year outlook period. This information is summarised by scenario and by zone, including the way each zone develops generation and transmission capacity from scenario to scenario.

To link back to the TNSPs' annual planning review processes, AEMO has identified developments that require:

- early attention to assess economic merit
- preparatory work to ensure the need can be addressed should conditions unfold in line with the driving scenarios, and
- monitoring and consideration in future NTNDPs.

NEMLink: a high-capacity backbone pre-feasibility study

As part of a longer term vision, and to initiate discussion on the topic, AEMO modelled the impact of significantly increasing transmission capacity between the regions. Referred to as NEMLink, this project has the potential to allow a largely unconstrained and reliable interchange of energy across the entire NEM.

Benefits of NEMLink include greater operational flexibility, an ability to locate new generation more effectively, and enhanced opportunities to share reserves. A concrete example of NEMLink's operating benefits is its capacity to balance the variability of wind or solar generation in one part of the NEM with hydro in the centre of the NEM and Tasmania.

NEMLink challenges the current regional character of the NEM, addressing the need for a truly national grid, while also providing for secure inter-regional trade and enhancing competition.

The NEMLink project was developed with input from TNSPs, and represents one view of a logical future extension of existing and planned 500 kV regional networks. As such, it could form a useful framework for future regional developments that serve the dual roles of meeting regional requirements and forming a link in the NEMLink chain.

Network Support and Control Ancillary Services (NSCAS)

NSCAS is an ancillary service for controlling active and reactive power flows, which assists with maintaining the power system in a secure operating state, and maintaining (or increasing) power transfer capabilities.

AEMO has looked at potential national and regional NSCAS requirements for the next five years. Regional assessments show the following NSCAS requirements:

- In New South Wales there is a Reactive Power Ancillary Service (RPAS) requirement for the next five years, to prevent over voltages in the Snowy area and provide sufficient voltage stability margins for supplying major load centres in Sydney.
- In Victoria there is an ongoing Network Loading Control Ancillary Service (NLCAS) requirement to increase power transfers from New South Wales to Victoria, and an RPAS requirement to avoid voltage collapse.
- There are no NSCAS requirements for other regions.

Generation clusters

The NTNDP generation expansion modelling suggests that multiple future generation investments, or clusters, may develop in areas (zones) with the most cost-effective renewable and non-renewable resources[1]. The location of these generation clusters is an important outcome of the national planning process, allowing planners to develop efficient connecting transmission and minimise overall costs to both customers and generators.

A number of potential zones have been identified, with actual connection enquiries from potential investors providing a useful indicator about their validity. In most cases, identified clusters correspond with investor intentions.

Based on the modelling of new generation, the leading zones are:

- North Queensland (NQ)
- South West Queensland (SWQ)
- Country Victoria (CVIC)
- South East South Australia (SESA)
- Northern South Australia (NSA), and
- Tasmania (TAS).

The following zones were not ranked as highly in the modelling, but are subject to significant potential investor interest, based on active connection enquiries[2]:

- Northern New South Wales (NNS)
- Central New South Wales (NCEN), and
- Melbourne (MEL)[3].

[1] Such as renewable biomass, solar, wind, and geothermal resources, and non-renewable gas and coal resources.

[2] This does not include new open cycle gas turbine (OCGT) generation (which can be flexibly located close to load centres or where the electricity transmission network is strong and near gas pipelines).

[3] The MEL zone includes a corridor from South West Victoria to the Metropolitan area.

Origins of the NTNDP

The inception of the NTNDP follows a report by the Energy Reform Implementation Group (ERIG) to the Council of Australian Governments (COAG) in 2007.

COAG recognised the importance of the national transmission planning function and agreed to establish an enhanced planning process for the national transmission network to ensure a more strategic and nationally coordinated approach to transmission network development.

In response to the report, COAG and the Ministerial Council on Energy (MCE) required:

- AEMO to take direct responsibility for undertaking the functions of the National Transmission Planner, and
- the National Transmission Planner to publish an annual NTNDP outlining the long-term, efficient development of the power system, including the current and future capability of the national transmission network, and its development options.

Next steps

Following the publication of the NTNDP, AEMO will be working with the TNSPs and other stakeholders to ensure that its conclusions are taken into account. Regional planners are obliged to consider the NTNDP's findings in their annual planning reviews to provide greater consistency between the regions, and enhance national benefits.

- AEMO will continue to improve the NTNDP analysis and responsiveness, working closely with industry stakeholders. Proposed enhancements for the 2011 NTNDP include:
- investigating modelling assumptions and approaches, which can underestimate national transmission benefits (for example, enforcing regional minimum reserve levels in generation expansion)
- determining if the costs and benefits that are not captured in the current modelling are material and can change current investment strategies, and
- incorporating large-scale investment projects like NEMLink, with greater emphasis on staging and timing optimisation

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Chapter 1 - Introduction

1.1 Introduction

The 2010 National Transmission Network Development Plan (NTNDP) represents the Australian Energy Market Operator Limited's (AEMO) independent view of a 20-year strategic plan for the electricity transmission network within the jurisdictions participating in the National Electricity Market (NEM). This consists of all Australian States and Territories except for Western Australia and the Northern Territory.

The NTNDP forms a key part of AEMO's role as the National Transmission Planner, with the overall objective of facilitating the development of an efficient national electricity network that considers potential transmission and generation investments. Specific NTNDP objectives include providing:

- a description of the NTNDP's role in NEM transmission planning
- an independent strategic plan for developing the national electricity transmission network, including information about where current network capability may need to be augmented in the future, and detailed development strategies for each potential network limitation identified
- models involving the co-optimisation of generation and transmission investment, and confidence in the economic justification for further investment
- a list of potential generation cluster zones for further investigation
- a view about Network Support and Control Ancillary Services (NSCAS) requirements for the next five years, and
- sufficient information and data to promote transparency in terms of the work carried out and the conclusions reached, as well as to facilitate independent analysis and further work by third parties.

The NTNDP is one of a collection of key planning publications that AEMO publishes annually. Together with the Electricity Statement of Opportunities (ESOO), the Gas Statement of Opportunities (GSOO), the Victorian Annual Planning Report (VAPR), the VAPR Update and the South Australian Supply and Demand Outlook (SASDO), 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 how the development of the transmission network is likely to evolve under a number of possible scenarios.

1.1.1 Background to the NTNDP project

The NEM transmission network

The NEM transmission network carries power from generators to major industrial users and local electricity distributors throughout the NEM and supports the provision of power to most of Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania, and South Australia.

The NEM transmission network:

- supports 19 million residents
- supplies 200,000 GWh of energy to businesses and households each year
- extends over 5,000 km from Far North Queensland to Tasmania, and westward to Adelaide and Port Augusta, and has approximately 40,000 km of transmission lines and cables
- is the longest alternating current (AC) system in the world
- comprises strong regional transmission networks connected with modest cross-border transmission capability
- is long and linear compared to Europe and North America, where the power systems are generally more strongly meshed
- can be costly to upgrade because of the large distances and resulting high capital costs of new transmission investments, and
- presents challenges for transmission investment, because comparatively-priced fuels often present efficient alternatives.

Information on current NEM infrastructure is provided in the annual planning report (APR) from each jurisdiction's transmission network service provider (TNSP). Key limitations of the current network are listed in Appendix D, a summary of key upcoming transmission network projects is provided in Appendix A, and the impact of upcoming projects is addressed in Chapter 3 and Chapter 4.

The ESOO and GSOO provide information about energy resources affecting the NEM.

Objectives of the NTNDP

AEMO is committed to the task of maximising overall economic benefits by delivering sound advice about efficient transmission network investment. To achieve this, 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.

The need to maintain competitive neutrality also drives AEMO to explore and effectively communicate options to deliver optimum benefits, whether these solutions involve generation, transmission, or other electricity industry sectors.

The NTNDP is expected to positively influence transmission investment by:

- providing a consistent plan that considers the augmentations required under a range of scenarios, and provides options that enable maintenance of a reliable power system irrespective of which scenario eventuates
- providing a national focus on market benefits and transmission augmentations in support of an efficient power system
- proposing a range of plausible future scenarios and exploring their impact on the electricity supply industry, with an emphasis on identifying national transmission grid needs under those scenarios
- identifying network needs early to increase the time available to identify non-network options, including demand-side and generation options, and
- considering alternative network project timings, including as a result of potential outcomes from the scenarios considered.

Transmission planning, the NTNDP and National Transmission Statement (NTS)

Together with the 2009 National Transmission Statement[4] (NTS), the 2010 NTNDP consultation and subsequent workshops identified a number of issues relating to transmission planning, AEMO's actions to address these issues, and the role and content of the NTNDP. The issues identified included:

- covering a wider range of scenarios
- better planning integration and improved data for high priority aspects, such as the value of customer reliability, price elasticity, energy efficiency developments, smart grid applications, and distributed generation
- the value of a detailed transmission network examination (rather than interconnectors alone)
- the provision of an Executive Briefing document summarising the results of the main report
- the value of the inputs database and supporting background information, and
- potential approaches to scenarios (whether multiple, unweighted scenarios should be used or a base case and sensitivities instead), the level of new wind generation, the level of open-cycle gas turbine (OCGT) support required for wind generation, and the provision of more detailed information about OCGT generation due to its impact on gas infrastructure.

For more information about how the 2010 NTNDP addresses these issues, see Chapter 8.

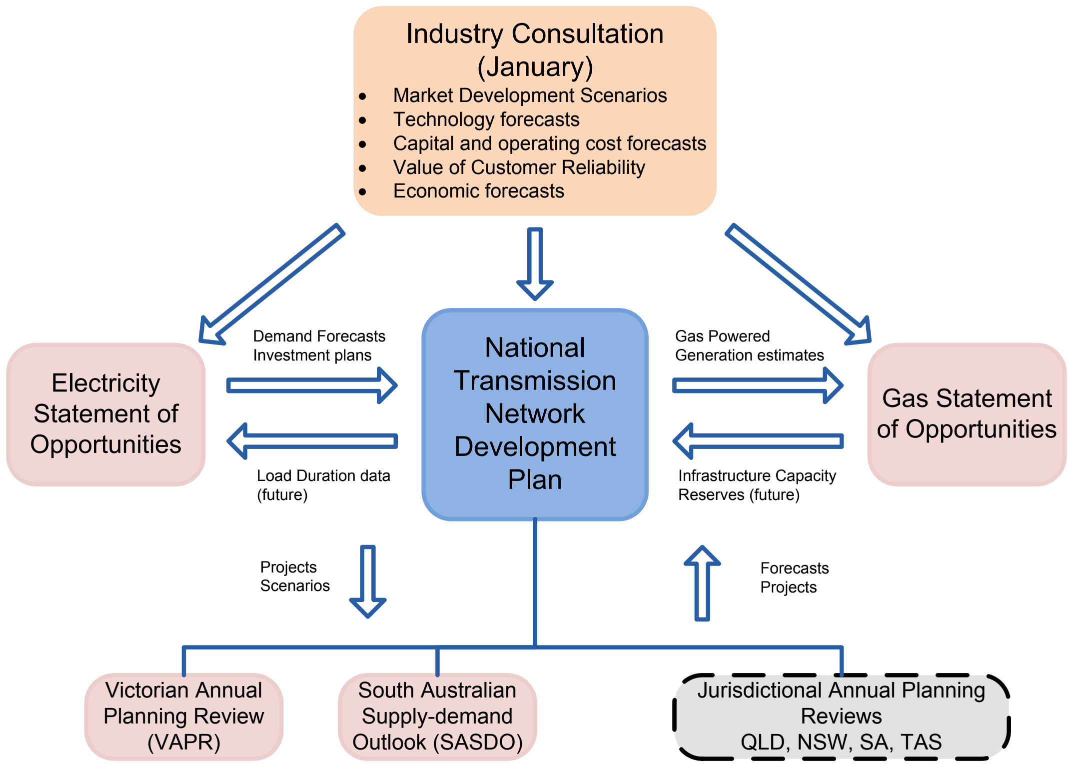
Annual planning reports and the NTNDP

The role of the National Transmission Planner is intended to provide a link between the NTNDP and the APR provided by each NEM jurisdiction's TNSP. The transmission system development program (set out at a high level in the NTNDP) will be addressed at the project level by each APR. AEMO will review the APRs and take their treatment of the projects into account as part of the development of each subsequent annual NTNDP.

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

[4] http://www.aemo.com.au/planning/0410-0025.pdf and http://www.aemo.com.au/planning/0410-0026.pdf

Figure 1-1 The NTNDP in the energy planning context



1.2 Scenario modelling and the NTNDP

The NTNDP models the way generation investment might evolve with various incentives and limitations under different market and policy environments. It also proposes transmission network capability augmentations that lead to an efficient combined investment in terms of both transmission network and non-network augmentations.

To provide robust planning models, the NTNDP considers a wide range of plausible scenarios (covering possible changes in the industry, and two carbon price trajectories) that include:

- Fast Rate of Change
- Uncertain World
- Decentralised World
- Oil Shock and Adaptation, and
- Slow Rate of Change.

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 2, Scenarios and Key Inputs.

Network development and regional reliability

Most network investment and augmentation in the NEM is driven by regional supply reliability obligations. As a result, AEMO has sought to model transmission expansion that accounts for both regional and national economic benefits. To achieve this, AEMO has reviewed the augmentation options developed by the jurisdictional planning bodies (JPBs) in their APRs, as well as working cooperatively with the TNSPs to develop further network and non-network options. These options range from incremental developments to 'big concept' projects driven by the long-term needs posed by particular scenarios.

The NTNDP modelling uses the existing transmission network and committed TNSP projects as a **base, but does not examine alternatives to committed projects.**

1.3 Content and structure of the National Transmission Development Plan for 2010

Chapter 2, Scenarios and Key Inputs, sets out the key drivers in each scenario, and describes their development and how they relate to scenarios used in other energy planning studies.

Chapter 3, Development by Scenario-Generation and Transmission Expansion, provides AEMO's view of a program for efficient development of the national electricity transmission system under each scenario.

Chapter 4, Development by Zone-Generation and Transmission Expansion, includes information about the development of generation and transmission infrastructure for each NTNDP region and zone.

Chapter 5, NEMLink: a Pre-feasibility Study into a High-Capacity Backbone, presents information about potential benefits from significantly increasing power transfer capabilities in the National Electricity Market (NEM).

Chapter 6, Network Support and Control Ancillary Services, sets out AEMO's view of potential NSCAS requirements for the next five years, and makes recommendations for consideration by the TNSPs.

Chapter 7, Generation Clusters, provides an overview of the potential generation cluster zones identified by AEMO, and a description of the methodology used to identify them.

Chapter 8, Evolution of the NTNDP, outlines how the 2010 NTNDP has been developed, and the way AEMO intends to develop the NTNDP in the future, including areas where stakeholder feedback is sought.

The National Transmission Development Plan Attachments, CD, and Appendices

The NTNDP is available as a printed report and on CD, and can be downloaded from AEMO's website[5].

The printed report includes information about the methodology applied to develop the generation and transmission expansion for each scenario (Attachment 1), network diagrams (Attachment 2), and a glossary.

[5] http://www.aemo.com.au .

Also available on CD and for download from the AEMO website are the NTNDP appendices and additional data files, which provide further information about:

- generation and transmission development (Appendix A)
- energy and maximum demand forecasts (Appendix B)
- network utilisation (Appendix C)
- network capability (Appendix D)
- market simulation outputs (Appendix E)
- NEMLink supplementary information (Appendix F)
- a congestion information resource (Appendix G)
- the NTNDP inputs database – non-confidential information (Appendix H)
- special protection schemes (Appendix I)
- National Electricity Rules obligations (Appendix J)
- locations of generation and transmission development under the scenarios (an interactive map), and
- detailed inputs, such as the time-sequential market simulation database.

Chapter 2 - Scenarios and Key Inputs

2.1 Summary

This chapter presents information about the scenarios used to develop the National Transmission Network Development Plan (NTNDP), and the key inputs into the modelling and analysis.

The scenarios, which are intended to provide a realistic vision of a series of plausible future socio-economic outcomes are analysed under the impact of a basic carbon price and an alternative carbon price (sensitivity):

- **Fast Rate of Change** describes a world where relatively strong emission reduction targets have been agreed internationally by both developed and developing countries, and there is high sustained economic growth in Australia. Successful adaptation to a carbon-constrained world is possible, due to government and industry investment in the development of new technologies. This is a high carbon price scenario. The sensitivity is a medium carbon price.
- **Uncertain World** describes a world characterised by carbon policy uncertainty both internationally and domestically, creating barriers for emerging technologies, and is coupled with high economic growth in Australia. This is a low carbon price scenario. The sensitivity is a zero carbon price.
- **Decentralised World** describes a world where Australia's energy network becomes highly decentralised by 2030, with significant investment in demand-side technologies. Moderate emission targets are coupled with medium economic and population growth, and all sectors of the Australian economy do well. This is a medium carbon price scenario. The sensitivity is a high carbon price.
- **Oil Shock and Adaptation** describes a world characterised by low reserves of oil coupled with internationally agreed emissions targets. Weak economic growth and moderate levels of population growth are observed. This is a medium carbon price scenario. The sensitivity is a low carbon price.
- **Slow Rate of Change** describes a world characterised by low economic growth coupled with internationally agreed low emission targets. Weak economic growth and low levels of population growth are observed. Boosting economic activity becomes a priority. This is a low carbon price scenario. The sensitivity is a zero carbon price.

Key inputs into the modelling and analysis include the:

- regional demand traces (based on annual energy and maximum demand (MD) projections), representing the demand placed on generating units for the 20-year outlook period
- annual energy and MD projections for each region, and
- regional projections developed for three different economic scenarios (high, medium, and low economic growth).

2.2 National Transmission Network Development Plan scenarios

This section describes the scenarios created to enable a study of the National Electricity Market (NEM) transmission network over the next 20 years, and the way the scenarios are expected to impact future generation and power flow patterns.

Table 2-1 lists the names and abbreviations used throughout the NTNDP to identify each scenario and corresponding scenario sensitivity. The scenario sensitivities are not intended to be fully consistent scenarios, but to test the impact of a different carbon price on scenario outcomes.

Table 2-1 Scenarios and sensitivities

Scenario name		Alternative carbon price (sensitivity)	
Fast Rate of Change, high carbon price	FC-H	medium carbon price	FC-M
Uncertain World, low carbon price	UW-L	zero carbon price	UW-0
Decentralised World, medium carbon price	DW-M	high carbon price	DW-H
Oil Shock and Adaptation, medium carbon price	OS-M	low carbon price	OS-L
Slow Rate of Change, low carbon price	SC-L	zero carbon price	SC-0

Development background

AEMO developed a series of scenarios in conjunction with the Department of Resources, Energy and Tourism (DRET), and through a Stakeholder Reference Group (SRG) made up of industry experts with a diverse range of experiences and interests[6]. The SRG's input was synthesised into a common strategic framework for long-term energy modelling. The five scenarios were then developed from different combinations of the principal energy sector and national transmission network development drivers.

Scenarios for the NTNDP

Each NTNDP scenario describes the Australian Stationary Energy sector in 2030, and explores a series of plausible outcomes given a series of uncertainties that include:

- the introduction of measures placing a cost on carbon emissions that is expected to lead to changes in consumption patterns, and generation fuel types and sources, and
- energy and MD forecasts driven by changes in the economy and demographics.

[6] Australia Pipeline Industry Association (APIA), Australian Academy of Technological Sciences and Engineering (ATSE), Australian National Low Emission Coal Research And Development (ANLEC R&D), Australian Petroleum Production and Exploration Association (APPEA), Clean Energy Council, Commonwealth Scientific and Industrial Research Organisation (CSIRO), DomGas Alliance, Energy Networks Association (ENA), Energy Retailers Association of Australia (ERAA), Energy Supply Association of Australia (ESAA), Energy Users Association of Australia (EUAA), Grid Australia, Major Energy Users, Minerals Council of Australia (MCA), National Generators Forum (NGF).

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 growth in demand (and the location of that growth)
- supply-side and demand-side responses to carbon policy, and
- distribution-connected generation responses to carbon policy.

All scenarios are addressed equally, with no scenario acting as a base case. This does not mean that each scenario has an equal probability of occurring. For example, the selection of five scenarios does not indicate each scenario has a 20% chance of occurring.

To ensure consistency between AEMO's planning documents and studies, these scenarios have also been applied to the 2010 Victorian Annual Planning Report (VAPR), South Australian Supply-Demand Outlook (SASDO), Electricity Statement of Opportunities (ESOO), and Gas Statement of Opportunities (GSOO).

2.2.1 Fast Rate of Change

Fast Rate of Change (FC-H) describes a world where relatively strong emission reduction targets have been agreed internationally by both developed and developing countries. The scenario assumes targets have been set to achieve a global carbon dioxide equivalent (CO_2-e) emission concentration not exceeding 450 ppm by 2050. Domestic and overseas governments have successfully introduced policy frameworks to implement the targets, and by 2030 all interim emission targets have been met. The transition to a carbon constrained future has been smooth.

Successful deployment of both centralised and decentralised supply-side technologies, combined with high demand-side participation (DSP), facilitates a rapid transformation of the sector to meet the strong emission targets. Australia remains competitive on the global stage and reaps the benefit of strong international growth.

Strong growth in China and India has driven high demand for Australia's energy and minerals resources and agricultural products. This has delivered high sustained economic growth in Australia and an Australian Government budget in surplus. Commodity prices are high, the domestic economy prospers, and Australia remains competitive internationally. Population growth is also high, and housing density has increased substantially.

Government and industry investment in low emissions technology such as carbon capture and sequestration (CCS) means that these technologies are cheaper than expected. The strong emphasis on research and development (R&D), and pilot and large-scale technology demonstration has meant that new demand and supply-side options have moved rapidly down learning curves, and have been successfully developed on a commercial scale. The process of R&D has also grown the domestic skill base required to efficiently install and operate new energy technologies.

Geothermal, solar, and wind are available for commercialisation on a large scale. Coal and gas generation can be fitted with CCS to enable continued operation in traditional generation locations.

Moderate international oil prices and high economic growth drive high international demand for Liquefied Natural Gas (LNG). This supports LNG production in Australia and gas prices in the northern States reach international parity.

The moderate oil price, coupled with a high carbon price range ramping up to AUD93/t CO2-e, results in a large shift in the transport sector towards electric plug-in vehicles. This shift contributes to a change in the distribution of energy loads and provides some energy storage capability.

Higher than average temperatures are experienced and there is widespread adoption by government of water management strategies such as desalination, powered by renewable energy.

Consumers are very supportive of low-emission technologies. Public attitudes towards the construction of new, low-emission generation and associated infrastructure have been positive, and consumers are well-educated about the costs of various low-emission supply options. Consequently, consumers have embraced DSP. There is strong uptake of small-scale distributed electricity generation and energy efficiency is observed across all sectors.

In this scenario, underlying demand for electricity is likely to be high due to factors such as high economic growth, sustained population growth, desalination, and the high uptake of electric plug-in vehicles. However, diversification of energy sources, emission reductions from new technologies, and improvements in energy efficiency and other types of DSP have been sufficient to enable the strong emission reduction targets to be met.

Carbon price sensitivity

The Fast Rate of Change scenario's medium carbon price sensitivity (FC-M) describes the same world as FC-H, but one where moderate, rather than relatively strong emission reduction targets have been implemented and met. The targets aim at restricting CO2-e emission concentration to less than 500 ppm by 2050, rather than 450 ppm as in FC-H. A medium carbon price ramping up to AUD62/t CO2-e is assumed.

2.2.2 Uncertain World

An Uncertain World (UW-L) is characterised by carbon policy uncertainty both internationally and domestically. This scenario assumes that while a carbon dioxide equivalent (CO2-e) emission concentration target not exceeding 550 ppm by 2050 has been agreed internationally, it is constantly being reviewed and debated. There has also been limited low-level intervention at both the State and Federal levels in Australia, including minimal levels of investment in low-emissions research and development (R&D). By 2020, the 20% target for renewable energy generation has been met, but not significantly exceeded.

Carbon policy uncertainty crates barriers for emerging demand and supply-side technologies. Strong international demand for Australia's resources drives high economic and population growth, resulting in high energy demand.

Global demand for mineral resources remains high, resulting in high commodity prices. Consequently, domestic economic growth is strong, with higher than average growth in the resource sector. Government policy supports new mining developments and there are new remote area electricity loads. Population growth is also higher than average, with immigration ensuring an adequate supply of skilled labour to support the economy. There has been significant urban sprawl.

A high risk premium is placed on capital investment in the electricity sector due to continuing carbon policy uncertainty. Low levels of investment in R&D results in slowed investment in new low-emission electricity generation technologies and potentially delays the anticipated retirement of older plant.

Deployment of new demand-side technologies is also muted, while the cost of small-scale renewable energy remains high. International oil prices are at moderate levels, but without a strong carbon price signal the penetration of electric plug-in vehicles is low.

High energy demand is due to the combination of a prosperous economy and a low carbon price ramping up to AUD44/t CO2-e. Improvements in domestic energy efficiency are offset by the income effect, enticing consumers to purchase larger homes and bigger appliances. Although there is moderate improvement in energy efficiency at industrial and commercial sites, this has minimal impact on electricity loads as production growth outweighs any savings. Overall, demand for electricity continues to grow. Higher than average temperatures account for an increasingly large component of weather-sensitive demand. By 2030, hydroelectric availability is limited due to prolonged drought, and there is widespread adoption of water management strategies such as desalination, though this need not be powered by renewable energy.

While consumers support the notion of a low-carbon future, they remain resistant to change as they lack detailed or pertinent knowledge about how this can be achieved. Wind farms are tolerated, but local community resistance has begun to force the selection of more remote sites. The government continues to promote solar thermal generation, given concerns about transmission network impacts from high wind-penetration and growing community resistance.

Domestic LNG production is limited as Australia struggles to capture its share of the international market, leading to low domestic gas prices across the eastern seaboard.

Carbon price sensitivity

The Uncertain World scenario's zero carbon price sensitivity (UW-0) describes the same world as UW-L, but one where there is no carbon price. The Large-scale Renewable Energy Target (LRET) is assumed, as in all scenarios and sensitivities, although in this sensitivity it is the sole measure to restrict CO2-e emissions.

2.2.3 Decentralised World

Under a Decentralised World (DW-M), Australia's energy network is highly decentralised by 2030 and there has been significant new investment in demand-side technologies. The scenario assumes that moderate emission reduction targets aimed at restricting carbon dioxide equivalent (CO2-e) emission concentration to less than 500 ppm have been implemented and met, both in Australia and internationally.

Demand-side technologies and distributed generation emerge as lower cost alternatives to new centralised supply-side options, such as geothermal generation or carbon capture and sequestration (CCS). The emergence of fuel cells in homes, coupled with the high uptake of commercial and industrial cogeneration and tri-generation, increases domestic demand for gas.

All sectors of the Australian economy are doing well, with economic growth at intermediate levels. Commodity prices, exchange rates, and oil prices are all moderate.

International demand for Liquefied Natural Gas (LNG) keeps pace with the medium global economic growth. Domestic LNG production from coal seam gas manages to capture a reasonable share of this international demand, but new gas supply discoveries in the domestic market keep gas prices low across the eastern seaboard.

New low-emission, base load power sources, such as geothermal and CCS technologies, have proven more expensive than first thought, depressing large-scale uptake. The renewable energy target provides incentives for strong growth in wind generation and small-scale renewable generation.

A medium carbon price ramping up to AUD62/t CO_2-e and moderately high oil prices have motivated a large number of consumers to purchase electric plug-in vehicles, adding to off-peak energy requirements, but also providing energy storage for the electricity system. This is supported by the smart grid that now operates, and helps manage the high levels of intermittent wind generation.

Demand-side initiatives and technologies that allow customers to intelligently manage their power usage have been successful, and have raised consumer awareness of their role in the energy system. Consequently, there is a strong focus on energy efficiency with more stringent appliance performance standards, and more productive use of energy. There has also been a change to the tariff structure to encourage consumers to actively participate, and consumers are now more responsive to price signals. Both homes and commercial buildings are routinely fitted with switches and appliances to manage or control demand usage. Solar hot water heaters and photovoltaic panels are in high demand and are now available at lower cost than in other scenarios due to technological improvements. There is also moderate demand for fuel cells in homes and commercial buildings.

There has been medium-level growth in Australia's population and a move towards high density housing and business centres. These concentrated population centres are supported by distributed generation, predominantly gas-fired cogeneration and tri-generation. Strong growth in distributed generation is also noticeable within the commercial and industrial sectors.

Above average temperatures continue to have an impact on peak demand. Prolonged and more frequent drought periods have resulted in the continued development of desalination plants to address water availability issues.

Overall, the low gas prices, growth in demand for fuel cells, and increased penetration of distributed cogeneration and tri-generation results in high domestic demand for gas.

Carbon price sensitivity

The Decentralised World scenario's high carbon price sensitivity (DW-H) describes the same world as DW-M, but one where relatively strong (rather than moderate) emission reduction targets have been implemented and met. The targets aim at restricting CO_2-e emission concentration to less than 450 ppm by 2050, rather than 500 ppm as in DW-M. A high carbon price ramping up to AUD93/t CO_2-e is assumed.

2.2.4 Oil Shock and Adaptation

Oil Shock and Adaptation (OS-M) represents a world in which oil reserves are in short supply, resulting in low global economic growth. Nonetheless, the scenario assumes there is international agreement that a carbon policy is essential to combat climate change. The scenario assumes that emission reduction targets are set to limit carbon dioxide equivalent (CO_2-e) emission concentration to 500 ppm by 2050.

After reaching agreement on a global carbon emissions policy, the international economy is challenged by a global oil shortage, putting upward pressure on oil and gas prices and leading to low economic growth both internationally and domestically. Higher than expected carbon capture and sequestration (CCS) costs and fossil fuel prices lead to greater reliance on centralised renewable energy options.

Weak economic growth but a moderate level of population growth leads to moderate to low underlying demand for electricity in all sectors of the economy. This has moderated the rate of increase in CO2-e emissions. However, demand-side initiatives and CCS have proven to be more costly than first anticipated, which has made meeting the CO2-e emission target more challenging.

Oil reserve shortages have driven up international demand for Liquefied Natural Gas (LNG), and domestic LNG production has increased, causing gas price rises.

Although money is tight, the penetration of electric plug-in vehicles has reached medium levels, due to high oil and CO2-e emission costs. Further uptake of electric plug-in vehicles is limited, as fewer people have the funds to purchase new cars and elect to switch to public transport instead.

The weak economic conditions create some incentive for all consumers (industrial, commercial, and residential) to save costs by improving energy efficiency. However, there is little uptake of residential and commercial photovoltaics due to relatively high costs, and fuel cell technology has not yet become commercially viable. Price responsive demand-side participation (DSP) remains at average levels.

Higher than average temperatures are experienced, and droughts occur more frequently and are more severe than previously anticipated. Desalination plants continue to be built to meet water demand, and it is stipulated by government that the energy requirement must be provided from renewable sources.

Carbon price sensitivity

The Oil Shock and Adaptation scenario’s low carbon price sensitivity (OS-L) describes the same world as OS-M, but one where low (rather than moderate) emission reduction targets have been implemented and met. The targets aim at restricting CO2-e emission concentration to less than 550 ppm by 2050, rather than 500 ppm as in OS-M. A low carbon price ramping up to AUD44/t CO2-e is assumed.

2.2.5 Slow Rate of Change

Slow Rate of Change (SC-L) is distinguished by a low rate of economic growth, both domestically and internationally. The scenario assumes a shortage of capital liquidity and high interest rates has led to limited investment. Additionally, a target carbon dioxide equivalent (CO2-e) emission concentration not exceeding 550 ppm by 2050 is assumed to have been agreed internationally, but Australia does not remain as competitive on the world stage. Lower-cost energy prices are available off-shore, leading some manufacturing and other energy-intensive industries to relocate overseas. Population growth is also low, with less demand for skilled migration.

Low domestic economic growth and population growth, driven by difficulties accessing capital, slows the rate of transformation of the Stationary Energy Sector. Australia moves further towards a service economy, with some manufacturing and energy-intensive industries moving off-shore.

Under this scenario, boosting economic activity is considered the key priority for government. To support the domestic coal industry, carbon capture and sequestration (CCS) research and development is supported by the Australian and State Governments, although the low demand growth tends to slow the rate at which this technology is deployed. Low commodity costs help to keep capital costs lower than average for new centralised generation options, although this is offset to some extent by the higher interest rates.

There is little demand-side response, as electricity prices remain relatively low and few residential or commercial consumers can afford to invest in small-scale renewable energy options. Despite the low electricity prices, there are some cost saving-related incentives for energy efficiency. Slow growth in demand and low carbon prices have not encouraged investment in distributed generation technologies, such as cogeneration and tri-generation. However, earlier government initiatives have led to moderate displacement of electric water heaters in favour of solar hot water units.

Due to low economic growth, international demand for Liquefied Natural Gas (LNG) is low. Consequently, there is little domestic LNG production and surplus supply keeps gas prices in the eastern States low. International oil prices are moderate, but few electric plug-in vehicles are purchased since the low carbon price, ramping up to AUD44/t CO2-e, does not provide sufficient incentive to switch.

Although not as high as first expected, temperatures continue to have an impact on peak demand. There are also fewer periods of drought than initially anticipated. The impact of climate change appears to be at the lower end of original estimates. Coupled with low population growth, these factors have led to low energy demand from desalination. These events provide less incentive for governments to set ambitious emission reduction targets or for consumers to change their behaviour.

Boosting economic activity is considered the key priority for government. To support the domestic coal industry, CCS research is supported but low demand growth slows this technology’s rate of deployment.

Carbon price sensitivity

The Slow Rate of Change scenario’s zero carbon price sensitivity (SC-0) describes the same world as SC-L, but one where there is no carbon price. The Large-scale Renewable Energy Target (LRET) is assumed, as in all scenarios and sensitivities, although in this sensitivity it is the sole measure to restrict CO2-e emissions.

2.2.6 Drivers and emissions targets

Two alternative carbon prices (and therefore emissions targets) are associated with each scenario, providing a total of 10 cases. Figure 2-1 shows the carbon price and timing trajectories the scenarios examine.

Table 2-2 lists the drivers and emission targets for each scenario.

Figure 2-1 Carbon price trajectories

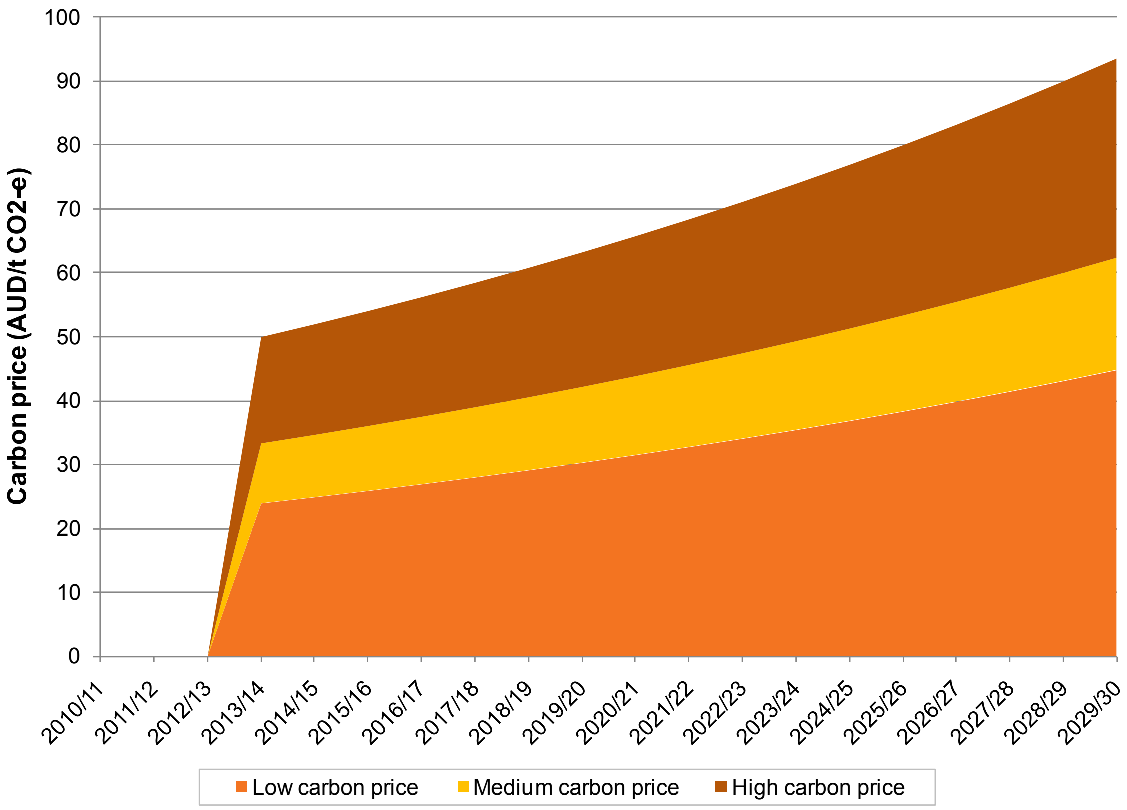


Table 2-2 Scenario drivers and emission targets

Scenario	Economic growth	Population growth	Global carbon policy	Centralised supply-side response	Decentralised supply-side response	Demand-side response	Emission targets below 2000 levels
Fast Rate of Change	High	High	Strong	Strong	Strong	Strong	-25%[3] (sensitivity -15%[2])
Uncertain World	High	High	Weak	Strong	Weak	Weak	-5%[1] (sensitivity no carbon price)
Decentralised World	Medium	Medium	Strong	Weak	Strong	Strong	-15%[2] (sensitivity -25%[3])
Oil Shock and Adaptation	Low	Medium	Moderate	Moderate (renewable)	Weak	Weak	-15%[2] (sensitivity -5%[1])
Slow Rate of Change	Low (mixed)	Low	Weak	moderate	Weak	Weak	-5%[1] (sensitivity no carbon price)

1. The -5% carbon emissions target (low carbon price) is associated with a carbon price trajectory from AUD0 to AUD44 per tonne CO2-e.
2. The -15% carbon emissions target (medium carbon price) is associated with a carbon price trajectory from AUD0 to AUD62 per tonne CO2-e.
3. The -25% carbon emissions target (high carbon price) is associated with a carbon price trajectory from AUD0 to AUD93 per tonne CO2-e.

2.2.7 Scenario development for future NTNDPs

The scenarios for the 2010 NTNDP were initially developed with a stakeholder group for development of the Australian Government's Energy White Paper.

AEMO does not anticipate that this process will be repeated each year, and so an alternative approach to scenario development is being considered that includes the following steps:

- AEMO reviews the previous year's scenarios and makes recommendations for new scenarios.
- A forum is held with the AEMO Stakeholder Reference Group (SRG) to discuss the previous year's scenarios as well as AEMO's recommendations, and the development of scenarios for the current year.
- A public consultation is held on the scenario recommendations.
- A second forum with the SRG is held to consider responses to the public consultation and to finalise the scenarios for the current year.

2.3 Key inputs

This section provides a high-level description of the key inputs. For more detailed information about these inputs, see Appendix H.

2.3.1 Energy and maximum demand projections

The NTNDP analysis relies on regional demand traces, which are based on annual energy and MD projections, to represent the demand placed on generating units for the 20-year outlook period.

Annual energy and MD projections for each region are supplied by the jurisdictional planning bodies (JPBs)[7], while the Load Forecast Reference Group (LFRG) co-ordinates the delivery of the projections, and ensures a consistent approach to forecasting techniques across the regions.

Regional projections provided as part of the 2009 ESOO were developed for three different economic growth scenarios (high, medium, and low economic growth). The 2010 NTNDP demand projections have been developed from these projections.

The 2009 ESOO energy and MD projections were based on assumptions that did not include carbon prices, energy efficiency initiatives, or plug-in electric cars. To develop the NTNDP projections, the 2009 ESOO projections were adjusted (where relevant) for the price elasticity effects of carbon pricing.

Additionally, to reflect the scenario drivers, projections developed for the Fast Rate of Change (FC-H) and Decentralised World (DW-M) scenarios and their carbon price sensitivities, were adjusted for energy efficiency initiatives and electric vehicles.

[7] AEMO develops the projections for Victoria and South Australia.

2.3.2 Generation inputs

Information has been provided by generators and potential generation investors about key operational parameters of current generating units and future projects. This information included the following:

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

AEMO contracted ACIL Tasman to provide estimates of future generation costs and other resource parameters, as inputs to the modelling of economic generation behaviour. This information is available from the NTNDP CD and AEMO's website, and includes the following:

- Generator fuel costs.
- Fixed operating and maintenance costs.
- Thermal efficiency factors.
- Emissions factors.
- Unit auxiliary loads.
- Capital costs for new generation investments.
- Resource availability and build limits (including non-renewable resources and renewable wind, solar, geothermal, and biomass resources).

Specific information for modelling hydroelectric generation has been obtained from Transend Networks (for Tasmania) and public sources. This information included the following:

- Tasmania Hydroelectric Capacity Model.
- Initial hydroelectric water storages.

2.3.3 Network inputs

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

- Network constraint equations (source: AEMO).
- Intra-regional loss factors for existing and committed generation (source: AEMO).
- Committed transmission augmentations (source: JPBs).
- Potential (non-committed) transmission augmentations (source: AEMO and the JPBs).
- Transmission project cost estimates (source: AEMO and the JPBs).

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Chapter 3 - Development by Scenario– Generation and Transmission Expansion

3.1 Summary

This chapter presents the outcomes of the optimised generation and transmission modelling for each scenario, and provides a view of future power system requirements that focuses on generation and transmission development impacts under five possible socio-economic futures involving a basic carbon price and an alternative carbon price (sensitivity). For more detailed results from each scenario's generation and transmission expansion modelling, see Appendix A. For information about the results by zone, see Chapter 4.

The following three scenarios show the range of outcomes observed.

The **Slow Rate of Change** scenario (SC-L) shows the least change, with only moderate levels of new base load gas-powered generation (with and without carbon capture and sequestration (CCS) technology), moderate new wind and geothermal generation, and slightly less retired capacity than other scenarios, but which is still significant. Less transmission network investment is required, although reinforcement of the existing network is needed to deliver new gas-powered generation from Northern New South Wales to the major load centres of Sydney, Wollongong, and Newcastle. The scenario's zero carbon price sensitivity (SC-0) shows less new base load gas-powered generation or retirement, and even less transmission network investment, and transmission network reinforcement from Northern New South Wales to the major New South Wales load centres is not required.

The **Decentralised World** scenario (DW-M) shows moderate change, with high levels of new conventional CCGT generation in New South Wales, Queensland, and Victoria, and moderate retirements. There are high levels of new wind generation, and moderate levels of new geothermal generation. Extensive reinforcement of the existing network is required to deliver gas-powered generation to the major load centres. The scenario's high carbon price sensitivity (DW-H) shows significant brown and black coal generation retirement (the highest of all the scenarios and scenario sensitivities), though it does not significantly alter the required transmission investment.

The **Fast Rate of Change** scenario (FC-H) shows the most change, with significant new base load gas-powered and coal-fired generation, making use of CCS technology, with significant retirement of brown coal and (to a lesser extent) black coal generation. Extensive reinforcement of the existing transmission network is required to deliver gas-powered and coal-fired conventional generation in existing locations, and remotely located new renewable generation, to the major load centres. The observed generation fleet does not change significantly under the scenario's medium carbon price sensitivity (FC-M), and the required transmission investment is unaltered.

Between AUD40 billion and AUD130 billion in investment is required to augment the shared transmission network and develop new generation assets across the National Electricity Market (NEM).

3.1 Summary…*cont*

The modelling generally indicates that a moderate to high carbon price will result in significant levels of retirement in the Latrobe Valley (Hazelwood, Morwell and Yallourn Power Stations), with subsequent replacement by gas-powered generation. Retirement of older and less efficient black coal plant in Queensland (Collinsville) and New South Wales (Liddell and Wallerawang) will also occur, though not to the same extent.

The Large-scale Renewable Energy Target (LRET) scheme is the prime driver of renewable generation over the next 10 years under all the scenarios. Wind power is the main generation technology in the short term, with other technologies, like geothermal and solar thermal generation, beginning to appear towards the end of the decade.

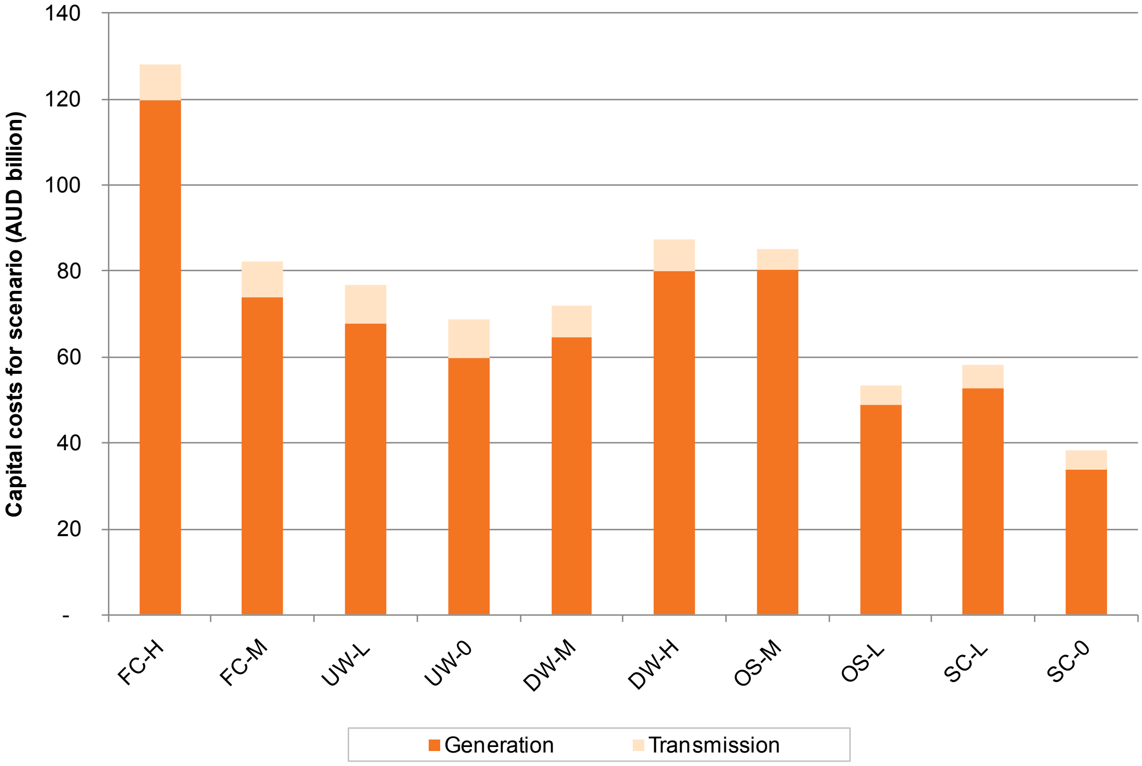
Augmentation of the Queensland to New South Wales (QNI) interconnector proceeds in five out of ten of the scenarios and their sensitivities, while in two of the scenarios an incremental upgrade of the Victoria-South Australia interconnector (Heywood) proceeds in the final years of the 20-year outlook period. This outcome reflects the high-level, least-cost modelling approach, where fuel costs and renewable potentials differ only marginally between the regions, and generation is planted to meet regional capacity requirements.

3.2 Capital investment summary

Based on AEMO’s scenario modelling, between AUD40 billion and AUD130 billion in investment is required to augment the shared transmission network and develop new generation assets across the NEM to meet demand over the next 20 years.

Figure 3-1 shows the capital cost requirements for the NEM over the next 20 years. These figures represent the total capital cost summed over this period, and have not been discounted.

Figure 3-1 Capital costs for all scenarios and sensitivities (2010/11 AUD billion)



Investment in new generation assets ranges from AUD40 billion to AUD120 billion. These figures represent capital costs only, and do not include tax or borrowing costs. There are three key drivers in the final generation investment figures:

- Demand growth, with high demand growth scenarios requiring a higher level of new generation to meet the greater need for additional capacity.
- Carbon price, with higher carbon prices leading to greater investment in high capital cost renewable or CCS-type generation.
- Retirements, with the scenarios displaying high levels of existing plant retirements requiring new generation to replace retiring plant.

For scenarios/sensitivities with higher carbon prices, the greater capital investment needed is partially offset by the lower operational costs of renewable generation (wind, solar, and geothermal), which are not shown here.

Investment in transmission assets ranges from AUD4 billion to AUD9 billion and includes only those types of augmentations within the scope of the National Transmission Development Plan (NTNDP) (as described in Chapter 4, Section 4.2).

3.3 Fast Rate of Change scenario

Fast Rate of Change (FC-H)[8] describes a world where relatively strong emission reduction targets have been agreed internationally by both developed and developing countries, and there is high sustained economic growth in Australia. Successful adaptation to a carbon-constrained world is partly possible, due to government and industry investment in the development of new technologies.

The scenario considers two carbon prices: a high price trajectory to achieve a 25% emissions reduction, and a medium price trajectory sensitivity to achieve a 15% emissions reduction.

3.3.1 Generation development

For the scenario and its sensitivity (respectively):

- Figure 3-2 and Figure 3-3 show the NEM's new generation capacity at the end of the 20-year outlook period.
- Figure 3-4 and Figure 3-5 show the energy production by fuel type over the course of the 20-year outlook period.

The observed new capacity includes significant levels of:

- open-cycle gas turbines (OCGT) located in zones hosting the major load centre for each region
- combined-cycle gas turbines (CCGT) located in the SWQ and LV zones
- CCGT with CCS in the LV and CAN zones, and
- coal-fired generation with CCS in the SWQ and CQ zones.

Significant brown (and to a lesser extent black) coal-fired generation retires. There is a high level of renewable plant, comprising wind and geothermal generation, with the most geothermal generation proceeding in the CVIC and NSA zones. By 2016/17, 1,000 MW of solar thermal generation proceeds (under the Solar Flagships Program), while 1,200 MW of biomass generation (the majority proceeding in the second half of the outlook period) is installed by 2029/30. Under the medium carbon price sensitivity (FC-M) less CCGT with CCS technology proceeds. Some coal-fired generation with CCS in the SWQ zone is replaced with coal-fired technology without CCS, while an additional 3,000 MW and 1,200 MW of OCGT generation proceeds in the NCEN and MEL zones, respectively.

[8] Identified as FC-M under the medium carbon price sensitivity.

Key assumptions impacting new generation include the following:

- High electrical energy and demand growth drives high levels of generation.
- The availability of lower-cost geothermal and CCS-type technology (relative to the other scenarios).
- Deployment of electric plug-in vehicle technology (modelled to increase overnight, off-peak demand), and increased regional annual energy use by approximately 6-10%, which tends to encourage greater penetration of base load high-utilisation plant, typically incorporating CCS technology due to the high carbon price.
- A return to long-term average inflows for major hydroelectric systems.
- An average growth in gas price.
- A low risk premium reflected in the lowest weighted average cost of capital (WACC) of all the scenarios (8.78%).

By the end of the outlook period, CCS plant and renewable technology accounts for approximately half of the energy produced. Under the medium carbon price sensitivity (FC-M), less energy is produced by technologies involving CCGT with CCS, and coal-fired generation with CCS, with more produced by conventional black-coal generation.

For both the scenario (FC-H) and its sensitivity (FC-M), while there is a significant amount of OCGT, actual OCGT energy production is relatively low. This reflects the requirement to install low cost generation to meet the least cost capacity constraint[9] .

The LRET target is achieved under both the scenario and its sensitivity, with renewable energy production 50% above the target by 2029/30 (for more information about LRET modelling, see Attachment 1).

[9] A constraint is applied in the least-cost expansion model to ensure installation of sufficient levels of capacity (for more information, see Attachment 1).

Figure 3-2 Total NEM new generation capacity in 2029/30 by technology–FC-H (MW)

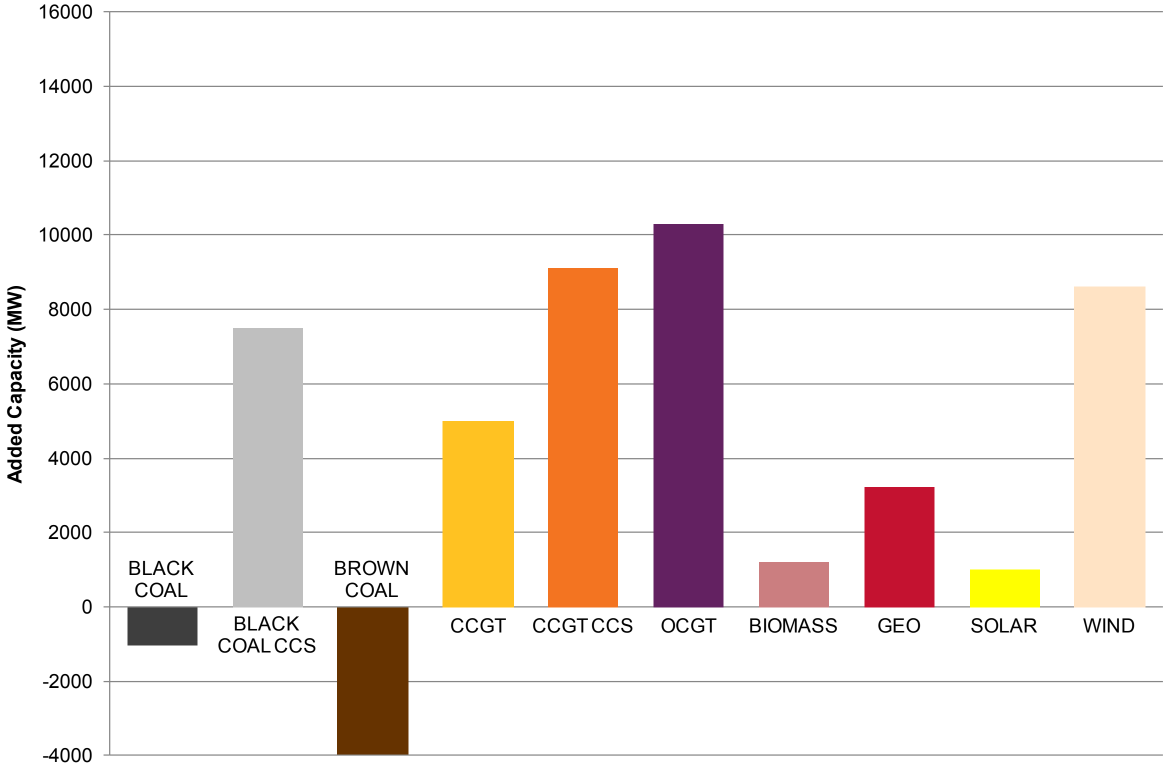


Figure 3-3 Total NEM new generation capacity in 2029/30 by technology–FC-M (MW)

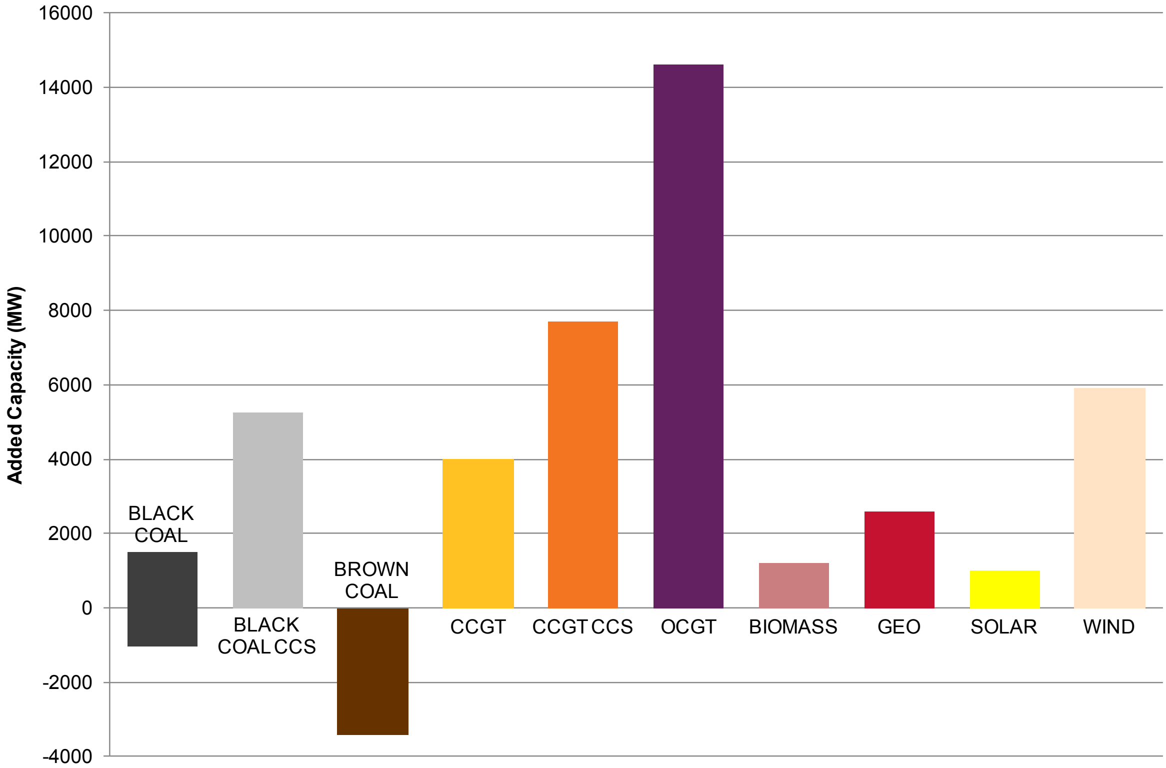


Figure 3-4 Total NEM generated energy by technology–FC-H (TWh)

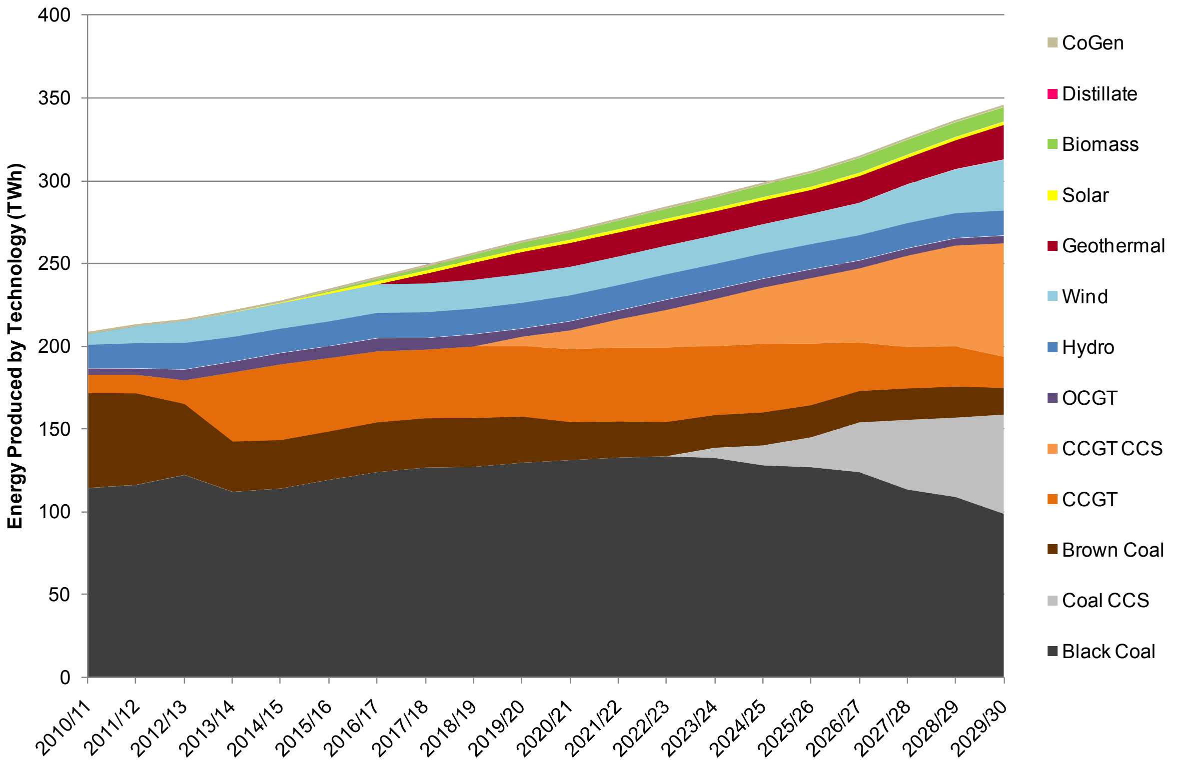
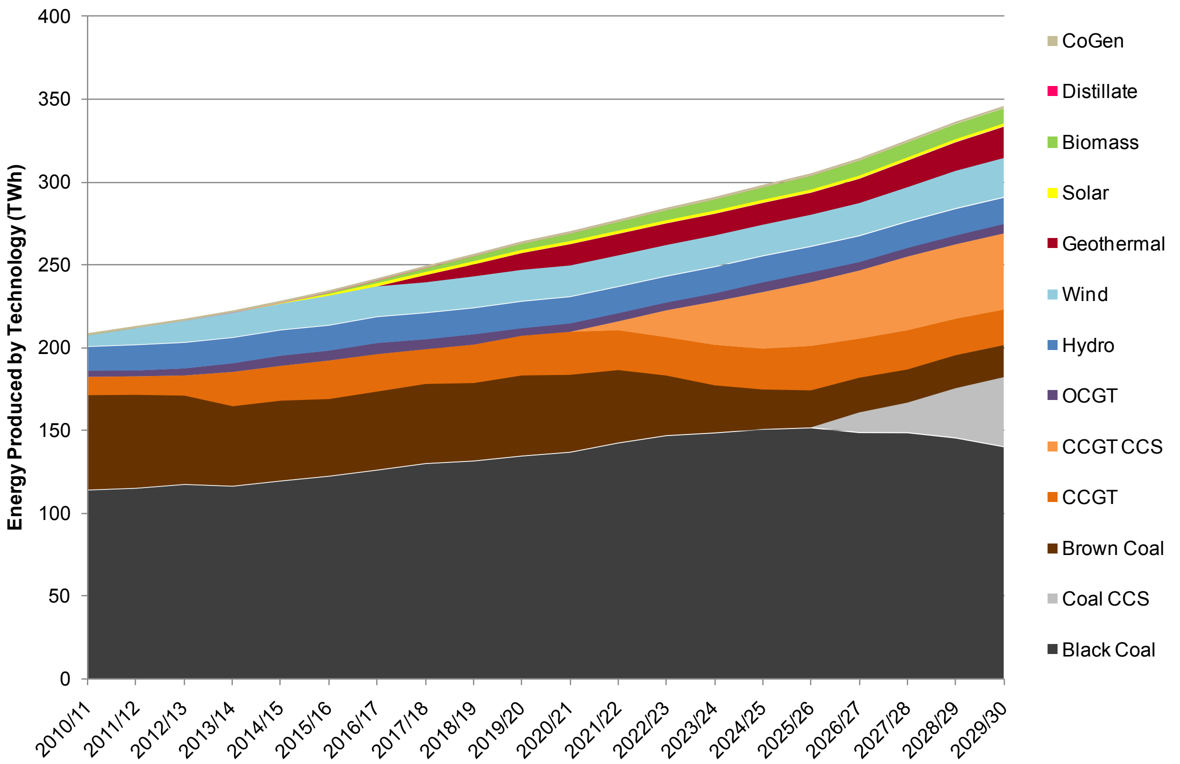


Figure 3-5 Total NEM generated energy by technology–FC-M (TWh)



3.3.2 Transmission development

Figure 3-6 shows a breakdown of transmission development projects by region under the Fast Rate of Change scenario (FC-H). For more information about individual projects, see Section 3.8.

Figure 3-6 Modelled augmentations by 2029/30 (FC-H)

Queensland

Under all scenarios, transmission development in Queensland is dominated by the development of the transmission network between the SWQ and SEQ zones to connect major generation and load centres, which is due to demand growth largely being met by new generation in the SWQ zone. Demand growth under the Fast Rate of Change (FC-H) scenario is consistent with high economic growth, and new generation in the SWQ zone drives a move to a strong 500 kV transmission network between the two zones. In addition to the committed 275 kV double circuit line, by the end of the 20-year outlook there are two new 500 kV double circuit lines between Western Downs in the SWQ zone and the load centres in the SEQ zone.

High demand growth also drives substantial reinforcement within the SEQ zone, including further supply to the Brisbane, North Coast, and Gold Coast areas.

New solar and biomass generation in North Queensland defers development of the Central to North Queensland corridor, resulting in relatively little need for augmentation until the modelled retirement of Collinsville Power Station towards the end of the 20-year outlook period.

There is some need for additional transmission capacity north of Ross to support demand growth in the far north of the State. Load growth in the Gladstone area, coupled with new coal-fired generation with CCS at Calvale leads to reinforcements from Calvale to Larcom Creek and Wurdong, together with reinforcement in the Gladstone area.

The Queensland to New South Wales (QNI) interconnector is augmented in 2014/15 in the least cost modelling, for both the scenario (FC-H) and its sensitivity (FC-M), providing for increased transfer capability between Queensland and New South Wales. The utilisation of QNI in the southerly direction progressively decreases, with New South Wales less reliant on imports from Queensland, though this trend is reversed in the later years of the outlook period.

New South Wales

New South Wales sees an extension of the 500 kV network at Bannaby to connect large-scale gas-powered generation in the Canberra and Yass areas. Further development of the 500 kV ring from Bannaby to outer Sydney, and strengthening of the 330 kV transmission network ring around Sydney, in the Kemps Creek area, is also proposed in later years to support rapid demand growth.

Lines in the Liddell to Armidale transmission network cause considerable congestion when there are higher power transfers from Queensland. This occurs during lighter demand periods, when New South Wales is typically importing from Queensland. An upgrade in 2014/15 increases the Queensland to New South Wales (QNI) interconnector’s southerly capability, putting further pressure on 330 kV circuits in the Armidale/Tamworth area. As a result, there may be significant market benefits from relieving this congestion.

Limitations on power flows on the 132 kV lines south of Lismore are relieved following the commissioning of the new 330 kV Dumaresq-Lismore line. Initial market modelling demonstrated forced southerly power flow on Directlink that often reached the southerly power flow limit. For later years, the corresponding constraint equations become violated. These constraint equations were removed from the model for the purposes of completing the NTNDP studies. This corresponds with reinforcement of the 132 kV lines between Lismore and Mullumbimby, suggesting that this reinforcement may be required in the future.

Victoria

New gas-powered generation in the LV zone and the south west of Victoria (part of the MEL zone) leads to significant expansion of the existing 500 kV transmission network. This scenario sees additional transmission lines from Loy Yang to Hazelwood and the Greater Melbourne Metropolitan Area, and expansion of the 500 kV transmission corridor from Heywood to Moorabool. This provides for a strong backbone connecting generation and the major load centre in Melbourne, and facilitates possible future 500 kV connections with South Australia and New South Wales.

The need for major transmission reinforcement in Metropolitan Melbourne is largely influenced by demand growth, new gas-powered generation at the Newport and Laverton North Power Stations, and the retirement of the Yallourn and Hazelwood Power Stations.

High load growth and up to 200 MW of exports from the CVIC to the NSA zone via Murraylink leads to a number of old 220 kV lines being replaced with high-capacity transmission lines, and the addition of 220 kV lines in the CVIC zone. A phase angle regulator on the 220 kV Buronga-Red Cliffs line has been identified to control power flow from Darlington to Buronga to Red Cliffs. In the scenario’s medium carbon price sensitivity (FC-M), a moderate level of wind generation is distributed in the CVIC zone, which is accommodated by the transmission augmentations required to meet high load growth generally, and high exports to South Australia via Murraylink.

Load growth in the Greater Melbourne Metropolitan Area leads to significant reinforcement between the area’s 500 kV and 220 kV transmission networks. The location and timing of additional 500/220 kV transformers is subject to the location of new generation in the area and load growth centres. A few 220 kV lines in the area require replacement with high temperature lines with significantly higher thermal capacity.

The abundance of cheap generation in Victoria promotes higher exports to New South Wales and Tasmania. Thermal limitations in the Snowy and Wagga area, along with transient stability limitations due to 500 kV faults in the Latrobe Valley, cause considerable congestion on the Victoria to New South Wales interconnector. A Victoria to New South Wales augmentation providing up to 1,600 MW increased power transfer capacity to New South Wales was not shown to be economic within the 20-year outlook period. However, a more modest, lower-cost augmentation to relieve transient stability limitations and to increase power transfer capability via Dederang to Jindera and up to Wagga may be beneficial.

South Australia

High demand growth drives the 275 kV and 132 kV transmission network augmentations across South Australia under both the scenario (FC-H) and its medium carbon price sensitivity (FC-M).

The ADE zone sees the development of the City West 275 kV bulk supply system, and projects for increasing the ratings of some existing 275 kV circuits to the line design ratings. In the NSA zone, demand growth leads to the reinforcement of the 275 kV and 132 kV transmission networks supplying the Eyre Peninsula, and the development of new 275/132 kV substations in the Barossa area, and the York Peninsula, respectively. In the SESA zone, local load growth, generation retirement, and the need for imports from Victoria via the Heywood interconnector all require augmenting the 275/132 kV transformation capacity and 132 kV transmission network capacity under both the scenario and its sensitivity.

Under FC-H and FC-M, development of significant geothermal generation in the NSA zone leads to the need for bulk power transfers from the Davenport area towards Para and further south. In FC-M this results in a need in later years to augment the backbone 275 kV transmission network between the Davenport and Para areas. This reinforcement does not proceed under FC-H due to the retirement of the Northern Power Station, resulting in a much less onerous requirement for transmission capacity from the NSA to the ADE zone.

While South Australia needs to rely on imports from Victoria to meet peak demand, extensive wind and geothermal penetration in South Australia leads to significant congestion associated with export from South Australia to Victoria under non-peak load conditions. Under FC-H, an incremental upgrade of the Heywood interconnector’s existing capacity proceeds in the least cost model towards the end of the 20-year outlook period. This incremental upgrade option (among others)[10] includes installing 275 kV series compensation between the South East Substation and the Tailem Bend Substation, and installing a third Heywood 500/275 kV transformer as well as necessary reactive compensation.

Tasmania

Under all scenarios a large amount of wind generation is installed in Tasmania, with potential locations in the north-west (at Burnie, requiring augmentation of the 220 kV Burnie-Sheffield and Sheffield-Palmerston lines), north-east (requiring uprating of 110 kV lines in the north-east or connections to the 220 kV transmission network near George Town), and central Tasmania (connecting to the existing 220 kV network at Waddamana).

New biomass and gas-powered generation connects to the 220 kV transmission network near George Town, with the gas-powered generation being supplied locally from around the George Town area.

New gas-powered generation provides additional security and reliability to the major load centre in Hobart, with up to 200 MW being added in the area to Hobart’s north, requiring augmentations to increase the capability of the existing gas transmission network, and an additional 220/110 kV transformation capacity around the Hobart and Burnie areas to meet the increased load growth.

A single asset failure on the 220 kV Palmerston-Waddamana line leads to unserved energy in Southern Tasmania, requiring an additional 220 kV transmission line between Palmerston and Southern Tasmania.

3.4 Uncertain World scenario

Uncertain World (UW-L)[11] describes a world characterised by carbon policy uncertainty both internationally and domestically, coupled with high economic growth in Australia.

[10] For more information, see transmission development VS1 in Chapter 4, Section 4.6.3, Table 4.24.

[11] Identified as UW-0 under the zero carbon price sensitivity.

The scenario considers two carbon prices: a low price trajectory to achieve a 5% emissions reduction, and a zero price trajectory sensitivity.

3.4.1 Generation development

For the scenario and its sensitivity (respectively):

- Figure 3-7 and Figure 3-8 show the NEM's new generation capacity at the end of the 20-year outlook period.
- Figure 3-9 and Figure 3-10 show the energy production by fuel type over the course of the 20-year outlook period.

The observed new capacity predominantly includes:

- open-cycle gas turbines (OCGT) located in zones containing the major load centre for each region, and
- combined-cycle gas turbines (CCGT) located to a significant extent in the NNS and SWQ zones, and to a lesser extent in the LV zone.

Relative to other scenarios, there is also a moderate level of wind technology located in the southern regions. Only 400 MW of solar thermal generation proceeds, while 1,200 MW of biomass generation (the majority proceeding in the second half of the outlook period) is installed by 2029/30. A small amount of black and brown coal generation retires. In the scenario's zero carbon price sensitivity (UW-0), some black and brown coal generation is planted in the NCEN and LV zones, respectively, with less CCGT (principally in the NNS zone), and significantly less wind generation.

Key assumptions impacting new generation include the following:

- High electrical energy and demand growth drives high levels of generation.
- An assumption of ongoing drought conditions in Australia, causing hydroelectric system inflows to fall to 80% of their long-term average, which tends to cause more renewable plant technology to proceed.
- Geothermal and CCS-type technology is unavailable.
- An average growth in gas price.
- A high risk premium due to uncertainty reflected in the highest weighted average cost of capital (WACC) of all the scenarios (11.78%).

By the end of the outlook period, black and brown coal still provide a significant amount of energy, but the bulk of new energy production comes from CCGT-type technology. In the scenario's zero carbon price sensitivity (UW-0), black and brown coal energy production increases slightly, with a lower level of CCGT generation.

Similarly to the Fast Rate of Change (FC-H) scenario, while there is a significant amount of OCGT planted, actual OCGT energy production is relatively low.

The LRET target is not met under the scenario (UW-L) during the middle years of the outlook period (2012/13-2022/23), and is not met in any year under the scenario's zero carbon price sensitivity (UW-0), with renewable generation between 40% and 60% of the LRET target.

Figure 3-7 Total NEM new generation capacity in 2029/30 by technology–UW-L (MW)

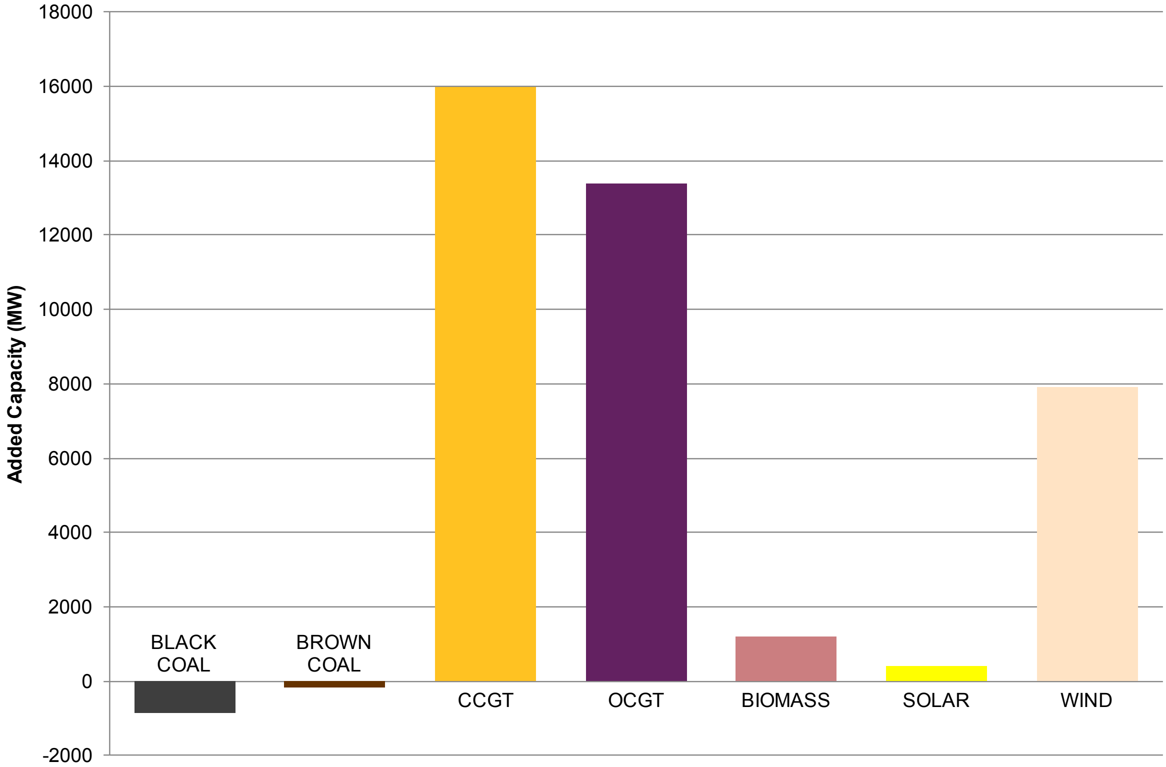


Figure 3-8 Total NEM new generation capacity in 2029/30 by technology–UW-0 (MW)

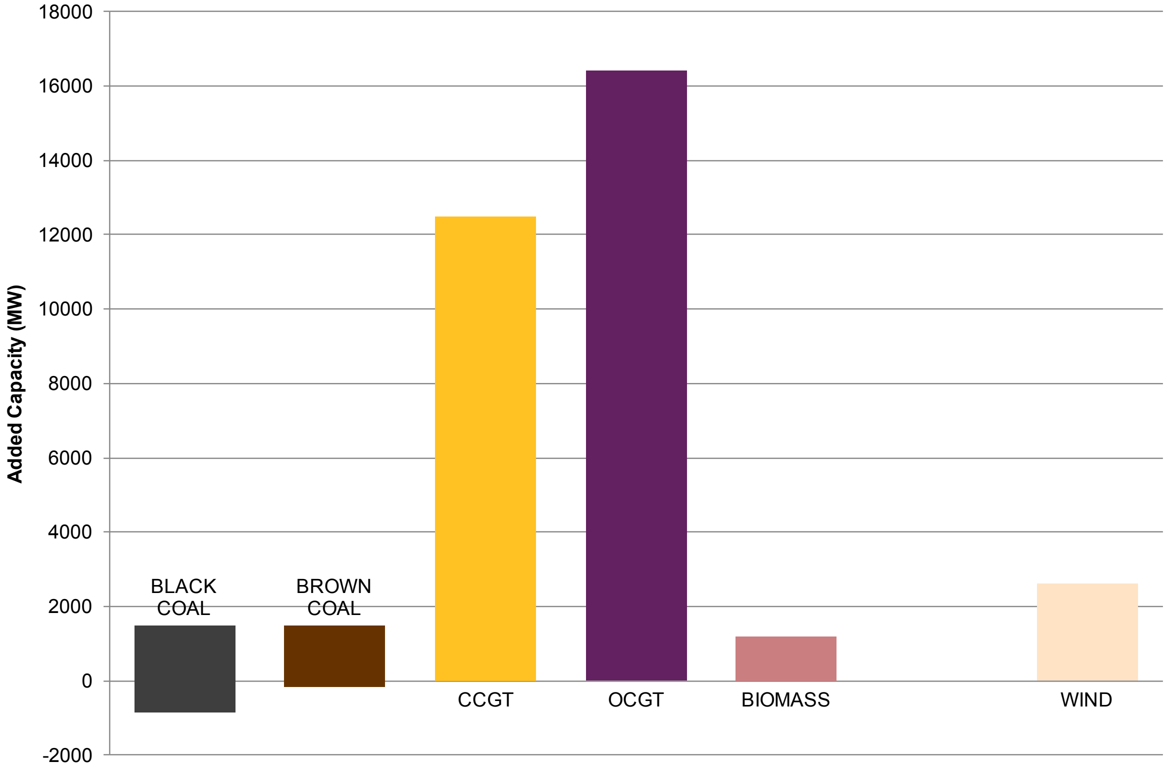


Figure 3-9 Total NEM generated energy by technology–UW-L (TWh)

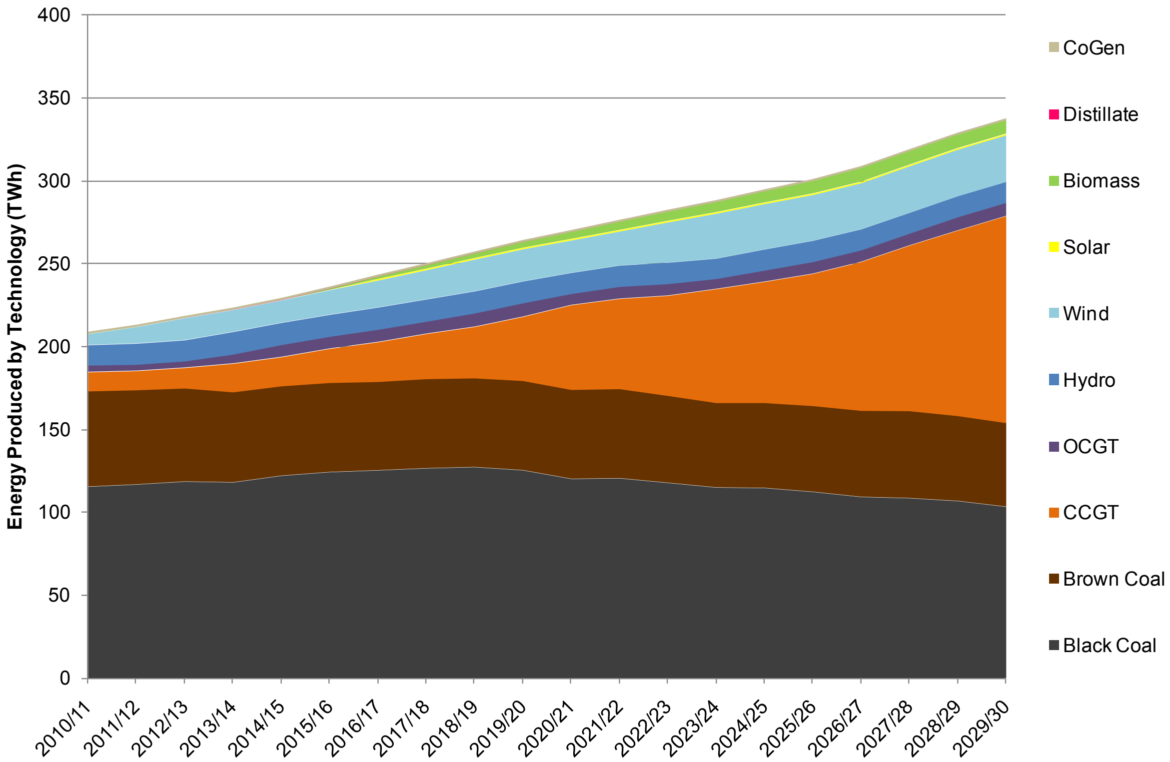
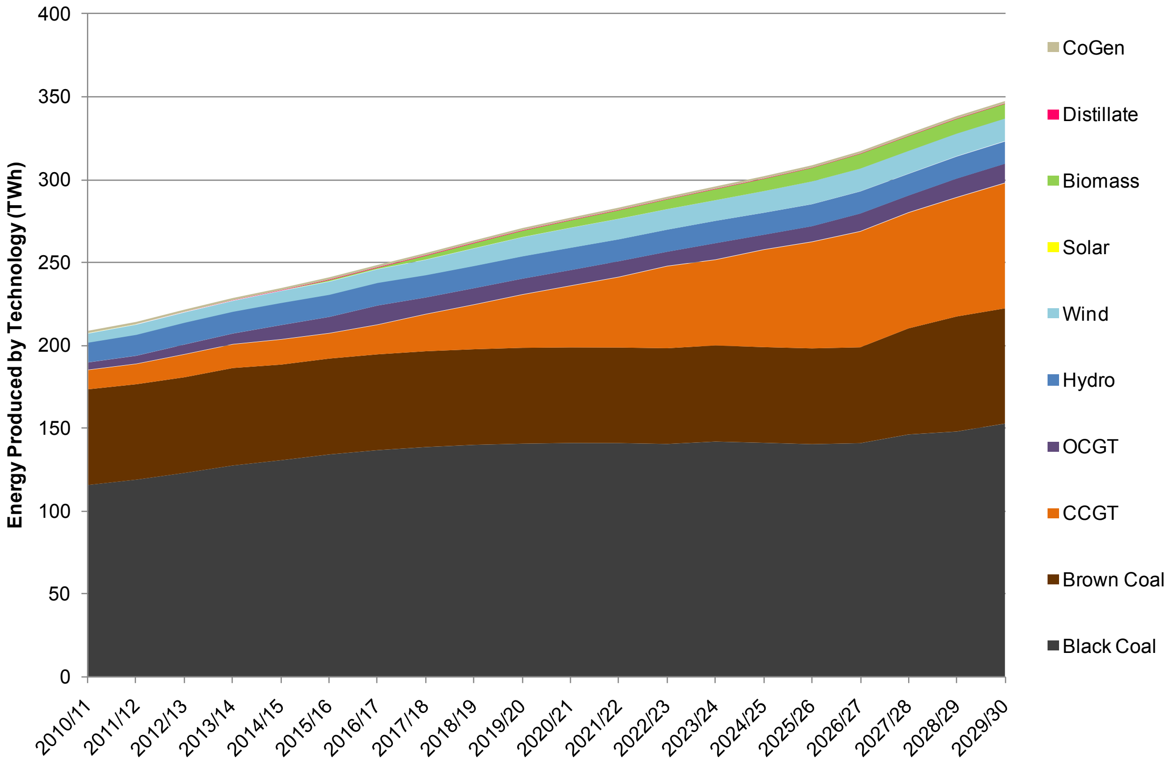


Figure 3-10 Total NEM generated energy by technology–UW-0 (TWh)



3.4.2 Transmission development

Figure 3-11 shows a breakdown of transmission development projects by region under the Uncertain World (UW-L) scenario. For more information about individual projects, see Section 3.8.

Figure 3-11 Modelled augmentations by 2029/30 (UW-L)

Queensland

Under all scenarios, transmission development in Queensland is dominated by the development of the transmission network between the SWQ and SEQ zones to connect major generation and load centres, which is due to the demand growth largely being met by new generation in the SWQ zone. Demand growth under the scenario (UW-L) is consistent with high economic growth, and the new generation in the SWQ zone drives a move to a strong 500 kV transmission network between SWQ and SEQ. In addition to the committed 275 kV double circuit line, by the end of the 20-year outlook period, there are two new 500 kV double circuit lines between Western Downs in the SWQ zone and the load centres in the SEQ zone.

High demand growth also drives substantial reinforcement within the SEQ zone, including further supply to the Brisbane, North Coast, and Gold Coast areas.

Additional transmission capacity from Calvale to Stanwell allows power transfers to meet the load growth in Gladstone and also north and south over this corridor.

Some new solar and biomass generation proceeds in North Queensland, deferring development of the Central to North Queensland corridor to some degree. The new generation capacity, however, is lower than under the Fast Rate of Change (FC-H) scenario, resulting in an earlier requirement for this corridor's augmentation.

There is also some need for additional transmission capacity north of Ross to support demand growth in the far north of the State.

New South Wales

As significant levels of new generation occur in Northern New South Wales (north of the location of the major load centres and existing major generation centres), transmission network development is extensive, and driven by high power flows from Northern New South Wales to the Central New South Wales load centres. The scenario's zero carbon price sensitivity (UW-0) includes more new generation in Central New South Wales, leading to differences in transmission system development between UW-L and UW-0.

In New South Wales, development of the transmission network is dominated by extensions of the 500 kV transmission network between the Hunter Valley and Northern New South Wales (inland), and the Hunter Valley and Eraring Power Station (via a substation at Newcastle). As UW-0 includes significant levels of generation in Central New South Wales, including the Marulan and Dapto areas, the sensitivity sees development of the 500 kV Sydney-Bannaby circuit. The timing for this development depends on the location of the new generation in Central New South Wales. This development may also occur under UW-L, if Central New South Wales generation becomes more concentrated in the Marulan and Dapto areas.

Increased north to south power flows result in the upgrade/re-arrangement of the 330 kV circuits between the Central Coast and Sydney. The 330 kV Wallerawang-Ingleburn feeder also carries some of the increased power flow from the north to the Sydney load centre, through the 500/330 kV substation at Mt Piper, resulting in the circuit's upgrade.

Augmentation of the Sydney 330 kV ring in its western and southern parts is driven by rapid load growth in the Sydney load centre.

The Victoria to New South Wales interconnector is augmented in 2014/15 in the least cost modelling for the scenario's sensitivity (UW-0), providing for increased transfer capability south into Victoria. In UW-0, the utilisation of the interconnector in the northerly direction progressively decreases, with New South Wales less reliant on imports from Victoria.

Victoria

Despite high demand growth, there is no geothermal generation development in Victoria. There is also no generation retirement, except for the generation at Energy Brix. The scenario's zero carbon price sensitivity (UW-0) sees no new wind generation, but the Victoria to New South Wales interconnector is augmented to transfer an additional 400 MW from New South Wales to Victoria from 2014/15 onwards. More generation (compared to the Fast Rate of Change (FC-H) scenario) is also located in the MEL zone's south-west corridor. An additional 500 kV line between the LV and MEL zones, and an additional two 500 kV lines between Heywood and Moorabool, are required to transfer power to the load centres in the Greater Melbourne Metropolitan Area.

High load growth and up to 200 MW of exports from the CVIC to the NSA zone via Murraylink leads to a number of 220 kV lines being replaced with high capacity transmission lines, and the addition of 220 kV lines in the CVIC zone. A phase angle regulator on the 220 kV Buronga-Red Cliffs line has been identified to control power flow from Darlington to Buronga to Red Cliffs. Under the scenario (UW-L), a moderate level of wind generation is distributed in the CVIC zone, which is accommodated by the transmission augmentations required to meet high load growth generally, and high exports to South Australia via Murraylink.

Load growth in the Greater Melbourne Metropolitan Area leads to significant reinforcement between the area's 500 kV and 220 kV transmission networks. The location and timing of additional 500/220 kV transformers is subject to the location of new generation in the area and the load growth centres. A few 220 kV lines in the area require replacement with high temperature lines with significantly higher thermal capacity.

With increased imports from New South Wales, potential overloading on the 330 kV Murray-Dederang line is avoided by adding a phase angle regulator on the 330 kV Jindera-Wodonga line and series compensation on the 330 kV Dederang-Wodonga line to increase the power flow from Wagga to Jindera to Wodonga. This scenario also requires uprating the 330 kV South Morang-Dederang lines and the 220 kV Eildon-Thomastown line with series compensation on the 220 kV Eildon-Thomastown line.

South Australia

High demand growth and significant gas-powered generation development in the ADE zone requires significant augmentation of the zone's 275 kV transmission network, including the City West 275 kV bulk supply system development, reconfiguration of the existing 275 kV transmission network, and projects to increase the ratings of a number of existing 275 kV circuits to the line design ratings under both the scenario (UW-L) and its zero carbon price sensitivity (UW-0). The transmission network reinforcement requirement is more extensive than under the Fast Rate of Change (FC-H) scenario and its medium carbon price sensitivity (FC-M), due to significantly higher gas-powered generation development in the ADE zone, and higher demand growth.

There is no need to reinforce the backbone 275 kV transmission network in the NSA zone from a reliability perspective, as this zone sees no new non-wind generation development. The main driver of network development in this zone is high demand growth, with both UW-L and UW-0 requiring reinforcement of the 275 kV and 132 kV transmission networks supplying the Eyre Peninsula, as well as a new 275/132 kV development on the York Peninsula and in the Barossa area of the NSA zone, respectively.

In the SESA zone, local load growth, generation retirement, and the need for imports from Victoria via the Heywood interconnector all require augmentations to increase the 275/132 kV transformation capacity and the 132 kV transmission network capacity under both UW-L and UW-0. Further, the scenario's zero carbon price sensitivity (UW-0) also requires the installation of 275 kV compensation, and more extensive 132 kV transmission network reinforcement than under UW-L. This is due to the need for higher imports from Victoria during the period 2015/16-2019/20, and higher demand growth under UW-0.

Tasmania

This scenario (UW-L) produces higher load projections than the other scenarios. Under all scenarios, a large amount of wind generation is installed in Tasmania (up to 2,050 MW), with potential locations in the north-west (at Burnie, requiring augmentation of the 220 kV Burnie-Sheffield and Sheffield-Palmerston lines), north-east (requiring uprating of 110 kV lines in the north-east or connections to the 220 kV transmission network near George Town), and central Tasmania (connecting to the existing 220 kV network at Waddamana).

New biomass and gas-powered generation connects to the 220 kV transmission network near George Town, with the gas-powered generation being supplied locally from around the George Town area.

New gas-powered generation provides additional security and reliability to the major load centre in Hobart, with up to 200 MW being added in the area to Hobart's north, requiring augmentations to increase the capability of the existing gas transmission network, and an additional 220/110 kV transformation capacity around the Hobart and Burnie areas to meet the increased load growth.

A single asset failure on the 220 kV Palmerston-Waddamana line will lead to unserved energy in Southern Tasmania, requiring an additional 220 kV transmission line between Palmerston and Southern Tasmania.

3.5 Decentralised World scenario

Decentralised World (DW-M)[12] describes a world where Australia's energy network becomes highly decentralised by 2030, with significant investment in demand-side technologies. Moderate emission targets are coupled with economic growth at intermediate levels.

The scenario considers two carbon prices: a medium price trajectory to achieve a 15% emissions reduction, and a high price trajectory sensitivity to achieve a 25% emissions reduction.

[12] Identified as DW-H under the high carbon price sensitivity.

3.5.1 Generation development

For the scenario and its sensitivity (respectively):

- Figure 3-12 and Figure 3-13 show the NEM's new generation capacity at the end of the 20-year outlook period.
- Figure 3-14 and Figure 3-15 show the energy production by fuel type over the course of the 20-year outlook period.

Similarly to the Uncertain World scenario (UW-L), the observed new capacity predominantly includes:

- open-cycle gas turbines (OCGT) located in zones hosting the major load centre for each region, and
- combined-cycle gas turbines (CCGT) located predominately in the NNS and SWQ zones, and to a lesser extent in the LV zone.

This is the only scenario under which installed CCGT capacity by the end of the 20-year outlook period is significantly higher than the installed OCGT. High levels of wind generation proceed, principally in the southern regions, while some geothermal plant proceeds, with the majority installed in the CVIC zone. By 2018/19, 800 MW of solar thermal generation is installed (under the Solar Flagships program), while 1,200 MW of biomass generation (the majority proceeding in the second half of the outlook period) is installed by 2029/30. Approximately 5,000 MW of black and brown coal generation retires, which is higher than under the Fast Rate of Change scenario (FC-H), with additional black coal retirements in New South Wales and Queensland. The DW-M scenario's high carbon price sensitivity (DW-H) has similar levels of new generation, though with slightly more retirements, and more renewable generation.

Key assumptions impacting new generation are similar to the FC-H scenario, with the key difference being a medium level of electrical energy and maximum demand growth, and a slightly higher weighted average cost of capital (WACC) (9.79%).

The energy production shows that over the 20-year outlook period, black and brown coal gradually provides less energy, with the bulk of new energy production from CCGT-type technology. The scenario's high carbon price sensitivity (DW-H) shows a similar result, though with the reduction of energy from black and brown coal generation falling earlier in the outlook period. Like the other scenarios, actual OCGT energy production is relatively low.

The LRET target is achieved in both the scenario (DW-M) and its sensitivity (DW-H) (for more information about LRET modelling, see Attachment 1).

Figure 3-12 Total NEM new generation capacity in 2029/30 by technology–DW-M (MW)

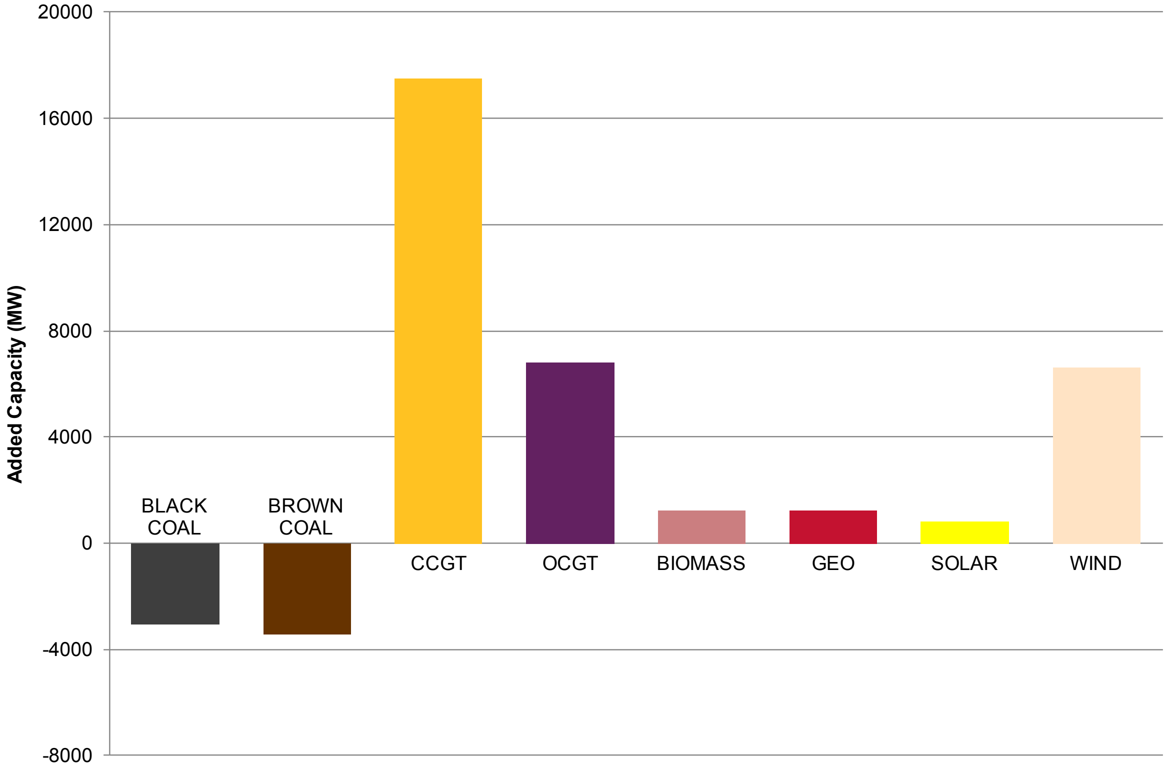


Figure 3-13 Total NEM new generation capacity in 2029/30 by technology–DW-H (MW)

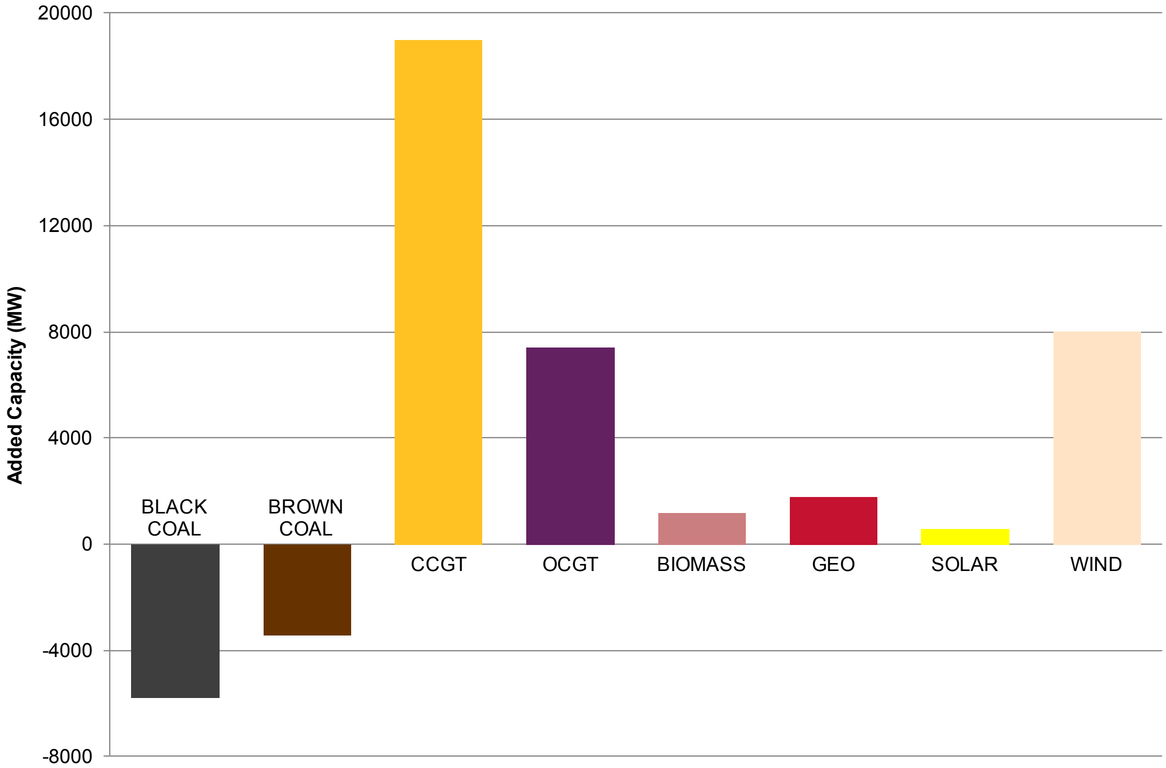


Figure 3-14 Total NEM generated energy by technology–DW-M (TWh)

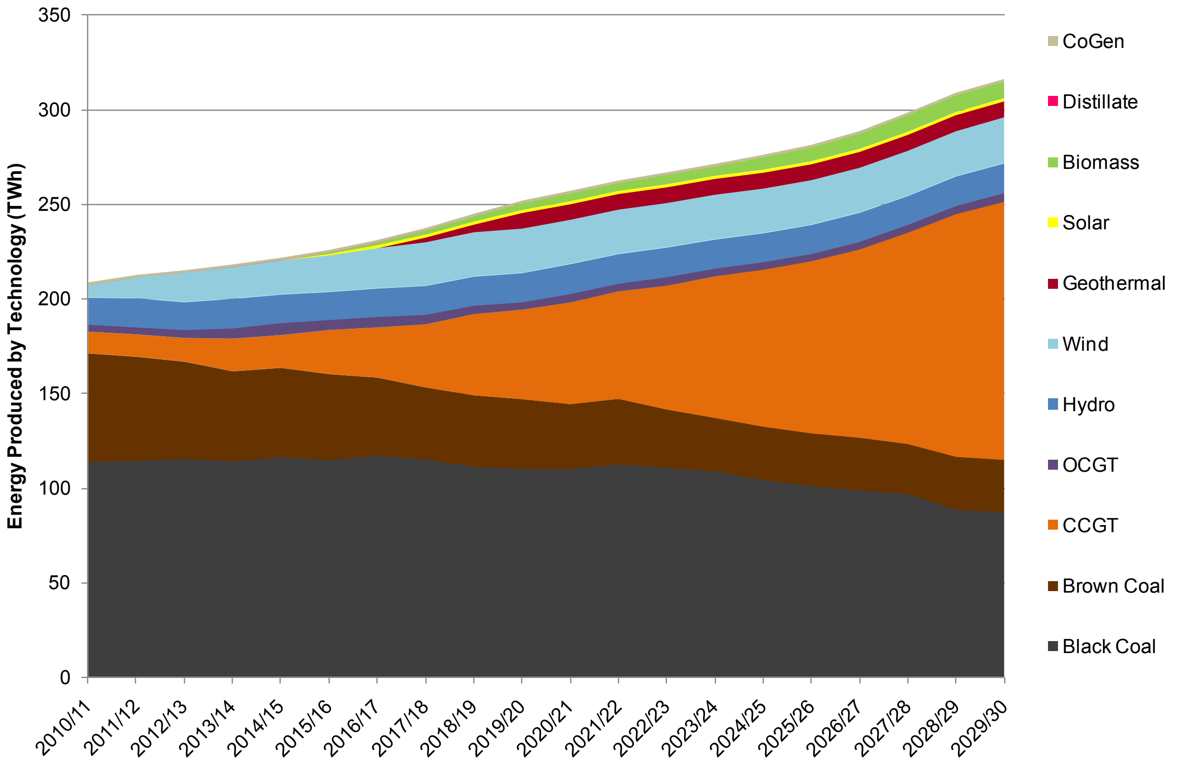
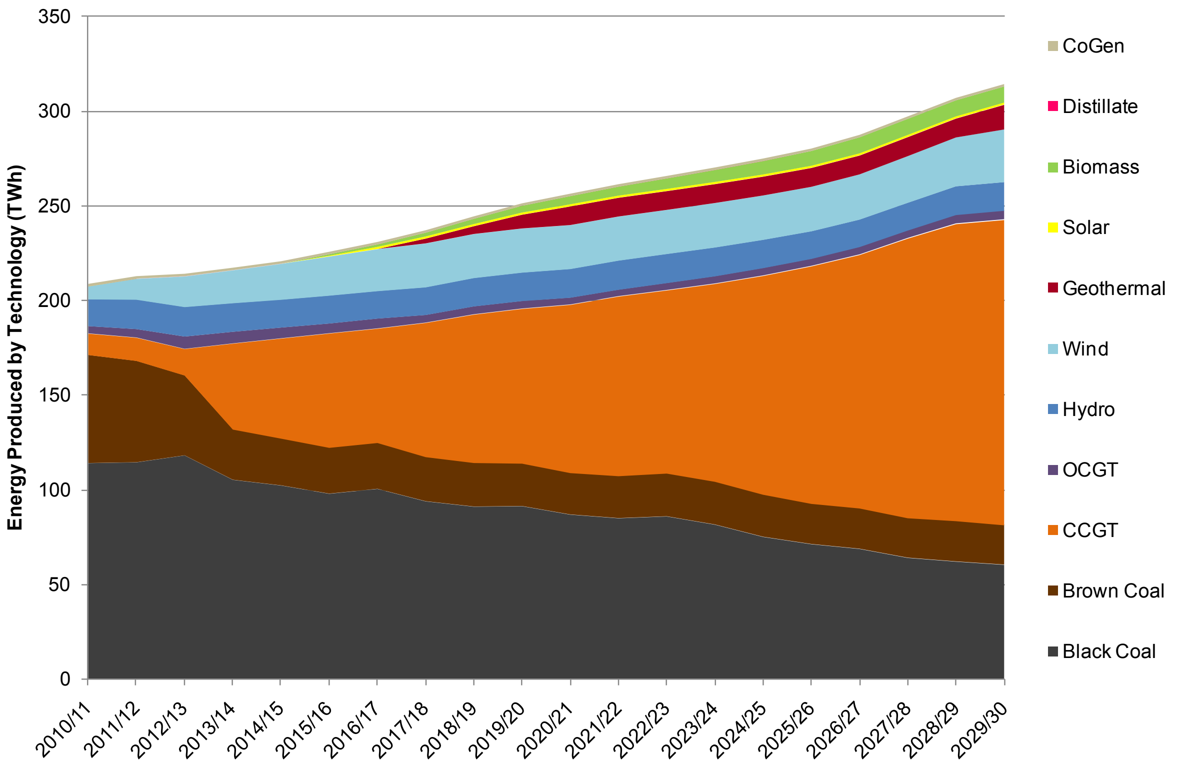


Figure 3-15 Total NEM generated energy by technology–DW-H (TWh)



3.5.2 Transmission development

Figure 3-16 shows a breakdown of transmission development projects by region under the Decentralised World (DW-M) scenario. For more information about individual projects, see Section 3.8.

Figure 3-16 Modelled augmentations by 2029/30 (DW-M)

Queensland

Under all scenarios, transmission development in Queensland is dominated by the development of the transmission network between the SWQ and SEQ zones to connect major generation and load centres, which is due to demand growth largely being met by new generation in the SWQ zone. Demand growth under the scenario (DW-M) is consistent with medium economic growth, and the new generation in the SWQ zone drives a move to a strong 500 kV system between the SWQ and SEQ zones. In addition to the committed 275 kV double circuit line, by the end of the 20-year outlook there are two new 500 kV double circuit lines between Western Downs in the SWQ zone and the load centres in the SEQ zone.

The timing and extent of the required SEQ zone augmentations is moderated by the introduction of new generation capacity within this zone, which more than offsets the retirement of Swanbank B.

Demand growth is sufficiently high under the DW-M scenario to drive substantial reinforcement within the SEQ zone, including further supply to the Brisbane, North Coast, and Gold Coast areas.

Additional transmission capacity from Calvale to Stanwell allows power to be transferred to meet the load growth in Gladstone and also north and south along this corridor. Although Collinsville Power Station is modelled to retire within the first five years of the outlook period, new solar and biomass generation in North Queensland defers development of the Central to North Queensland corridor until towards the end of the 20-year outlook period.

There is some need for additional transmission capacity north of Ross to support demand growth in the far north of the State.

New South Wales

The requirement for transmission network development is extensive. This is driven by high power flows from Northern New South Wales to the Central New South Wales load centres, which is due to significant levels of new generation in Northern New South Wales (north of the location of the major load centres and existing major generation centres), and a significant net reduction in generation capacity in central New South Wales.

New South Wales transmission network development is dominated by extensions of the 500 kV transmission network between the Hunter Valley and Northern New South Wales (inland), and the Hunter Valley and Eraring Power Station (via a substation at Newcastle).

Under the DW-M scenario, increased north to south power flow requires an additional 500/330 kV transformer at the Eraring Power Station, and upgrading/re-arranging the 330 kV circuits between the Central Coast and Sydney.

As generation at Wallerawang retires, an additional 330 kV Wallerawang-Mt Piper circuit is required to carry the re-distributed power flows.

Victoria

Significant new generation appears in the MEL zone, and all existing brown-coal generation at Energy Brix, Hazelwood, and Yallourn retires, with new LV zone generation appearing at the same locations. The existing 500 kV line capacity between Hazelwood and Melbourne can accommodate new generation in the LV zone, but additional 500 kV lines are required between Loy Yang and Hazelwood if new generation is connected at Loy Yang.

An additional 500 kV line between Moorabool and Heywood is required to accommodate increased generation in the MEL zone.

High load growth and up to 200 MW of exports from the CVIC to the NSA zone via Murraylink, requires replacement of a number of 220 kV lines with high capacity transmission lines, and additional 220 kV lines in the CVIC zone. A phase angle regulator on the 220 kV Buronga-Red Cliffs line has been identified to control power flow from Darlington to Buronga to Red Cliffs.

A moderate level of wind generation is distributed in the CVIC zone, and the transmission augmentation required to meet this scenario's high load growth and high exports to South Australia via Murraylink will be sufficient to accommodate this.

Load growth in the Greater Melbourne Metropolitan Area leads to moderate reinforcement of the area's 500 kV and 220 kV transmission networks. The location and timing of additional 500/220 kV transformers is subject to the location of new generation in the area and the load growth centres. A few 220 kV lines in the area require replacement with high temperature lines with significantly higher thermal capacity.

South Australia

South Australia sees moderate transmission network development due to moderate economic growth and new generation. Close to 70% of new non-wind generation occurs in the ADE zone in the form of gas-powered generation, and South Australia relies heavily on imports from Victoria to meet peak demand. Transmission network development is driven mainly by demand growth rather than generation development.

Both the scenario (DW-M) and the high carbon price sensitivity (DW-H) require the City West 275 kV bulk supply transmission system development in the ADE zone. The zone's transmission network reinforcement requirement is less extensive than scenarios with high economic growth (FC-H, FC-M, UW-L and UW-0), due to lower demand growth and less new generation. Under both the medium carbon price (DW-M) and the high carbon price sensitivity (DW-H), the NSA zone requires reinforcement of the 275 kV and 132 kV transmission networks supplying the Eyre Peninsula, and development of a new 230/132 kV substation in the Barossa area of the NSA zone. The requirement for a new 275/132 kV substation to overcome 132 kV York Peninsula transmission network overloading occurs approximately 5-10 years later than the scenarios with high economic growth.

In the SESA zone, augmentation is driven by imports, local load growth, and generation development. Under the scenario's high carbon price sensitivity (DW-H), the need for a third South East 275/132 kV transformer is identified towards the end of 20-year outlook period.

Under the medium carbon price scenario (DW-M), 275 kV series compensation is proposed, as the additional third transformer is unable to cope with the overload under peak load conditions. The increase in power flow through the SESA zone's 275 kV transmission network, together with decreased power flow through the South East 132 kV transmission network (as a result of installing 275 kV series compensation) pushes the requirement for a third South East transformer beyond the 20-year outlook period.

Tasmania

Under all scenarios, a large amount of wind generation is installed in Tasmania, with potential locations in the north-west (at Burnie, requiring augmentation of the 220 kV Burnie-Sheffield and Sheffield-Palmerston lines), north-east (requiring a 110 kV line uprating in the north-east, or connection to the 220 kV transmission network near George Town), and central Tasmania (connecting to the existing 220 kV network at Waddamana).

New biomass and gas-powered generation connects to the 220 kV transmission network near George Town, with the gas-powered generation being supplied locally from around the George Town area.

New gas-powered generation provides additional security and reliability to the major load centre in Hobart, with up to 200 MW being added in the area to Hobart's north, and augmentations to increase the capability of the existing gas transmission network, requiring an additional 220/110 kV transformation capacity around the Hobart and Burnie areas to meet the increased load growth.

A single asset failure on the 220 kV Palmerston-Waddamana line will lead to unserved energy in Southern Tasmania, requiring an additional 220 kV transmission line between Palmerston and Southern Tasmania.

3.6 Oil Shock and Adaptation scenario

Oil Shock and Adaptation (OS-M)[13] describes a world characterised by low reserves of oil, coupled with internationally agreed emissions targets. Weak economic growth and a moderate level of population growth is observed.

The scenario considers two carbon prices: a medium price trajectory to achieve a 15% emissions reduction, and a low price trajectory sensitivity to achieve a 5% emissions reduction.

3.6.1 Generation development

For the scenario and its sensitivity (respectively):

- Figure 3-17 and Figure 3-18 show the NEM's new generation capacity at the end of the 20-year outlook period.
- Figure 3-19 and Figure 3-20 show the energy production by fuel type over the course of the 20-year outlook period.

The combination of high gas prices and reduced hydroelectric inflows significantly impacts new generation. Unlike the other scenarios, no combined-cycle gas turbine (CCGT)-type generation proceeds under either the scenario (OS-M) or its low carbon price sensitivity (OS-L). Compared to other scenarios, a moderate level of open-cycle gas turbine (OCGT)-type generation proceeds in zones hosting the major load centre for each region, and 1,500 MW and 750 MW of new black coal

[13] Identified as OS-L under the low carbon price sensitivity.

(without CCS) generation proceeds in the SWQ and NCEN zones, respectively, despite the medium carbon price.

High gas prices encourage new renewable generation. Approximately 4,000 MW of wind generation and a significant level of new geothermal generation (the highest of all the scenarios) proceeds, despite this scenario's lower energy and demand projections. The most geothermal generation proceeds in the CVIC and LV zones. By 2016/17, 1,000 MW of solar thermal generation proceeds (under the Solar Flagships program), while a further 1,200 MW of solar thermal and 1,200 MW of biomass generation is installed by 2029/30. A substantial amount of brown coal generation retires, and a lesser amount of black coal. The scenario's low carbon price sensitivity (OS-L) shows more black coal in the SWQ zone, as well as new OCGT-type generation, less geothermal generation, and the most wind generation installed of all the scenarios (9,700 MW). There are also less generation retirements.

Key assumptions impacting new generation include the following:

- Low electrical energy and demand growth.
- The availability of geothermal and CCS-type technology.
- An assumption of ongoing drought conditions in Australia, causing hydroelectric system inflows to fall to 85% of their long-term average.
- High gas price growth, reflected by the absence of high utilisation gas-powered generation like CCGT, and coal-fired generation without CCS proceeding despite a carbon price.
- An average risk premium reflected in an average level of weighted average cost of capital (WACC) of all the scenarios (9.79%).

The energy production shows that for the duration of the 20-year outlook period, black coal generation increases slightly, brown coal generation decreases, and renewables show a substantial increase in total energy provided. The scenario's low carbon price sensitivity (OS-L) is similar, though the reduction of brown-coal generation is more gradual and occurs later in the 20-year outlook period. As for other scenarios, the actual generation from OCGT is relatively low.

The LRET target is achieved in the scenario (OS-M) with renewable energy production 90% above the target by 2029/30, while the target is only just met in the low carbon price sensitivity (OS-L).

Figure 3-17 Total NEM new generation capacity in 2029/30 by technology—OS-M (MW)

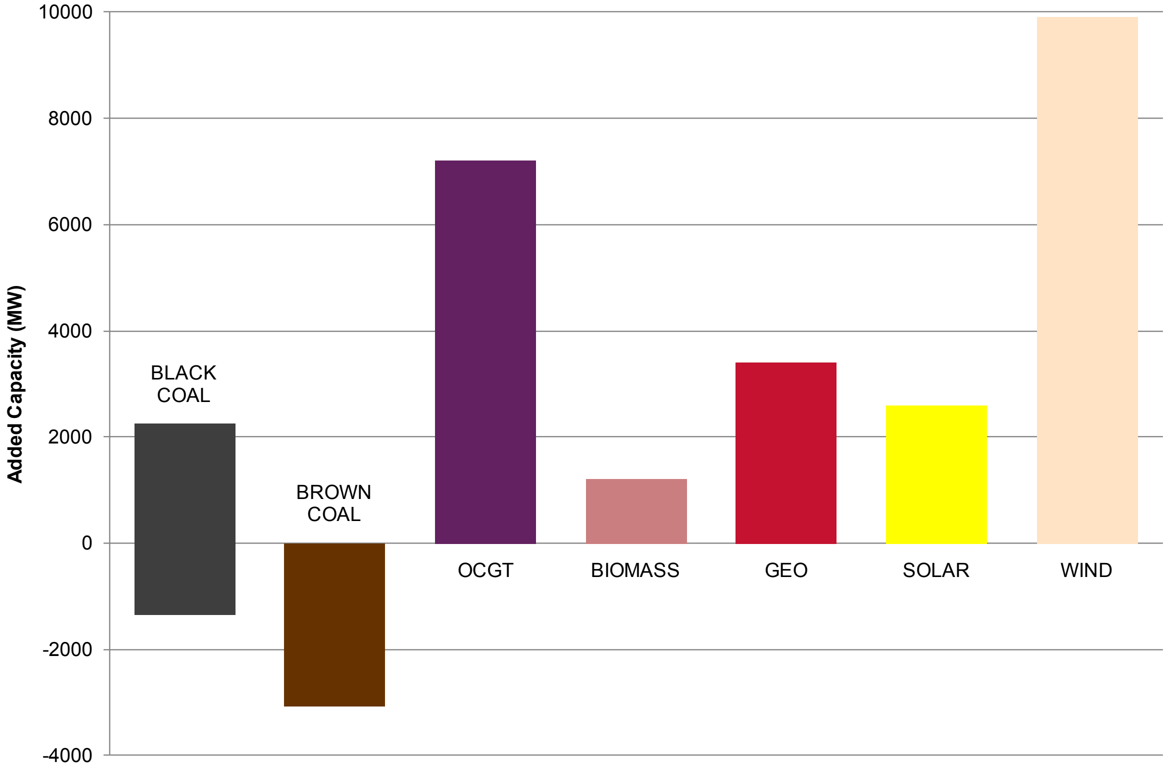


Figure 3-18 Total NEM new generation capacity in 2029/30 by technology–OS-L (MW)

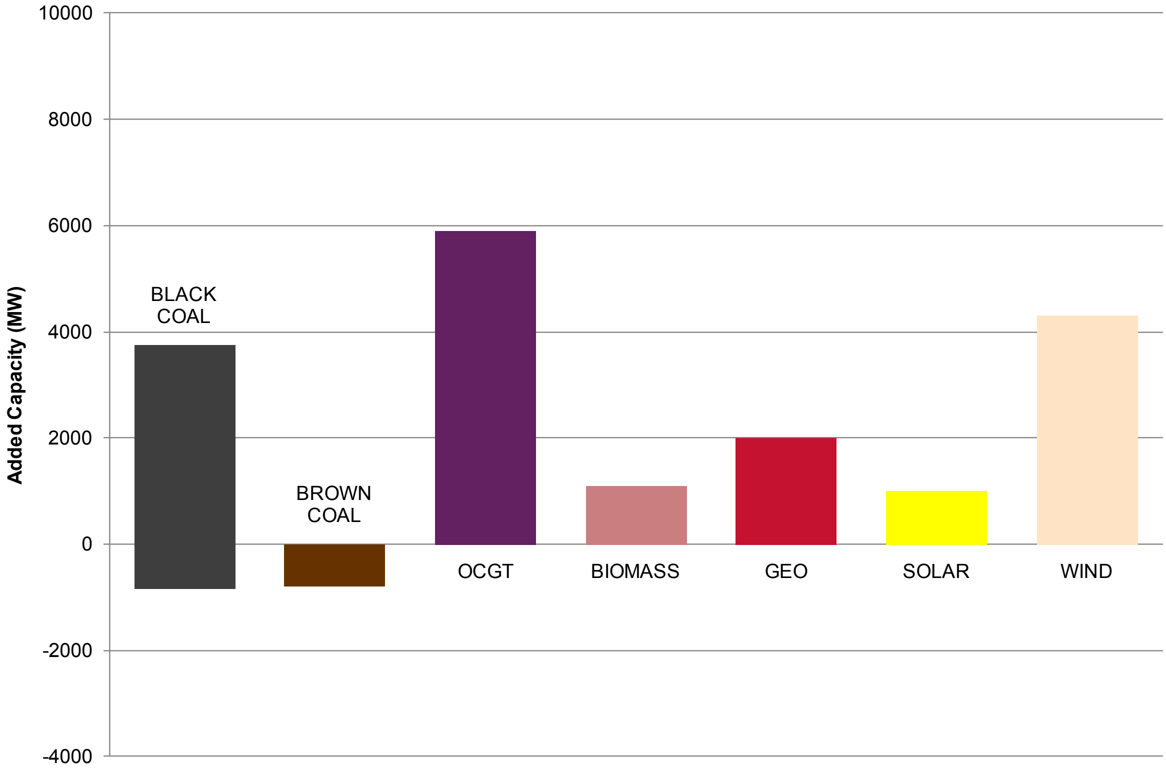


Figure 3-19 Total NEM generated energy by technology–OS-M (TWh)

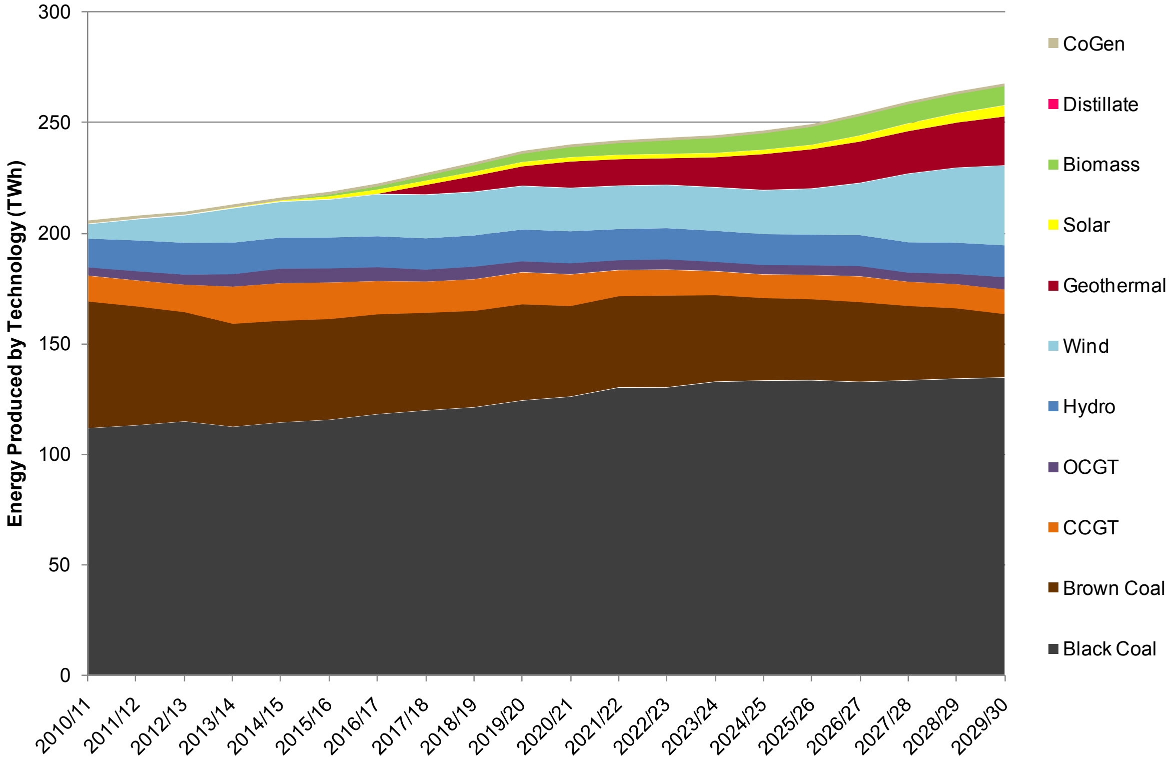
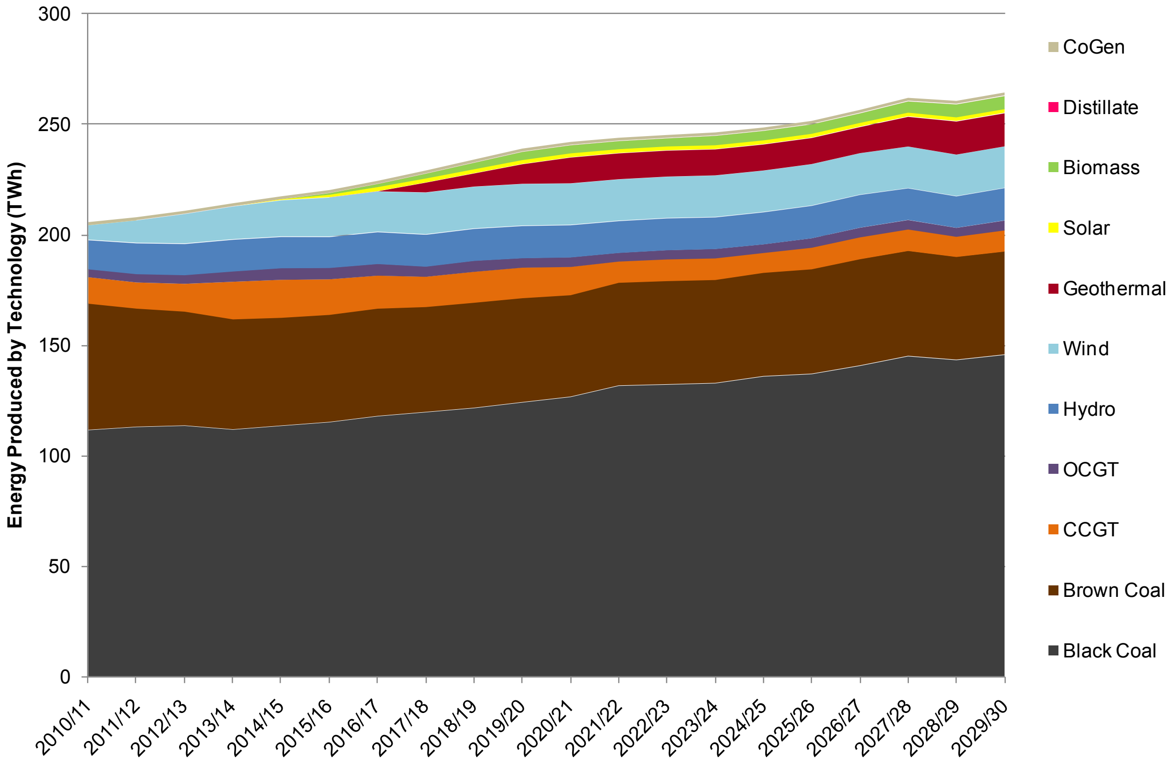


Figure 3-20 Total NEM generated energy by technology–OS-L (TWh)



3.6.2 Transmission development

Figure 3-21 shows a breakdown of transmission development projects by region under the Oil Shock and Adaptation (OS-M) scenario. For more information about individual projects, see Section 3.8.

Figure 3-21 Modelled augmentations by 2029/30 (OS-M)

Queensland

Under all scenarios, transmission development in Queensland is dominated by the development of the transmission network between the SWQ and SEQ zones to connect major generation and load centres, which is due to demand growth largely being met by new generation in the SWQ zone. Demand growth under the scenario (OS-M) is consistent with low economic growth, and new generation in the SWQ zone drives a move to a strong 500 kV transmission network between SWQ and SEQ. In addition to the committed 275 kV double circuit line, by the end of the 20-year outlook period, there are two new 500 kV double circuit lines between Western Downs in the SWQ zone and the load centres in the SEQ zone. The need for this additional line occurs later than in scenarios with higher demand growth, and the line is not upgraded to 500 kV within the 20-year outlook period.

The timing and extent of the required SEQ zone augmentations is moderated by the introduction of new generation capacity within this zone, which more than offsets the retirement of Swanbank B.

Lower demand growth under this scenario defers the need for much of the reinforcement within the SEQ zone that is seen under scenarios with higher demand growth. However, there is still need for some reinforcement of supply to the Brisbane area.

Additional transmission capacity from Calvale to Stanwell is still required to reliably transfer power towards Gladstone and the north and south of the State. However, this augmentation is also deferred to the second half of the 20-year outlook period.

More solar thermal generation proceeds under this scenario. New solar and biomass generation in North Queensland, coupled with the low load growth, defers further development of the Central to North Queensland corridor.

There is some need for additional transmission capacity north of Ross to support demand growth in the far north of the State, but only towards the end of the 20-year outlook period.

The Queensland to New South Wales (QNI) interconnector is augmented in 2014/15 in the least-cost modelling for both the scenario (OS-M) and its sensitivity (OS-L), providing for increased transfer capability between Queensland and New South Wales. The utilisation of QNI in the southerly direction progressively decreases, with New South Wales less reliant on imports from Queensland.

New South Wales

Modest new generation mostly occurs in Central New South Wales, the location of major load centres and existing generation.

Transmission network development is also modest, dominated by the 500 kV Bannaby-Sydney transmission network expansion, which is being driven by new gas-powered generation in the Marulan and Dapto areas. The timing of this project depends heavily on the location of new (mainly gas-powered) generation in Central New South Wales. Augmentation of Western and Southern parts of the Sydney 330 kV ring is driven by rapid load growth in the Sydney load centre.

Victoria

Low demand leads to the retirement of all existing brown-coal generation at Energy Brix and part of the generation at Hazelwood. Under the scenario (OS-M), part of Yallourn generation is retired towards 2030. When considering the amount of retired generation, there is no net additional generation in the LV zone.

There is significant new gas-powered generation in the MEL zone, and geothermal and a moderate level of wind generation in the CVIC zone. An additional 500 kV line between Moorabool and Heywood is required to accommodate the increased MEL zone generation.

Increased load growth, and up to 200 MW exports from the CVIC to the NSA zone via Murraylink, requires the replacement of several 220 kV lines with high capacity transmission lines, and some additional 220 kV lines in the CVIC zone. A phase angle regulator on the 220 kV Buronga-Red Cliffs line has been identified to control the power flow from Darlington to Buronga to Red Cliffs.

The transmission augmentations required to meet high load growth and high exports to South Australia via Murraylink are sufficient to accommodate the new generation in the CVIC zone.

Load growth in the Greater Melbourne Metropolitan Area requires two additional 500/220 kV transformers in this area. One 220 kV double circuit radial line in the area requires replacement with high temperature lines with significantly higher thermal capacity.

South Australia

Development in South Australia is not significant due to less new generation and low economic growth. From a supply-demand balance perspective, South Australia relies heavily on imports from Victoria to meet peak demand.

The City West 275 kV bulk supply system development in the ADE zone is required under both the scenario (OS-M), and the low carbon price sensitivity (OS-L). The network reinforcement requirement is less extensive, when compared to the high economic growth scenarios - Fast Rate of Change (FC-H and FC-M) and Uncertain World (UW-L and UW-0) - due to lower demand growth and low levels of new generation. In the NSA zone, however, both carbon prices require reinforcing the 275 kV and 132 kV transmission network supplying the Eyre Peninsula, and development of a new 230/132 kV substation in the Barossa area of the NSA zone. A new 275/132 kV substation to supply York Peninsula load is not required within the 20-year outlook period.

South Australia relies on imports from Victoria to meet peak demand due to a shortage of new generation. In the meantime, extensive new wind and geothermal generation in South Australia leads to significant congestion associated with exports from South Australia to Victoria under non-peak load conditions. An incremental upgrade of the Heywood interconnector’s existing capacity proceeds in the least cost model towards the end of the 20-year outlook period under a medium carbon price (OS-M).

Tasmania

Under all scenarios a large amount of wind generation is installed in Tasmania (up to 2,050 MW), with potential locations in the north-west (at Burnie, requiring augmentation of the 220 kV Burnie-Sheffield and Sheffield-Palmerston lines), north-east (requiring uprating of 110 kV lines in the north-east or connections to the 220 kV transmission network near George Town), and central Tasmania (connecting to the existing 220 kV network at Waddamana).

New biomass generation connects to the 220 kV transmission network near George Town, and there is no new gas-powered generation. Additional 220/110 kV transformation capacity is required around the Hobart and Burnie areas to meet the increased load growth.

A single asset failure on the 220 kV Palmerston-Waddamana line will lead to unserved energy in Southern Tasmania, requiring an additional 220 kV transmission line between Palmerston and Southern Tasmania.

3.7 Slow Rate of Change scenario

Slow Rate of Change (SC-L)[14] describes a world characterised by low economic growth, coupled with internationally agreed low emission targets. Weak economic growth and low population growth is observed.

The scenario considers two carbon prices: a low price trajectory to achieve a 5% emissions reduction, and a zero price trajectory.

3.7.1 Generation development

For the scenario and its sensitivity (respectively):

- Figure 3-22 and Figure 3-23 show the NEM's new generation capacity at the end of the 20-year outlook period.
- Figure 3-24 and Figure 3-25 shows the energy production by fuel type over the course of the 20-year outlook period.

Similarly to the Uncertain World scenario (UW-L), new generation capacity predominantly includes:

- open-cycle gas turbines (OCGT located in zones hosting the major load centre for each region, and
- combined-cycle gas turbines (CCGT) located in the NNS and SWQ zones.

Along with the Fast Rate of Change scenario (FC-H), SC-L is the only other scenario where CCGT with CCS technology proceeds, located in the LV zone.

[14] Identified as SC-0 under the zero carbon price sensitivity.

The full suite of renewable generation technologies (geothermal, biomass, solar thermal under the Solar Flagships program, and wind) are implemented, though installed capacities are not significant, reflecting low energy and demand growth. There is no new coal-fired generation, and significant black and brown coal-fired generation retirement (the most of all the scenarios with a low carbon price). Under the scenario's zero carbon price sensitivity (SC-0), there are no retirements, with some black coal-fired generation in the SWQ zone proceeding, less CCGT, and no CCGT with CCS . The zero carbon price sensitivity (SC-0) also sees the lowest amount of new wind generation of all the studies considered.

Key assumptions impacting new generation include the following:

- Low electrical energy and demand growth.
- The availability of geothermal and CCS-type technology.
- The availability of lower cost geothermal and CCS-type technology (relative to the other scenarios).
- The medium growth of gas prices.
- A high risk premium due to uncertainty reflected in the highest weighted average cost of capital (WACC) of all the scenarios (11.78%).

Energy production shows that over the duration of the 20-year outlook period, there are decreases in brown coal-fired and to a lesser extent black coal-fired generation, while CCGT generation increases significantly, especially during the second half of the outlook period. The SC-0 sensitivity shows black coal-fired generation increasing and brown coal-fired generation and CCGT remaining relatively constant over the 20-year outlook period, while (like the other scenarios) actual energy production from OCGT is relatively low.

The LRET target is met under the scenario (SC-L) in every year except 2016/17, when it falls slightly below its target, while it is not met prior to 2023/24 in the zero carbon price sensitivity (SC-0).

Figure 3-22 Total NEM new generation capacity in 2029/30 by technology–SC-L (MW)

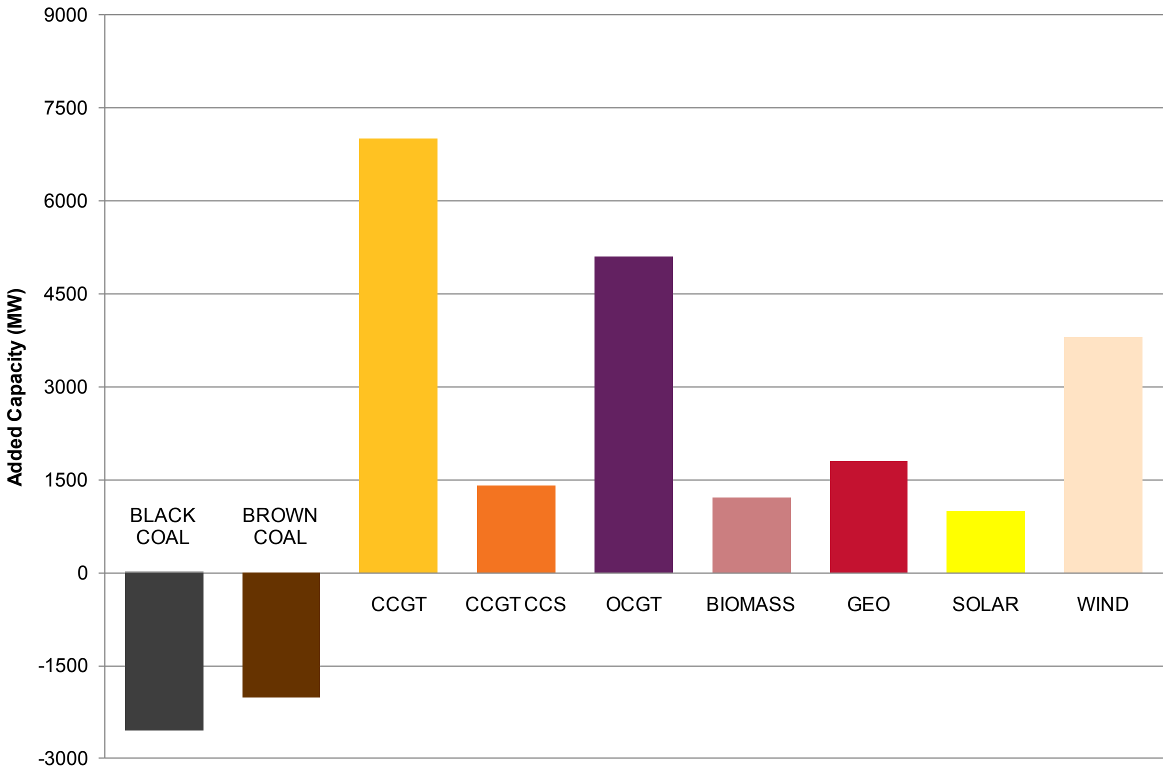


Figure 3-23 Total NEM new generation capacity in 2029/30 by technology–SC-0 (MW)

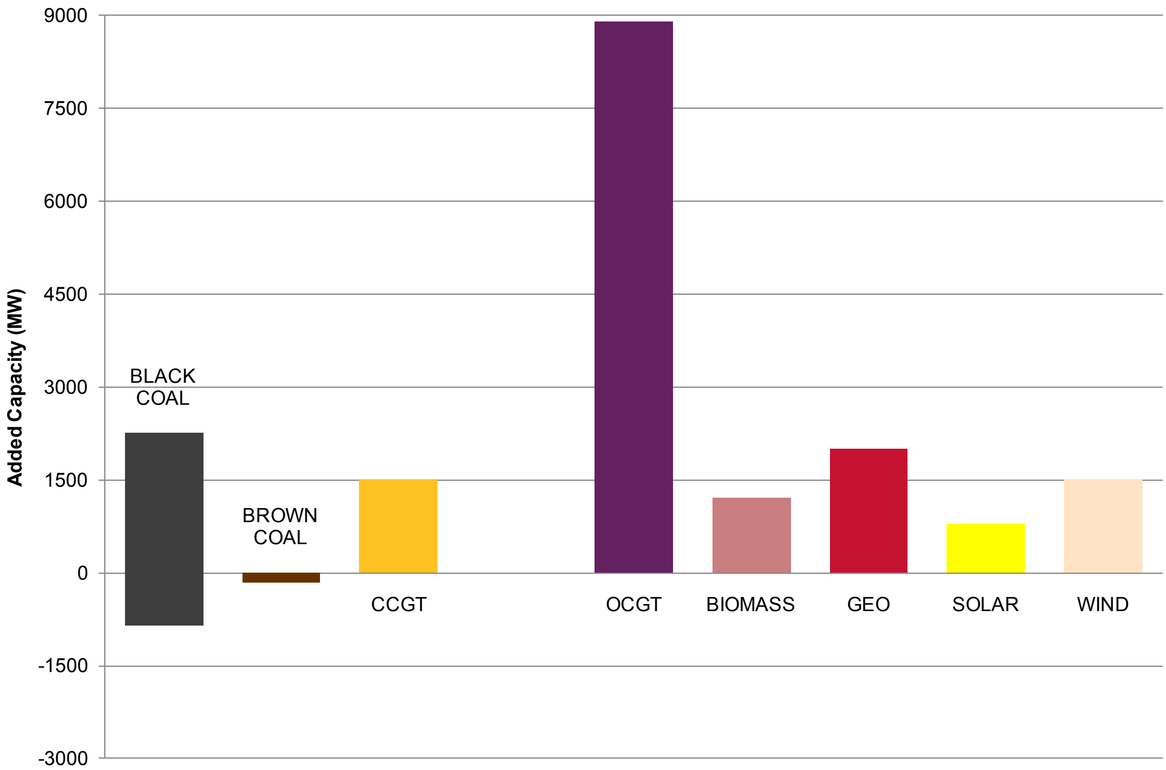


Figure 3-24 Total NEM generated energy by technology–SC-L (TWh)

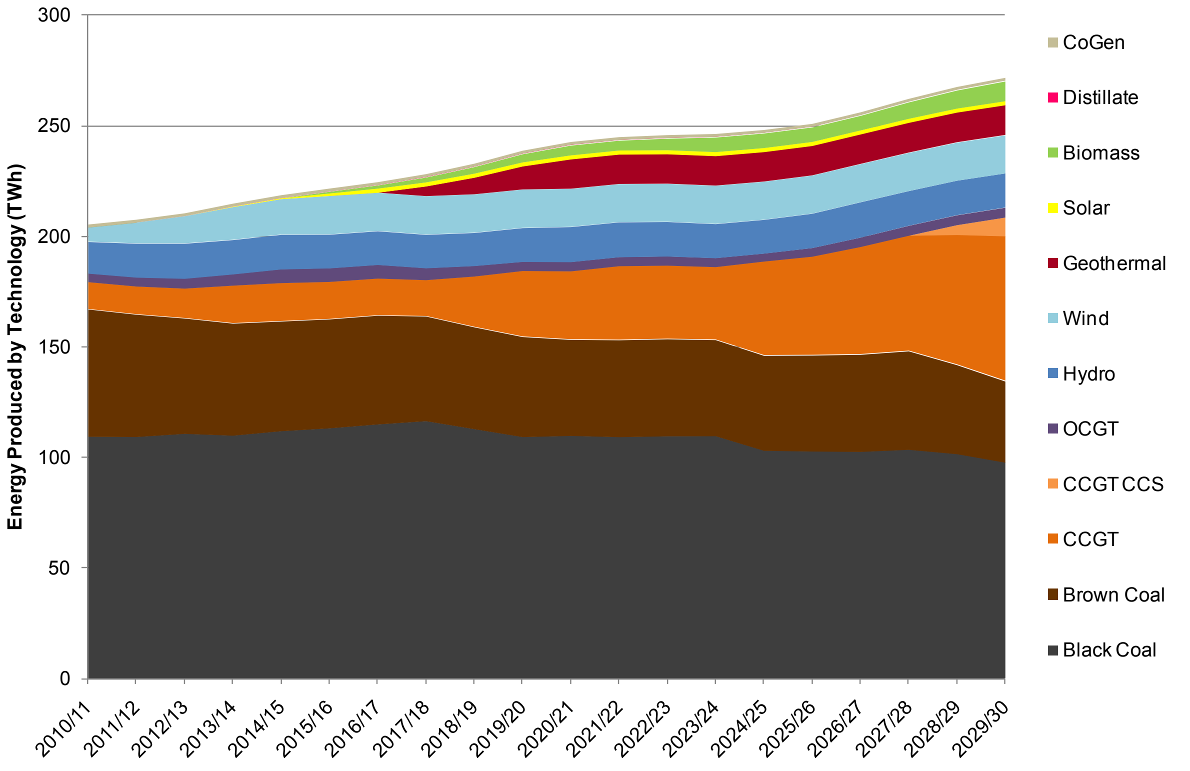
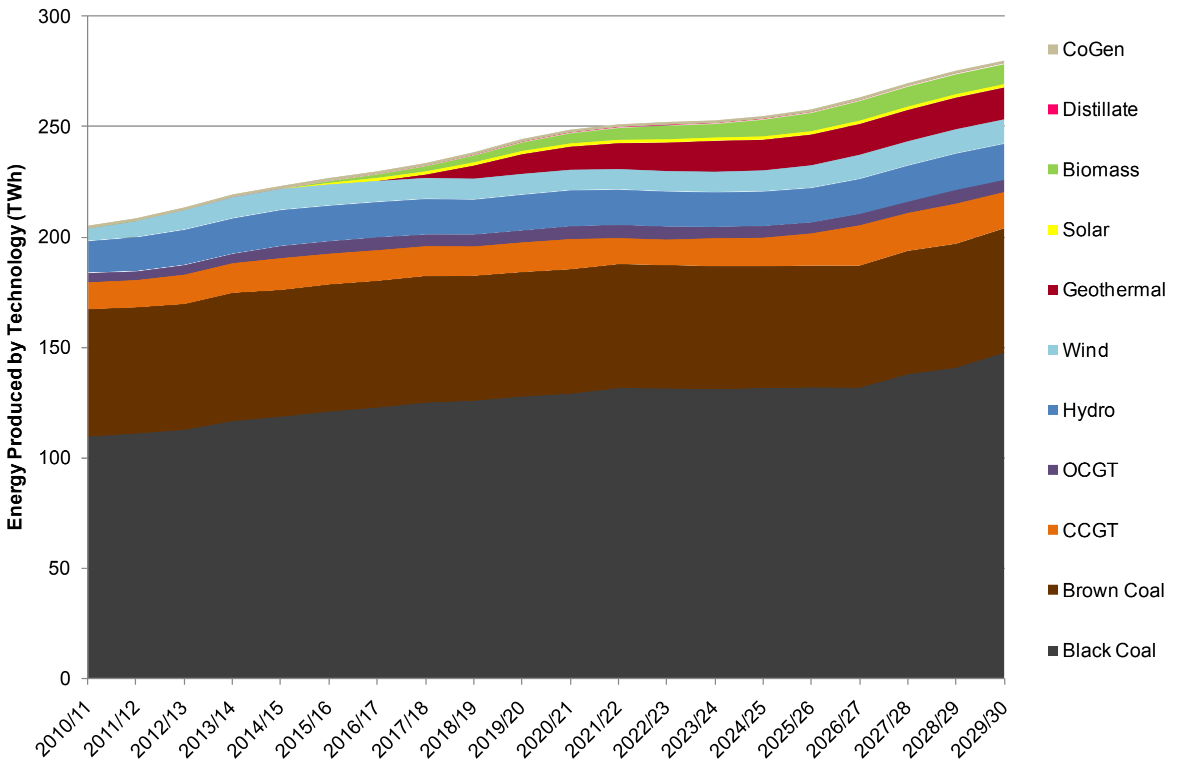


Figure 3-25 Total NEM generated energy by technology–SC-0 (TWh)



3.7.2 Transmission development

Figure 3-26 shows a breakdown of transmission development projects by region under the Slow Rate of Change (SC-L) scenario. For more information about individual projects, see Section 3.8.

Figure 3-26 Modelled augmentations by 2029/30 (SC-L)

Queensland

Under all scenarios, transmission development in Queensland is dominated by the development of the transmission network between the SWQ and SEQ zones to connect major generation and load centres, which is due to demand growth largely being met by new generation in the SWQ zone. Demand growth under the scenario (SC-L) is consistent with low economic growth, and new generation in the SWQ zone drives a move to a strong 500 kV transmission network between SWQ and SEQ. In addition to the committed 275 kV double circuit line, by the end of the 20-year outlook there are two new 500 kV double circuit lines between Western Downs in the SWQ zone and the load centres in the SEQ zone. The need for this additional line occurs later than in scenarios with higher demand growth, and the line is not upgraded to 500 kV within the 20-year outlook period.

The timing and extent of the required SEQ zone augmentations is moderated by the introduction of new generation capacity within this zone, which more than offsets the retirement of Swanbank B.

Lower demand growth under this scenario defers the need for much of the reinforcement within the SEQ zone that is seen under scenarios with higher demand growth. However, there is still a need for some reinforcement for supply to the Brisbane and Gold Coast areas.

Additional transmission capacity from Calvale to Stanwell is still required to reliably transfer power towards Gladstone and the north and south of the State. However, this augmentation is also deferred to the second half of the 20-year outlook period. New solar and biomass generation in North Queensland coupled with the low load growth defers further development of the Central to North Queensland corridor.

There is some need for additional transmission capacity north of Ross to support demand growth in the far north of the State, but only towards the end of the 20-year outlook period.

The Queensland to New South Wales (QNI) interconnector is augmented in 2014/15 in the least cost modelling for the scenario (SC-L), providing for increased transfer capability between Queensland and New South Wales. The utilisation of QNI in the southerly direction progressively decreases, with New South Wales less reliant on imports from Queensland.

The Queensland to New South Wales (QNI) interconnector is augmented in 2014/15 on the basis of delivering net market benefits under the scenario's zero carbon price sensitivity (SC-0).

New South Wales

There are very different levels of new generation under the scenario (SC-L) and the zero carbon price sensitivity (SC-0), and different transmission network development requirements.

The sensitivity (SC-0) sees most new generation occurring in Central New South Wales, the location of the major load and existing major generation centres. Little major transmission network development has been identified. A 500 kV Sydney-Bannaby-Yass-Wagga area double circuit line is also developed to support a super-critical black coal generation development. Had this new generation been concentrated in the Marulan and Dapto areas, this sensitivity would have seen the 330 kV Bannaby-Sydney circuit upgraded to (or replaced by) 500 kV circuits.

The scenario (SC-L) sees most new generation occurring in Northern New South Wales, and significant generation retirement in Central New South Wales. Transmission network development is extensive, driven by high power flows from Northern New South Wales to the Central New South Wales load centres. Extensions of the 500 kV transmission network dominate development of the New South Wales transmission network. These occur between the Hunter Valley and Northern New South Wales (inland), and the Hunter Valley and Eraring Power Station via a substation at Newcastle. Increased southward power flows result in the upgrade/re-arrangement of the 330 kV circuits between the Central Coast and Sydney. As Wallerawang generation retires, an additional 330 kV Wallerawang-Mt Piper circuit is required to carry the re-distributed power flows.

Victoria

There are very different levels of new generation under the scenario (SC-L) and the zero carbon price sensitivity (SC-0). Under the scenario, new generation capacity in the LV zone exactly offsets generation retirements. Under the sensitivity, there is an additional 400 MW, and the existing 500 kV lines between the LV and MEL zones are sufficient to accommodate this increase.

New gas-powered generation proceeds in the MEL zone, and geothermal generation proceeds in the CVIC zone. Under the scenario, an additional 500 kV line between Moorabool and Heywood is required to accommodate this increased MEL zone generation.

Increased load and up to 200 MW of exports from the CVIC to the NSA zone via Murraylink leads to a number of 220 kV lines being replaced with high capacity transmission lines, and the addition of 220 kV lines in the CVIC zone. A phase angle regulator on the 220 kV Buronga-Red Cliffs line has been identified to control the power flow from Darlington to Buronga to Red Cliffs. A moderate level of wind generation is distributed in the CVIC zone, which is accommodated by the transmission augmentations required to meet high load growth generally, and high exports to South Australia via Murraylink.

Load growth in the Greater Melbourne Metropolitan Area requires the addition of two new 500/220 kV transformers in the metropolitan area. One 220 kV double circuit radial line in the area requires replacement with high temperature lines with significantly higher thermal capacity.

South Australia

Transmission development is not significant, as in most areas major transmission network developments implemented early in the 20-year outlook period provide sufficient capacity to accommodate moderate levels of new generation and demand growth later on.

Both the scenario (SC-L) and the zero carbon price sensitivity (SC-0) require development of the City West 275 kV bulk supply system in the ADE zone, requiring reinforcement of the 275 kV and 132 kV transmission network supplying the Eyre Peninsula, and development of a new 230/132 kV substation in the Barossa area of the NSA zone.

The sensitivity (SC-0) requires a new 275/132 kV substation on the York Peninsula, and installation of 275 kV series compensation in the SESA zone, with the former driven by higher demand growth, and the latter driven by higher import requirements (compared to SC-L).

Tasmania

Under all scenarios, a large amount of wind generation is installed in Tasmania (up to 2,050 MW), with potential locations in the north-west (at Burnie, requiring augmentation of the 220 kV Burnie-

Sheffield and Sheffield-Palmerston lines), north-east (requiring uprating of 110 kV lines in the north-east or connections to the 220 kV transmission network near George Town), and central Tasmania (connecting to the existing 220 kV network at Waddamana). There is a moderate amount of new wind generation in the sensitivity (SC-0), requiring uprating of the 110 kV line in the north-east.

New biomass and gas-powered generation connects to the 220 kV transmission network near George Town, with the gas-powered generation being supplied locally from around the George Town area.

New gas-powered generation provides additional security and reliability to the major load centre in Hobart, with up to 200 MW being added in the area to Hobart's north, requiring augmentations to increase the capability of the existing gas transmission network, and an additional 220/110 kV transformation capacity around the Hobart and Burnie areas to meet the increased load growth. No new gas-powered generation is added under the scenario (SC-L).

A single asset failure on the 220 kV Palmerston-Waddamana line will lead to unserved energy in Southern Tasmania, requiring an additional 220 kV transmission line between Palmerston and southern part of Tasmania.

3.8 Transmission Network Augmentations

This section provides a reference list of the transmission network augmentations modelled by 2029/30.

Table 3-1 Modelled augmentations by 2029/30

Dev No	Transmission development
Q1	A new Ross-Chalumbin double-circuit line (single circuit strung)
Q2	Stringing an additional 275 kV Stanwell-Broadsound circuit
Q3	Broadsound-Nebo 275 kV series capacitors
Q4	A new 275 kV Calvale-Stanwell double circuit line
Q5	Switch the 275 kV Gladstone-Gin Gin circuit into 275 kV Wurdong
Q6	A new 275 kV Broadsound-Lilyvale single circuit line
Q7	A 275 kV Calvale-Larcom Creek double circuit line
Q8	Rebuild 275 kV Larcom Creek-Gladstone double circuit line
Q9	A new 275 kV Calvale-Wurdong double circuit line
Q10	A new 500 kV Halys-Greenbank double circuit line (initially operating at 275 kV)
Q11	A new 500 kV Western Downs-Halys double circuit line (northern route first build) initially operating at 275 kV
Q12	Upgrade 275 kV Western Downs-Halys (northern route first build) and 275 kV Halys-Blackwall to 500 kV
Q13	A new 500 kV Western Downs-Halys double circuit line (northern route second build) and upgrade the 275 kV Halys-Greenbank line to 500 kV
Q14	A new 275 kV Blackwall-Belmont double circuit line
Q15	A new 275 kV Blackwall-South Pine double circuit line
Q16	A new 275 kV Loganlea-Greenbank double circuit line (one circuit strung)

Dev No	Transmission development
Q17	Rebuild the 275 kV Greenbank-Mudgeeraba single circuit to double circuit
Q18	A new 275 kV Greenbank-Molendinar double circuit line
Q19	A new 275 kV South Pine-Palmwoods double circuit line
Q20	The 275 kV South Pine-Rocklea circuit diverted directly into Blackwall and a new 275 kV Blackwall-Rocklea single circuit
Q21	A new 275 kV Blackwall-Rocklea double circuit line
Q22	String a second circuit of the 275 kV Loganlea-Greenbank double circuit line
Q23	Uprate the 275 kV Greenbank-Swanbank circuit (+200 MVA)
QN1	Series compensation on the 330 kV Armidale-Dumaresq circuits and 330 kV Dumaresq-Bulli Creek 330 kV circuits
N1	500 kV Bannaby-Yass line development
N3	500 kV Bannaby-Sydney double circuit line development
N4	500 kV Hunter Valley-Eraring via Newcastle development
N5	500/330 kV Eraring Power Station transformer replaced with 1,500 MVA unit and add new parallel 500/330 kV Eraring Power Station transformer
N6	Greater Newcastle/Central Coast area, install an additional 500/330 kV transformer
N7	500 kV Hunter Valley-Northern New South Wales development (three circuits)
N8	500 kV Hunter Valley-Northern New South Wales development (four circuits)
N9	Upgrade high voltage 330 kV Ingleburn-Wallerawang Power Station connections (77) Address attendant voltage control issues for Sydney 330 kV system
N10	330 kV Mt Piper-Wallerawang additional 330 kV circuit development
N11	330 kV Kemps Creek-Liverpool circuit development
N12	Kemps Creek-Sydney West or Sydney South 330 kV circuit development
N13	Kemps Creek replace 500/330 kV transformer-1,500 MVA and add new parallel transformer (for a total of three)
N14	Install a 500/330 kV parallel transformer at future Sydney 500 kV substation
N15	Rearrange Central Coast 330 kV connections and install line series reactors-redistribute power flows
N16	330 kV Sydney North-Vales Point Power Station circuit (22), circuit upgrade for a rating of 1,215/1,429 MVA
NV1	A new 220 kV, 250 MVA phase angle regulator on 220 kV Buronga-Red Cliffs interconnection
NV2	Victoria-New South Wales Interconnection upgrade involving: • installation of a fourth 330/220 kV Dederang transformer and a third 700 MVA 330/220 kV South Morang transformer • a phase angle regulator on the 330 kV Jindera-Wodonga circuit • uprating of the 220 kV Eildon-Thomastown and 330 kV South Morang-Dederang circuits • a cut-in of the 220 kV Rowville-Thomastown circuit at South Morang, and • series capacitors on the 220 kV Eildon-Thomastown and 330 kV Wodonga-Dederang circuits
S1	Increase the ratings of both 275 kV Torrens Island B-Kilburn and Torrens Island B-Northfield circuits to line design ratings by relevant protection and selected plant modifications
S2	Increase the rating of the 275 kV Northfield-Kilburn circuit to line design rating by relevant protection and selected plant modifications
S3	Cut-in the 275 kV Torrens Island B-Cherry Gardens circuit at Para. Increase the rating of the 275 kV Torrens Island B-Para circuit to line design rating by relevant protection and selected plant modifications
S4	Establish the second 275 kV Davenport-Cultana line and reinforcement of 275/132 kV transformation capacity at Cultana, and rearrangement of the132 kV Davenport-Whyalla and Whyalla-Middle back/Yadnarie lines

Dev No	Transmission development
S5	Establish a 275/132 kV injection point in the vicinity of Hummocks with 1 x 200 MV.A transformer, and construct a 275 kV double circuit line from the existing West circuit to the substation location
S6	Uprate the 275 kV Para -Brinkworth-Davenport circuits from 65 °C to 80 °C
S7	Install the second 275/132 kV Templers transformer (No.4) in conjunction with 132 kV network reconfiguration
S8	Install 275 kV series compensation between South East Substation and Tailem Bend Substation
S9	Install the third South East 275/132 kV transformer
S10	Rebuild the existing 132 kV Mt Gambier-Blanche circuit as a high capacity circuit
S11	Rebuild the existing South East-Mt Gambier into double circuits
T1	Waddamana switching configuration and upgrade of 110 kV Palmerston-Waddamana line to 220 kV operation
T2	Uprate the 110 kV Norwood-Scottsdale line or connection of new generation to 220 kV network along Hadspen-George Town corridor
T3	Replace the existing 220 kV Burnie-Sheffield single circuit line with a new 220 kV double circuit line
T4	A new 220 kV Sheffield-Palmerston double circuit line
T5	A new 220/110 kV transformer in the Hobart area
T6	A new 220/110 kV 200 MVA transformer (2nd) at Burnie Substation
T7	A new 220/110 kV 150 MVA transformer (2nd) at Palmerston Substation or new 220/110 kV substation at Longford or Riverside
V1	A new 500 kV Loy Yang-Hazelwood line
V2	A new 500 kV Hazelwood-Cranbourne line and cut-in the existing 500 kV Hazelwood-Rowville line at Cranbourne
V3	A new 500 kV Hazelwood-Coldstream line; Reuse of 500 kV Coldstream-Templestowe line; 500 kV Templestowe switchyard; 220 kV Upgrade Rowville-South Morang line to 500 kV operation and cut-in at Templestowe
V5	A new 500/220 kV 1,000 MVA transformer at Ringwood, Rowville or Cranbourne
V6	An additional 500/220 kV 1,000 MVA transformer at Ringwood, Rowville or Cranbourne
V7	Re-conductor 220 kV Rowville-Springvale line
V8	A new 500 kV Moorabool-Mortlake/Heywood line (3rd line)
V9	A new 330/220 kV 700 MVA transformer at South Morang (3rd transformer), and a cut-in of the 220 kV Rowville-Thomastown circuit at South Morang to form a third 220 kV South Morang-Thomastown line
V10	Re-conductor the 220 kV Brunswick-Thomastown circuits
V11	Re-conductor the 220 kV Heatherton-Springvale circuits
V12	Cut-in the 220 kV Rowville-Templestowe line at Ringwood, and cut-in the 220 kV Thomastown-Ringwood line at Templestowe
V13	An additional 500/220 kV 1,000 MVA transformer in the eastern part of the Greater Melbourne Metropolitan Area
V14	An additional 500/220 kV 1,000 MVA transformer in the western part of the Greater Melbourne Metropolitan Area
V15	An additional 500/220 kV 1,000 MVA transformer in the western part of the Greater Melbourne Metropolitan Area
V16	Cut-in the 220 kV Eildon-Thomastown line at South Morang
V18	An additional 500/220 kV 1,000 MVA transformer in the eastern part of the Greater Melbourne Metropolitan Area
V19	An additional 500/220 kV 1,000 MVA transformer in the eastern part of the Greater Melbourne Metropolitan Area

Dev No	Transmission development
V20	An additional 500/220 kV 1,000 MVA transformer in the western part of the Greater Melbourne Metropolitan Area
V21	A new 500 kV line Moorabool-Mortlake/Heywood (4th line)
V22	A new 330/220 kV Dederang transformer (4th)
V27	Replace the 220 kV Dederang-Glenrowan circuits with a 220 kV double circuit line
V28	A new 220 kV Ballarat-Moorabool line (3rd line)
V29	Replace the existing single circuit 220 kV Ballarat-Bendigo line with a 220 kV double circuit line
V30	Uprate the existing 220 kV Geelong-Moorabool lines
V31	Uprate the existing 220 kV Ballarat-Bendigo line
V32	Replace the existing 220 kV single Bendigo-Kerang circuit line with a new 220 kV double circuit line
V34	Replace the existing 220 kV Kerang-Wemen-Red Cliffs single circuit line with a new 220 kV double circuit line
V35	Uprate the No.1 220 kV Ballarat-Moorabool line
V36	A new 220 kV Moorabool-Geelong line (3rd line)
V37	Replace the existing No.1 220 kV Moorabool-Ballarat single circuit tower with 220 kV double circuit line
V38	Uprate the 220 kV Moorabool-Terang line
V39	Uprate the 220 kV Ballarat-Horsham line
VS1	A third Heywood 500/275 kV transformer, a 100 MVAr capacitor bank at South East Substation, 275 kV series compensation between the South East Substation and Tailem Bend Substation, a SVC at Tailem Bend, increase of the relevant circuit ratings to line design ratings by protection and selected plant modifications
VS2	A third Heywood 500/275 kV transformer, a 100 MVAr capacitor bank at South East Substation, a third South East 275/132 kV transformer, increase of the relevant circuit ratings to line design ratings by protection and selected plant modifications

Chapter 4 - Development by Zone-Generation and Transmission Expansion

4.1 Summary

This chapter presents the outcomes of the optimised generation and transmission modelling for each scenario by geographical area (zone). It provides an alternative to the scenario-based view of future power system requirements in Chapter 3, by focussing on the impact the scenarios have on generation and transmission development in each region.

Generation expansion modelling results are aggregated into conventional and renewable generation (split between more variable wind and solar generation, and more controllable hydroelectric, geothermal, and biomass generation). Transmission development modelling results examine the way the scenarios impact each zone's transmission network, outlining the emerging limitations for each zone, and identifying possible solutions.

A map-based view of each region's generation and transmission development is provided with the interactive map, which is available from the National Transmission Development Plan (NTNDP) CD and the NTNDP website, and shows existing, committed, and potential transmission augmentations by time period and scenario (enabling a step through of developments over time).

As a general guide, transmission network development is likely to be required soonest in the zones with multiple augmentations in the first five years, and is most likely to be required in the zones with multiple augmentations under all scenarios.

Longer-term augmentations arising under some scenarios are more dependent on future conditions (for example, the rate of demand growth, and carbon pricing policies). As a result, although a commitment cannot be made without greater certainty, ongoing scrutiny is required to maintain the option to proceed.

Queensland has the highest energy and maximum demand (MD) growth, and the highest levels of new installed generation capacity in every scenario, predominantly in SWQ. Supply limitations to the major load centres in the SEQ zone arise, the timing largely influenced by SEQ zone demand and new generation within the two zones. Significant multiple augmentations are required under all scenarios to address these limitations, including committed augmentations by Powerlink to build new 275 kV and 500 kV double circuit lines (initially operating at 275 kV) within the first five years.

New South Wales experiences the lowest percentage energy growth across most scenarios, and its MD growth is only slightly higher than South Australia's, which has the lowest. The location and type of installed generation capacity modelled varies significantly across the scenarios, reflecting the differences in each scenario's assumed fuel costs, though there remain significant amounts of existing base load black-coal generation across all scenarios. Significant augmentations are required under the majority of scenarios, including extension of the currently incomplete 500 kV transmission ring around Sydney and 500 kV transmission lines to connect major new gas-powered generation in Central Northern New South Wales.

4.1 Summary…*cont*

In Victoria, the transmission network in the CVIC zone requires augmentation to meet demand growth and high exports from Victoria to South Australia via Murraylink during peak summer demand, as well as to accommodate new generation investments. Multiple significant transmission network augmentations are seen under all scenarios, including new 220 kV lines and a new 220 kV, 250 MVA phase angle regulator within the first five years.

Despite only modest energy and MD growth in Victoria, multiple significant augmentations are seen under all scenarios in the MEL zone, including two augmentations in the first five years. Additional transformers (principally 500/220 kV) are required in the MEL zone to meet increased load growth in the Melbourne and Geelong Greater Metropolitan Area. Additionally, a number of 220 kV lines are reaching their maximum design capability and have been identified for replacement with high temperature conductors.

South Australia experiences low energy growth, and the lowest MD growth in every scenario. The presence of good quality renewable generation in South Australia results in high levels of renewable generation modelled in this region to meet the Large-scale Renewable Energy Target (LRET). New generation other than wind varies significantly between scenarios, but South Australia relies on imports from Victoria to meet peak demand in all scenarios. In the ADE zone, demand growth and new gas-powered generation drives the augmentation of the zone's 275 kV transmission network, including a committed project by ElectraNet to establish a 275 kV bulk supply west of the central business district. In the NSA zone, demand growth leads to the augmentation of 275 kV and 132 kV transmission networks supplying several major load centres, while in the SESA zone, 275 kV and 132 kV transmission network augmentations are seen under some scenarios to meet the zone's load demand and to upgrade the Heywood interconnector's power transfer capability.

Tasmania has the lowest existing and projected energy and MD, and meeting the LRET drives most of the new installed generation capacity. With some of the highest quality wind resources in the National Electricity Market (NEM), modelling shows high levels of new wind generation in the central, north-eastern, and north-western areas of Tasmania, leading to multiple significant augmentations under all scenarios. This includes new 220 kV double circuit lines, as well as upgrading existing lines to 220 kV, and an additional 220/110 kV transformer in the Hobart area due to increased load growth.

In terms of zones generally, the NSA, NQ, and CQ zones each have one transmission augmentation seen under all scenarios. The NSA zone augmentation is seen in the first five years. The NVIC and NNS zones have some projects that are seen in the first five years but only under a limited number of scenarios.

Projects in the NCEN, CAN, LV, SESA, and ADE zones are only seen after the first five years, and then only in a limited number of scenarios.

The analysis for each region presents a series of tables showing the impacts the scenarios have on transmission network development (which vary due to changed generation expansion timing responses specific to a particular scenario), with the objective of highlighting changes in timing or augmentation need across the scenarios.

For a more detailed description of the augmentations under each scenario, including the augmentations considered to be committed, see Appendix A.

4.2 Optimised transmission and generation expansion

The NTNDP uses a combination of three, broad categories of studies:

- High-level, least-cost expansion modelling.
- Power system simulation studies.
- Time-sequential market simulation studies.

The high-level, least-cost expansion modelling seeks to provide a co-optimised set of new entry generation, interconnector capability upgrades, and generation retirements across the NEM for the next 20 years, indicating optimal future transmission network development technologies, locations, timings, and capacities.

The power system simulation studies assess the adequacy of the transmission network to reliably meet projected MD with existing and new generation.

The time-sequential market simulation studies simulate the operation of the market under the generation and transmission expansion determined by the high-level, least-cost expansion modelling.

The development plan for each region is an output of this combined suite of studies. The generation expansion and inter-regional projects derive from the least-cost expansion modelling. The proposed intra-regional augmentation projects and identified residual congestion derive from the power system simulation studies and the time-sequential market simulation studies.

For a detailed description of the process used to develop the optimised generation and transmission plan, see Attachment 1.

4.2.1 Scope of transmission developments considered in the NTNDP

AEMO assessed transmission network adequacy and identified limitations and potential solutions using an approximation of the jurisdictional planning criteria. Taking a long-term, NEM-wide view, the NTNDP focuses on the ability of the main transmission network (generally 220 kV and above) to reliably support major power transfers between generation and demand centres in the NEM. AEMO has confined the scope of the analysis to thermal limitations on the main transmission network that arise during diversified regional peak demands.

Using power system simulation studies, AEMO monitored the loading of main transmission lines and transformers under system intact (pre-contingency, when all other equipment is in service) and also under single contingency situations (N-1 criterion). The transmission lines and transformers that were monitored form part of the main transmission network that supports major NEM power transfers. In general, this refers to the lines of nominal voltage of 220 kV and above, although in some cases the monitoring was extended to lower voltages, particularly in areas where lower voltage is used for bulk power transfer, such as in parts of South Australia and Tasmania.

The NTNDP power system studies considered diversified peak loading conditions for the regions as a whole, and not the local MDs at individual connection points. Connection point MD requirements are important for maintaining local supply reliability, but are beyond the scope of the NTNDP. As a result, the timing of developments the NTNDP identifies, and in some cases an augmentation option itself, may be affected by the development of lower voltage, local transmission networks.

In addition to the augmentations 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.

The modelled augmentations the NTNDP outlines are indicative. For the purposes of strategic planning, it is useful to identify possible options to address observed limitations. As the investment timeframe approaches, more detailed investigations are carried out to ascertain issues such as constructability, outage requirements, and planning permit and easement requirements. Further, the National Electricity Rules (NER) provide a process for analysing and selecting potential alternative solutions (including non-network alternatives) through a Regulatory Investment Test for Transmission (RIT-T) and an associated consultation process. Until a solution has undergone the RIT-T process it cannot be considered certain.

4.2.2 Presentation of transmission network developments

This chapter provides information about transmission network developments identified through the NTNDP simulation studies. This information is summarised by zone and indicates how the timing or need for these developments vary from scenario to scenario.

To correlate with the transmission network service provider (TNSP) annual planning review processes, AEMO has:

- summarised the developments occurring in the first 10 years under at least one scenario, and
- categorised the developments on the basis of the timeframe over which the triggers were identified, how sensitive the triggers are to future conditions, and the risks and consequences of not doing preparatory work.

Table 4-1 lists the guiding criteria used to categorise these developments.

Table 4-1 Guiding criteria for categorising transmission network developments occurring in the first 10 years

Category	Trigger timing	Opportunity cost
Early attention	Development is triggered in the first five-year period under most scenarios and in the second five-year period in most of the remaining scenarios	High opportunity cost if not done (or has limited or expensive work-arounds)
Preparatory work	Development is generally triggered in the second five-year period in most scenarios but possibly later in others	High opportunity cost if a need is established and it requires some long lead-time works (for example, easement acquisition)
Monitoring	Development is triggered in the first or second five-year period in some scenarios	Likely to have work-arounds if the triggering conditions unfold (in other words, a relatively low opportunity cost if the development is delivered late)

4.3 Queensland development plans

4.3.1 Generation expansion

Queensland experiences the highest energy and MD growth, and the highest levels of new installed capacity in every scenario.

Non-renewable

In all scenarios (except a Decentralised World's high carbon price sensitivity (DW-H)), 1,200 MW of gas-powered open-cycle gas turbine (OCGT) generation is placed in the SEQ zone, and is installed prior to any other generation type. This reflects the assumed lower cost of connection[15] in the SEQ zone. 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.

Additional capacity is subsequently planted in the SWQ zone, which has cheaper fuel costs (for both gas and coal) than the CQ and NQ zones. This additional capacity is a mix of both gas-powered closed-cycle gas turbine (CCGT) and OCGT generation across all the scenarios except Oil Shock and Adaptation (OS-M), where high gas prices result in base load gas-powered generation being replaced by coal-fired generation even in the presence of a carbon price.

Under a Fast Rate of Change (FC-H), only coal-fired generation with carbon capture and sequestration (CCS) proceeds, though some generation is replaced by coal-fired generation without CCS under the scenario's medium carbon price sensitivity (FC-M).

[15] An additional cost (million dollars per MW) is applied to all new generation in the least-cost model, as described in Appendix G.

Coal-fired generation without CCS also proceeds under the Oil Shock and Adaptation scenario (OS-M) and its low carbon price sensitivity (OS-L), and the Slow Rate of Change scenario's (SC-L) zero carbon price sensitivity (SC-0), though not under the Uncertain World scenario (UW-L) or its zero carbon price sensitivity (UW-0). This result, while counter-intuitive, reflects the fact that, unlike the FC-H and DW-M scenarios, the UW-L demand trace was not modified to account for the impact of plug-in electric vehicles, which increase the overnight base load demand. The UW-L scenario also has a higher modelled weighted average cost of capital (WACC) input assumption (11.78%), reflecting an assumed higher financial risk, causing high capital cost technology (like coal-fired generation) to be less economic.

When developing the regional transmission network development plan, some SWQ zone generation (and SEQ zone generation in the DW-H sensitivity) was moved to the CQ zone. This occurs when fuel cost increases associated with moving generation to a higher fuel-cost zone are lower than the savings from deferring a transmission network augmentation to meet reliability requirements.

Renewable

Queensland has less available wind resources than the other regions, and less wind generation as a result, which is assumed to make no contribution during times of peak demand. Wind generation only proceeds in the Fast Rate of Change (FC-H) and Oil Shock and Adaptation (OS-M) scenarios, with a higher carbon price resulting in wind generation entering earlier.

Biomass generation located in the NQ zone proceeds in all scenarios, reflecting its low fuel costs and high contribution to the capacity constraint[16] included in the least-cost expansion model, as compared to wind and solar.

Solar thermal generation located in the NQ and CQ zones proceeds in every scenario except Uncertain World (UW-L).

Geothermal generation in the south west of the region only proceeds in the FC-H scenario (a high carbon price).

Retirements

Both the Gladstone and Collinsville Power Stations were modelled as potential candidates for retirement, while the Mackay and Swanbank B Power Stations were modelled as fixed retirements consistent with the 2010 Electricity Statement of Opportunities (ESOO).

Collinsville retires from 2011/12 (the first allowable year) in the Decentralised World scenario (DW-M), and in the final years of the Fast Rate of Change scenario (FC-H) and its medium carbon price sensitivity (FC-M), and the Slow Rate of Change scenario (SC-L) respectively. Gladstone retires from 2025/26 only under the Decentralised World (DW-M) scenario's high carbon price sensitivity (DW-H).

Table 4-2 lists the existing and projected installed capacities in the region.

[16] A constraint is applied in the least-cost model to ensure sufficient levels of capacity are installed (for a description, see Appendix G).

Table 4-2 Existing and projected Queensland installed capacity (MW)

Scenario	CPT		Existing	2014/15	2019/20	2024/25	2029/30
Fast Rate of Change	H	Gas/Coal/Oil	12,071	14,136	16,709	19,009	24,822
		Wind/Solar	0	100	700	700	750
		Hydro/Geo/Biomass	648	648	948	1,048	1,048
sensitivity	M	Gas/Coal/Oil	12,071	14,236	16,809	18,609	23,972
		Wind/Solar	0	0	700	700	700
		Hydro/Geo/Biomass	648	648	1,048	1,048	1,048
Uncertain World	L	Gas/Coal/Oil	12,071	15,184	17,957	20,457	24,257
		Wind/Solar	0	0	200	200	200
		Hydro/Geo/Biomass	648	648	648	848	1,048
sensitivity	0	Gas/Coal/Oil	12,071	14,836	17,709	20,309	24,009
		Wind/Solar	0	0	0	0	0
		Hydro/Geo/Biomass	648	648	648	948	1,048
Decentralised World	M	Gas/Coal/Oil	12,071	13,449	15,922	16,922	19,922
		Wind/Solar	0	0	400	400	400
		Hydro/Geo/Biomass	648	648	748	948	1,048
sensitivity	H	Gas/Coal/Oil	12,071	13,449	15,422	16,922	19,742
		Wind/Solar	0	0	300	300	300
		Hydro/Geo/Biomass	648	648	748	1,048	1,048
Oil Shock and Adaptation	M	Gas/Coal/Oil	12,071	13,036	13,909	15,409	15,809
		Wind/Solar	0	100	500	500	1,550
		Hydro/Geo/Biomass	648	648	948	1,048	1,048
sensitivity	L	Gas/Coal/Oil	12,071	13,036	13,909	15,409	16,159
		Wind/Solar	0	100	700	700	700
		Hydro/Geo/Biomass	648	648	1,048	1,048	1,048
Slow Rate of Change	L	Gas/Coal/Oil	12,071	13,036	14,109	15,109	17,222
		Wind/Solar	0	100	500	500	500
		Hydro/Geo/Biomass	648	648	748	1,048	1,048
sensitivity	0	Gas/Coal/Oil	12,071	13,336	14,509	15,309	17,809
		Wind/Solar	0	0	400	400	400
		Hydro/Geo/Biomass	648	648	948	1,048	1,048

4.3.2 Transmission development 10-year summary

Table 4-3 lists the transmission network developments identified over the next 10 years under at least one scenario. For more information about the production of this table and its categories, see Section 4.2.2.

Table 4-3 Queensland transmission development 10-year summary

Transmission development	Rating	Status/reference
QN1 - Series compensation on the 330 kV Armidale-Dumaresq circuits and 330 kV Dumaresq-Bulli Creek circuits	Early attention	Powerlink and TransGrid advise they are investigating the economic viability and an optimal timing of a QNI upgrade (Powerlink 2010 APR, Section 5.2.3, TransGrid 2010 APR, Section 6.3.4)
Q1 - A new Ross-Chalumbin double circuit line (single circuit strung)	Preparatory work	Powerlink advises that planned works to upgrade the 132 kV system north of Yabulu may also address this issue
Q2 - Stringing an additional 275 kV Stanwell-Broadsound circuit	Monitoring	Powerlink 2010 APR, Chapter 4, Section 4.5.3, Appendix G, Table G.2
Q3 - 275 kV Broadsound-Nebo series capacitors	Monitoring	Powerlink 2010 APR, Appendix G, Table G.2
Q4 - A new 275 kV Calvale-Stanwell double circuit line	Preparatory work	Powerlink Regulatory Test Final Report (27/9/10), 'Maintaining a reliable electricity supply within Central Queensland' (http://www.powerlink.com.au/data/portal/00005056/content/06049001285550212538.pdf)
Q10 - A new 500 kV Halys-Greenbank double circuit line (initially operating at 275 kV)	Preparatory work	Powerlink 2010 APR, Appendix G, Table G.2
Q11 - A new 500 kV Western Downs-Halys double circuit line (northern route first build) initially operating at 275 kV	Preparatory work	
Q14 - A new 275 kV Blackwall-Belmont double circuit line	Early attention	Powerlink's 2010 APR, Chapter 4, Section 4.5.6, outlines a number of projects involving new construction and line rearrangements between Blackwall and Brisbane
Q15 - A new 275 kV Blackwall-South Pine double circuit line	Early attention	
Q16 - A new 275 kV Loganlea-Greenbank double circuit line (one circuit strung)	Preparatory work	

4.3.3 Transmission development by zone

North Queensland (NQ)

The NQ zone is a net importer of energy throughout the 20-year outlook period, and generation development varies significantly across the scenarios. New biomass generation of 400 MW is modelled under all scenarios by 2029/30. Solar thermal generation is also modelled under most scenarios. Under Oil Shock and Adaptation (OS-M), solar thermal generation reaches a high point of 600 MW (installed capacity) by the end of the outlook period. OCGT, CCGT, and coal-fired generation is not installed under any scenario due to the relatively higher fuel costs in this zone.

The retirement of Collinsville Power Station, which is modelled to occur within the first five years under a Decentralised World (DW-M), and much later under other scenarios, also influences the timing of emerging limitations.

Committed projects

The NQ zone's development strategy builds on Powerlink's committed projects, which include building a new 275 kV double circuit line between Strathmore and Ross to increase supply to the north and far north of the State, and also some works to the 132 kV transmission network to increase supply capability to the Bowen area (between Townsville and Mackay)[17].

These projects are listed in Appendix A, and have been included in the power system modelling to capture their effect on transmission level power flow patterns.

Development strategy

Table 4-4 outlines the modelled transmission developments, as well as the variation under each scenario in terms of need and timing.

Table 4-4 Transmission development summary by project for NQ

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
Q1 - A new Ross-Chalumbin double-circuit line (single circuit strung)	2	2	2	2	3	3	4	4	4	4
Q2 - Stringing an additional 275 kV Stanwell-Broadsound circuit	4	4	3	2	4	4				
Q3 - Broadsound-Nebo 275 kV series capacitors	4	4		2						

The numbers and shading relate to augmentation trigger timeframes (as observed in the NTNDP modelling):

1	2010/11 – 2014/15
2	2015/16 – 2019/20
3	2020/21 – 2024/25
4	2025/26 – 2029/30

As demand growth exceeds new generation, the zone continues to rely on generation from the central and southern zones. For the majority of scenarios, however, there is sufficient new generation to defer transmission network reinforcement for many years.

Thermal limitations first appear between 2015/16-2019/20 on the 275 kV Ross-Chalumbin circuits, when supplying the far north of the NQ zone. Options to address this limitation include providing additional 275 kV capacity.

[17] Powerlink 2010 APR, Chapter 3, Table 3.2, and Chapter 4, Section 4.4.2 and Section 4.5.3.

Powerlink Queensland is implementing a staged replacement of coastal 132 kV lines between Yabulu South and Woree. Existing lines are being replaced by dual voltage (275 kV and 132 kV) double-circuit lines with both circuits initially operating at 132 kV.

The upgrade of the new 275 kV Woree circuits to their design voltage may also relieve the Ross-Chalumbin thermal limitations. As the NTNDP modelling located no new generation north of Ross, this limitation's timing is only driven by demand growth. Scenarios with lower economic growth show the timing of this limitation as late as 2025/26-2029/30.

Limitations on supply to the NQ zone also appear as early as 2015/16-2019/20 due to 275 kV transmission constraints from Calvale within the CQ zone. These limitations also affect supply to the Gladstone area.

For scenarios with medium and high economic growth, limitations on transmission from the CQ to the NQ zone appear again within another five to ten years due to insufficient transmission capability north of the Stanwell area. In 2002, Powerlink commissioned a 275 kV Stanwell-Broadsound double-circuit transmission line with only one circuit strung. An option to address this limitation involves stringing the second circuit.

As well as thermal limitations, modelling also suggested that voltage stability considerations will bring forward the stringing of the second 275 kV Stanwell-Broadsound circuit for the Fast Rate of Change scenario (FC-H), and the Uncertain World scenario's zero carbon price sensitivity (UW-0). UW-0 also requires additional support, which can be provided by installing series capacitors on existing 275 kV lines, like the 275 kV Broadsound-Nebo line.

Under some conditions, existing NQ zone generation (including relatively high-cost, liquid-fuelled units) may be required to supply the local load. The NTNDP analysis has not considered the potential market benefits of advancing some of these projects[18] to reduce the reliance on high-cost generation.

The market simulation studies identified no significant residual congestion associated with the NQ zone.

CopperString

In September 2010, the Queensland Government released draft terms of reference for an environmental impact statement for the proposed CopperString transmission line between the Townsville and North-West Queensland transmission network[19]. The project is intended to be capable of transferring 400 MW. At the time of writing, connections have not been finalised, but the terms of reference refer to a connection between a new substation at Woodstock (south of Townsville) and the existing Chumvale Substation near Cloncurry, with the preferred alignment being approximately 720 km long.

[18] Advancing projects becomes justifiable if the market benefits exceed the present value cost of doing so.

[19] For more information about the terms of reference, see the Queensland Government Department of Infrastructure and Planning website (at http://www.dip.qld.gov.au/projects/energy/electricity/copperstring-project.html).

The project website sets out an indicative timeline that aims for completion in late 2013[20]. The NTNDP studies have not modelled this project, which is not yet committed. The new transmission line is expected to advance the timing of some augmentations in both the NQ and CQ zones, to support the corresponding increase in NQ zone demand. The extent of the impact, however, depends on the net demand resulting from this new connection, taking the output of generation sources connecting to CopperString into account.

Central Queensland (CQ)

The CQ zone is a net exporter of energy throughout the 20-year outlook period, and generation development varies across the scenarios, ranging from a low of 300 MW under the Uncertain World scenario's zero carbon price sensitivity (UW-0) to a high of 2,200 MW under a Fast Rate of Change (FC-H) by 2029/30. New generation that would otherwise be in the SWQ or SEQ zones is modelled in the CQ zone to defer transmission augmentation. This new generation comprises solar and coal-fired generation with carbon capture and sequestration (CCS) around the Calvale area, and OCGT generation located at Gladstone.

The modelling retires the Gladstone Power Station toward the end of the 20-year outlook period under the Decentralised World scenario's high carbon price sensitivity (DW-H).

Committed projects

There are no committed projects relating to this zone.

Development strategy

Table 4-5 outlines the modelled transmission developments, as well as the variation under each scenario in terms of need and timing.

Table 4-5 Transmission development summary by project for CQ

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
Q4 - A new 275 kV Calvale-Stanwell double circuit line	2	2	2	2	2	2	3	3	2	2
Q5 - Switch the 275 kV Gladstone-Gin Gin circuit into 275 kV Wurdong	3	3			4	4	3	3	3	3
Q6 - A new 275 kV Broadsound-Lilyvale single circuit line	4	4	4	4						

[20] See the CopperString project website at: http://www.copperstring.com.au/project-timeline.html .

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
Q7 – A 275 kV Calvale-Larcom Creek double circuit line	4	4								
Q8 - Rebuild 275 kV Larcom Creek-Gladstone double circuit line	4	4								
Q9 - A new 275 kV Calvale-Wurdong double circuit line	4	4								

The numbers and shading relate to augmentation trigger timeframes (as observed in the NTNDP modelling):

1	2010/11 – 2014/15
2	2015/16 – 2019/20
3	2020/21 – 2024/25
4	2025/26 – 2029/30

The need to reinforce supply within the CQ zone and to the neighbouring NQ zone is evident from 2015/16-2019/20, where post-contingent overloads on the 275 kV Calvale-Wurdong and Calvale-Stanwell circuits arise under peak demand conditions. Powerlink Queensland released an application notice in July 2010, and a final report in September 2010, which identified this limitation and various options for its relief[21]. Powerlink Queensland recommends the construction of a 275 kV double-circuit line from Calvale to Stanwell by summer 2013/14. The timing of this limitation in the NTNDP is deferred, largely due to differences in the assumptions involving new generation developments in the NQ zone.

From 2020/21-2024/25, the supply from the CQ zone to the NQ zone is constrained under some scenarios due to insufficient transmission capability north of the Stanwell area.

Emerging limitations also arise from 2020/21-2024/25 due to the thermal overload of a 275 kV Calvale-Wurdong circuit on outage of a 275 kV Gladstone-Wurdong circuit. The timing of this limitation is strongly influenced by the level of new generation at Calvale and Gladstone. The development of the 500 kV transmission network between the SWQ and SEQ zones also has a significant impact by improving power transfers from South to Central Queensland on the Western and Eastern Corridors. Scenarios showing the earliest timings have higher levels of new generation at Calvale, no new generation at Gladstone, and limited 500 kV infrastructure. An option to relieve this limitation is to switch the 275 kV Gladstone-Gin Gin circuit into the 275 kV Wurdong transmission network.

Under the scenarios with high economic growth (Fast Rate of Change (FC-H) and Uncertain World (UW-L)), numerous limitations emerge from 2025/26-2029/30 when trying to meet supply requirements to the Gladstone area, and also to support northerly power transfers to meet NQ zone demand. Limitations include 275 kV Calvale-Wurdong circuit overloads on outage of a 275 kV Calvale-Stanwell circuit, 275 kV Larcom Creek-Gladstone circuit overloads on outage of a 275 kV

[21] Powerlink Queensland, Final Report - Maintaining a Reliable Supply within Central Queensland, 27 September 2010, at http://www.powerlink.com.au/data/portal/00005056/content/06049001285550212538.pdf

Calvale-Wurdong circuit, and 275 kV Gladstone-Wurdong circuit overloads on outage of a parallel circuit.

The trip of a Gladstone Power Station generating unit may also cause overloads on some circuits. Feasible options to address these limitations include a new 275 kV Calvale-Larcom Creek double circuit line, rebuilding the 275 kV Larcom Creek-Gladstone double circuit line, and a new 275 kV Calvale-Wurdong double circuit line.

Supply to the Lilyvale area via two 275 kV Broadsound-Lilyvale circuits is also constrained in the later years of the 20-year outlook period, due to the overload of one circuit on outage of a parallel circuit. Reinforcing supply to the area via an additional 275 kV Broadsound-Lilyvale circuit is an option.

The market simulations identified no significant residual congestion associated with the CQ zone.

South West Queensland (SWQ)

The SWQ zone presents a favourable site for future new generation, with its abundance of comparatively low cost coal and gas reserves. All scenarios model significant new generation in this zone, far outweighing load growth in the area. This results in a need to augment the local transmission network in order for this generation, coupled with imports via the Queensland to New South Wales interconnector, to support loads in neighbouring zones. As comparatively little new generation is planted elsewhere in Queensland, and Swanbank B Power Station is retiring, extensive augmentation is required from South West to South East Queensland to support the rapid load growth.

To the north, the need for augmentation between the SWQ and CQ zones is less evident. There is a surplus of generation in Central and North Queensland in the early years, and power flows along this corridor are typically southerly under peak demand conditions. As generation in the SWQ zone increases, power transfers via an SWQ-CQ zone corridor are reversed, and the SWQ zone begins to support load in the CQ and NQ zones. The combination of some new generation in the CQ and NQ zones, together with the existing spare capacity to reverse the flows on the SWQ-CQ corridor, results in a lack of need for significant augmentation for the 20-year outlook period.

Committed projects

The SWQ zone's development strategy begins with Powerlink Queensland's recently committed works involving construction of two new 275 kV substations at Western Downs and Halys (summer 2012/13), a new 275 kV transmission line connecting the Western Downs to the substations at Halys (summer 2012/13), rearrangement of lines between the Braemar Substation and Kogan Creek Power Station to connect the substations at Western Downs and Braemar (summer 2012/13), and a new 500 kV transmission line between the substations at Halys and Blackwall, initially operating at 275 kV (summer 2014/15)[22].

These projects are listed in Appendix A, and have been included in the power system modelling to capture their effect on transmission level power flow patterns.

[22] Powerlink 2010 APR, Chapter 3, Table 3.2.

Development strategy

Table 4-6 outlines the modelled transmission developments, as well as the variation under each scenario in terms of need and timing.

Table 4-6 development summary by project for SWQ

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
QN1 - Series compensation on the 330 kV Armidale-Dumaresq circuits and the 330 kV Dumaresq-Bulli Creek circuits	1	1					1	1		1
Q10 - A new 500 kV Halys-Greenbank double circuit line (initially operating at 275 kV)	2	2	2	2	2	2	4	4	4	4
Q11 - A new 500 kV Western Downs-Halys double circuit line (northern route first build) initially operating at 275 kV	2	2	2	2	2	2	3	3	3	2
Q12 - Upgrade 275 kV Western Downs-Halys (northern route first build) and 275 kV Halys-Blackwall to 500 kV	3	3	3	3	4	4				
Q13 - A new 500 kV Western Downs-Halys double circuit line (northern route second build) and upgrade the 275 kV Halys-Greenbank line to 500 kV	4	4	4	4						

The numbers and shading relate to augmentation trigger timeframes (as observed in the NTNDP modelling):

1	2010/11 – 2014/15
2	2015/16 – 2019/20
3	2020/21 – 2024/25
4	2025/26 – 2029/30

Following committed developments, limitations on supply to South East Queensland arise from 2015/16-2019/20, due to various post-contingent overloads on 275 kV transmission elements within and between the SWQ and SEQ zones. The timing of these thermal limitations varies with each scenario, and is largely influenced by SEQ zone demand and new generation within the SWQ and SEQ zones. Under scenarios with high and medium demand growth (Fast Rate of Change (FC-H), Uncertain World (UW-L) and Decentralised World (DW-M)), these limitations arise between 2015/16-2019/20, and can be addressed by the development of a new 500 kV Western Downs-Halys transmission line to Greenbank, initially operating at 275 kV.

Under the majority of scenarios, further thermal limitations on transfers from SWQ to SEQ appear within another five to ten years. Options to address these issues include upgrading the transmission lines between Western Downs and Halys, and Halys and Blackwall to their design voltage rating of 500 kV. These developments are also driven by SEQ zone demand and new generation within the SWQ and SEQ zones. Scenarios experiencing the highest demand growth also need more reinforcement. One option includes an additional 500 kV Western Downs-Halys transmission line, coupled with an upgrade of the 275 kV Halys-Greenbank line to 500 kV between 2025/26-2029/30.

In addition to the reliability projects, a power transfer capability upgrade between the NNS and SWQ zones (the Queensland to New South Wales (QNI) interconnector) also proceeds under the Fast

Rate of Change (FC-H) and Oil Shock and Adaptation scenarios(OS-M), and the Slow Rate of Change scenario's zero carbon price sensitivity (SC-0). The least-cost modelling suggests such an augmentation delivers net market benefits.

This augmentation is motivated 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. The simulated market expansion suggests an economic timing for this augmentation of 2014/15, involving the installation of series compensation on the 330 kV Armidale-Dumaresq and Dumaresq-Bulli Creek lines.

The least-cost modelling does not fully account for the market benefits from increased generation reserve sharing, which previous studies found to be potentially significant for the Queensland to New South Wales (QNI) interconnector. Accounting for these benefits potentially makes the augmentation more attractive in the identified scenarios, as well as under other scenarios, which AEMO considers warrants further QNI augmentation studies. Powerlink Queensland and TransGrid advise that they have agreed to undertake investigations during 2010 and 2011 to evaluate the economic viability (and optimal timing) of a QNI upgrade, applying Regulatory Investment Test for Transmission (RIT-T) methodology[23].

In July 2010, Powerlink Queensland released an application notice that identified the potential increase in demand in the area as a result of significant new coal seam gas and mining developments, and supporting infrastructure[24]. The projected load increase is well beyond the capacity of the existing transmission network, with Powerlink Queensland and Ergon Energy identifying that action will be required as early as winter 2013. In order to meet these needs, Powerlink Queensland proposes new 275 kV developments from Western Downs to Columboola and Wandoan South. Due to the timing of the application notice, these new loads were not explicitly modelled in the NTNDP power system analysis studies.

A transient stability limit and a voltage stability limit preventing voltage collapse on loss of the Kogan Creek Power Station generating units, both of which restrict power flow from the NNS to the SWQ zone, show considerable residual congestion in time sequential market simulations across all the scenarios. These limitations are associated with inter-regional power transfer, which was initially assessed in the least-cost expansion modelling, although no specific projects targeting these limitations were considered. Further detailed analysis may be warranted to assess the market benefits of specific projects to address these limitations.

South East Queensland (SEQ)

Development within the SEQ zone focuses on increasing supply to major loads, including the wider Brisbane area, Sunshine Coast, and the Gold Coast.

The modelling of new generation in the SEQ zone is influenced by SEQ zone fuel cost assumptions (which are comparable to the SWQ zone's), and the proximity to the load centre, which provides advantages to the development of a least-cost plan. Other factors, however, possibly limit the

[23] Powerlink 2010 APR, Chapter 4, Section 4.4.8. TransGrid 2010 APR, Chapter 6, Section 6.3.4.

[24] Powerlink Queensland, "Maintaining a Reliable Supply to the Surat Basin North West Area", July 2010, http://www.powerlink.com.au/data/portal/00005056/content/92232001278043000561.pdf .

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 by placing an upper limit on the allowable generation capacity and type of new generation in this zone. The limit is reached quickly in the majority of scenarios, because the assumed fuel costs are comparable to other zones, and new generation near the load centre requires less transmission network investment. The rapid demand growth in the area, however, far outweighs the capacity from generation development, requiring considerable augmentation to enable power flows from the SWQ zone.

Committed projects

The SEQ zone's development strategy begins with Powerlink Queensland's recently committed works involving construction of a new 500 kV transmission line between the substations at Halys and Blackwall, initially operating at 275 kV[25].

These projects are listed in Appendix A, and have been included in the power system modelling to capture their effect on transmission level power flow patterns.

Development strategy

Table 4-7 outlines the modelled transmission developments, as well as the variation under each scenario in terms of need and timing.

Table 4-7 Transmission development summary by project for SEQ

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
Q14 - A new 275 kV Blackwall-Belmont double circuit line	1	1	1	1	1	1	1	1	1	1
Q15 - A new 275 kV Blackwall-South Pine double circuit line	1	1	1	1	1	1	2	2	2	2
Q16 - A new 275 kV Loganlea-Greenbank double circuit line (one circuit strung)	2	2	2	2	3	3	4	4	4	4
Q17 - Rebuild the 275 kV Greenbank-Mudgeeraba single circuit to double circuit	3	3	3	3	4	4			4	4
Q18 - A new 275 kV Greenbank-Molendinar double circuit line	3	3	4	4	4	4				
Q19 - A new 275 kV South Pine-Palmwoods double circuit line	4	4	4	4	4	4				
Q20 - The 275 kV South Pine-Rocklea circuit diverted directly into Blackwall and a new 275 kV Blackwall-Rocklea single circuit	4	4	4	4	4	4				
Q21 - A new 275 kV Blackwall-Rocklea double circuit line	4	4	4	4						

[25] Powerlink 2010 APR, Chapter 3, Table 3.2.

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
Q22 - String a second circuit of 275 kV Loganlea-Greenbank double circuit line	4	4	4	4	4	4				
Q23 - Uprate the 275 kV Greenbank-Swanbank circuit (+200 MVA)	4	4	4	4						

The numbers and shading relate to augmentation trigger timeframes (as observed in the NTNDP modelling):

1	2010/11 – 2014/15
2	2015/16 – 2019/20
3	2020/21 – 2024/25
4	2025/26 – 2029/30

Thermal limitations on supply from Blackwall to Belmont appear in all the scenarios within the first five years of the 20-year outlook period. Under scenarios with higher demand, limitations on power transfers from Blackwall to South Pine and Greenbank to Loganlea are also apparent in this time frame. Potential options to address these limitations include new transmission line developments from Blackwall to Belmont, Blackwall to South Pine, and Greenbank to Loganlea. Depending on the location of future generation, a 500 kV line (initially operating at 275 kV) from Blackwall to South Pine may be attractive. This facilitates additional 500 kV options for connection from Halys in the SWQ zone to South Pine, to support demand both north and south of South Pine.

Powerlink Queensland has identified works to address the Blackwall-Belmont and Greenbank-Loganlea limitations, which include installing a new 275 kV transmission line from the Blackwall and Swanbank area to a point west of the transmission corridor between the substations at Loganlea and Belmont. As part of this work, Powerlink Queensland intends to rearrange sections of the existing 275 kV transmission lines in the area, which will also relieve limitations on the Blackwall-South Pine transmission lines. However, with the high rate of demand growth being supplied via South Pine, it is anticipated that the Blackwall-South Pine limitations will reappear quite quickly within the 20-year outlook period.

Within 10 years, emerging limitations arise on 275 kV transmission lines supplying Mudgeeraba and Molendinar from Greenbank. The timing of these limitations varies from 2020/21 to beyond the 20-year outlook period, depending on demand growth. Options to address these limitations include an additional 275 kV Greenbank-Molendinar transmission line, and rebuilding the 275 kV Greenbank-Mudgeeraba single circuit to create a double circuit.

Towards the end of the 20-year outlook period, limitations on the 275 kV Greenbank-Loganlea circuits arise again under scenarios with medium and high economic growth. Options to address this include stringing the vacant side of the second 275 kV Greenbank-Loganlea transmission line. Limitations also emerge on the 275 kV South Pine-Palmwoods, Blackwall-South Pine, Blackwall-Rocklea, and Swanbank-Greenbank lines. Options to address these limitations include additional 275 kV South Pine-Palmwoods, and Blackwall-Rocklea transmission lines, as well as diverting the 275 kV South Pine-Rocklea circuit directly into Blackwall, and uprating the existing Swanbank-Greenbank circuit.

4.4 New South Wales development plans

4.4.1 Generation expansion

New South Wales experiences the lowest percentage energy growth across most scenarios, and its MD growth is only slightly higher than South Australia's (with the lowest growth). The location and type of installed generation capacity modelled varies significantly across the scenarios, reflecting the differences in each scenario's assumed fuel costs, though there remain significant amounts of existing base load black coal generation across all scenarios.

Non-renewable

New OCGT generation is modelled in the NCEN zone under all the scenarios except Decentralised World (DW-M) and Slow Rate of Change (SC-L). The amount installed varies from 6,900 MW in the Fast Rate of Change scenario's medium price sensitivity (FC-M), to 600 MW in the Decentralised World scenario's high price sensitivity (DW-H). For any single scenario, a higher carbon price reduces the NCEN zone's installed OCGT capacity, substituting it with higher capacity-factor type generation (coal, CCGT, CCGT with carbon capture and sequestration (CCS), or geothermal).

The CCGT generation installed under the Uncertain World (UW-L), Decentralised World (DW-M), and Slow Rate of Change (SC-L) scenarios is all located in the NNS zone. This reflects the fuel price for gas within New South Wales, which is cheapest in the NNS zone under these scenarios.

Under the Fast Rate of Change (FC-H) scenario, the CAN and NCEN zones have lower fuel prices. CCGT generation with CCS proceeds in the CAN zone with a high carbon price, and CCGT without CCS proceeds in the NCEN zone under the Fast Rate of Change scenario's medium carbon price sensitivity (FC-M).

Relatively small amounts of new coal-fired generation without CCS are modelled in the:

- Oil Shock and Adaptation (OS-M) scenario, and its low carbon price sensitivity (OS-L), which reflects the high gas price assumption, and
- Uncertain World (UW-L) and Slow Rate of Change (SC-L) scenario zero carbon price sensitivities (UW-0 and SC-0), with generation proceeding in the NCEN zone.

In New South Wales, coal-fired generation with CCS does not proceed in any of the scenarios.

Renewable

New South Wales has wind resources available across the region from the SWNSW to the NNS zone, which is assumed to contribute 5% of its capacity to peak demand in the region.

The CAN zone is assumed to have the highest amount of high capacity-factor wind available, and wind generation proceeds whenever there is a price on carbon, except under the Slow Rate of Change scenario (SC-L). A lower amount of wind also proceeds in the NCEN and SWNSW zones under the Fast Rate of Change (FC-H) scenario, the Decentralised World scenario's high carbon price sensitivity (DW-H), and the Oil Shock and Adaptation scenario's low carbon price (OS-L) sensitivity.

Biomass generation located in the NNS, NCEN, and CAN zones proceeds in all the scenarios, while geothermal generation in the NCEN zone proceeds only in the OS-M scenario (replacing wind capacity).

Retirements

The Liddell, Wallerawang C, and Vales Point Power Stations were modelled as potential candidates for retirement, while Munmorah was modelled as a fixed retirement consistent with the ESOO.

Of the candidates for retirement, the least cost model retired a Liddell unit from 2011/12 (the first allowable year) in the DW-H sensitivity, with the remaining units retiring from 2024/25 onwards. A single unit was retired in the final year of the 20-year outlook period under the SC-L scenario. Wallerawang retires from 2011/12 under SC-L and the DW-H carbon price sensitivity, while one unit retires from 2011/12 under DW-M and OS-M.

Table 4-8 lists the existing and projected installed capacities in the region.

Table 4-8 Existing and projected New South Wales installed capacity (MW)

Scenario	CPT		Existing	2014/15	2019/20	2024/25	2029/30
Fast Rate of Change	H	Gas/Coal/Oil	14,053	13,633	15,733	18,233	20,333
		Wind/Solar	224	524	724	827	4,225
		Hydro/Geo/Biomass	2,717	2,780	2,780	2,880	3,080
sensitivity	M	Gas/Coal/Oil	14,053	13,633	16,033	18,633	21,533
		Wind/Solar	224	324	724	727	2,325
		Hydro/Geo/Biomass	2,717	2,780	2,780	3,080	3,080
Uncertain World	L	Gas/Coal/Oil	14,053	13,633	15,633	18,133	21,133
		Wind/Solar	224	224	232	727	727
		Hydro/Geo/Biomass	2,717	2,780	3,080	3,080	3,080
sensitivity	0	Gas/Coal/Oil	14,053	13,633	16,233	18,823	22,033
		Wind/Solar	224	224	226	228	230
		Hydro/Geo/Biomass	2,717	2,780	2,980	2,980	3,080
Decentralised World	M	Gas/Coal/Oil	14,053	13,133	14,633	16,633	18,568
		Wind/Solar	224	324	927	927	927
		Hydro/Geo/Biomass	2,717	2,780	3,080	3,080	3,080
sensitivity	H	Gas/Coal/Oil	14,053	12,118	14,118	16,068	18,143
		Wind/Solar	224	624	1,226	1,226	1,626
		Hydro/Geo/Biomass	2,717	2,780	3,080	3,080	3,080

Scenario	CPT		Existing	2014/15	2019/20	2024/25	2029/30
Oil Shock and Adaptation sensitivity	M	Gas/Coal/Oil	14,053	13,133	13,733	14,333	15,383
		Wind/Solar	224	224	727	826	3,425
		Hydro/Geo/Biomass	2,717	2,780	2,880	3,080	3,080
	L	Gas/Coal/Oil	14,053	13,633	13,933	14,533	16,183
		Wind/Solar	224	324	727	727	727
		Hydro/Geo/Biomass	2,717	2,780	2,780	2,780	2,780
Slow Rate of Change sensitivity	L	Gas/Coal/Oil	14,053	12,633	14,133	15,133	15,618
		Wind/Solar	224	224	226	226	226
		Hydro/Geo/Biomass	2,717	2,780	3,080	3,080	3,080
	0	Gas/Coal/Oil	14,053	13,633	14,833	15,433	17,683
		Wind/Solar	224	224	226	226	226
		Hydro/Geo/Biomass	2,717	2,780	2,880	3,080	3,080

4.4.2 Transmission development 10-year summary

Table 4-9 lists the transmission network developments identified over the next 10 years under at least one scenario. For more information about the production of this table and its categories, see Section 4.2.2.

Table 4-9 New South Wales transmission development 10-year summary

Transmission development	Rating	Status/reference
QN1 - Series compensation on 330 kV Armidale-Dumaresq circuits and 330 kV Dumaresq-Bulli Creek circuits	Early attention	Powerlink and TransGrid advise they are investigating the economic viability and optimal timing of a QNI upgrade (Powerlink 2010 APR, Section 5.2.3, TransGrid 2010 APR, Section 6.3.4)
NV1 - A new 220 kV, 250 MVA phase angle regulator on the 220 kV Buronga-Red Cliffs line	Preparatory work	AEMO and ElectraNet are intending to investigate the ongoing requirements for South Australian imports over Murraylink, and options to support load growth in the Riverland and other areas. AEMO and TransGrid are intending to investigate the impacts for the New South Wales system from high Murraylink power transfers at the time of peak demand.
NV2 - A Victoria-New South Wales interconnector upgrade	Preparatory work	AEMO and TransGrid are intending to investigate the benefits of upgrading the Vic-NSW interconnection
N4 - A 500 kV Hunter Valley-Eraring (via Newcastle) development	Early attention	TransGrid advises a seven-year time-frame for development of the 500 kV system supporting the Newcastle-Sydney-Wollongong load area (TransGrid 2010 APR, Section 6.4.5, TransGrid Strategic Network Development Plan 2008, Section 3.5)

Transmission development	Rating	Status/reference
N5 - Replace the 500/330 kV Eraring Power Station transformer with a 1,500 MVA unit, and add a new parallel 500/330 kV Eraring Power Station transformer	Early attention	TransGrid has proposed installing a second 500/330 kV transformer to address stability issues (TransGrid 2010 APR, Section 6.2.9)
N7/8 - 500 kV Hunter Valley-Northern New South Wales developments	Monitoring	TransGrid describes replacing the 330 kV lines in this area with 500 kV as longer-term plans (TransGrid 2010 APR, Section 6.4.2)
N9 - Upgrade terminal equipment at the 330 kV Ingleburn-Wallerawang Power Station line to achieve full line rating. Address attendant voltage control issues for 330 kV Sydney system	Monitoring line issues and early attention to voltage control issues	TransGrid is addressing this voltage control issue as part of its reactive planning
N10 - Additional 330 kV Mt Piper-Wallerawang circuit	Early attention	NTNDP studies indicate the need for this augmentation depends on the retirement/output levels of Wallerawang Power Station generating units. Further planning work is being progressed by TransGrid (TransGrid 2010 APR, Section 6.4)

4.4.3 Transmission development by zone

The TransGrid 'Strategic Network Development Plan 2008'[26] provides more information about a number of the projects described here, as well as describing other transmission development options.

Northern New South Wales (NNS)

The NNS zone connects the rest of the New South Wales region to the Queensland region via the Terranora and QNI (the Dumaresq-Bulli Creek 330 kV lines) interconnectors. With no existing major generation sources, the NNS zone is a net importer of power and a corridor for power flows between Queensland and New South Wales.

The projected load growth for the zone is above the region's average, with Coffs Harbour, Tamworth, Lismore, and Terranora being the major centres contributing to this growth.

Committed projects

The NNS zone's development strategy builds on TransGrid's committed and advanced projects, which include upgrading the 330 kV Tamworth-Armidale line, establishing a 330 kV Dumaresq-Lismore line, replacing the 132 kV single circuit line between Kempsey and Port Macquarie with a double circuit line, extending the 330 kV network around and within the Sydney CBD, extending the Armidale SVC capacity, and implementing a power oscillation damper for the Armidale SVC (which increases interregional power transfer capability by improving system stability)[27].

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[26] http://www.transgrid.com.au/aboutus/pr/Pages/PlanningDocuments.aspx .

[27] TransGrid, 2010 APR.

These projects are listed in Appendix A, and have been included in the power system modelling to capture their effect on transmission level power flow patterns.

Development strategy

Table 4-10 outlines the modelled transmission developments, as well as the variation under each scenario in terms of need and timing.

Table 4-10 Transmission development summary by project for NNS

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
QN1 - Series compensation on 330 kV Armidale-Dumaresq circuits and 330 kV Dumaresq-Bulli Creek 330 kV circuits	1	1					1	1		1
N7 - Hunter Valley-Northern New South Wales 500 kV development (three circuits)				3					3	
N8 - Hunter Valley-Northern New South Wales 500 kV development (four circuits)			3		2	3				

The numbers and shading relate to augmentation trigger timeframes (as observed in the NTNDP modelling):

1	2010/11 – 2014/15
2	2015/16 – 2019/20
3	2020/21 – 2024/25
4	2025/26 – 2029/30

The NNS zone's transmission network is highly meshed, which means that new generation and transmission developments will affect power flows in a number of circuits at a number of voltage levels.

Due to significant gas reserves and the assumption of relatively low costs, significant new gas-powered generation is modelled to proceed in the NNS zone under the Uncertain World (UW-L), Decentralised World (DW-M), and Slow Rate of Change (SC-L) scenarios. This new generation creates very high power flows from the NNS to the NCEN load centres, leading to pre- and post-contingency overloads of the 330 kV circuits between Liddell and Tamworth. A possible option for addressing this limitation includes implementing a 500 kV Hunter Valley-Northern New South Wales development.

The least-cost expansion modelling selects a power transfer capability upgrade between the SWQ and NNS zones (via QNI) on the basis of delivering net market benefits. This occurs in five out of the ten scenarios and carbon price sensitivities.

Restrictions arise on network power flows between the NNS and SWQ zones to ensure power system and voltage stability. The time sequential market simulations show that these restrictions cause considerable residual congestion across all scenarios. For more information about the constraint equations relating to this congestion (and its frequency), see Appendix H.

Central New South Wales (NCEN)

The NCEN zone has most of the generation capacity and demand in New South Wales, with the Newcastle, Sydney, and Wollongong load centres comprising over 75% of New South Wales demand at the time of the MD[28]. Under all the scenarios except the Fast Rate of Change scenario's medium price sensitivity (FC-M), NCEN zone demand growth out strips generation growth, making it generally a net power importer during MD periods.

Munmorah Power Station is modelled as a fixed retirement under all scenarios. In addition, the least-cost expansion models further generation capacity retirements for a number of scenarios (DW-M and the DW-H sensitivity, SC-L, and Oil Shock and Adaptation (OS-M)), with the higher carbon price sensitivities, resulting in higher rates of coal-fired generation retirement. This capacity is generally replaced by new gas-powered generation in the NCEN (under OS-M) or NNS zones (under DW-M and the DW-H sensitivity, and SC-L). The NCEN zone's new gas-powered generation is not necessarily located at the same transmission network locations as the retired generation.

In addition, significant new gas-powered generation in the NCEN zone also occurs under the Fast Rate of Change (FC-H) and Uncertain World (UW-L) scenarios, and the Oil Shock and Adaptation scenario's (OS-M) low carbon price sensitivity (OS-L). Significant new gas-powered generation in the neighbouring NNS zone also occurs under the UW-L scenario.

Transmission augmentations in this zone are driven by the need to support power flows from new gas-powered generation developments within the NCEN and NNS zones, and to provide capacity support for increased load in the Sydney, Newcastle, and Central Coast locations.

Committed projects

The NCEN zone's development strategy builds on TransGrid's committed projects and advanced proposals, which include 132 kV transmission network developments (generally driven by reliability limitations for supply to the North Coast, Central West, and other load areas in the zone), such as replacing the 132 kV single circuit line between Kempsey and Port Macquarie with a double circuit line. Other projects involve the construction of 330 kV lines and cables (for example Newcastle-Waratah West, Tomago-Tarro, Tomago-Taree, Avon-Marulan, Marulan-Dapto, Dapto-Kangaroo Valley, and the Western Sydney transmission network)[29].

These projects are listed in Appendix A, and have been included in the power system modelling to capture their effect on transmission level power flow patterns.

Development strategy

Table 4-11 outlines the modelled transmission developments, as well as the variation under each scenario in terms of need and timing.

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[29] TransGrid, 2010 APR.

Table 4-11 Transmission development summary by project for NCEN

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
N3 - 500 kV Bannaby-Sydney double circuit line development	3	3		3			4	3		
N1 - 500 kV Bannaby-Yass line development	4									
N4 - 500 kV Hunter Valley-Eraring via Newcastle development			3	3	2	2			2	
N5 - 500/330 kV Eraring Power Station transformer replace with 1,500 MVA unit and Add new parallel 500/330 kV Eraring Power Station transformer			3	3	2	3				
N6 - Greater Newcastle/Central Coast area, install an additional 500/330 kV transformer			4							
N7 - 500 kV Hunter Valley-Northern New South Wales development (three circuits)				3					3	
N8 - 500 kV Hunter Valley-Northern New South Wales development (four circuits)			3		2	3				
N9 - Upgrade high voltage 330 kV Ingleburn-Wallerawang Power Station connections (77) 1,215/1,429 MW Address attendant voltage control issues for Sydney 330 kV system			2	2						
N10 - 330 kV Mt Piper-Wallerawang additional 330 kV circuit development					3	2			2	
N11 - 330 kV Kemps Creek-Liverpool circuit development	3	3	3	3			4			
N12 - Kemps Creek-Sydney West or Sydney South 330 kV circuit development	4	4	3	3			4			
N13 - Kemps Creek replace 500/330 kV transformer-1500 MVA and Add new parallel transformer (for total of 3)	4	4	3	3			4	4		
N14 - Install 500/330 kV parallel transformer at future Sydney 500 kV substation	4	4		4						
N15 - Rearrange Central Coast 330 kV connections and install line series reactors-redistribute power flows			4			4			4	
N16 - Sydney North-Vales Point Power Station 330 kV circuit (22) circuit upgrade for a rating of 1215/1429 MVA				4						

The numbers and shading relate to augmentation trigger timeframes (as observed in the NTNDP modelling):

1	2010/11 – 2014/15
2	2015/16 – 2019/20
3	2020/21 – 2024/25
4	2025/26 – 2029/30

The most notable feature of the development strategy involves the 500 kV ring around Sydney. Currently, the 500 kV part is incomplete, with lower voltage 330 kV lines in the north (Bayswater-Eraring) and in the south (Bannaby-Sydney) completing the ring. Limitations occur on these 330 kV circuits under most scenarios. Replacing these lines in the north or south (or both) with 500 kV lines solves a number of potential overloads, with the timing and extent of the works dependent on the size and location of new generation.

TransGrid advises that voltage control requirements for the Sydney network will also be a driving factor in the development of the Bannaby-Sydney 500 kV development. This issue may arise for all scenarios.

The zone's transmission network is highly meshed, which means that new generation and transmission developments will affect power flows in a number of circuits at a number of voltage levels.

Generally, scenarios with significant new generation in the NNS zone tend to result in loading issues on lines between this generation centre and the NCEN load centres, including the 330 kV Liddell-Tamworth, Liddell-Greater Newcastle, and Bayswater-Regentville lines. Possible solutions involve developing the northern link of the 500 kV ring, as well as new 500 kV lines between the NCEN and NNS zones. This occurs for half of the scenario cases analysed.

New generation in the NCEN and CAN zones tends to result in loading issues on the 330 kV southern link. Possible solutions involve developing the 500 kV Bannaby-Sydney line replacement, along with a series of upgrades to the 330 kV Sydney transmission network, including new 500/330 kV transformer capacity. This occurs in six out of the ten scenarios and sensitivities.

In addition to the 500 kV ring developments, when new generation occurs in the CAN zone or when new gas-powered generation occurs in the southern part of the NCEN zone, northerly power flow loading issues arise on the 330 kV Yass-Bannaby and Yass-Marulan lines. A possible solution involves replacing the 330 kV Yass-Bannaby line with a 500 kV line, although there may be options to upgrade the existing lines to higher ratings (depending on the level of new generation to the south and the actual capacity available to upgrade the existing lines[30]).

Some of the new gas-powered generation in the NCEN zone (mainly open-cycle gas turbine (OCGT)) was modelled in the western coalfields (around Mt Piper and Wallerawang) and central coast areas (around Eraring, Vales Point, and Munmorah). As this generation was introduced, emerging power flow overloads were observed for the 330 kV Ingleburn-Wallerawang line. A possible solution for addressing this limitation includes upgrading the line's terminal equipment to allow the line to reach its full rating. Any voltage control issues arising in the Sydney 330 kV transmission network, from these large power flows will also be addressed.

The modelled retirement of Wallerawang Power Station in some scenarios potentially causes 330 kV Mt Piper-Wallerawang line overloads for outage of the parallel line. A possible solution for addressing this overload includes developing a third 330 kV Mt Piper-Wallerawang line.

[30] TransGrid, 2010 APR, Section 6.4.1.

No significant residual congestion associated with the NCEN zone was observed in the time-sequential market simulation studies.

Canberra (CAN)

The CAN zone is a net importer of power and a major power corridor connecting the SWNSW and NCEN zones. During 10% probability of exceedence (POE) MD conditions in New South Wales, power generally flows north, from SWNSW to CAN and from CAN to NCEN.

This zone continues to be a net importer of power, except under the Fast Rate of Change (FC-H) scenario, which includes sufficient new gas-powered generation for it to become a net exporter in the longer term.

Transmission augmentations for the CAN zone are needed to support power flows to the NCEN zone.

Committed projects

The CAN zone's development strategy builds on TransGrid's committed projects, which are generally related to meeting reliable supply to the Australian Capital Territory (ACT).

These projects are listed in Appendix A, and have been included in the power system modelling to capture their effect on transmission level power flow patterns.

Development strategy

Table 4-12 outlines the modelled transmission developments, as well as the variation under each scenario in terms of need and timing.

Table 4-12 Transmission development summary by project for CAN

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
N1 - Bannaby-Yass 500 kV line development	4									

The numbers and shading relate to augmentation trigger timeframes (as observed in the NTNDP modelling):

1	2010/11 – 2014/15
2	2015/16 – 2019/20
3	2020/21 – 2024/25
4	2025/26 – 2029/30

Load growth in the New South Wales region and new generation in the CAN and SWNSW zones leads to overloads of the 330 kV Yass-Bannaby and Yass-Marulan circuits. A possible solution for addressing these overloads includes implementation of a 500 kV Bannaby-Sydney circuit.

No significant residual congestion associated with the NCEN zone was observed in the time-sequential market simulation studies.

South West New South Wales (SWNSW)

The SWNSW zone connects the rest of the New South Wales region to the Victorian region via the 330 kV Lower and Upper Tumut to Murray lines, the 330 kV Albury-Wodonga line, and the 220 kV Buronga-Redcliffs line. The SWNSW zone contains a large amount of mainly hydroelectric generation. Although there is some demand within this zone, it is a net exporter of power to New South Wales load centres during the MD, and continues to be so throughout the 20-year outlook period under all scenarios.

SWNSW zone transmission network augmentations are required to support power flows from Victoria.

Committed projects

The SWNSW zone's development strategy builds on TransGrid's committed projects, including the establishment of a control scheme, which addresses potential overloading of the 132 kV Jindera-Albury-ANM transmission circuits.

These projects are listed in Appendix A, and have been included in the power system modelling to capture their effect on transmission level power flow patterns.

Development strategy

Table 4-13 outlines the modelled transmission developments, as well as the variation under each scenario in terms of need and timing.

Table 4-13 Transmission development summary by project for SWNSW

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
NV1 - A new 220 kV, 250 MVA phase angle regulator on the 220 kV Buronga-Red Cliffs line	1	1	1	1	1	1	1	1	1	1
NV2 - Victoria-New South Wales Interconnection upgrade involving: • installation of a fourth 330/220 kV Dederang transformer and a third 700 MVA 330/220 kV South Morang transformer • phase angle regulator on the 330 kV Jindera-Wodonga circuit • uprating of the 220 kV Eildon-Thomastown and 330 kV South Morang-Dederang circuits • cut-in of the 220 kV Rowville-Thomastown circuit at South Morang, and series capacitors on the 220 kV Eildon-Thomastown and 330 kV Wodonga-Dederang circuits				1						

The numbers and shading relate to augmentation trigger timeframes (as observed in the NTNDP modelling):

1	2010/11 – 2014/15
2	2015/16 – 2019/20
3	2020/21 – 2024/25
4	2025/26 – 2029/30

The zone's transmission network is highly meshed, which means that new generation and transmission developments will affect power flows in a number of circuits at a number of voltage levels.

Overloads on the 220 kV Balranald-Buronga line arise over the 20-year outlook period under all scenarios, due to high power exports from Victoria to South Australia over the Murraylink interconnector. A possible solution involves installing a phase shifting transformer on the 220 kV Buronga-Red Cliffs circuit to regulate the power flow between the CVIC and SWNSW zones.

The least-cost expansion modelling selected a SWNSW to CVIC zone (330 kV Victoria to New South Wales interconnector) power transfer capability upgrade in the Uncertain World scenario's zero carbon price sensitivity (UW-0), on the basis that it delivers net market benefits. The upgrade involves an upgrade to a significant number of 220 kV and 330 kV lines in Victoria, and the addition of transformers at Dederang and South Morang (for more information, see Appendix A,).

The upgrade provides benefits by increasing the capability for New South Wales to export power to Victoria during low demand periods. This is especially the case during the initial years following the augmentation, allowing existing black coal generation in New South Wales to increase its annual output. The modelling suggests that under this scenario the upgrade's economic timing occurs in the short term (by 2014/15), but only under UW-0. AEMO will conduct more detailed studies to further assess the benefit of this augmentation.

Time-sequential market simulations show considerable transmission network congestion across all scenarios caused by potential overload of the 330 kV Murray-Upper Tumut line for an outage of the 330 kV Murray-Lower Tumut line. This forms part of the Victoria to New South Wales interconnector, and although potential upgrades were modelled, no projects to upgrade this line were selected. Further analysis may be warranted to assess the market benefits of this upgrade. For more information about the constraint equations related to this congestion (and its frequency), see Appendix H.

4.5 Victorian development plans

4.5.1 Generation expansion

Victoria experiences modest energy growth across all scenarios, with typically slightly higher energy and MD growth than New South Wales. High levels of existing brown coal base load generation significantly impacts new generation capacity across all the scenarios.

Non-renewable

New OCGT generation is modelled in the MEL zone in all scenarios. The amount installed varies from 5,400 MW in the Uncertain World scenario (UW-L) to 1,500 MW in the Fast Rate of Change scenario (FC-H). High levels of OCGT capacity in the Uncertain World scenario (UW-L) coincide with the lowest levels of existing generation retirements.

New CCGT generation proceeds in the Fast Rate of Change (FC-H), Uncertain World (UW-L), and Decentralised World (DW-M) scenarios and their carbon price sensitivities, with the highest amount proceeding under DW-M (4,000 MW, as existing generation in the La Trobe Valley is retired). For scenarios where existing capacity is retired from 2011/12, the CCGT proceeds in parallel. CCGT with CCS is modelled in FC-H and its carbon price sensitivity (FC-M), and the Slow Rate of Change scenario (SC-L). This is driven by base load generation retirements in the La Trobe Valley.

New coal-fired generation is only modelled in the UW-L scenario's zero carbon price sensitivity (UW-0).

Renewable

Victoria has good wind resources in the MEL and CVIC zones, and a small amount in the LV zone, which is assumed to contribute 8% of its capacity to peak demand in the region. Wind proceeds in the MEL zone under all scenarios without a zero carbon price sensitivity. The modelling results in similar outcomes for wind in the CVIC zone, with new generation proceeding in all scenarios with a carbon price, except for the Fast Rate of Change (FC-H) scenario.

Victoria has good geothermal resources in the CVIC zone, and the modelling has geothermal generation proceeding in all scenarios except an Uncertain World (UW-L). In fact, the assumed maximum build limit of 1,000 MW proceeds in the FC-H, Oil Shock and Adaptation (OS-M), and Slow Rate of Change (SC-L) scenarios, and the Decentralised World scenario's high carbon price sensitivity (DW-H), while only 800 MW proceeds in the Decentralised World Scenario (DW-M). Geothermal generation in the LV zone, ranging from 200 MW to 800 MW also proceeds in the FC-H, DW-M, OS-M, and SC-L scenarios.

Retirements

The least-cost expansion modelling shows Victoria having the highest level of retirement of existing generation in scenarios with a price on carbon. Hazelwood, Yallourn, and Morwell (Energy Brix) were all modelled as potential candidates for retirement. The modelling retires Morwell in every scenario by 2014/15. Hazelwood is modelled to retire fully in the Fast Rate of Change (FC-H), Decentralised World (DW-M), and Oil Shock and Adaptation (OS-M) scenarios. Yallourn is modelled to fully retire in the Fast Rate of Change (FC-H) and Decentralised World (DW-M) scenarios, and only partially in the OS-M scenario.

Table 4-14 lists the existing and projected installed capacities in the region.

Table 4-14 Existing and projected Victorian installed capacity (MW)

Scenario	CPT		Existing	2014/15	2019/20	2024/25	2029/30
Fast Rate of Change	H	Gas/Coal/Oil	9,210	9,725	11,902	13,934	16,734
		Wind/Solar	385	885	1,085	1,085	1,085
		Hydro/Geo/Biomass	1,972	2,030	2,840	2,840	3,440
sensitivity	M	Gas/Coal/Oil	9,210	9,545	11,522	13,934	17,334
		Wind/Solar	385	1,185	1,585	1,585	1,585
		Hydro/Geo/Biomass	1,972	2,030	2,840	3,040	3,240

Scenario	CPT		Existing	2014/15	2019/20	2024/25	2029/30
Uncertain World	L	Gas/Coal/Oil	9,210	9,645	12,022	14,521	16,921
		Wind/Solar	385	485	1,485	2,835	2,885
		Hydro/Geo/Biomass	1,972	2,030	2,040	2,040	2,040
sensitivity	0	Gas/Coal/Oil	9,210	9,645	12,122	14,921	17,321
		Wind/Solar	385	385	385	385	385
		Hydro/Geo/Biomass	1,972	2,030	2,030	2,040	2,030
Decentralised World	M	Gas/Coal/Oil	9,210	8,945	10,222	11,634	13,534
		Wind/Solar	385	2,285	2,285	2,285	2,285
		Hydro/Geo/Biomass	1,972	2,030	2,840	2,840	2,840
sensitivity	H	Gas/Coal/Oil	9,210	9,258	10,435	11,334	13,534
		Wind/Solar	385	1,585	1,785	1,785	2,385
		Hydro/Geo/Biomass	1,972	2,030	2,840	3,040	3,440
Oil Shock and Adaptation	M	Gas/Coal/Oil	9,210	8,545	9,122	9,221	9,914
		Wind/Solar	385	1,385	1,785	1,785	3,735
		Hydro/Geo/Biomass	1,972	2,030	2,840	3,640	3,840
sensitivity	L	Gas/Coal/Oil	9,210	8,645	9,222	9,821	10,421
		Wind/Solar	385	1,385	1,585	1,585	1,585
		Hydro/Geo/Biomass	1,972	2,030	2,840	3,040	3,440
Slow Rate of Change	L	Gas/Coal/Oil	9,210	8,645	9,222	10,121	11,221
		Wind/Solar	385	1,385	1,585	1,585	1,585
		Hydro/Geo/Biomass	1,972	2,030	3,040	3,240	3,240
sensitivity	0	Gas/Coal/Oil	9,210	9,045	9,622	9,921	10,821
		Wind/Solar	385	385	385	385	385
		Hydro/Geo/Biomass	1,972	2,030	2,840	3,640	3,640

4.5.2 Transmission development 10-year summary

Table 4-15 lists the transmission network developments identified over the next 10 years under at least one scenario. For more information about the production of this table and its categories, see Section 4.2.2.

Table 4-15 Victorian transmission development 10-year summary

Transmission development	Rating	Status/reference
V1 - A new 500 kV Loy Yang-Hazelwood line	Monitoring	Victorian 2010 APR, Section 9.3.1
V5 - A new 500/220 kV 1,000 MVA transformer at Ringwood, Rowville, or Cranbourne	Early attention	AEMO is undertaking an assessment of the available network and non-network augmentation options and non-network options as part of the 2011 APR (Victorian 2010 APR, Section 9.3.4)
V6 – An additional 500/220 kV 1,000 MVA transformer at Ringwood, Rowville, or Cranbourne	Preparatory work	
V7 - Re-conductor the 220 kV Rowville-Springvale line	Preparatory work	This limitation is observed beyond the first five-year period. AEMO will monitor the load at the Springvale and/or Heatherton terminal stations and identify available network and non-network options including necessary lead-times (Victorian 2010 APR, Section 9.3.4)
V8 – A new 500 kV Moorabool-Mortlake/Heywood line (third line)	Monitoring	This augmentation is triggered by new generation connections to the 500 kV Moorabool-Mortlake/Heywood line. AEMO will consider its as part of new generation connection enquiries on the line (Victorian 2010 APR, Section 9.3.2)
V9 – A new 330/220 kV 700 MVA transformer at South Morang (third transformer), and a cut-in of the 220 kV Rowville-Thomastown circuit at South Morang to form a third 220 kV South Morang-Thomastown line	Preparatory work	AEMO is undertaking an assessment of the available network and non-network augmentation options and non-network options as part of the 2011 APR (Victorian 2010 APR, Section 9.3.4)
V15 - An additional 500/220 kV 1,000 MVA transformer in the western part of the Greater Melbourne Metropolitan Area	Monitoring	This augmentation is triggered in the first 10 years by the combination of high demand growth and lack of new generation south of Geelong. AEMO will monitor the progress of these factors.
NV2 - A Victoria-New South Wales interconnector upgrade	Preparatory work	AEMO and TransGrid are intending to investigate the benefits of upgrading the Vic-NSW interconnector
V16 - Cut-in on the 220 kV Eildon-Thomastown line at South Morang	Monitoring	This augmentation is triggered in the first 10 years by a combination of high demand growth and increased imports from New South Wales as a result of an interconnector upgrade. AEMO will consider the need for this augmentation as part of investigations into an upgrade of the Victoria-New South Wales capability (Victorian 2010 APR, Sections 9.3.4 and 9.3.3)
V22 - A new 330/220 kV Dederang transformer (fourth)	Monitoring	
V28 - A new 220 kV Ballarat-Moorabool line (third line)	Early attention	AEMO is undertaking a detailed assessment of the constraint that triggers this augmentation as part of the 2011 APR (Victorian 2010 APR, Section 9.3.5)
NV1 - A new 220 kV, 250 MVA phase angle regulator on the 220 kV Buronga-Red Cliffs interconnection	Early attention	AEMO and ElectraNet are intending to investigate the ongoing requirements for South Australian imports over Murraylink, and options to support load growth in the Riverland and other areas. AEMO and TransGrid are intending to investigate the impacts for the New South Wales system from high Murraylink power transfers at time of peak demand.

Transmission development	Rating	Status/reference
V29 - Replace the existing, single circuit 220 kV Ballarat-Bendigo line with a 220 kV double circuit line	Early attention	These limitations are triggered by demand growth in CVIC and high power transfers to South Australia via Murraylink. AEMO is intending to undertake an assessment of these limitations (Victorian 2010 APR, Section 9.3.5)
V31 - Uprate the existing 220 kV Ballarat-Bendigo line	Early attention	
V32 - Replace the existing, single circuit 220 kV Bendigo-Kerang line with a new 220 kV double circuit line	Monitoring	
V34 - Replace the existing 220 kV Kerang-Wemen-Red Cliffs single circuit line with a new 220 kV double circuit line	Monitoring	
V30 - Uprate the existing 220 kV Geelong-Moorabool lines	Early attention	AEMO is currently undertaking a detailed assessment of this limitation and options to address it (Victorian 2010 APR, Section 9.3.5)

4.5.3 Transmission development by zone

Latrobe Valley (LV)

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

Other than under the Uncertain World (UW-L) scenario, and the Uncertain World and Slow Rate of Change scenarios' zero carbon price sensitivities (UW-0 and SC-0), the modelling retires a significant amount of brown coal generation and predominantly replaces it with OCGT and CCGT generation, as well as some brown coal-fired and geothermal generation. Consistent with a least-cost development, it is assumed that new LV zone generation will be located in the same places as the retired brown coal generation. This enables the existing transmission network to accommodate the new generation with minimal (or no) new transmission. Additional new generation was assumed for connection at the 500 kV terminal stations at Loy Yang and Hazelwood.

Committed projects

There are no committed projects relating to this zone.

Development strategy

Table 4-16 outlines the modelled transmission developments, as well as the variation under each scenario in terms of need and timing.

Table 4-16 Transmission development summary by project for LV

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
V1 - A new 500 kV Loy Yang-Hazelwood line	2	2	3	2	4	4				
V2 –A new 500 kV Hazelwood-Cranbourne line and cut-in the existing 500 kV Hazelwood-Rowville line at Cranbourne	3	3	4	4						
V3 - A new 500 kV Hazelwood-Coldstream line; Reuse of 500 kV Coldstream-Templestowe line; 500 kV Templestowe switchyard; 220 kV Upgrade Rowville-South Morang line to 500 kV operation and cut-in at Templestowe	4	4								

The numbers and shading relate to augmentation trigger timeframes (as observed in the NTNDP modelling):

1	2010/11 – 2014/15
2	2015/16 – 2019/20
3	2020/21 – 2024/25
4	2025/26 – 2029/30

Additional new generation in the LV zone results in transmission network constraints between the LV and MEL zones, requiring new 500 kV lines between the two. In the Fast Rate of Change (FC-H) and Uncertain World (UW-L) scenarios, an additional new 500 kV line is identified between Hazelwood and Cranbourne with switching of the existing 500 kV Hazelwood-Rowville line at Cranbourne. Further, an additional 500 kV line is also identified by 2029/30 under FC-H, which can be located in the northern easement between Hazelwood and Templestowe (via Coldstream), and involves re-use of an unused section of 500 kV line between Templestowe and Coldstream, and the development of a 500 kV terminal station at Templestowe. This requires upgrading the existing 220 kV Rowville-Thomastown line between Rowville and South Morang to its designed operating voltage of 500 kV, with switching at the 500 kV Templestowe Terminal Station, providing a reliable network between Rowville and South Morang.

If additional generation is connected at Loy Yang, additional 500 kV lines are needed between Loy Yang and Hazelwood.

The Victorian export transient stability limit shows significant residual congestion under all scenarios. In addition to restricting export via all Victorian interconnectors, it also restricts flow on the Queensland to New South Wales (QNI) interconnector. This limitation has been identified previously in the 2009 National Transmission Statement (NTS) and earlier Annual National Transmission Statement (ANTS) studies. A possible option to improve this limit involves installing a braking resistor at the Hazelwood Terminal Station. This project was not considered in the least-cost expansion modelling, because stability limitations cannot be accurately modelled, and further detailed analysis may be warranted to assess the market benefits from relieving this constraint. AEMO is currently assessing the Victorian export transient stability limit as part of the annual planning review. The outcomes of this review will be reported in the 2011 Victorian Annual Planning Report.

Melbourne (MEL)

The Melbourne and Geelong Greater Metropolitan Area is projected to remain the dominant load centre in Victoria. With increased load growth, additional 500/220 kV transformers are needed to supply the load. Possible locations for new 500/220 kV transformers in the eastern part of the Greater/ Melbourne Metropolitan Area are Cranbourne, Coldstream, Narre Warren, Ringwood, Rowville, and Templestowe, and in the western part are Donnybrook, Keilor, Moorabool, and Truganina. Additional 330/220 kV, 500/330 kV, and possible 500/220 kV transformers will be needed at South Morang. The order of possible locations needs further investigation (with due consideration given to distribution business plans for new 220/66 kV terminal stations and to the exact locations of new generation).

The modelling shows the loading on a number of 220 kV lines reaching their maximum design capability. These critical lines have been identified for replacement with high temperature conductors, which is possible with the existing towers (with some modifications).

Committed projects

The MEL zone's development strategy includes connecting Mortlake Power Station (capacity 580 MW) by establishing a 500 kV terminal station at Mortlake with connection to the (No.2) 500 kV Moorabool-Heywood line (with completion anticipated by late 2010)[31].

These projects are listed in Appendix A, and have been included in the power system modelling to capture their effect on transmission level power flow patterns.

Development strategy

Table 4-17 outlines the modelled transmission developments, as well as the variation under each scenario in terms of need and timing.

Table 4-17 Transmission development summary by project for MEL

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
V5 - A new 500/220 kV 1,000 MVA transformer at Ringwood, Rowville or Cranbourne	1	1	1	1	1	1	2	2	2	2
V6 – An additional 500/220 kV 1,000 MVA transformer at Ringwood, Rowville or Cranbourne	2	2	2	2	2	2	4	4	4	4
V7 - Re-conductor 220 kV Rowville-Springvale line	2	2	2	2	2	2	3	3	3	3
V8 - A new 500 kV Moorabool-Mortlake/Heywood line (3rd line)		3	2	3	4	4	4		4	
V9 - A new 330/220 kV 700 MVA transformer at South Morang (3rd transformer), and a cut-in of the 220 kV Rowville-Thomastown circuit at South Morang to form a third 220 kV South Morang-Thomastown line	3	3	3	1	4	4				

[31] AEMO, 2010 Victorian Annual Planning Report, Chapter 3, Section 3.3.1.

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
NV2 - Victoria-New South Wales Interconnection upgrade involving: • installation of a fourth 330/220 kV Dederang transformer and a third 700 MVA 330/220 kV South Morang transformer • phase angle regulator on the Jindera-Wodonga 330 kV circuit • uprating of the 220 kV Eildon-Thomastown and 330 kV South Morang-Dederang circuits • cut-in of the 220 kV Rowville-Thomastown circuit at South Morang, and • series capacitors on the Eildon-Thomastown 220 kV and Wodonga-Dederang 330 kV circuits				1						
V10 - Re-conductor the 220 kV Brunswick-Thomastown circuits	3	3	3	3	3	4				
V11 - Re-conductor the 220 kV Heatherton-Springvale circuits	3	3	3	3	4	4				
V12 - Cut-in the 220 kV Rowville-Templestowe line at Ringwood, and cut-in the 220 kV Thomastown-Ringwood line at Templestowe	3	3	3	3	4	4				
V13 – An additional 500/220 kV 1,000 MVA transformer in the eastern part of the Greater Melbourne Metropolitan Area	3	3	3	3	4	4				
V14 – An additional 500/220 kV 1,000 MVA transformer in the western part of the Greater Melbourne Metropolitan Area	3	3	3	3	4	4				
V15 – An additional 500/220 kV 1,000 MVA transformer in the western part of the Greater Melbourne Metropolitan Area	4	4	2	3	4	4				
V16 - Cut-in the 220 kV Eildon-Thomastown line at South Morang				2						
V2 - A new 500 kV Hazelwood-Cranbourne line and cut-in the existing 500 kV Hazelwood-Rowville line at Cranbourne	3	3	4	4						
V18 – An additional 500/220 kV 1,000 MVA transformer in the eastern part of the Greater Melbourne Metropolitan Area	4	4	4	4						
V19 – An additional 500/220 kV 1,000 MVA transformer in the eastern part of the Greater Melbourne Metropolitan Area	4	4	4	4						
V20 – An additional 500/220 kV 1,000 MVA transformer in the western part of the Greater Melbourne Metropolitan Area			4	4						
V3 - A new 500 kV Hazelwood-Coldstream line, reuse of the 500 kV Coldstream-Templestowe line, a 500 kV Templestowe switchyard, upgrade 220 kV Rowville-South Morang line to 500 kV operation and cut-in at Templestowe	4	4								
V21 - A new 500 kV line Moorabool-Mortlake/Heywood (4th line)			4							

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
VS1 – A third Heywood 500/275 kV transformer, a 100 MVAr capacitor bank at South East Substation , 275 kV series compensation between South East Substation and Tailem Bend Substation, a SVC at Tailem Bend, increase of the relevant circuit ratings to line design ratings by protection and selected plant modifications	4									
VS2 - A third Heywood 500/275 kV transformer, a 100 MVAr capacitor bank at South East Substation, a third South East 275/132 kV transformer, increase of the relevant circuit ratings to line design ratings by protection and selected plant modifications							4			

The numbers and shading relate to augmentation trigger timeframes (as observed in the NTNDP modelling):

1	2010/11 – 2014/15
2	2015/16 – 2019/20
3	2020/21 – 2024/25
4	2025/26 – 2029/30

Connection of significant additional new generation in the 500 kV South West Victoria Corridor requires additional 500 kV transmission lines, to begin between Moorabool and Heywood, and connecting at Moorabool.

A total of eight new 500/220 kV transformers are identified in the Melbourne and Geelong Greater Metropolitan Area to meet the increased load growth. For a list of indicative locations, see Table 4-17. South Morang is one of the key terminal stations with 500 kV, 330 kV, and 220 kV voltage levels. A new 330/220 kV transformer is identified to meet increased load growth and increased imports from New South Wales.

Potential constraints on the 220 kV lines between Rowville and South Morang are removed by switching the 220 kV Rowville-Templestowe line at Ringwood and the 220 kV Thomastown-Ringwood line at Templestowe.

The 220 kV Rowville-Springvale-Heatherton and Thomastown-Brunswick lines are identified for replacement with high temperature conductors using the same easement.

The time-sequential market simulation studies show significant residual transmission network congestion associated with the thermal ratings of the 500/300 kV South Morang (F2) transformer, and the 330 kV South Morang-Dederang line, and restricting power flows out of the MEL zone. Further detailed analysis may be warranted to quantify the market benefits from relieving these limitations.

All new generation and transmission projects will result in system-wide, short-circuit level changes, requiring further studies to examine the related issues.

Country Victoria (CVIC)

Over the 20-year outlook period, most of the CVIC zone's transmission network requires augmentation to meet demand growth and high exports from Victoria to South Australia via Murraylink during summer high-demand periods, and to accommodate new generation. A number of 220 kV lines are identified for replacement with higher capacity transmission lines. If significant generation is added, further augmentation will be required. One option is to construct new 500 kV transmission lines, initially operated at 220 kV.

Committed projects

There are no committed projects relating to this zone.

Development strategy

Table 4-18 outlines the modelled transmission developments, as well as the variation under each scenario in terms of need and timing.

Table 4-18 Transmission development summary by project for CVIC

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
V28 - A new 220 kV Ballarat-Moorabool line (3rd line)	1	1	1	1	1	1	1	1	1	1
NV1 - A new 220 kV, 250 MVA phase angle regulator on 220 kV Buronga-Red Cliffs interconnection	1	1	1	1	1	1	1	1	1	1
V29 - Replace the existing single circuit 220 kV Ballarat-Bendigo line with a 220 kV double circuit line	1	1	1	1	2	2	2	2	2	2
V30 - Uprate the existing 220 kV Geelong-Moorabool lines	1	1	1	1	1	1				
V31 - Uprate the existing 220 kV Ballarat-Bendigo line					1	1	1	1	1	1
V32 - Replace the existing 220 kV single Bendigo-Kerang circuit line with a new 220 kV double circuit line	2	2	2	2	2	2	4	4	4	4
V34 - Replace the existing 220 kV Kerang-Wemen-Red Cliffs single circuit line with a new 220 kV double circuit line	2	2	2	2	3	3				
V35 - Uprate the No.1 220 kV Ballarat-Moorabool line	3	3	3	3	3	3				4
V36 - A new 220 kV Moorabool-Geelong line (3rd line)			3	3						

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
V37 - Replace the existing No.1 220 kV Moorabool-Ballarat single circuit tower with 220 kV double circuit line	4	4	4	4						
V38 - Uprate the 220 kV Moorabool-Terang line	4	4	4	4						
V39 - Uprate the 220 kV Ballarat-Horsham line	4	4	4	4						

The numbers and shading relate to augmentation trigger timeframes (as observed in the NTNDP modelling):

1	2010/11 – 2014/15
2	2015/16 – 2019/20
3	2020/21 – 2024/25
4	2025/26 – 2029/30

Transmission lines between Moorabool and Red Cliffs as well as between Buronga and Darlington Point are heavily constrained at times of peak demand in the CVIC zone coupled with 200 MW export to South Australia via Murraylink. New transmission lines and a phase angle regulator on the 220 kV Red Cliffs-Buronga line have been identified to address these limitations. The timing of these developments depends on peak demand in the CVIC zone and Murraylink export requirements.

An additional 220 kV Ballarat-Moorabool line, and uprating the existing No.1 220 kV Ballarat-Moorabool line are identified to avoid overloading of the parallel line. Under scenarios with a high demand growth, the existing No.2 220 kV Ballarat-Moorabool line is replaced with a new double circuit 220 kV line.

The single circuit 220 kV Ballarat-Bendigo-Kerang-Wemen-Red Cliffs lines are identified for replacement with new 220 kV double circuit lines.

Northern Victoria (NVIC)

The NVIC zone includes major interconnectors between Victoria and New South Wales. The zone also provides electrical transmission for Victorian hydroelectric stations in the Kiewa, Dartmouth, and Eildon schemes, and Murray hydroelectric generation. The least-cost modelling under the Uncertain World scenario's zero carbon price sensitivity (UW-0) modelled an additional 400 MW power transfer capability from New South Wales to Victoria, comprising a number of transmission augmentations in the NVIC zone.

Committed projects

There are no committed projects relating to this zone.

Table 4-19 outlines the modelled transmission developments, as well as the variation under each scenario in terms of need and timing.

Table 4-19 Transmission development summary by project for NVIC

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
V22 - A new 330/220 kV Dederang transformer (4th)	4	4	4	1						
NV2 – A Victoria-New South Wales Interconnection upgrade involving: • installation of a fourth 330/220 kV Dederang transformer and a third 700 MVA 330/220 kV South Morang transformer • phase angle regulator on the 330 kV Jindera-Wodonga circuit • uprating of the 220 kV Eildon-Thomastown and 330 kV South Morang-Dederang circuits • cut-in of the 220 kV Rowville-Thomastown circuit at South Morang, and • series capacitors on the 220 kV Eildon-Thomastown and 330 kV Wodonga-Dederang circuits				1						
V27 - Replace the 220 kV Dederang-Glenrowan circuits with a 220 kV double circuit line	3	3	3	3	4	4				

The numbers and shading relate to augmentation trigger timeframes (as observed in the NTNDP modelling):

1	2010/11 – 2014/15
2	2015/16 – 2019/20
3	2020/21 – 2024/25
4	2025/26 – 2029/30

With additional 220 kV lines identified in the CVIC zone, the timing for an additional 330/220 kV transformer at Dederang is deferred for 10 years in all scenarios except the Uncertain World scenario's zero carbon price sensitivity (UW-0). Under UW-0, increased imports from New South Wales require a series of potential augmentations, including a phase angle regulator on the 330 kV Wodonga-Jindera line, series compensation on the 330 kV Wodonga-Dederang and 220 kV Eildon-Thomastown lines, and uprating of the 330 kV South Morang-Dederang and the 220 kV Eildon-Thomastown lines.

To meet the high demand projections, the 220 kV Dederang-Glenrowan lines also require replacement with high capacity lines.

4.6 South Australian development plans

4.6.1 Generation expansion

South Australia experiences low energy growth, and the lowest MD growth in every scenario, and installed levels of new installed capacity are largely driven by a constraint to meet the Large-scale

Renewable Energy Target (LRET)[32]. This constraint is applied to the NEM, but the presence of good quality renewable generation in South Australia results in high levels of renewable generation modelled in this region.

Non-renewable

All non-renewable capacity installed in the region is modelled to be met by OCGTs in the ADE zone, except for 1,000 MW of CCGT in the Uncertain World scenario's zero price sensitivity (UW-0). With good quality renewable base load options, like biomass and geothermal generation, and high levels of new wind generation, there is little new non-renewable base load generation. Installed OCGT capacity is over 1,000 MW under the Fast Rate of Change (FC-H), Uncertain World (UW-L), and Decentralised World (DW-M) scenarios.

Renewable

The region has good wind resources available in the SESA and NSA zones, which is assumed to contribute 3% of its capacity to peak demand in the region. At least 1,000 MW of wind is planted for all scenarios, with a high of 3,200 MW under the Decentralised World scenario's high carbon price sensitivity (DW-H).

South Australia has good quality renewable base load options, such as biomass generation in the SESA zone, and geothermal generation in the SESA and NSA zones. Installed biomass capacity of 200 MW is modelled under all scenarios. Geothermal capacity is also modelled in all scenarios except UW-L, where it is assumed to be unavailable.

Retirements

The Playford, Northern, and Torrens Island 'A' Power Stations were all modelled as potential candidates for retirement. Playford Power Station retires by 2014/15 in all scenarios except UW-L, UW-0, and the Slow Rate of Change scenario's zero carbon price sensitivity (SC-0). The Northern Power Station retires in the 20-year outlook's final year for the FC-H scenario only, while Torrens Island 'A' Power Station does not retire under any scenario.

Table 4-20 lists the existing and projected installed capacities in the region.

[32] A constraint is applied in the least-cost model to ensure sufficient levels of renewable energy is generated (for a description, see Attachment 1).

Table 4-20 Existing and projected South Australian installed capacity (MW)

Scenario	CPT		Existing	2014/15	2019/20	2024/25	2029/30
Fast Rate of Change sensitivity	H	Gas/Coal/Oil	3,387	3,349	3,549	3,949	3,803
		Wind/Solar	1,152	2,405	2,405	2,405	3,405
		Hydro/Geo/Biomass	0	0	700	1,000	1,600
	M	Gas/Coal/Oil	3,387	3,549	3,549	3,949	4,149
		Wind/Solar	1,152	2,405	2,405	2,405	2,405
		Hydro/Geo/Biomass	0	0	700	1,000	1,600
Uncertain World sensitivity	L	Gas/Coal/Oil	3,387	3,589	3,989	4,589	5,389
		Wind/Solar	1,152	2,405	3,405	3,905	4,005
		Hydro/Geo/Biomass	0	0	200	200	200
	0	Gas/Coal/Oil	3,387	3,589	3,989	4,589	5,189
		Wind/Solar	1,152	1,205	1,805	2,405	2,405
		Hydro/Geo/Biomass	0	0	200	200	200
Decentralised World sensitivity	M	Gas/Coal/Oil	3,387	3,349	3,549	3,749	4,349
		Wind/Solar	1,152	2,705	3,405	3,405	3,805
		Hydro/Geo/Biomass	0	0	500	600	600
	H	Gas/Coal/Oil	3,387	3,349	3,549	3,749	4,349
		Wind/Solar	1,152	2,605	3,705	3,705	4,405
		Hydro/Geo/Biomass	0	0	300	600	600
Oil Shock and Adaptation sensitivity	M	Gas/Coal/Oil	3,387	3,149	3,149	3,149	3,149
		Wind/Solar	1,152	2,405	2,405	2,405	2,905
		Hydro/Geo/Biomass	0	0	500	800	1,200
	L	Gas/Coal/Oil	3,387	3,149	3,149	3,149	3,349
		Wind/Solar	1,152	2,405	2,405	2,405	2,405
		Hydro/Geo/Biomass	0	0	500	800	800
Slow Rate of Change sensitivity	L	Gas/Coal/Oil	3,387	3,349	3,349	3,349	3,749
		Wind/Solar	1,152	2,405	2,405	2,405	2,405
		Hydro/Geo/Biomass	0	0	500	800	800
	0	Gas/Coal/Oil	3,387	3,389	3,389	3,389	3,989
		Wind/Solar	1,152	1,705	1,705	1,805	2,205
		Hydro/Geo/Biomass	0	0	500	600	600

4.6.2 Transmission development 10-year summary

Table 4-21 lists the transmission network developments identified over the next 10 years under at least one scenario. For more information about the production of this table and its categories, see Section 4.2.2.

Table 4-21 South Australian transmission development 10-year summary

Transmission development	Rating	Status/reference
S4 – Establish the second 275 kV Davenport-Cultana line and reinforce the 275/132 kV transformation capacity at Cultana. Rearrange the 132 kV Davenport-Whyalla and Whyalla-Middleback/Yadnarie lines	Early attention	ElectraNet commenced a Regulatory Test for this project in July 2010 (http://www.electranet.com.au/project_detail.php?id=34) and ElectraNet APR 2010, Section 17.4.
S5 - Establish a 275/132 kV injection point in the vicinity of Hummocks with one 200 MVA transformer, and construct a 275 kV double circuit line from the existing west circuit to the substation location	Preparatory work	This augmentation is driven by demand growth in the South Australian mid-North area. On the basis of local peak demands in the region, the ElectraNet APR identifies a timing of 2018 (ElectraNet 2010 APR, Section 14.4.1, Table 14-1)
S8 - Install 275 kV series compensation between the South East Substation and the Tailem Bend Substation	Monitoring	ElectraNet 2010 APR, Section 11.2.2, Table 11-1
NV1 – A new 220 kV, 250 MVA phase angle regulator on the 220 kV Buronga-Red Cliffs interconnection	Early attention	AEMO and ElectraNet are intending to investigate the ongoing requirements for South Australian imports over Murraylink, and options to support load growth in the Riverland and other areas. AEMO and TransGrid are intending to investigate the impacts for the New South Wales system from high Murraylink power transfers at time of peak demand

4.6.3 Transmission development by zone

Adelaide (ADE)

The ADE zone, which covers the Adelaide Metropolitan Area and Eastern Hills, is the major load centre, accounting for approximately 70% of the region's total demand throughout the 20-year outlook period. Significant levels of new gas-powered generation, predominantly OCGT, are modelled in the ADE zone under the Fast Rate of Change scenario (FC-H) and its medium carbon price sensitivity (FC-M), the Uncertain World scenario (UW-L) and its zero carbon price sensitivity (UW-0), and a Decentralized World (DW-M) and its high carbon price sensitivity (DW-H).

New generation capacities vary significantly between the scenarios, ranging from over 2,000 MW under UW-L and its zero carbon price sensitivity (UW-0) to zero under the Oil Shock and Adaption scenario (OS-M).

Different assumptions regarding the specific locations of new ADE zone gas-powered generation require reinforcement of different parts of the zone's transmission network. If all new generation in the zone is assumed to be developed in the vicinity of Torrens Island, augmentation is required for the 275 kV transmission network linking the new power stations in the vicinity of Torrens Island and the Adelaide Metropolitan Area and Eastern Hills load centres. Alternatively, should future ADE zone generation development be partially or entirely located in the vicinity of Tepko (near Tungkillo, approximately 40 kilometres east of Adelaide), transmission network augmentations in the vicinity of Tepko/Tungkillo will be required.

The studies assumed that all new ADE zone gas-powered generation is located in the vicinity of Torrens Island. Sensitivity studies were also carried out to identify potential augmentation requirement impacts with up to 1,000 MW of new gas-powered generation located in the vicinity of Tepko instead (discussed in the Development strategy section).

Committed projects

The ADE zone's development strategy begins with ElectraNet's committed projects involving the development of a 275 kV bulk supply west of the central business district (City West), and includes the installation of a 275 kV underground cable from Torrens Island 'B' Power Station to City West. The project is driven by compliance with the South Australian Electricity Transmission Code (ETC), and the need to overcome other thermal overloading issues in the distribution network. ElectraNet expects to complete the project in 2011/12[33].

These projects are listed in Appendix A, and have been included in the power system modelling to capture their effect on transmission level power flow patterns.

Development strategy

Table 4-22 outlines the modelled transmission developments, as well as the variation under each scenario in terms of need and timing.

Table 4-22 Transmission development summary by project for ADE

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
S1 - Increase the ratings of both 275 kV Torrens Island B-Kilburn and Torrens Island B-Northfield circuits to line design ratings by relevant protection and selected plant modifications	4	4	4	3						
S2 - Increase the rating of the 275 kV Northfield-Kilburn circuit to line design rating by relevant protection and selected plant modifications				3						

[33] ElectraNet, Annual Planning Report, June 2010, Chapter 12, Section 12.4.1 and Section 12.4.5.

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
S3 – Cut-in the 275 kV Torrens Island B-Cherry Gardens circuit at Para. Increase the rating of the 275 kV Torrens Island B-Para circuit to line design rating by relevant protection and selected plant modifications			4	4						

The numbers and shading relate to augmentation trigger timeframes (as observed in the NTNDP modelling):

1	2010/11 – 2014/15
2	2015/16 – 2019/20
3	2020/21 – 2024/25
4	2025/26 – 2029/30

Subsequent to the committed augmentations in this zone, 275 kV transmission network limitations emerge over the next 10-20 years, depending on the scenario. The first limitation is associated with the post-contingency overloading of the 275 kV Torrens Island ‘B’-Kilburn and Torrens Island ‘B’-Northfield circuits, as well as the 275 kV Kilburn-North Field circuit. Possible options for addressing these limitations include increasing the ratings of these three circuits to the line design ratings, via relevant protection and selected plant modifications.

Another emerging limitation is associated with the post-contingency overloading of the 275 kV Torrens Island ‘B’-Para circuit during an outage of the 275 kV Pelican Point-Parafield Gardens West circuit (or vice versa). New generation development in the vicinity of Torrens Island is the main driver of this network limitation. A possible solution is to connect the Para Substation to the existing 275 kV Torrens Island ‘B’-Cherry Gardens circuit, and increasing the rating of the newly formed Torrens Island ‘B’-Para circuit to its line design rating, via relevant protection and selected plant modifications between 2025/26 and 2029/30.

The time-sequential market simulation studies show considerable residual transmission network congestion under all the scenarios, which is associated with thermal limits to prevent overloading the 275 kV Tailem Bend-Cherry Gardens circuit for loss of the Tailem Bend-Tungkillo circuit. The congestion level increases during the second half of the 20-year outlook period. Options for addressing this limitation include stringing the vacant side of the existing 275 kV Tailem Bend-Tungkillo circuit.

Impact of alternative generation location in the vicinity of Tepko

Limitations driven by new ADE zone gas-powered generation in the vicinity of Tepko are associated with post-contingency overloading of the 275 kV Tungkillo-Tailem Bend circuit, the 275 kV Tailem Bend-Cherry Gardens circuit, and the 132 kV Mobilong-Tailem Bend circuit. Possible transmission network development strategies to enable connection of generation up to approximately 1,000 MW in the vicinity of Tepko include the following:

- Cut-in the existing 275 kV Tungkillo-Tailem Bend circuit at Tepko (for connection up to approximately 200 MW).
- Install a new 275 kV circuit between Tungkillo and Tepko (for connection up to approximately 400 MW).
- Cut-in the existing 275 kV Tailem Bend-Cherry Gardens circuit at Tepko and at Tungkillo, respectively (for connection up to approximately 600 MW).

- install a new 275 kV circuit between Tungkillo and Tepko, and increase the rating of the 275 kV Tungkillo-Cherry Gardens circuit to its line design rating (for connection up to 1,000 MW).

Further reinforcement along the Tungkillo-Cherry-Happy Valley transmission corridor may also be required, depending on the generation support available in the vicinity of Torrens Island.

Studies also show that with up to 1,000 MW of new generation capacity in the ADE zone located in the vicinity of Tepko, the limitation associated with the post-contingency overloading of the 275 kV Torrens Island 'B'-Para and 275 kV Pelican Point-Parafield Gardens West circuits do not occur under any of the scenarios. As a result, the possible solution involves connecting the existing 275 kV Torrens Island 'B'-Cherry Gardens circuit to Para and increasing the rating of the newly formed Torrens Island 'B'-Para circuit to its line design rating can be avoided.

Other transmission network augmentations are driven by demand growth and are therefore not affected by relocating generation to the vicinity of Tepko.

Northern South Australia (NSA)

The NSA zone has significant wind and geothermal resources, which comprise the new generation types in this zone. Modelled geothermal generation capacities range from zero to over 1,000 MW, and wind generation capacities range from approximately 500 MW to 1,800 MW. The retirement of Playford Power Station and Northern Power Station in some scenarios, coupled with demand growth in the zone, avoids the need for extensive reinforcement of the 275 kV transmission capacity between the ADE and NSA zones over the 20-year outlook period.

Committed projects

The NSA zone's development strategy begins with the establishment of the Templers 275/132 kV substation to overcome the thermal and voltage constraints in the Barossa area. This project is a committed project and is expected to be completed in 2011/2012[34].

These projects are listed in Appendix A, and have been included in the power system modelling to capture their effect on transmission level power flow patterns.

Development strategy

Table 4-23 outlines the modelled transmission developments, as well as the variation under each scenario in terms of need and timing.

[34] ElectraNet, Annual Planning Report, June 2010, Section 14.4.

Table 4-23 Transmission development summary by project for NSA

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
S4 - Establish the second 275 kV Davenport-Cultana line and reinforcement of 275/132 kV transformation capacity at Cultana, and rearrangement of the132 kV Davenport-Whyalla and Whyalla-Middle back/Yadnarie lines	1	1	1	1	1	1	1	1	1	1
S5 - Establish a 275/132 kV injection point in the vicinity of Hummocks with 1 x 200 MV.A transformer, and construct a 275 kV double circuit line from the existing West circuit to the substation location	3	3	3	2	4	4				4
S6 - Uprate the 275 kV Para –Brinkworth-Davenport circuits from 65 °C to 80 °C		4								
S7 - Install the second 275/132 kV Templers transformer (No.4) in conjunction with 132 kV network reconfiguration			4	4						

The numbers and shading relate to augmentation trigger timeframes (as observed in the NTNDP modelling):

1	2010/11 – 2014/15
2	2015/16 – 2019/20
3	2020/21 – 2024/25
4	2025/26 – 2029/30

In July 2010, ElectraNet released an Application Notice identifying limitations on the Eyre Peninsula, and the projects to relieve them. The limitations are associated with unsatisfactory Eyre Peninsula voltages and thermal overloading of the 132 kV Davenport-Whyalla circuits under contingency conditions. The projects, expected to be completed in 2013[35], involve establishing a second 275 kV Davenport-Cultana line, reinforcing the 275/132 kV transformation capacity at Cultana, and rearranging the 132 kV Davenport-Whyalla and Whyalla-Middle Back/Yadnarie circuits. The projects were modelled in all 2010 NTNDP scenarios.

Following these developments, emerging limitations arise due to post-contingency overloading of the 132 kV Waterloo-Hummocks circuit during outage of the 132 kV Bungama-Hummocks circuit, and the 132 kV Snowtown Tee-Hummocks circuit during outage of the 132 kV Waterloo-Hummocks circuit. Driven by demand growth, the timing of these limitations varies from scenario to scenario. The Uncertain World scenario's zero carbon price sensitivity (UW-0) experiences limitations in the period 2015/16-2019/20, while scenarios with lower economic growth experience them later on in the outlook period or not at all. Possible solutions include the development of a new 275/132 kV substation near Hummocks in conjunction with the construction of a 275 kV double circuit line between this substation and the existing 275 kV Bungama-Para circuit.

An emerging limitation associated with overloading the existing 275 kV Davenport-Brinkworth-Para circuit during the outage of one of the remaining 275 kV circuits from Davenport to Para and Robertstown is observed under the Fast Rate of Change scenario's medium carbon price sensitivity

[35] ElectraNet, New Large Network Asset – Cultana Augmentation, Regulatory Test Application Notice, July 2010.

(FC-M). This sensitivity sees the highest levels of geothermal generation modelled in the NSA zone without retiring the Northern Power Station. The limitation is driven by the need to transfer a high volume of power injected into the Davenport area towards Adelaide. This limitation occurs in the period from 2025/26-2029/30. A possible solution includes uprating the 275 kV Davenport-Brinkworth-Para circuits.

In the last five years of the 20-year outlook period, a limitation associated with overloading the 275/132 kV Para transformer is observed under scenarios with high economic growth (Uncertain World (UW-L) and the scenario's zero carbon price sensitivity (UW-0). A possible solution includes adding a second 275/132 kV transformer at Templers in conjunction with a 132 kV network reconfiguration in the Barossa area.

The time-sequential market simulation studies show considerable levels of residual transmission network congestion associated with the 132 kV transmission network out of Robertstown. These include:

- pre-contingent thermal constraints on the 132 kV circuits to the Riverland, which reduces the ability to export energy to Victoria through the Murraylink interconnector, and
- thermal constraints on the Robertstown-Waterloo circuit for loss of a 275/132 kV Robertstown transformer.

Although this is not considered to have a reliability impact, because imports from Victoria are assumed, constraining market dispatch has a market impact. As a result, further analysis to quantify the market benefits from relieving these limitations may be warranted.

Possible options include extending the 275 kV transmission network to the Riverland area. The scope of works involves establishing a 275 kV substation at Monash with one 200 MVA 275/132 kV and two 225 MVA 275/66 kV transformers in conjunction with constructing a 275 kV Robertstown-Monash double circuit line and a 66 kV Monash-Berri double circuit line.

The time-sequential market simulation studies also show considerable levels of residual transmission network congestion associated with a constraint equation to prevent the 275 kV Davenport-Brinkworth circuit overloading during a 275 kV Davenport-Bungama circuit outage. This congestion occurs due to the significant new geothermal and wind generation development in the NSA zone.

An option for relieving this limitation includes uprating the existing 275 kV Davenport-Brinkworth circuit. Under some scenarios, more extensive augmentation may be required, such as rebuilding the existing Davenport-Brinkworth single circuit as a high-capacity double circuit line.

More detailed analysis is required to quantify the market benefits of projects to relieve these limitations.

South East South Australia (SESA)

The SESA zone includes several major load centres, and has wind, geothermal, and biomass generation development potential. Large-scale generation is assumed to be injected directly into 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 275 kV Tailem Bend-South East circuits. When meeting peak loads in South Australia, new generation in the SESA zone competes directly with imports from Victoria via the Heywood interconnector.

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

The SESA transmission and sub-transmission network has two major roles:

- supplying the loads in SESA zone, and
- providing for power transfers with Victoria.

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

Committed projects

There are no committed projects relating to this zone.

Development strategy

Table 4-24 outlines the modelled transmission developments, as well as the variation under each scenario in terms of need and timing.

Table 4-24 Transmission development summary by project for SESA

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
S8 - Install 275 kV series compensation between South East Substation and Tailem Bend Substation				2		3				4
S9 - Install the third South East 275/132 kV transformer	4	4	4	4	4					
S10 - Rebuild existing 132 kV Mt Gambier-Blanche circuit into high capacity circuit	4	4	4	4						
S11 - Rebuild existing South East-Mt Gambier into double circuits				4						
VS1 - A third Heywood 500/275 kV transformer, a 100 MVAr capacitor bank at South East Substation , 275 kV series compensation between the South East Substation and Tailem Bend Substation, a SVC at Tailem Bend, increase of the relevant circuit ratings to line design ratings by protection and selected plant modifications	4									

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
VS2 - A third Heywood 500/275 kV transformer, a 100 MVAr capacitor bank at the South East Substation, a third South East 275/132 kV transformer, increase of the relevant circuit ratings to line design ratings by protection and selected plant modifications							4			

The numbers and shading relate to augmentation trigger timeframes (as observed in the NTNDP modelling):

1	2010/11 – 2014/15
2	2015/16 – 2019/20
3	2020/21 – 2024/25
4	2025/26 – 2029/30

Emerging limitations associated with post-contingency overloading in the South East 132 kV transmission network are driven by the combined effect of several factors: generation capacity and demand in the SESA zone, and the need for imports from Victoria during peak demand conditions. These limitations first emerge in the period 2015/16-2019/20 under the Uncertain World scenario's zero carbon price sensitivity (UW-0), and later under scenarios with lower economic growth (Decentralised World (DW-M) and Slow Rate of Change (SC-0)). Possible solutions for addressing these limitations include installing 275 kV series compensation between South East Substation and Tailem Bend Substation. The 275 kV series compensation augments the power transfer capability of the SESA zone's transmission network by increasing power flow through the high capacity 275 kV transmission network, and reducing power flow through the 132 kV network.

Limitations associated with the post-contingency overloading of one of the 275/132 kV South East transformers during the outage of the remaining transformer were identified in the period 2025/26-2029/30 under scenarios with high and medium economic growth (FC-H, FC-M, UW-L, UW-0 and DW-H). A possible solution includes installing a third 275/132 kV transformer in the existing South East Substation.

A requirement to reinforce the 132 kV Mt Gambier-Blanche circuit's power transfer capability under scenarios with high economic growth (FC-H, FC-M, UW-L and UW-0) was identified in the period 2025/26-2029/30. The limitations are associated with post-contingency overloading of the existing 132 kV circuit during the outage of the 132 kV Snuggery-Snuggery Tee-South East circuits. The limitation is primarily being caused by demand growth in the SESA zone, the retirement of the Snuggery Power Station, and imports via the Heywood interconnector (to a lesser extent). A possible solution includes converting the existing 132 kV circuit between Mt Gambier and Blanche to a high-capacity circuit.

Additionally, post-contingency overloading of the existing 132 kV circuit between Snuggery and Blanche emerges during an outage of the 132 kV South East-Mt Gambier circuit under the Uncertain World scenario's zero carbon sensitivity (UW-0). This limitation's timing depends on the combined load demand at the Blanche substation and Mt Gambier Substation. A possible solution includes converting the existing circuit between South East and Mt Gambier to a double circuit line.

In addition to the reliability projects, upgrading the Heywood interconnector's power transfer capability also proceeds under the Fast Rate of Change (FC-H) and the Oil Shock and Adaptation

(OS-M) scenarios, which, as an output of the least-cost expansion modelling, suggests this augmentation delivers net economic market benefits. In both cases, the augmentation proceeds in the period 2025/26-2029/30, and includes installing additional transformers at the Heywood Substation and South East Substation, respectively, a shunt capacitor bank at the South East Substation, and the utilization of the line design ratings for relevant 275 kV and 132 kV circuits in the SESA zone and Eastern Hills. Under FC-H, however, the augmentation also includes 275 kV Tailem Bend-South East circuit series compensation for reinforcement of the import and export capability of the Heywood interconnector.

The 460 MW export limit on power transfers from South Australia to Victoria was a source of significant residual congestion in the time-sequential market simulation studies, although the least-cost expansion modelling only selected this augmentation towards the end of the 20-year outlook period under the Fast Rate of Change (FC-H) and the Oil Shock and Adaptation (OS-M) scenarios. AEMO and ElectraNet have been working on a joint feasibility study to assess options for augmenting the export capacity from South Australia (for more information, see the ElectraNet-AEMO Joint Feasibility Study Report[36]).

The time-sequential market simulation studies also show significant levels of residual transmission network congestion associated with preventing thermal overloads of the 275/132 kV South East transformer. This transmission network congestion restricts the output of high levels of SESA zone generation connected to 132 kV transmission networks. Congestion occurs most frequently during the first half of the 20-year outlook period, and less frequently in the second half, with future SESA zone wind farms assumed to connect directly to the 275 kV transmission network. A possible solution includes installing a third 275/132 kV transformer at the existing South East Substation.

In addition, the time-sequential market simulation studies reveal significant levels of residual transmission network congestion associated with overloading of the 132 kV Keith-Snuggery and Keith-Tailem Bend circuits for the loss of one of the 275 kV South East-Tailem Bend circuits. These limitations restrict imports into South Australia via the Heywood interconnector, as well as restricting the output of SESA zone generation. A possible solution includes installing 275 kV series compensation between the South East Substation and Tailem Bend Substation to boost power flow through the 275 kV circuits in the SESA zone.

Green Grid

In July 2010, a consortium funded by the South Australian Government issued the Green Grid report, which studied the feasibility of locating a significant amount of wind generation and supporting infrastructure on the Eyre Peninsula.

The consortium proposed a transmission network development called the Green Grid, comprising new 500 kV transmission infrastructure supported by South Australian transmission network and interconnector augmentations to facilitate development of up to 4,000 MW of wind generation in two stages (2,000 MW in each stage).

[36] ElectraNet–AEMO Joint Feasibility Study, South Australian Interconnector Feasibility Study Draft Report (http://www.electranet.com.au/network_interconnector.html).

The report concluded that a viable business case exists for transmission investment to unlock large-scale wind energy on the Eyre Peninsula[37]. Although the NTNDP has not tested a Green Grid sensitivity, the development's impact was considered in the ElectraNet-AEMO Joint Feasibility Study report[38].

South Australian Interconnector Feasibility Study

ElectraNet and AEMO undertook a joint feasibility study into transmission development options to increase the power transfer capability between South Australia and other NEM load centres[39].

The study assessed the technical and economic merit of transmission development options that may allow further development of South Australia's renewable resources, and support South Australian demand, particularly at peak times.

This study differed from the analysis performed for the NTNDP, in that it was specific to the connection of South Australia to the rest of the NEM, and considered more interconnector upgrade options, ranging from incremental upgrades to existing interconnectors to major new high-capacity interconnectors between South Australia and the eastern States. However, like the NTNDP, the study allowed for a NEM-wide, least-cost development to proceed, except under one sensitivity (the Green Grid sensitivity), which forced a high amount of renewable development in South Australia. The study modelled the Fast Rate of Change (FC-H), Decentralised World (DW-M), and Oil Shock and Adaptation (OS-M) scenarios.

A key finding of the draft report (published on 19 November 2010) is that incremental upgrades to the Heywood interconnector are economically justified during the 2020s, though the sensitivity that considered high renewables development in South Australia under the FC-H scenario (the Green Grid sensitivity[40]) brought the optimal timing forward to 2017/18.

Although the NTNDP did not test a Green Grid sensitivity, the conclusions of the least-cost development scenarios are consistent with the NTNDP results, where an incremental upgrade to the Heywood interconnector or significant residual congestion is also observed towards the end of the 20-year outlook period.

4.7 Tasmanian development plans

4.7.1 Generation expansion

Tasmania experiences the lowest existing and projected energy and MD of all the regions. As a result, levels of new installed capacity in the least-cost modelling are largely met through a constraint

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37 Green Grid, Unlocking Renewable Energy Resources of South Australia, a feasibility assessment of transmission and generation potential for 2000 MW of wind energy in the Eyre Peninsula (http://www.renewablessa.sa.gov.au/investor-information/green-grid).

38 ElectraNet–AEMO Joint Feasibility Study, South Australian Interconnector Feasibility Study Draft Report (http://www.electranet.com.au/network_interconnector.html).

39 http://www.aemo.com.au/corporate/0177-0001.html.

40 http://www.renewablessa.sa.gov.au/investor-information/green-grid .

to meet the Large-scale Renewable Energy Target (LRET). This constraint is applied to the entire NEM, but the presence of good quality renewable generation in Tasmania results in high levels of modelled renewables.

Non-renewable

All non-renewable capacity installed in Tasmania is met by OCGTs, and OCGT-type generation proceeds under the Fast Rate of Change (FC-H) and Uncertain World (UW-L) scenarios, and the Slow Rate of Change scenario's zero carbon price sensitivity (SC-0). The highest amount of new OCGT occurs under UW-L (600 MW), where the assumption of reduced inflows in this predominantly hydroelectric-based system has the most impact. With a good quality renewable base load option like biomass, and high levels of new wind generation, no further base load generation is required.

Renewable

Tasmania has the highest quality wind resources available in the NEM, with high levels of wind generation during non-peak demand periods, but an assumed contribution of 0% of capacity during peak demand periods. The least-cost expansion models at least 500 MW of wind under all scenarios, and a high of 2,050 MW under UW-L.

The least cost expansion also models the full 300 MW of available biomass generation under all scenarios except for the Oil Shock and Adaptation scenario's low carbon price sensitivity (OS-L).

Retirements

There are no retirements modelled for the Tasmanian region.

Table 4-25 lists the existing and projected installed capacities in the region.

Table 4-25 Existing and projected Tasmanian installed capacity (MW)

Scenario	CPT		Existing	2014/15	2019/20	2024/25	2029/30
Fast Rate of Change	H	Gas	386	386	386	586	786
		Wind/Solar	140	1,340	1,340	1,340	1,540
		Hydro/Geo/Biomass	2,049	2,158	2,182	2,282	2,482
sensitivity	M	Gas	386	386	386	586	786
		Wind/Solar	140	1,340	1,340	1,340	1,340
		Hydro/Geo/Biomass	2,049	2,158	2,182	2,282	2,482
Uncertain World	L	Gas	386	386	386	586	986
		Wind/Solar	140	1,340	1,640	2,190	2,190
		Hydro/Geo/Biomass	2,069	2,158	2,182	2,482	2,482
sensitivity	0	Gas/	386	386	386	586	986
		Wind/Solar	140	340	1,140	1,340	1,540
		Hydro/Geo/Biomass	2,069	2,158	2,182	2,482	2,482

Scenario	CPT		Existing	2014/15	2019/20	2024/25	2029/30
Decentralised World	M	Gas	386	386	386	386	586
		Wind/Solar	140	1,540	1,540	1,540	1,540
		Hydro/Geo/Biomass	2,069	2,158	2,182	2,282	2,482
sensitivity	H	Gas	386	386	386	386	586
		Wind/Solar	140	1,340	1,540	1,540	1,540
		Hydro/Geo/Biomass	2,069	2,158	2,182	2,282	2,482
Oil Shock and Adaptation	M	Gas	386	386	386	386	386
		Wind/Solar	140	1,340	1,540	1,540	1,540
		Hydro/Geo/Biomass	2,069	2,158	2,182	2,282	2,482
sensitivity	L	Gas	386	386	386	386	386
		Wind/Solar	140	1,340	1,340	1,340	1,340
		Hydro/Geo/Biomass	2,069	2,158	2,182	2,182	2,382
Slow Rate of Change	L	Gas	386	386	386	386	386
		Wind/Solar	140	1,340	1,540	1,540	1,540
		Hydro/Geo/Biomass	2,069	2,158	2,182	2,182	2,482
sensitivity	0	Gas	386	386	386	386	586
		Wind/Solar	140	640	640	640	640
		Hydro/Geo/Biomass	2,049	2,158	2,182	2,282	2,482

4.7.2 Transmission development 10-year summary

Table 4-26 lists the transmission network developments identified over the next 10 years under at least one scenario. For more information about the production of this table and its categories, see Section 4.2.2.

Table 4-26 Tasmanian transmission development 10-year summary

Transmission development	Rating	Status/reference
T1 - Configure Waddamana switching, and upgrade the 110 kV Palmerston-Waddamana line to 220 kV operation	Early attention	Transend advises it is currently making a detailed assessment of this limitation
T2 - Uprate the 110 kV Norwood-Scottsdale line, or connect new generation to the 220 kV transmission network along the Hadspen-George Town corridor	Early attention	Transend advises it is investigating as part of new connection enquiries/applications
T3 - Replace the existing 220 kV Burnie-Sheffield single circuit line with a new 220 kV double circuit line	Early attention	This limitation is recognised in the Transend report: 'Future wind generation in Tasmania' published in May 2009

Transmission development	Rating	Status/reference
T4 - A new 220 kV Sheffield-Palmerston double circuit line	Early attention	Transend 2010 APR, Section 2.3.2, and Transend report: 'Future wind generation in Tasmania' published in May 2009
T5 - A new 220/110 kV transformer in the Hobart area	Monitoring	

4.7.3 Transmission development by zone

Tasmania (TAS)

Hydroelectric generation predominates in the TAS zone (81% of the total installed capacity), and is geographically dispersed across the region. Gas-powered generating units are connected in the George Town area, and wind generation is connected at Burnie. The zone's transmission network comprises 220 kV transmission lines as a backbone 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 the power stations and the 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.

The TAS zone includes new biomass and gas-powered generation, and very high levels of new wind generation. In terms of the transmission network, South Tasmania is the preferred location for new gas-powered generation, providing additional reliability and security to the zone's major load centre for the least cost. The existing gas transmission network, however, cannot accommodate significant gas-powered generation in the south, suggesting further investigation is required, leading to options for increasing gas transmission network capabilities. In this study, a maximum of 200 MW of gas-powered generation was assumed at the 220 kV Lindisfarne Substation. All new biomass generation was modelled at the 220 kV George Town Substation. Wind generation was modelled in the North West, North East, and Central parts of the TAS zone.

Connection of a large amount of wind generation causes significant operational issues. If wind generation displaces conventional hydroelectric and gas-powered generation, it will result in reduced fault levels at critical locations, as well as reduced inertia. This may also result in voltage instability, posing limits due to transient stability, and causing HVDC commutation failure with the disconnection of the HVDC link. A possible network solution involves installing synchronous condensers at strategic locations.

Committed projects

The TAS zone's development strategy includes constructing a new 220 kV Waddamana-Lindisfarne double circuit transmission line and installing two 220/110 kV transformers at Lindisfarne (with completion anticipated by early 2011)[41], and augmenting the 110 kV Sheffield-Burnie line to increase

[41] Transend Networks, 2010 APR, Chapter 4, Section 4.3.4.

its winter/summer rating from 172/110 MVA to 244/208 MVA (with completion anticipated by late 2011)[42].

These projects are listed in Appendix A, and have been included in the power system modelling to capture their effect on transmission level power flow patterns.

Development strategy

Table 4-27 outlines the modelled transmission developments, as well as the variation under each scenario in terms of need and timing.

Table 4-27 Transmission development summary by project for TAS

Transmission development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
T1 - Waddamana switching configuration and upgrade of 110 kV Palmerston-Waddamana line to 220 kV operation	1	1	1	1	1	1	1	1	1	1
T2 - Uprate 110 kV Norwood-Scottsdale line or connection of new generation to 220 kV network along Hadspen-George Town corridor	1	1	1	1	1	1	1	1	1	1
T3 - Replace the existing 220 kV Burnie-Sheffield single circuit line with a new 220 kV double circuit line	1	1	1	2	1	1	1	1	1	4
T4 - A new 220 kV Sheffield-Palmerston double circuit line	1	1	1	2	1	1	1	1	1	4
T5 - A new 220/110 kV transformer in Hobart area	3	3	2	2	3	3	4	4	4	3
T6 - A new 220/110 kV 200 MVA transformer (2nd) at Burnie Substation	4	4	4	3	4	4			4	
T7 - A new 220/110 kV 150 MVA transformer (2nd) at Palmerston Substation or new 220/110 kV substation at Longford or Riverside				4						

The numbers and shading relate to augmentation trigger timeframes (as observed in the NTNDP modelling):

1	2010/11 – 2014/15
2	2015/16 – 2019/20
3	2020/21 – 2024/25
4	2025/26 – 2029/30

Additional wind generation connected to Burnie in the North West requires new 220 kV transmission lines between Burnie and Sheffield. Significant wind generation connected to the West Coast area will require transmission capacity increases between Palmerston and Sheffield.

In the north east, the 110 kV transmission network can only accommodate a limited amount of new generation in addition to the committed wind generation at Mussleroe (168 MW). Further new

[42] Transend Networks, 2010 APR, Chapter 4, Section 4.2.8.

generation requires uprating the 110 kV Scottsdale-Norwood circuits. George Town is a possible 220 kV connection point for a significant amount of new wind generation in the north-east.

In the central area, new wind generation is modelled around Waddamana, with a connection to the 220 kV Waddamana transmission network.

The Sheffield-Burnie transmission network capacity upgrade is triggered by increased load or the significant new wind generation in the Burnie area (or both). The upgrade involves replacing 220 kV lines between Sheffield and Burnie with a new 220 kV double circuit line, and the addition of a 220/110 kV transformer at Burnie.

The Sheffield-Palmerston line upgrade is also triggered by significant wind generation in the Burnie area, with increased power flow from the north to the south of Tasmania. This upgrade involves a new 220 kV double circuit line between Sheffield and Palmerston, and the disconnection of the existing 220 kV single circuit from 220 kV operations.

Increased load growth in the Hobart area requires an additional 220/110 kV transformer. Possible locations for a new transformer include the existing 220 kV substation at Lindisfarne, or a new 220 kV substation at Risdon, with a 220 kV line extension from Lindisfarne to Risdon. The preferred location for the new transformer requires further analysis of the 110 kV transmission network's limitations.

The Uncertain World scenario's zero carbon price sensitivity (UW-0) has the highest demand projection. Under UW-0, an additional 220/110 kV transformation capacity is needed to meet the increased load in the Launceston area. A possible location for the additional transformers is Palmerston, and for the new substations includes Longford or Riverside.

A single asset failure on the 220 kV Palmerston-Waddamana line leads to unserved energy in Southern Tasmania. A possible option to address this limitation involves constructing an additional 220 kV transmission line between Palmerston and Southern Tasmania.

Chapter 5 - NEMLink: A Pre-feasibility Study into a High-Capacity Backbone

5.1 Summary

This chapter presents information about the high-level study carried out by AEMO into the potential benefits from significantly increasing power transfer capabilities in the National Electricity Market (NEM) (from South Australia and Tasmania to Queensland).

AEMO has designed a conceptual project called NEMLink, which is designed to enable large-scale power transfers between the regions[43]. NEMLink's objective is to initiate discussion involving the concept of significant transmission investment for the purposes of developing major generation centres to more efficiently service the NEM.

The NEMLink project was developed with input from transmission network service providers (TNSPs), and represents one view of a logical future extension of existing and planned 500 kV regional transmission networks. As such, it could form a useful framework for future regional developments that could serve dual roles of meeting regional requirements and forming a link in the NEMLink chain.

The NEMLink assessment provides information about:

- the conceptual project's technical aspects and estimated project cost, which is approximately AUD8.3 billion, and
- a high level assessment of potential benefits, which were significant under a set of optimistic assumptions.

The magnitude of the benefits observed under one of the scenarios considered, and the uncertainty associated with any future price on carbon, may warrant further analysis across a different suite of scenarios, and investigation of the staged construction of NEMLink subsections.

5.2 Methodology

The methodology behind the assessment of NEMLink is based on an initial set of assumptions describing NEMLink's possible modelling. These include assumptions that NEMLink:

- allows for the transfer of approximately 3,000 MW between the mainland regions, and 500 MW between the Tasmanian and Victorian regions

[43] The portion of this project located within New South Wales is based on the 500 kV transmission system development plan presented in "Strategic Network Development Plan 2008" by TransGrid.

- provides for more sharing of reserve generation capacity between regions, allowing for a reduction of the total NEM installed capacity
- has half the inter-regional power transfer losses as existing interconnectors, which is captured by modifying the dynamic marginal loss factors between the regions, and
- proceeds from 2020/21.

A generation expansion was determined using the high-level least-cost expansion model. Power system simulation studies were performed to confirm the feasibility of NEMLink with the resulting generation fleet, and to assess NEMLink's impact on the requirement for other augmentations in the scenarios modelled. Time-sequential market simulation studies were conducted in parallel to obtain an estimate of the market benefits.

5.2.1 Technical features of the NEMLink concept

Although AEMO's objective was to generically investigate the net benefits from significantly enhancing inter-regional power transfer capabilities, an augmentation concept is also required to enable power system modelling, and to provide an understanding of the associated costs.

For the purposes of the initial NEMLink study, AEMO designed a conceptual augmentation comprising a:

- high capacity 500 kV double circuit, alternating current (AC) transmission backbone connecting the mainland regions, and
- 400 kV high-voltage direct current (HVDC) connection between Tasmania and the mainland, similar to the existing Basslink.

The concept builds on and integrates elements included in regional strategic plans[44] and it includes a number of intermediate substations, switching stations, and devices for reactive compensation and power flow control.

AEMO has selected 500 kV because it is the highest voltage currently in use in the NEM. Although HVDC offers advantages over AC transmission over long distances, AC has the advantage of being able to be conveniently tapped along its length (for example, to pick up generation sources). There are other possible designs that achieve a similar result.

Figure 5-1 shows an illustration of the NEMLink concept. For more information about the NEMLink concept, and its development for modelling purposes, see Appendix F.

[44] See for example, TransGrid's Strategic Network Development Plan 2008, (http://www.transgrid.com.au/aboutus/pr/Documents/Strategic%20Development%20Network%20Plan%202008.pdf), the ElectraNet-AEMO Joint Feasibility Study: South Australian Transmission Transfer Capability Feasibility Study, November 2010 (http://www.aemo.com.au/corporate/0177-0001.html).

Figure 5-1 The NEMLink concept

AEMO engaged consulting engineers[45], and consulted with transmission network service providers (TNSPs) to obtain a high-level cost estimate appropriate for the pre-feasibility assessment, which is estimated to be AUD8.3 billion (with a quoted accuracy of ±30%). Given NEMLink's significant length, the most significant cost component is the transmission line, which is assumed to be AUD1.8 million per kilometre. This estimate also assumes that the conditions will be generally favourable along the length of the line.

The NEMLink concept has been advanced for the purposes of conducting a high-level pre-feasibility assessment, and an allowance of 10% has been made to the route length to account for potential deviations from the most direct route. AEMO has not, however, investigated the appropriateness of the individual components, and the issues associated with acquiring the necessary easements.

5.2.2 Market modelling for NEMLink

NEMLink was modelled under the Fast Rate of Change scenario (FC-H) and the Uncertain World scenario's zero carbon price sensitivity (UW-0). Both scenarios represent high economic growth, with a requirement for significant new generation, and form the base case scenarios for the NEMLink study. Analysing scenarios with high and zero carbon price trajectories, however, enables an assessment of the impact of carbon pricing on NEMLink's potential benefits. For each scenario, the market benefits were determined by comparing the results of a modelled case with NEMLink against a base case without NEMLink.

Unlike the scenario studies, where the least-cost expansion model can alter a transmission project's timing to minimise total system cost, the NEMLink augmentation was assumed to proceed from 2020/21, and alternate timings were not permitted.

NEMLink is expected to significantly impact transmission network power flows and limits, invalidating all existing network constraint equations. For the purposes of the pre-feasibility study, AEMO made a simplifying assumption that with NEMLink in service, all existing network constraint equations can be relaxed (making the model unconstrained from a transmission network perspective). This is an optimistic assumption unrealisable in practice, given there are transmission network limitations that will not be significantly altered by NEMLink (for example, limitations to the north of South West Queensland, or the Riverland in South Australia). This simplifying assumption's impact is to overestimate NEMLink's market benefits.

5.3 Generation and transmission development

5.3.1 Generation expansion

For the purposes of the assessment, the least-cost expansion model assumed that generation capacity to meet a region's reserve requirements can be sourced from any region. This makes the Reliability Standard a NEM-wide rather than a regional requirement. The fact that regional maximum demands (MDs) do not all occur at the same time (demand diversity), means that NEM-wide MDs

[45] Sinclair Knight Merz Pty Ltd

are lower than the sum of the regional MDs, reducing the overall installed capacity requirement. To account for this, the assessment assumes a NEM-wide MD approximately 3,000 MW less than the sum of the regional MDs[46].

NEM-wide generation expansion allows for the selection of new generation from the most economic sources in the NEM (within maximum power transfer capabilities). It also provides for a higher level of flexibility in the mix of peaking and base load plant in order to meet MD and energy requirements at the lowest cost.

The effect is that NEMLink results in significant shifts in new generation, predominantly increasing new generation in the SWQ and LV zones, and reducing it elsewhere (for more information about the changes in generation expansion, see Appendix F).

5.3.2 NEMLink impacts on other transmission developments

NEMLink gives rise to less new generation in New South Wales, South Australia, and Tasmania. This result culminates in significantly increased energy sharing between the regions, enabled by their large and relatively unconstrained transmission connections. Despite NEMLink's high capacity, very few intra-regional augmentations were avoided, because the need for augmentation is driven by intra-regional load centres rather than inter-regional bulk power transfers.

In Queensland, approximately 1,700 MW more generation proceeds by 2029/30, but this is almost all located in the already generation-intensive SWQ zone, and is directly connected to the end of NEMLink. As a consequence, no intra-regional developments were avoided. The assumed levels of series compensation also appeared to prevent overloading any lower capacity lines running in parallel, such as the existing Queensland to New South Wales (QNI) interconnector.

In New South Wales, approximately 4,500 MW less generation proceeds by 2029/30, making this region an even larger importer during peak demand periods. However, the combination of NEMLink and the intra-regional augmentations already identified in the base case scenarios is adequate to supply the load. Some transmission network developments in the region are already included in the NEMLink concept, and should not be double-counted in the cost-benefit analysis. These include the:

- Armidale-Dumaresq series compensation
- 500 kV Yass-Bannaby double circuit line, and
- 500 kV Bannaby-Sydney double circuit.

In Victoria, no intra-regional developments are avoided, as very similar levels of generation proceed by the year 2029/30, and the 500 kV NEMLink backbone does not run in parallel with the main generation centre in the LV zone and the load centre in the MEL zone.

In South Australia, approximately 800 MW less new generation occurs. To support additional imports from NEMLink, reinforcement between the NEMLink connection point and the load centre (such as a 275 kV Cherry Gardens-Happy Valley single circuit line) may be required towards the end of the 20-year outlook period.

[46] Based on diversity factors published in the 2010 Electricity Statement of Opportunities (ESOO).

In Tasmania, approximately 1,400 MW less generation proceeds, potentially triggering requirements for reinforcement during high power transfers from Victoria, particularly if water storages are low. Otherwise, no local network developments were avoided.

5.4 Market benefits

Table 5-1 lists the estimated present value (PV) of gross market benefits generated by NEMLink and the PV of transmission costs. For more information about the discounted cash flow calculation, see Appendix F. UW-0 uses a higher discount rate, to reflect the high risk premium assumed for this scenario, as described in Chapter 2, Section 2.2.2.

Market benefits calculated in the base case scenarios accrue from changes in:

- generation capital costs and avoided fixed costs, determined by comparing generation costs from the least-cost expansion with and without NEMLink (for more information, see Appendix F)
- transmission capital costs, determined by comparing the cost of transmission projects deferred (or brought forward) by NEMLink
- transmission system losses, determined by comparing the cost of inter-connector losses from the time sequential modelling with and without NEMLink (for more information about how the value of losses was determined, see Appendix F)
- operating costs, determined by comparing the total operating costs (including emission costs) from the time sequential modelling with and without NEMLink, and
- changes in involuntary load shedding (reliability benefits), indicating improved customer reliability, determined by comparing the unserved energy from the time sequential modelling with and without NEMLink, and valuing the difference at an assumed value of customer reliability of AUD55,000/MWh.

AEMO has not sought to quantify other relevant market benefits that may exist, such as competition benefits and option values.

Table 5-1 NEMLink discount rate, transmission costs, gross market benefits, and cost benefit ratio

Scenario	Discount rate	PV transmission costs (+/- 30%) AUD billion	PV gross market benefits AUD billion	Cost benefit ratio
Fast Rate of Change (FC-H)	8.78	4.4	3.9	0.9
Uncertain World (UW-0)	11.37	3.3	1.7	0.5

The modelling results indicate the following:

- Under FC-H, the gross market benefits are lower than the transmission costs, though the benefits are of the same order as the costs, and further analysis may be warranted.
- Under UW-0, the gross market benefits are significantly lower than the transmission costs, and further analysis may not be warranted.

Figure 5-2and Figure 5-3 show the annual maximum market benefits (by benefit type) under FC-H and UW-0. The results show the following:

- Under FC-H, the final years of the outlook period show significant operating costs benefits, and negative capital cost benefits.
- Under UW-0, the operating costs benefits are more modest than observed under FC-H, and capital cost benefits are positive across all years.
- The loss benefit from reduced inter-connector losses is negative in both scenarios, despite the assumed reduction in transmission network losses with a modified marginal loss factor equation.

Under FC-H, the NEMLink augmentation allows high capital cost, low emission-intensity generation technologies (such as geothermal and coal with carbon capture and sequestration (CCS)) to enter the NEM during the later years of the 20-year outlook period, which has a significant operating costs advantage over existing base load generation, due to the high carbon price (AUD93.5/t carbon dioxide equivalent (CO2-e) in 2029/30). This cost advantage results in a significant operating costs benefit, which more than compensates for the negative capital cost benefit from the installation of the high capital cost, low emission-intensity generation[47].

Under scenario UW-0 (and a zero carbon price), the NEMLink augmentation allows some additional high capital cost, low fuel cost, coal-fired generation, resulting in a positive operating costs benefit. However, with no carbon price impact on existing base load coal generation, there is less advantage from building significant amounts of high capital cost, low emission-intensity plant.

NEMLink‘s losses are assumed to be lower than currently observed for the transmission network. When compared to the current network, however, the significant magnitude of NEMLink’s power transfers leads to even greater transmission losses.

AEMO expects some components of the NEMLink concept to provide more market benefits than others, and that optimising the staging of NEMLink (or the design capacity of certain components) will improve the net market benefits. Quantifying the extent of this improvement has not been possible as part of this assessment.

AEMO considers that a broader suite of scenarios and the staged building of NEMLink subsections both warrant further analysis, given the magnitude of benefits observed under one of the scenarios, and the uncertainty associated with any future carbon price.

[47] The installed capacity is actually lower with NEMLink despite the greater total capital cost of plant installed.

Figure 5-2 Annual NEMLink market benefits (FC-H)

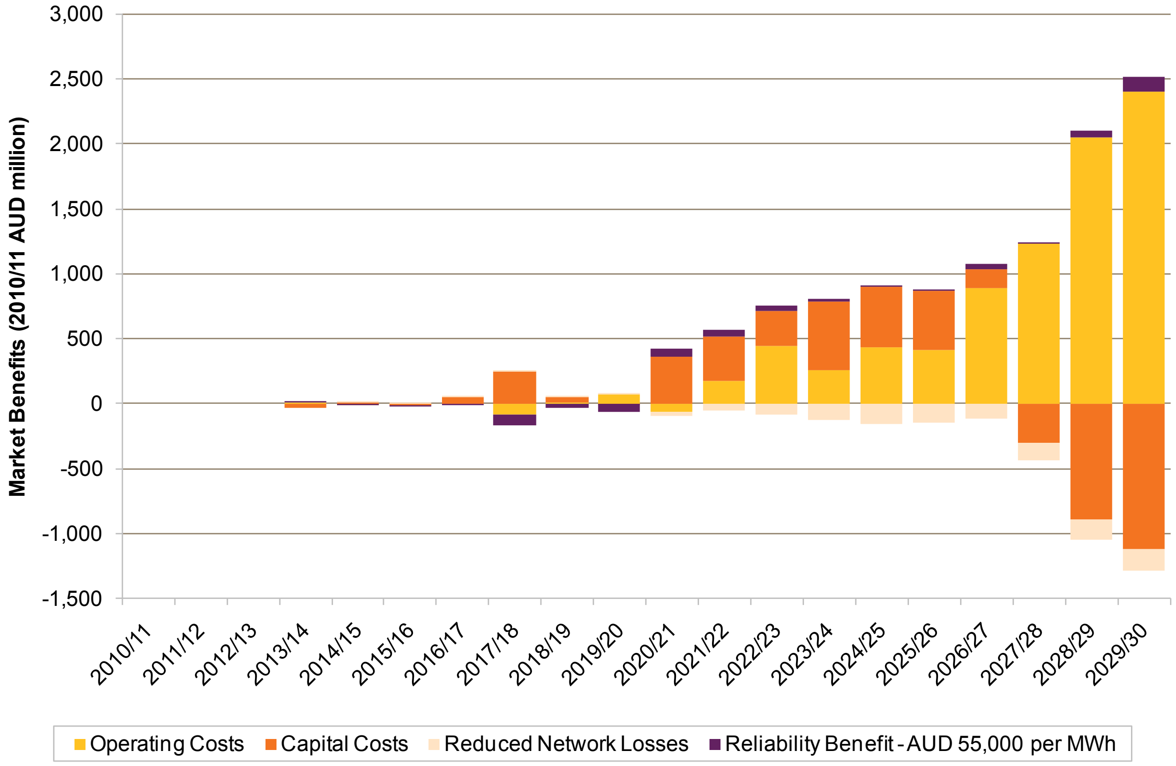
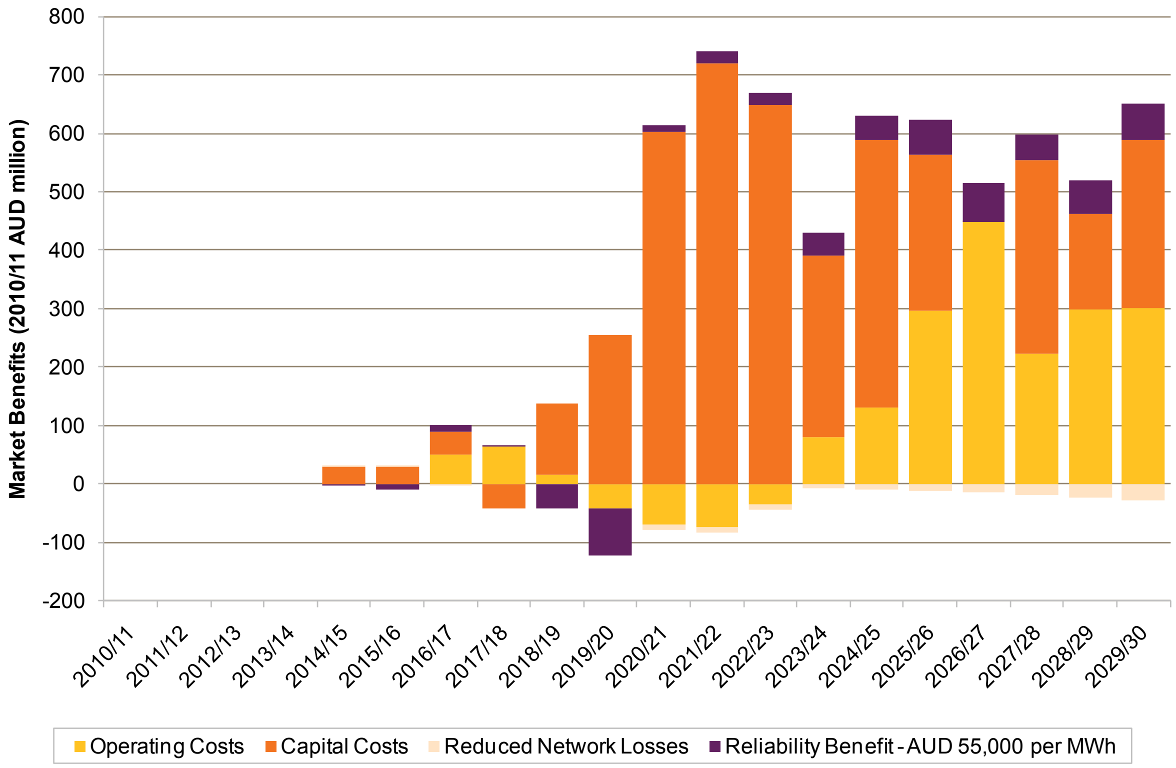


Figure 5-3 Annual NEMLink market benefits (UW-0)



Chapter 6 - Network Support and Control Ancillary Services

6.1 Summary

This chapter provides information about National Electricity Market (NEM) requirements for Network Support and Control Ancillary Services (NSCAS). NSCAS is an ancillary service for controlling active and reactive power flows, which assists with maintaining the power system in a secure operating state, and maintaining (or increasing) power transfer capabilities.

AEMO has looked at potential national and regional NSCAS requirements for the next five years, so as to provide the market with sufficient notice for these requirements to be met through orderly investment. Previously, short contracting lead times may have limited the options available to address NSCAS requirements (with construction lead times, for example, potentially ruling out efficient transmission investment options).

AEMO generally expects transmission network service providers (TNSPs) to procure NSCAS, and only procures NSCAS itself to meet short-term operational requirements (in cases of unexpected demand or plant failure) from sources available at the time.

Regional assessments indicate the following NSCAS requirements:

- In New South Wales there is a Reactive Power Ancillary Service (RPAS) requirement for the next five years, to prevent over voltages in the Snowy area and provide sufficient voltage stability margins for supplying major load centres in Sydney.
- In Victoria there is an ongoing Network Loading Control Ancillary Service (NLCAS) requirement to increase power transfers from New South Wales to Victoria, and an RPAS requirement to avoid voltage collapse.
- There are no NSCAS requirements for the other regions.

The regional assessments are intended to indicate the approximate extent, duration, and location of NSCAS requirements, enabling TNSPs and other market participants to make investment proposals or establish operating arrangements to deliver services efficiently, and in a manner consistent with the Regulatory Investment Test for Transmission (RIT-T).

In the absence of this investment, AEMO can contract for services if they are available, or constrain power flows to maintain secure power system operations.

6.2 Reporting on future NSCAS requirements

This report on future NSCAS requirements is being made in advance of a possible National Electricity Rules (NER) change being considered by the Australian Energy Market Commission (AEMC). The proposed change obliges AEMO to identify NSCAS requirements in the annual NTNDP for a planning outlook of at least five years from the start of the NTNDP's year of publication.

The AEMC is expected to publish its final determination in April 2011.

For more information about this change, see the AEMC website[48].

6.3 Types of Network Support and Control Ancillary Services

NSCAS comprises a wide range of services that can be provided by TNSPs through the use of equipment that is not part of their regulated assets; by generators through the provision of reactive power above the agreed access standard; by market participants, generally through changing the load and/or generation on the transmission network; and by non-market participants through the control of customer load and small-scale embedded generation (demand-side participation).

NSCAS, a non-market ancillary service, is used to cover any shortage of the existing and planned network control services and network support services delivered by TNSPs using their regulated assets. If the existing and planned network control services and network support services provided by the TNSPs are sufficient, then NSCAS is not required. Types of NSCAS comprise Network Loading Control Ancillary Services (NLCAS), and Reactive Power Ancillary Services (RPAS).

6.3.1 Network Loading Control Ancillary Services

NLCAS reduces the loading on transmission lines to maintain active power flow and system security after a credible contingency event.

Types of NLCAS may include, but are not limited to, an increase in standby or small-scale generation, phase shift transformers and other equipment used to control power flow, and the control of customer load.

6.3.2 Reactive Power Ancillary Services

RPAS controls reactive power flow into or out of the transmission network. RPAS requirements are far more localised than NLCAS due to the inefficiencies of transporting reactive power.

[48] http://www.aemc.gov.au/Electricity/Rule-changes/Open/Network-Support-and-Control-Ancillary-Services.html

Types of RPAS include:

- reactive power capacities of generating units (including wind farms) above contracted amounts
- capacitors and reactors
- synchronous condensers and static VAR compensators
- control of customer load, and
- small-scale generation.

6.4 Assessing future NSCAS requirements

Assessing future NSCAS requirements involves:

- indentifying key issues
- collecting data (relevant to key issues)
- developing load-flow study cases, and
- conducting power system simulation studies.

6.4.1 Identifying key issues

A key issue is an issue that:

- is presently being managed by existing NSCAS contracts, or
- may not have been sufficiently addressed by the relevant TNSP in its latest Annual Planning Report (APR).

AEMO identifies key issues by reviewing previous APRs and AEMO planning documents (such as the National Transmission Statement (NTS) and the Electricity Statement of Opportunities (ESOO)), from operational experience, and from the solutions proposed by the relevant TNSP.

AEMO's Power System Adequacy - Two-Year Outlook[49] analysed historical data to examine potential voltage fluctuations at a number of locations. AEMO subsequently identified a number of key issues at locations where voltage fluctuations are likely to increase under certain operating conditions, creating power system security issues.

Not all power system limitations represent key issues. Some limitations are managed by restricting power flows when required, rather than via NSCAS contracts, and most are addressed by the actions taken by TNSPs. No NLCAS requirement has been reported in the 2010 NTNDP other than for key issues. The 2011 NTNDP will include information about the benefits of using NLCAS to relieve some of the other power system limitations.

[49] http://www.aemo.com.au/electricityops/0410-0051.pdf

6.4.2 Collecting data

AEMO collects the necessary information to enable a more detailed investigation of the key issues and their potential solutions. The type of information collected includes (but is not limited to):

- continuous and short-term ratings of current transmission assets from the relevant TNSP
- historical power system snapshots representative of high and low demand conditions
- committed transmission network developments and new generation proposals as identified in the APRs, ESOO, and Medium-term Projection of System Adequacy (MT PASA)
- connection point MW and MVAr forecasts from the most recent relevant APR (or equivalent)
- generating unit reactive power contracted amounts
- RPAS previously procured and dispatched by AEMO, and
- technical details of existing network support agreements.

6.4.3 Developing load-flow study cases

AEMO develops load-flow study cases using the data collected for each key issue. The cases, which are used to model the relevant power system operating conditions to assess NSCAS requirements, consider projected 10% probability of exceedence (POE) maximum demand (MD) each year for the next five years (to 2014/15), as well as demand during historical light load periods..

6.4.4 Conducting power system simulation studies

Various credible contingency events are investigated using power system simulations for the five-year outlook, and the impact of these contingencies determines the level of NSCAS required to satisfy the National Electricity Rules (NER).

6.5 Common assessment assumptions

This section lists the common assumptions applied to each regional assessment. Region-specific assumptions are listed with the relevant regional assessment.

6.5.1 Generation and interconnector power transfer assumptions

Assumptions about generation and interconnector power transfers include the following:

- All scheduled generating units required to meet the 10% POE MD, and all committed new generating units (as identified in the ESOO and MT PASA) are in service.
- Some proposed generation will be in service[50] if required to meet the 10% POE MD.

[50] Proposed generation is identified in the ESOO, and its availability is determined in consultation with the relevant TNSP.

- When simulating credible contingency events, the critical generating unit may be out of service as a prior outage (treated as N-1-g) to enable the examination of variations in total generation availability[51].
- Generating unit capacities are as identified in the ESOO.
- Generating unit reactive power outputs are capped to the values specified in their performance standards (including any existing RPAS contracts).
- Future generation dispatch patterns derive from the short-run marginal costs (as used in the NDNTP market simulations) and the observed operational history of existing generating units.
- Intermittent generation is operating at either its maximum or minimum, whichever requires most NSCAS.

6.5.2 Load and demand assumptions

Assumptions about load and demand include the following:

- When determining NLCAS and reactive power supply requirements, a 10% POE MD, medium economic growth forecast as developed by AEMO for the NTNDP.
- When determining reactive power absorption requirements, minimum regional demand remains constant for the outlook period. Minimum regional demand refers to actual demand conditions over the past 12 months.
- All active and reactive power loads behave as constant static loads.

6.5.3 Other assumptions

General assumptions include the following:

- When determining RPAS requirements, only committed transmission network augmentations are modelled. The impact of non-committed projects where commitment is expected in the near future is also considered.
- Existing network support arrangements remain in place, unless the relevant TNSP confirmed otherwise.
- Relevant control schemes are enabled as appropriate for the assessment of RPAS requirements.
- All installed reactive plant is available and in service.
- Only credible contingency events are considered[52]. The worst contingency event modelled is based on the outcomes of a credible contingency screening study.
- Prior (planned) transmission network outages do not affect RPAS requirements[53].

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[51] This is only the case if remaining generation still meets the 10% POE MD, the situation is realistic and has occurred before, and is in line with criteria given in the relevant TNSP's APR or as agreed by the TNSP.

[52] AEMO simulates an N-1 credible contingency. Other contingencies, however, may also be checked.

[53] This is because they are not permitted to proceed if power system security cannot be maintained.

6.6 Queensland assessment

The analysis of the key regional issues, involving a voltage stability limit for Far North Queensland (FNQ) transmission network power transfers, a voltage stability limit for power transfer from Central Queensland (CQ) to South Queensland (SQ), and requirements for reactive power reserves within South East Queensland (SEQ), revealed:

- that committed transmission network augmentations result in an acceptable voltage profile for the region[54], and
- no NSCAS requirement above the level already proposed by the TNSP.

6.7 New South Wales assessment

The analysis of the key regional issues, involving voltage stability/control associated with supplying major load centres from the region's major coal-fired generating centres, and overvoltage in Upper Tumut and Kangaroo Valley during light load conditions, revealed:

- no NLCAS requirement
- a supplying RPAS requirement for the next five years to ensure acceptable voltage quality and sufficient voltage stability margins for supplying major load centres in Sydney, and
- an absorbing RPAS requirement for the next five years to manage voltage quality in the Snowy area under light load conditions.

Table 6-1 summarises the NSCAS requirements for the next five years.

[54] Potential under-voltage has been identified on the 110 kV transmission network at Dalby and Daandine, if the Daandine Power Station is out of service.

Table 6-1 NSCAS requirements for New South Wales

Type of NSCAS[7]	2010/11	2011/12	2012/13	2013/14[1]	2014/15[1]
Supplying RPAS[2]	650 MVAr[3]	650 MVAr[3] 150 MVAr[4]	650 MVAr[3] 150 MVAr[4]	650 MVAr[3]	650 MVAr3
Absorbing RPAS[5]	650 MVAr[6]	650 MVAr[6]	650 MVAr[6]	650 MVAr[6]	650 MVAr6

1. The RPAS requirements for 2013/14 and 2014/15 assume implementation of a non-committed development at Holroyd by summer 2013/14. AEMO is unable to assess RPAS requirements in the absence of this development, as TransGrid's regional 10% POE MD forecast specifically takes it into account.
2. Although not committed, TransGrid proposes in its 2010 APR to initiate contracts in 2010 to procure sufficient supplying RPAS as an alternative to installing 330 kV capacitor banks under a contingent project arrangement.
3. RPAS from generating units in the Hunter Valley, Central Coast, and Western Coalfields. This includes the existing 500 MVAr NCAS contracts with these generating units.
4. RPAS equivalent to a capacitor bank at the 330 kV Haymarket bus.
5. Although not committed, TransGrid proposes to relocate a 330 kV shunt reactor from Kemps Creek to Yass, which will reduce the absorbing RPAS requirement by approximately 100 MVAr.
6. RPAS from Snowy Hydro generating units running as synchronous condensers.
7. These results are consistent with the modelling inputs used by AEMO. TransGrid may use different inputs, which may lead to different results. AEMO will work with TransGrid to better understand the input differences and their impacts.

6.8 Victorian assessment

The analysis of the key regional issues, involving a review of the existing NLCAS for increasing power transfer via the 330 kV Murray-Dederang lines, voltage quality and voltage stability issues in the Greater Melbourne and Geelong area, and an overvoltage issue at the 220 kV Eildon and Mt Beauty buses, revealed:

- an ongoing NLCAS requirement of approximately 260 MW to increase power transfers from New South Wales to Victoria over the 330 kV Murray-Dederang lines by approximately 300 MVA, to approximately 1,600[55] MVA, and
- no RPAS requirement for the period 2010/11-2013/14, and an RPAS requirement of 200 MVAr at Rowville in 2014/15, to avoid voltage collapse.

Table 6-2 NSCAS requirements for Victoria

Type of NSCAS	2010/11	2011/12	2012/13	2013/14	2014/15
NLCAS	260 MW	260 MW	260 MW	260 MW	260 MW
Supplying RPAS	0 MVAr	0 MVAr	0 MVAr	0 MVAr	200 MVAr[1]

1. RPAS equivalent to a capacitor bank at Rowville.

55 This is a pre-contingency power transfer limit. Following a trip of one of the Murray-Dederang circuits, the power flow on the remaining circuit will be restricted to approximately 100 MVA by this NLCAS and an automated control scheme (DBUSS-line scheme).

6.9 South Australian assessment

The analysis of the key regional issues, involving low voltage in the Eastern Hills and mid-North areas, revealed:

- an RPAS requirement of approximately 20 MVAr at Mount Barker and 35 MVAr at Dorrien in 2010/11. Alternatively, the issue can be managed under existing load shedding schemes.

Table 6-3 summarises the NSCAS requirements for the next five years.

Table 6-3 NSCAS requirements for South Australia

Type of NSCAS	2010/11	2011/12	2012/13	2013/14	2014/15
Supplying RPAS1	20 MVAr1 35 MVAr1	0 MVAr	0 MVAr	0 MVAr	0 MVAr

1. This requirement can also be managed under existing load shedding schemes.

6.10 Tasmanian assessment

The analysis of the key regional issues, involving a voltage stability issue in supplying Southern Tasmania, overvoltage in Northern Tasmania, and low voltage/voltage stability issues at George Town, revealed:

- no NSCAS requirement over the next five years[56]

[56] AEMO found an RPAS requirement only when Gordon generation is very low and southwards power transfer is high during winter peaks, which is unlikely.

Chapter 7 - Generation Clusters

7.1 Summary

This chapter provides information about areas (zones) with the potential for multiple future generation investments (or clusters) to make best use of available renewable and non-renewable resources[57]. This information has been provided as a result of National Transmission Development Plan (NTNDP) generation expansion modelling that suggests new generation will be attracted to zones with the most cost-effective resources. As a result, regional planners need to consider the potential benefits of planning for adequate capacity to cater for multiple future connections at these locations.

The NTNDP modelling identifies a number of potential cluster zones, with leading zones defined as those with the highest number of scenarios and sensitivities showing five or more new generating units[58]. Actual connection enquiries from potential investors provide a useful indicator about the alignment of the modelling with current investor interest. In most cases, identified clusters correspond with investor intentions.

Based on the modelling of new generation, the leading zones are:

- North Queensland (NQ)
- South West Queensland (SWQ)
- Country Victoria (CVIC)
- South East South Australia (SESA)
- Northern South Australia (NSA), and
- Tasmania (TAS).

The following zones were not ranked as highly in the modelling, but are subject to significant potential investor interest, based on the number of active connection enquiries[58]:

- Northern New South Wales (NNS)
- Central New South Wales (NCEN), and
- Melbourne (MEL).

[57] Such as renewable solar, wind, and geothermal resources and non-renewable gas and coal resources.

[58] This does not include new open cycle gas turbine (OCGT) generation (which can be flexibly located close to load centres or where the electricity transmission network is strong and near gas pipelines).

7.2 Methodology

The primary goal of the potential generation cluster analysis is to identify zones where multiple future generation developments may be located to make best use of the available resources, both renewable (biomass, solar, geothermal, and wind) and non-renewable (coal and gas).

This approach was adopted due to the possible implications for transmission network development in locations where generation can be clustered to make use of previously unexploited resources, or to make better use of existing resources. Where this occurs, consideration should be given to the potential benefits of planning for adequate capacity to cater for multiple connections at these locations.

New open-cycle gas turbine (OCGT) power stations are not included in the assessment of potential generation clusters because they can be flexibly located near existing gas transmission pipelines, and are generally positioned to best meet peak demand (close to load centres or where the electricity transmission network is strong), not to coincide with the location of gas resources. OCGT power stations may be located close to a gas resource if the power stations are large or if there are gas pipeline limitations preventing their connection near the load centre. However, due to their low utilisation factor they are generally expected to be located where the electricity transmission network has capacity to support them rather than in a location requiring significant network extensions.

This chapter is motivated by, but not dependent on, the current Scale Efficient Network Extension (SENE) National Electricity Rule (NER) change being conducted by the Australian Energy Market Commission (AEMC), a final decision about which is due February 2011. Regardless of the outcome of the NER change process, AEMO sees value in providing information about where generation may cluster. Throughout AEMO's consultations, stakeholders indicated strong support for the NTNDP to include this type of information (see Chapter 8, Section 8.3.4).

7.2.1 Leading zones - NTNDP market simulation results

The NTNDP market simulations developed a least-cost generation/transmission expansion on the basis of assumed capital and operating costs, while taking transmission costs into account (for both generation connections and transmission network augmentations)[59]. While this expansion provided insight into efficient long-term development, it did not consider all factors a generation investor may take into account when making an investment decision. As a result, the generation clusters identified by the market simulations were compared with current interest from generation project proponents.

The market simulation results were reviewed for each zone under each scenario and sensitivity. AEMO then identified leading zones from the NTNDP market simulation results that showed potential generation clusters, with the deciding factor in each zone being the number of scenarios and sensitivities showing five or more new generating units (excluding OCGTs).

[59] For more information about the methodology behind the simulated generation expansion, see Attachment 1.

For the purposes of identifying the zones with the greatest incidence of clustering, leading zones have been defined as those having eight or more scenarios or sensitivities showing five or more new generating units (excluding OCGTs).

For the purposes of the analysis, the following generation sizes by fuel type were assumed: 750 MW (coal), 500 MW (CCGT), 100 MW (biomass), 200 MW (solar, geothermal, and wind).

High-level generation expansion results

Six zones were identified as each having eight or more scenarios or sensitivities showing five or more new generating units (excluding OCGTs). For more information about these zones, see Section 7.3.

Although some of the remaining ten zones showed clustering under some scenarios, this occurred under six or fewer scenarios.

For a complete list of the NTNDP generation expansion results, see Appendix A.

7.2.2 Investor interest

The assessment of investor interest is based on publicly announced proposals identified in the 2010 Electricity Statement of Opportunities (ESOO), and information about active connection enquiries from transmission network service providers (TNSPs)[60]. Where a proposal is not for a specific capacity and involves a range of possible capacities, AEMO has used the higher value of the range.

It is unlikely that all connection enquiries will proceed, however, in cases, for example, where development appears to be uneconomic due to remoteness, or due to the level of transmission network congestion (although these projects may become more attractive in the future with a stronger transmission network).

The market simulations are expected to partially address these limitations by considering potential new generation in locations that may not yet have seen investor interest, but where the assumed fuel prices and resource availability become competitive over time (compared to other options).

7.2.3 Presentation of generation clusters

Generation clusters are presented in Figure 7-1 and Table 7-1 on the basis of the NTNDP zones, which are broad geographic zones. The actual location of generation within a zone, however, may significantly affect transmission capability and congestion, causing a need for network augmentation.

AEMO has aggregated information about generation investment to protect the confidentiality of generation connection information, which is partly based on confidential information from connection enquiries and other communications with project proponents.

Figure 7-1 shows a map summarising the results. The aggregate capacity shown under 'NTNDP results' reflects the results of the scenario with the highest modelled new generation capacity. The

60 The level of detail provided by the TNSPs can differ, and results were reviewed with the TNSPs to address potential double counting.

generation interest shown is the sum of the investor interest in the zone (as described in Section 7.2.2), using the higher end of the range if proponents have indicated a range for potential new generation. Table 7-1 lists more information for all zones.

7.3 Results for leading zones

7.3.1 North Queensland (NQ)

- In nine out of ten scenarios and sensitivities, simulations show five or more new generating units[61], with an average of seven units in these scenarios/sensitivities.
- The types of simulated generation include biomass and solar.
- The scenario/sensitivity with the highest simulated generation capacity showed 1,800 MW across eleven units.
- Generation investment interest is low compared to other zones, with approximately 390 MW across seven units. The interest being expressed is in hydroelectric and wind generation.

7.3.2 South West Queensland (SWQ)

- In all scenarios and sensitivities, simulations show five or more new generating units[61], with an average of eleven units.
- The types of simulated generation include coal, CCGT, geothermal, and wind.
- The scenario/sensitivity with the highest simulated generation capacity showed 8,650 MW across fifteen units.
- Generation investment interest is moderate compared to other zones, with approximately 2,585 MW across six units. The interest being expressed is in coal, gas, wind, and solar generation.

7.3.3 Country Victoria (CVIC)

- In nine out of ten scenarios and sensitivities, simulations show five or more new generating units[61], with an average of eight units in these scenarios/sensitivities.
- The types of simulated generation include geothermal and wind.
- The scenario/sensitivity with the highest simulated generation capacity showed 2,250 MW across eleven units.
- Generation investment interest is moderate compared to other zones, with approximately 2,090 MW across fifteen units. The interest being expressed is in wind and solar generation.

7.3.4 South Eastern South Australia (SESA)

- In all scenarios and sensitivities, simulations show five or more new generating units[61], with an average of six units.
- The types of simulated generation are biomass, geothermal, and wind.

[61] Excluding OCGTs.

- The scenario/sensitivity with the highest simulated generation capacity showed 1,500 MW across nine units.
- Generation investment interest is low compared to other zones, with approximately 1,395 MW across fewer than five units. The interest being expressed is in wind generation only.

7.3.5 Northern South Australia (NSA)

- In eight out of ten scenarios and sensitivities, simulations show five or more new generating units[62], with an average of nine units in these scenarios/sensitivities.
- The types of simulated generation include geothermal and wind.
- The scenario/sensitivity with the highest simulated generation capacity showed 2,400 MW across twelve units.
- Generation investment interest is high compared to other zones, with approximately 5,315 MW across twenty-seven units. The interest being expressed is in coal, gas, solar, wind, and geothermal generation.

7.3.6 Tasmania (TAS)

- In all scenarios and sensitivities, simulations show five or more new generating units[62], with an average of ten units.
- The types of simulated generation include biomass and wind.
- The scenario/sensitivity with the highest simulated generation capacity showed 2,350 MW across thirteen units.
- Generation investment interest is moderate compared to other zones, at 998 MW maximum and fewer than five units. The interest being expressed is in biomass and wind generation.

7.4 Results for zones subject to significant interest

Although the NNS and MEL zones showed significant clustering under a number of scenarios and sensitivities, they were not identified as leading zones. Generation project proponents have, however, shown significant interest in these zones as well as the NCEN zone.

7.4.1 Northern New South Wales (NNS)

- In five out of ten scenarios and sensitivities, simulations show five or more new generating units[62], with an average of eleven units in these scenarios/sensitivities.
- The types of simulated generation include CCGT, biomass, and wind.
- The scenario/sensitivity with the highest simulated generation capacity showed 7,100 MW across fifteen units.
- Generation investment interest is high compared to other zones, with approximately 4,000 MW across twenty units. The interest being expressed is in solar and wind.

[62] Excluding OCGTs.

7.4.2 Central New South Wales (NCEN)

- In only one out of ten scenarios and sensitivities, simulations show five or more new generating units[63], with six units in this scenario/sensitivity.
- The types of simulated generation include coal, CCGT, geothermal, biomass, and wind.
- The scenario/sensitivity with the highest simulated generation capacity showed 1,600 MW across three units.
- Generation investment interest is some of the highest in the National Electricity Market (NEM), with approximately 9,700 MW across twenty-eight units. The interest being expressed is in coal, gas, solar, and wind.

7.4.3 Melbourne (MEL)

- In four out of ten scenarios and sensitivities, modelling shows five or more new generating units[63], with an average of eight units in these scenarios/sensitivities.
- The only type of (non-OCGT) simulated generation is wind.
- The scenario/sensitivity with the highest simulated generation capacity showed 2,100 MW across eleven units.
- Generation investment interest is high compared to other zones, with approximately 6,260 MW across twenty-three units. The interest being expressed is in gas and wind.

[63] Excluding OCGTs.

Figure 7-1 Leading zones and generation clusters

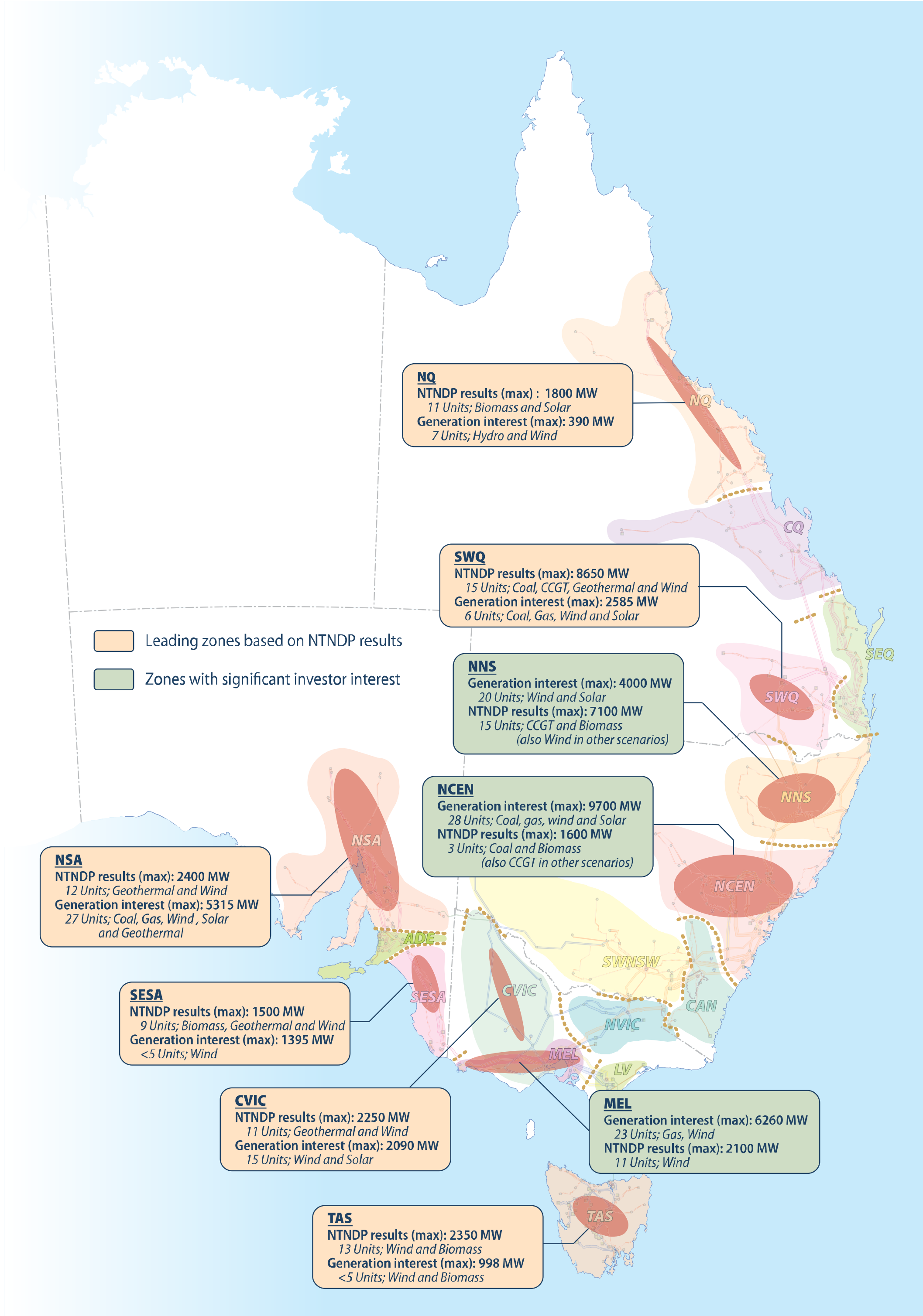

Table 7-1 NTNDP market simulation results and generation investor interest for each NTNDP zone (excluding OCGT)

NTNDP zone	Investor interest			NTNDP market simulation results					
	Aggregate capacity (MW)	Number of units	Type	Highest modelled new generation capacity in any one scenario or sensitivity			Number of scenarios or sensitivities where modelling shows five or more new generating units	Average number of units (in scenarios or sensitivities where modelling shows five or more new generating units)	Type
				Aggregate capacity (MW)	Number of units	Scenario/ sensitivity[1]			
NQ	390	7	Hydro, wind	1,800	11	OS-M	9	7	Biomass, solar
CQ	600	Fewer than 5	Gas, solar	1,900	4	FC-H, FC-M	1	6	Coal, solar
SEQ	400	Fewer than 5	Gas	0	0	Not applicable	0	0	Not applicable
SWQ	2,585	6	Coal, gas, wind, solar	8,650	15	FC-H	10	11	Coal, CCGT, geothermal, wind
NNS	4,000	20	wind, solar	7,100	15	DW-H	5	11	CCGT, biomass, wind
NCEN	9,700	28	Coal, gas, wind, solar	1,600	3	UW-0	1	6	Coal, CCGT, biomass, geothermal, wind
CAN	2,000	10	Wind, solar	4,400	14	FC-H	3	10	CCGT, biomass, wind
SWNSW	2,000	10	solar, wind	1,500	8	FC-H	2	6	Wind

NTNDP zone	Investor interest			NTNDP market simulation results					
	Aggregate capacity (MW)	Number of units	Type	Highest modelled new generation capacity in any one scenario or sensitivity			Number of scenarios or sensitivities where modelling shows five or more new generating units	Average number of units (in scenarios or sensitivities where modelling shows five or more new generating units)	Type
				Aggregate capacity (MW)	Number of units	Scenario/ sensitivity[1]			
NVIC	0	0	Not applicable	0	0	Not applicable	0	0	Not applicable
LV	1,655	Fewer than 5	Gas, wind	9,700	21	FC-H	6	11	Coal, CCGT, geothermal
MEL	6,260	23	Gas, wind	2,100	11	OS-M	4	8	Wind
CVIC	2,090	15	wind, solar	2,250	11	OS-M	9	8	Geothermal, wind
ADE	300	Fewer than 5	Gas	1,000	2	UW-0	0	0	CCGT
NSA	5,315	27	Coal, gas, wind, solar, geothermal	2,400	12	FC-H	8	9	Geothermal, wind
TAS	998	Fewer than 5	Wind and biomass	2,350	13	UW-L	10	10	Biomass, wind

1. **Scenario**
   - FC-H - Fast Rate of Change - high carbon price
   - UW-L - Uncertain World - low carbon price
   - DW-M - Decentralised World - medium carbon price
   - OS-M - Oil Shock and Adaptation -medium carbon price
   - SC-L - Slow Rate of Change - low carbon price

Scenario sensitivity
- medium carbon price - FC-M
- zero carbon price - UW-0
- high carbon price - DW-H
- low carbon price OS-L
- zero carbon price SC-0

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Chapter 8 - Evolution of the NTNDP

8.1 Summary

This chapter describes the development process of the National Transmission Network Development Plan's (NTNDP) scope, content, modelling, and analysis, as well as providing AEMO's views about the NTNDP's future development. This information is provided in response to the 2010 NTNDP consultation, and is intended to show the extent to which AEMO has addressed issues raised by stakeholders at the time. Information about issues where AEMO is seeking further stakeholder feedback is also discussed.

AEMO has responded to the key outcomes from its 2010 NTNDP consultation[64] process and subsequent development of the 2010 NTNDP by:

- addressing issues raised by stakeholders in terms of the NTNDP's development and content
- maintaining consistency by basing the 2010 NTNDP maximum demand (MD) forecasts on the forecasts developed for the 2009 ESOO (modelling lead times preclude the use of the 2010 ESOO forecasts, although they are used for benchmarking)
- examining a wide range of possible future scenarios, including the adoption of energy efficiency initiatives, embedded generation, and electric vehicle use
- researching improvements for a national Value of Customer Reliability (VCR)
- conducting scenario sensitivity studies
- developing a high-level, least-cost generation and transmission model, and
- improving the Monte Carlo market simulation model.

The consultation process delivered a number of key initiatives and improvements. In particular, the switch to a newer modelling technique, which took time to implement, has opened new investigative avenues. For the 2011 NTNDP, there are still several areas of improvement that will be progressed and prioritized based on the NTNDP consultation, which is scheduled to commence in late January 2011.

8.2 Origins of the NTNDP

The NTNDP supersedes the 2009 National Transmission Statement (NTS)[65], which was a transitional document that replaced the Annual National Transmission Statement (ANTS). Providing views about possible transmission network development, the various transmission planning publications each consider:

- simulated future network capability, utilisation, and congestion

[64] http://www.aemo.com.au/planning/ntndp.html
[65] http://www.aemo.com.au/planning/0410-0025.pdf and http://www.aemo.com.au/planning/0410-0026.pdf

- consolidated views about current and emerging limitations, and the network and non-network solutions available to address them, and
- the cost effectiveness, under various scenarios, of the projects most likely to relieve congestion, and the market benefits for a selection of transmission network projects.

Table 8-1 lists the key differences between the ANTS, NTS, and NTNDP, which include study timeframes, the types and number of scenarios being studied, and the projects considered.

Table 8-1 Overview of differences between the ANTS, NTS, and NTNDP

Topic	ANTS	NTS	NTNDP
Outlook time-frame	13 years	20 years	20 years
Consideration of scenarios	One base case with sensitivities	Two scenarios	Five scenarios, each analysing a base carbon price and a carbon price sensitivity
Projects considered	JPB projects only	JPB projects only	JPB and AEMO-originated projects

8.2.1 The NTNDP and the NTS

In 2009, the NTS set the agenda for the development of the NTNDP. Priorities indentified in the NTS included the need to respond to issues raised by stakeholders, the use of scenarios, and the need for updated modelling.

AEMO undertook significant stakeholder engagement to act on this agenda, including releasing a consultation paper in January 2010 (see Section 8.3), and holding a number of workshops with the Department of Resources, Energy and Tourism (DRET) and other stakeholders in order to develop scenarios for the 2010 NTNDP. The NTNDP also provides updated data and models, and a least-cost optimised generation and transmission expansion modelling approach.

Table 8-2 lists the priorities identified by the NTS and their impact on the 2010 NTNDP.

Table 8-2 Priorities for the NTNDP

Priority identified by the NTS	Impact on the NTNDP
Respond to specific stakeholder requirements identified in consultations	Incorporating responses to issues raised by stakeholders during the 2010 NTNDP consultation process (for more information, see Section 8.3)
Refresh simulation data, particularly the: • demand forecasts • inclusion of a price elasticity modelling approach, and • consistent application of assumptions encompassing energy efficiency initiatives, smart grid applications, and embedded generation	In order to provide a consistent approach, given the time needed to conduct the modelling and analysis, the 2010 NTNDP demand forecasts are based on forecasts developed for the 2009 ESOO The scenarios developed for the NTNDP examine a wide range of future possibilities, including the adoption of energy efficiency initiatives, embedded generation, and electric vehicle use. The input data used for the NTNDP modelling was adjusted to account for these potential developments

Priority identified by the NTS	Impact on the NTNDP
Move towards improved national data for the Value of Customer Reliability (VCR) in the assessment of unserved energy (USE) benefits	AEMO has undertaken research into improving information for a national VCR.
Include a small number of select, high-priority sensitivity studies	A carbon price sensitivity study was modelled for each scenario.
Explore options for generation/transmission co-optimisation over the first 7-10 years of the simulation and for modelling the Network Support and Control Services (NSCAS) market	A high-level, least-cost generation and transmission model has been developed for the NTNDP studies, and potential future NSCAS requirements have been addressed as part of the NTNDP (for more information, see Chapter 6)
Apply lessons learned during the production of the NTS, and further tune the simulations	The Monte Carlo market simulation model used for the NTS market modelling has been improved for the NTNDP in terms of: • an improved six pond model for simulating Tasmanian hydro-electric generation • updated new entry connection points for wind and conventional generation to reflect known and expected generation development, and • improved loss modelling for the NEMLink analysis (see Chapter 5)
Explore other long-term techniques to reduce costs and address the requirement for a 'what if' capability	The high-level, least-cost generation and transmission model developed for the NTNDP studies enables a wider range of scenarios to be addressed than was possible for the ANTS and NTS. AEMO intends to revise and improve this model for future NTNDP studies

Table 8-3 lists an overview of the broader issues the NTNDP was intended to resolve (as described in the 2009 NTS), as well as AEMO's stated intentions for resolution, and its current actions.

Table 8-3 NTS issues related to the NTNDP

Issue	Issue description	Stated resolution	Current action
Scenarios and long-term strategic focus	Scenario planning should provide the basis on which to build a vision for long-term transmission network development	AEMO will work with DRET and a reference group of diverse stakeholders to develop scenarios for long-term transmission network planning	AEMO is applying five scenarios, with two carbon emissions prices each, to the analysis for the 2010 NTNDP and other AEMO planning reports
	The NTS reported only two scenarios. AEMO believes there is value in considering more scenarios that test a broader range of likely outcomes	An expanded set of scenarios will support production of the 2010 NTNDP	AEMO developed an expanded set of scenarios in conjunction with DRET and stakeholders

Issue	Issue description	Stated resolution	Current action
National optimisation	The studies do not sufficiently explore the potential for national optimisation: regional network augmentations worth approximately AUD10 billion are assumed in the studies, and national optimisation is limited to AUD0.44 billion of augmentations defined by the jurisdictional planning bodies (JPBs) as conceptual	AEMO will consult with stakeholders on a wider range of development options to identify how national and regional co-optimisation of transmission network investment can increase the value of national planning	AEMO consulted with transmission network service providers (TNSPs), generators, and other stakeholders on development options for the NTNDP
	There is value in testing some of the assumed transmission network projects included in the simulations, and examining the potential to better align the work programs of individual JPBs to the efficient national development of the transmission network		The study work is designed to identify opportunities for co-optimisation of national and regional network investment
Communication	Enhancing overall outcomes requires effectively communicating the lessons learned from scenario planning to a wide range of parties including many non-expert stakeholders, especially those involved in policy development, planning, and environmental approval processes. For example, the primary link between the electricity industry and the wider economy is the average delivered cost of electricity (ADCE) Results should be expressed in terms of the ADCE so they are understood and accessible to the widest range of potential interested parties	AEMO will develop improved communication support in consultation with a wide range of stakeholders. AEMO is also exploring ways of expressing results in terms of impacts on the ADCE	AEMO established the Stakeholder Reference Group (SRG) and briefed key industry stakeholder groups The NTNDP will be launched to stakeholders and AEMO staff will present the key findings and respond to stakeholder questions and comments at sessions in selected capital cities Expressing the ADCE is complex, due to the range of end-user tariffs and the frequency of tariff change. AEMO will seek stakeholder feedback on approaches to expressing results as ADCE
Inclusion of all benefits	Ideally, transmission planning must ensure all benefits are properly realised. Robust and efficient methods to value potential benefits, such as competition benefits and strategic (real option) value, which may be very important to some grid investments, are yet to be developed, and these investments may be undervalued	AEMO will explore options and consult with stakeholders to identify techniques for the appropriate incorporation of benefits into planning processes	AEMO has been considering potential approaches, and will seek stakeholder feedback in 2011
Preparing the grid for climate change	Planning must address the increasing incidence of extreme weather events. The inclusion of high impact, low probability (HILP) events needs further development, as supply interruptions due to HILP have caused major economic loss	AEMO will explore options, develop the necessary databases, and build the capability to incorporate HILP event considerations into national transmission network plans	AEMO is incorporating HILP event considerations in its Victorian planning and intends to extend this to its national planning following further development

Issue	Issue description	Stated resolution	Current action
Development of plan projects	The NTS considers only network development options provided by the JPBs AEMO intends to devise its own options, including 'big concept' transmission network projects that are driven by a particular scenario and seek to provide the overall lowest cost development of the power system 'Big concept' projects fall into two groups: stronger eastern seaboard inter-regional network backbone; and national network 'meshing' via links to remote areas	AEMO will consult with stakeholders and develop a range of transmission options, including 'big concept' infrastructure projects that are driven by the demands of a particular scenario The objective is to seek and provide the overall lowest cost, long-term development of the power system	The 2010 NTNDP presents information about a high-level study carried out by AEMO into the potential benefits from significantly increasing power transfer capabilities in the NEM AEMO has designed a conceptual project called NEMLink, which is designed to enable large-scale power transfers between the regions (see Chapter 5)
Integrated planning	Long-term integrated energy planning is required for security of national electricity supply. This planning increasingly depends on gas supplies, including pipeline networks Integrated gas and electricity planning will prove essential if security of electricity supply is to be assured	AEMO will consult with stakeholders on options for the necessary level of integrated planning	Consultation with stakeholders on the 2009 NTS and 2009 Gas Statement of Opportunities (GSOO) indicated an interest in more integrated planning. AEMO will explore this further with stakeholders in 2011
Conceptual framework	The economic assessment framework currently used by AEMO and other energy industry planners has shortcomings. For example, the economic cost of transmission failure (and conversely the benefits of reliability), network energy losses, and the effect of the network on competition require further consideration	AEMO will further develop the conceptual framework in consultation with stakeholders to identify the full value of specific transmission investments to the Australian economy. Options for Renewable Energy Certificate market modelling and benefits assessment will also be considered	AEMO has begun exploring many of these issues with the Stakeholder Reference Group (SRG) and will continue to consult on potential improvements. In 2011, AEMO (in conjunction with stakeholders) will explore approaches to better consider the value of reliability, including its impact on long-term economic development

Issue	Issue description	Stated resolution	Current action
Structure of the industry	AEMO's high-level analysis of the steps required to realise the benefits of transmission network investments reveals some implementation risks that are relatively unique to the electricity industry, especially in the areas of procurement and funding	AEMO will raise the prospect of a fundamental and wide-ranging review to determine whether a new concept of transmission, and its relationship with energy markets, will better meet the challenges of the next few decades. Priority aspects proposed for consideration include: • options for a service-based model as an alternative to the asset/territory based model • better location signals for generation investors • firm access to network capacity for connected parties, and • national transmission service pricing as an alternative to current jurisdictional regimes	AEMO contributed to the AEMC review of transmission, and will contribute to further AEMC reviews on this issue

8.3 2010 NTNDP consultation

AEMO's consultations with stakeholders revealed considerable support for an independent document presenting a whole-of-NEM perspective for the transmission network, as well as support for information about 'big concept' transmission projects extending beyond individual regions/jurisdictions.

AEMO has taken this approach with the NTNDP, as well incorporating information about the projects making up the large, inter-regional interconnector (referred to as NEMLink), which will greatly enhance the power transfer capability of the transmission network as a whole (for more information about NEMLink, see Chapter 5).

A major aspect of the 2010 NTNDP's formal consultation involved the release of the consultation paper on 29 January 2010. AEMO sought comments from stakeholders about the scope and purpose of the NTNDP, as well as more detailed issues, like the proposed modelling approaches and input data.

The consultation closed on 12 March 2010, and AEMO received submissions from the following organisations:

- Alinta Energy
- Australian Academy of Technological Sciences and Engineering (ATSE)
- Australian Energy Regulator (AER)
- Clean Energy Council
- ElectraNet
- Ergon Energy
- Geodynamics
- Institute of Environmental Studies, University of New South Wales (IES UNSW)
- International Power
- Macquarie Generation
- MirusWind
- National Generators Forum (NGF)
- Office of Energy Planning and Conservation, Tasmanian Government
- Origin Energy
- Powerlink
- TransGrid

For more information about the NTNDP consultation, see the AEMO website and the summary of submissions[66], and individual submissions from stakeholders[67].

8.3.1 Scope, purpose, and methodology

Table 8-4 provides a high-level overview of the feedback AEMO received about the scope, purpose, and methodology behind the NTNDP, and AEMO's responses.

Table 8-4 Scope, purpose, and methodology

Topic	Feedback	AEMO response
Evolving scope	Most stakeholders recognised that the scope of the NTNDP will need to be fluid, and to evolve iteratively through ongoing consultation	The 2010 NTNDP forms the basis for ongoing discussions. The scope of future NTNDPs will be determined through further stakeholder engagement
The transmission network and new generation	Some generators indicated support for broader transmission network planning to avoid congestion as more generation is connected, particularly wind The generators also noted that omitting option value and competition benefits from the scope may undermine the NTNDP analysis	AEMO will consult with stakeholders on approaches to include option values and competition benefits in future NTNDP modelling
Purpose: an independent strategic plan	Most stakeholders expressed satisfaction with the purpose of the NTNDP and see it as playing an important role in informing investment decisions	The NTNDP will continue to be an independent report providing stakeholders with information about the future direction of the transmission network
Methodology – Network Support and Control Ancillary Services (NSCAS)	Some government departments noted the importance of not overlooking NSCAS while recognising that network control services are ideally provided within the market	The 2010 NTNDP includes NSCAS information (see Chapter 6), as will future NTNDP reports

8.3.2 Modelling and scenarios

Table 8-5 provides a high-level overview of the feedback AEMO received about the modelling and scenarios underpinning the NTNDP's analysis and AEMO's responses.

[66] http://www.aemo.com.au/planning/0418-0006.pdf .
[67] http://www.aemo.com.au/planning/ntndp.html.

Table 8-5 Modelling and scenarios

Topic	Feedback	AEMO response
Mid-term and long-term modelling	The TNSPs expressed general support for using different approaches to modelling the mid- and long-term. Support was also indicated for considering 'big concept' projects While stakeholders generally supported the modelling time frames, some TNSPs noted that the 20-year planning outlook was too short for consideration of major transmission projects	NTNDPs will continue to use different approaches to modelling the mid- and long-term The 2010 NTNDP includes information on a conceptual project called NEMLink, which is designed to enable large-scale power transfers between the regions (see Chapter 5) AEMO will seek stakeholder views about potential 'big concept' projects for consideration in future NTNDPs
National Transmission Flow Paths (NTFPs)	Stakeholders expressed varying opinions with respect to NTFPs, with some noting that NTFPs are useful for conceptualising the transmission network as a whole Some generators indicated that NTFPs may be useful, but it is important to recognise future flow paths based on generation and load patterns The AER noted that a rigid definition of NTFPs would be unworkable and risks limiting the benefits of the NTNDP	AEMO has not used NTFPs in the 2010 NTNDP. NTFPs may be used in the future, provided a balance can be achieved between the rigidity of their definition and the utility of the concept for understanding the transmission network
Transparency of modelling	Stakeholders commented that small variations in the inputs to models can produce significantly different outputs, and expressed the view that transparency in terms of the assumptions and the provision of model inputs will provide significant benefits. It was also noted that model outcomes need to be verified through cooperation with TNSPs	The NTNDP is intended to be a starting point for analysis. Details about the models, assumptions, and input data are provided in the NTNDP's accompanying CD-ROM. AEMO will continue to work with TNSPs on the development of the NTNDP's modelling and analysis
Scenarios - climate change policy	Stakeholders noted that the NTNDP scenarios need to reflect new greenhouse gas reduction policy proposals	The scenarios cover a spectrum of possible climate policy, from no action to significant reductions in carbon emissions. All proposed climate change policies lie somewhere within this range, though some may not be considered explicitly In consultation with stakeholders, AEMO will continue to take policy developments into account for future NTNDP scenarios
Scenario assumptions	Generators noted that, in their opinion, some scenarios were unlikely and that more detail regarding the assumptions used to develop the scenarios will be useful (such as carbon projections, global abatement commitment, and energy efficiency/elasticity). TNSPs noted that the scenarios do not capture the full range of development activity (such as developments in wind and geothermal power)	AEMO will continue to work with stakeholders on scenario development for future NTNDPs. AEMO does not consider scenarios to be projections, but rather a guide to a 'what if' analysis. Scenarios are not in themselves extrapolations of current trends to forecast future states

Topic	Feedback	AEMO response
Presentation of scenarios	Most stakeholders indicated a preference for scenarios to be presented equally, and with no weighting given to their relative likelihoods. Stakeholders noted that they can use the scenario input data in their own modelling. Consequently, stakeholders see the scenarios as guides, and will form their own opinion on the likelihood of the scenarios' realisation	AEMO does not intend to assign weightings to various scenarios as they are a tool for a 'what if' analysis. AEMO encourages stakeholders to use the scenarios as a starting point for their own investigations and has included the CD-ROM with the NTNDP in order to facilitate this process

8.3.3 Interaction with other planning documents, regulations, and reviews

Table 8-6 provides a high-level overview of the feedback AEMO received about the NTNDP's interaction with other planning documents, regulations and reviews, and AEMO's responses.

Table 8-6 Interaction with other planning documents, regulations, and reviews

Topic	Feedback	AEMO response
Relation to APRs	TNSPs support the whole-of-NEM approach in general, noting that some localised drivers that will be prominent in the APRs may not be prominent in the NTNDP Some generators noted that the NTNDP presents an opportunity to provide an independent opinion beyond the TNSP's APRs, and that in their opinion the NTNDP's predecessor (the ANTS) suffered from a lack of transparency, which prevented market participants from assessing transmission network development beyond the APRs upon which the ANTS was based The AER noted that the NTNDP presents a significant opportunity for consideration of major transmission network augmentation options that may not be considered by the APRs	AEMO considers that the APRs will continue to play an important role in the development of the transmission network, and does not intend to duplicate all the information contained within them AEMO will continue to use the NTNDP as a means for stakeholders to consider the transmission network from a whole-of-NEM perspective, including major transmission network augmentations
Interaction with TNSP Revenue Resets	Stakeholders noted the significant opportunity that the NTNDP presents in harmonising transmission network planning, and also noted its potential influence on regulatory Revenue Resets The AER considers that the NTNDP will provide significant potential assistance with performing its regulatory responsibilities	Through taking a whole-of-NEM perspective, AEMO intends the NTNDP to assist with the harmonisation of transmission network planning and the performance of regulatory responsibilities, and will continue to work with stakeholders to ensure future NTNDPs facilitate this process

Topic	Feedback	AEMO response
Transmission frameworks	Stakeholders expressed a range of views in relation to the NTNDP and transmission frameworks. These ranged from proposed regulatory changes to transfer TNSP responsibilities to AEMO, to more general descriptions of the principles for developing such frameworks Some stakeholders declined to comment on this issue as they did not consider it to be a part of the NTNDP	AEMO does not intend the NTNDP to replace the APRs or to assume the TNSP's transmission network planning responsibilities
Regulated Investment Test for Transmission (RIT-T)	Generators noted that the NTNDP does not substitute for the application of the RIT-T process, and that the AER retains full responsibility for determining the allowable revenue base for TNSPs TNSPs noted that AEMO must take care when identifying preferred solutions before they have passed the RIT-T, or the market may be misinformed	The NTNDP is not a substitute for the RIT-T, and full responsibility for determination of the TNSP revenue base remains with the AER

8.3.4 Scale Efficient Network Extensions

Throughout AEMO's consultations, stakeholders indicated strong support for the NTNDP to include information about Scale Efficient Network Extensions (SENE). At the date of publication, however, the Australian Energy Market Commission (AEMC) has not confirmed the criteria or rules regarding the definition and establishment of SENEs in the NEM, and the NTNDP has not included this information as a result. In the absence of a formal SENE definition, Chapter 7 includes information about generation clusters in order to facilitate an examination of the relevant issues.

Table 8-7 provides a high-level overview of the feedback AEMO received about SENEs, and AEMO's responses.

Table 8-7 Scale Efficient Network Extensions

Topic	Feedback	AEMO response
Inclusion of SENEs in the NTNDP	Many stakeholders expressed strong support for the NTNDP to include information about SENEs, including support for inclusion of SENEs prior to changes to the NER being completed	AEMO believes that any NER changes should be confirmed before detailed consideration of SENEs is included in the NTNDP. To facilitate further consideration of the issue among stakeholders, AEMO has included discussion about generation clusters in Chapter 7

Topic	Feedback	AEMO response
Identifying SENEs	Stakeholders generally agree with AEMO's proposed criteria for identifying SENEs. Several additional criteria were suggested, however, and increased detail was requested Stakeholders indentified a number of locations as potential SENEs including the Cooper Basin, the Walcha area south of Armidale, Western Victoria, and the Eyre Peninsula	AEMO will continue to work with stakeholders to develop the criteria for identifying SENEs, and encourages stakeholders to propose potential SENE sites
Developing SENEs	Stakeholders expressed conflicting views about the rules for the development of SENEs by TNSPs	AEMO will consider SENEs in detail once any relevant NER changes have been confirmed

8.4 Future NTNDP development

AEMO is committed to the ongoing evolution of its planning documents to better meet stakeholder needs, and stakeholder workshops are held after the publication of each key planning document. Workshops for the NTNDP will be held in February 2011 (alongside workshops for the Gas Statement of Opportunities (GSOO)). As well as providing stakeholders with an opportunity to ask questions about the documents, AEMO will also be asking stakeholders for feedback, including suggestions about how they can be improved.

AEMO will also be publishing an NTNDP consultation paper in January 2011, as required by the NER, which will seek stakeholder feedback on specific areas of the NTNDP that AEMO intends to develop for 2011.

8.5 Scenarios for the 2011 NTNDP

The 2010 NTNDP scenarios were developed by AEMO and industry stakeholders (via the Stakeholder Reference Group (SRG)) for the DRET Energy White Paper development project. AEMO is using a similar process for its 2011 planning documents, with the resulting scenarios to be used for the 2011 VAPR, ESOO, NTNDP and GSOO.

Information about the development of the scenarios for 2011 will be available from the AEMO website as it becomes available[68]

[68] http://www.aemo.com.au

Attachment 1 - Methodology for Modelling Development of the Network

A1.1 Introduction

This attachment describes how the interconnected National Electricity Market (NEM) power system was modelled for the 2010 NTNDP studies, why these models were chosen, and how they were developed.

The NTNDP modelling framework was developed in consultation with the TNSPs to ensure accurate modelling of the regions and the inclusion of appropriate planning criteria.

A1.1.1 Relationship between the scenarios and the models

Each scenario portrays Australia's socio-economic environment over a 20-year outlook period (to 2030), which is described through the following scenario drivers:

- Economic growth.
- Population growth.
- Global carbon policy.
- Carbon price.
- Decentralised supply-side responses.
- Centralised supply-side responses.
- Demand-side responses.

The drivers determine the values of key inputs to NEM modelling, such as the yearly demand profile over the 20-year outlook period, generation fuel costs, and new generation technology costs.

Modelling the NEM under each scenario provides the means to explore generation and transmission development to 2030. In the NTNDP, the generation and transmission expansion is determined through modelling the least-cost expansion of the system as a whole (involving changes to generating plant and the transmission network).

A1.1.2 Framework for the models

The NTNDP modelling comprises a combination of the following studies and simulations:

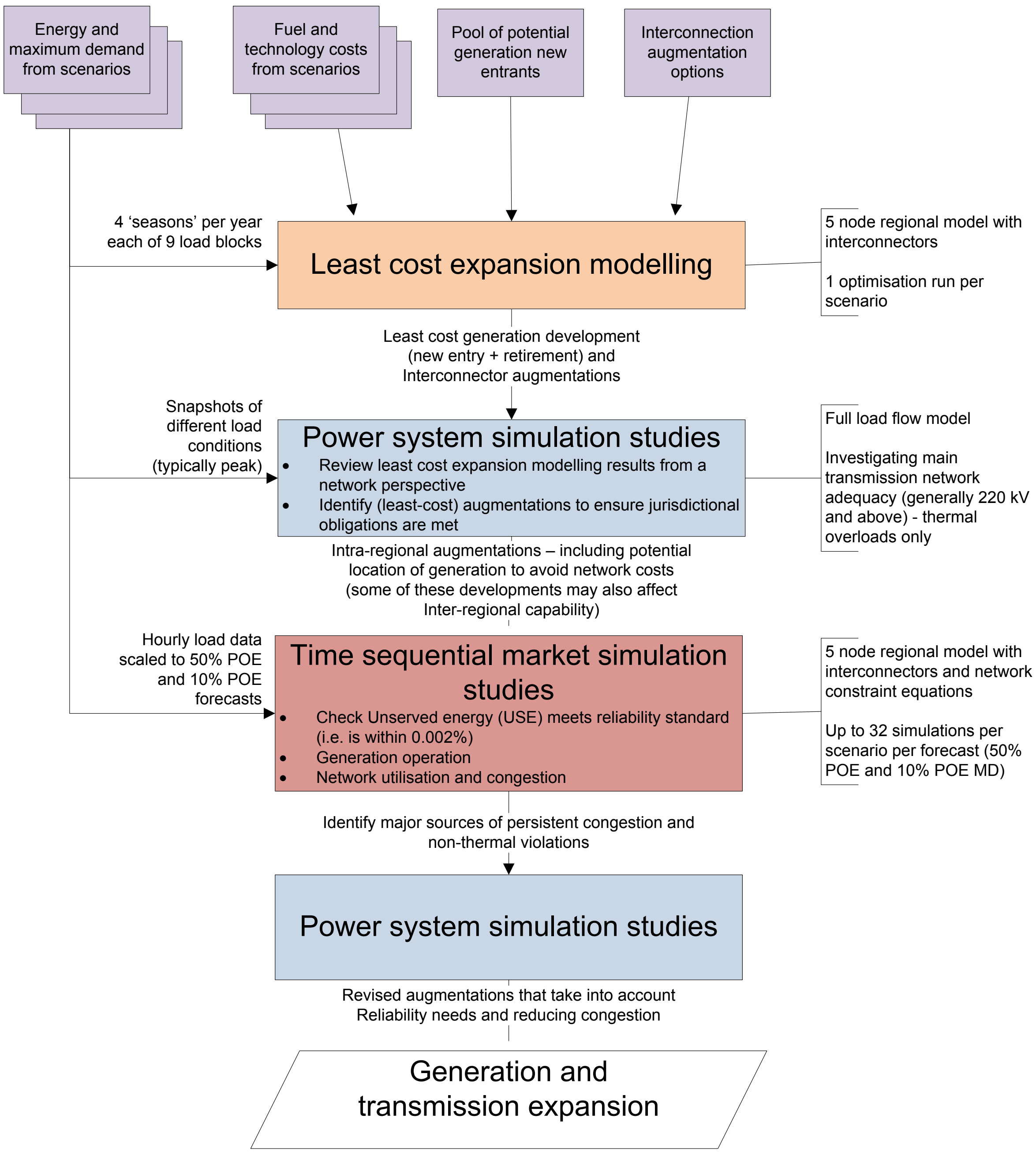
- **High-level, least-cost expansion modelling** produces a co-optimised expansion plan considering generation and inter-regional connectors, which minimises overall capital and operating costs subject to meeting predefined minimum reserve levels (MRLs).
- **Power system simulation studies** refine the least-cost expansion modelling by including intra-regional network augmentations based on meeting jurisdictional planning criteria at the main transmission network level.

- **Time-sequential market simulation studies** identify the remaining transmission network congestion, and further refine the power system simulation study results. The time-sequential studies also produce a detailed set of market operation outcomes, including economic dispatch outcomes, reliability indicators, and transmission network utilisation.

This framework was chosen because it allowed AEMO to develop a high-level generation and transmission network development plan across a wide range or scenarios.

Figure A1-1 shows an overview of the modelling process.

Figure A1-1 Overview of the NTNDP modelling framework



A1.1.3 Consultation process for developing the models

AEMO consulted with TNSPs during the development of the various models for the 2010 NTNDP, and sought TNSP comments about the reasonableness of the adopted processes, methodologies, and assumptions, including the:

- planning criteria
- assumed system conditions (generation dispatch and wind farm output)
- transmission network ratings
- representation of the transmission network in the load flow
- load representation, and
- inter-regional power transfer capacities.

The TNSPs were invited to comment on the preliminary results of the studies in respect of the:

- least-cost expansion study results (new generation by NTNDP zone, and the new inter-regional links)
- specific generation locations/connection points within each region, and
- intra-regional transmission network development requirements identified via power system studies.

TNSPs were also invited to provide feedback on any other issues that will help to improve the 2010 NTNDP process and outcomes.

A1.2 Least-cost expansion modelling

The objective of the high-level, least-cost expansion modelling is to provide a co-optimised set of new generation developments, inter-regional transmission network augmentations, and generation retirements across the NEM for the next 20 years. This expansion plan provides an indication of the optimal combined technology, location, timing, and capacity of future generation and inter-regional transmission developments.

This plan is then analysed in more detail through subsequent power system analysis and time-sequential market simulations.

AEMO used the MARKAL[69] least-cost expansion modelling tool for the 2010 NTNDP analysis.

A1.2.1 The MARKAL modelling tool

The MARKAL modelling tool's principal feature is that it solves quickly and enables a large number of scenarios and sensitivity studies to be explored in a short amount of time. Its purpose is to produce

[69] A modelling system developed and maintained by the Energy Technology and Systems Analysis Project within the International Energy Agency (IEA).

expansion plans that can be refined and analysed through further study, not to provide information about transmission network congestion or to quantify the market benefits of specific investments.

MARKAL uses a Mixed Integer Linear Programming (MILP) technique[70] to optimise generation and transmission expansion across the entire simulation horizon in a single solve. MILP techniques are frequently used in capacity expansion planning, producing optimised, least-cost generation and transmission expansion for a range of input parameters and constraints. The NTNDP modelling selects between generation expansion, generation retirement, and inter-regional transmission development options to develop an optimal electricity system arrangement.

The MARKAL model represents the transmission network using a simplified five node (regional) model with interconnectors. It does not model intra-regional network elements, but does apply generation marginal loss factors to account for the 'electrical distance' to the regional reference node. A further simplification is that demand profiles are entered as four seasonal blocks containing nine load blocks each, providing 36 time segments that represent each year.

MARKAL schedules new generation, augments interconnector capability, and retires existing generation plant to minimise the total system costs (capital and operating), subject to:

- dispatching generation to supply each load duration curve block (the energy balance)
- meeting the Reliability Standard[71] (the capacity balance, taking account of MRLs), and
- meeting Large-scale Renewable Energy Target (LRET) obligations.

In MARKAL, the Reliability Standard is represented by the requirement for enough generation or demand-side participation (DSP) capacity to meet each region's 10% probability of exceedence (POE) maximum demand (MD) plus predefined regional MRLs each year. This requirement is expressed in MARKAL so as to scale the existing operational MRLs with regional demand growth, and take into account the capacity of the interconnectors to share generation capacity between adjoining regions.

MARKAL identifies generation retirement if that retirement yields lower system costs by avoiding fixed operating and maintenance (FOM) costs. Only a subset of existing generation with high emission intensities is considered as candidate generation for retirement. Capital costs are considered a sunk cost for existing generation, and do not enter into the retirement decision. Balancing the saving in FOM costs is the requirement to add replacement generating capacity.

A1.2.2 Assumed transmission capacities between regions

In MARKAL, the transmission network is represented by five nodes (regions) connected by interconnectors of a specified capacity. Table A1-1 lists the assumed interconnector capacity used to assess the benefit and timing of interconnector augmentations.

70 An algorithm that optimises (minimises or maximises) the result of a linear equation using a number of control variables. It is subject to a set of constraints (or limits) on these variables, expressed as linear equalities and inequalities.

71 The Reliability Standard defines a minimum acceptable level of reliability to be met in each region. For more information about the latest review of the Reliability Standard, see the AEMC's website (http://www.aemc.gov.au/Market-Reviews/Completed/Review-of-the-Reliability-Standard-and-Settings.html).

Table A1-1 Least cost model – inter-regional transfer capability

Regional demand	Interconnector	All demand periods (ex-summer off-peak)	Summer off-peak
QNI	NSW to QLD	300 MW	300 MW
	QLD to NSW [3]	900 MW	900 MW
Terranora	NSW to QLD	122 MW	122 MW
	QLD to NSW	220 MW	220 MW
Vic-NSW	VIC to NSW	900 MW + 0.35 x Murray generation	900 MW + 0.35 x Murray generation
	NSW to VIC	400 MW + 0.35 x Tumut generation	400 MW + 0.35 x Tumut generation
Heywood	VIC to SA	360 MW	360 MW
	SA to VIC	400 MW	400 MW
Murraylink	VIC to SA	220 MW	220 MW
	SA to VIC	188 - 0.034 SA DEMAND	198 - 0.034 x SA DEMAND
Basslink	TAS to Vic	594 MW	594 MW
	VIC to TAS	390 MW	390 MW

MARKAL was provided with a list of possible inter-regional upgrade options to select from. Table A1-2 lists these options, together with the assumed improvements to the inter-regional transfer capabilities listed in Table A1-3, a cost estimate and an estimate of the option's impact on existing inter-regional loss factor equations. The cost estimate provided in this table is indicative and was sourced from previous studies available at the start of the simulation process (for example, the 2009 National Transmission Statement (NTS) or from planning estimates). Further work has been done to refine some of these estimates (see Chapter 5 - NEMLink: A Pre-feasibility Study into a High Capacity Backbone, and the AEMO-ElectraNet Joint Feasibility Studies[72]).

[72] Http://www.aemo.com.au/corporate/0177-0001.html

Table A1-2 List of inter-regional upgrade options provided to least-cost expansion model

Option	Description	Forward power flow direction	Forward upgrade (MW)	Reverse upgrade (MW)	Indicative cost ($M) (±50%)	Assumed loss factor impact
QN Option 1	Armidale second 330 kV SVC	NSW to QLD	100		50	No change
QN Option 2	Bulli Creek to Dumaresq and Dumaresq to Armidale 330kV thyristor controlled component series capacitors (and supporting works)	NSW to QLD	300	600	125	No change
QN Option 3	Bulli Creek or Dumaresq 1,500 MW HVDC back- to-back asynchronous link	NSW to QLD	700	400	490	No change
QN Option 4	330kV Bulli Creek–Bayswater double circuit line (with intermediate switching stations)	NSW to QLD	1,300	900	950	Reduce 50%
QN Option 6	500 kV Western Downs-Bayswater double circuit line (with intermediate switching stations and dynamic compensation devices)	NSW to QLD	2,100	1,400	950	Reduce 50%
VN Option 1	Loy Yang braking resistor, second 1,000 MVA 500/330kV South Morang transformer and uprating of 330 kV South Morang-Dederang lines	VIC to NSW	170	-	73	No change
VN Option 2	Project VN1 plus a +280/-120 MVAr SVC at Dederang	VIC to NSW	220	-	146	No change
VN Option 3	Fourth 330/220kV Dederang transformer, a phase angle regulator on the 220kV Shepparton-Bendigo line and uprating of the 330 kV South Morang-Dederang lines and the 220 kV Eildon-Thomastown lines	VIC to NSW	150	150	116	No change
VN Option 4	Project VN3 plus a third 700 MVA 330/220 kV South Morang transformer, cut-in the Rowville-Thomastown 220 kV line at South Morang, series capacitors on the 220 kV Eildon-Thomastown lines and the 330 kV Wodonga-Dederang lines, and a phase angle regulator on the 330 kV Jindera-Woodonga line	VIC to NSW	0	500	221	No change
VN Option 5	Project VN4 plus a third 330 kV Dederang-South Morang line with series compensation, a new 330 kV Jindera-Dederang line, a fourth 330/220 V South Morang transformer, cut-in the 220kV Eildon-Thomastown line at South Morang		500	1,600	1,300	Reduce 25%
VT	A second HVDC undersea cable	TAS to VIC	500	600	720	Reduce 50%

Option	Description	Forward power flow direction	Forward upgrade (MW)	Reverse upgrade (MW)	Indicative cost ($M) (±50%)	Assumed loss factor impact
VS Option 1	Installing a third Heywood transformer, a, a third South East transformer, a100 MVAr capacitor bank at South East, and the removal of some limiting equipment on relevant lines	VIC to SA	120	250	61	No change
VS Option 2	As per VS option 1, with series compensation of the 275 kV Tailem Bend-South East lines, and a Tailem Bend SVC	VIC to SA	240	250	89	No change
VS Option 3	500kV AC double circuit line from Krongart to Heywood Stage 1-1000 MVA capacity	VIC to SA	800	800	700	Reduce 25%
SN	A 500 kV AC double circuit line from Wilmington to Mount Piper (1,100km)	NSW to SA	1000	1000	2424	Assume same as QNI

A1.2.3 Key outputs

There are three key outputs from the MARKAL modelling tool:

- New generation scheduling shows the optimal capacity, technology, location, and timing of each development.
- Generation retirements show the number of retiring units and retirement timing for each candidate plant.
- Interconnector expansions show the selected upgrade options and their timing (where interconnector upgrades were selected).

A1.3 Power system simulation studies

The power system simulation studies have two main functions:

- Testing the real-world viability of the least-cost expansion modelling output.
- Assessing the adequacy of the main transmission network (generally 220 kV and above) to reliably support major power transfers between NEM generation and demand centres, and identifying potential solutions when there is insufficient transmission network capability.

The studies also refine this modelling by identifying intra-regional augmentations that reduce the cost of developing the NEM as a whole, as well as ensuring that the modelling outputs meet jurisdictional reliability obligations by accounting for contingency events, and ensuring these obligations are satisfied.

AEMO's assessment of transmission network adequacy is based on an approximation of the jurisdictional planning criteria, which confines the scope of the analysis to main transmission network thermal limitations that arise during diversified regional peak demands.

AEMO carried out this assessment at five-yearly intervals over the 20-year outlook period, 2014/15, 2019/20, 2024/25, and 2029/30.

A1.3.1 Description of the model

The power system simulation study model represents the:

- existing transmission network
- committed transmission network augmentations
- sub-transmission network to a level of detail that includes the lines running in parallel with the transmission network
- connection points
- generating unit capacities, and
- demand levels of the loads represented at connection points.

The loading of transmission lines and transformers is determined for an intact power system (pre-contingency, when all other equipment is in service), and also under various single contingency events, to see if it remains within allowable equipment ratings. The monitored transmission lines and transformers form part of the main transmission network that supports major NEM power transfers. In general, this refers to lines of a nominal voltage of 220 kV and above, although in some cases the monitoring was extended to lower voltages, particularly in areas where lower voltages are used for bulk power transfer, such as in parts of South Australia and Tasmania.

This assessment is done under 10% POE MD conditions for each region, which is modelled by considering the demand at connection points coincident with the regional 10% POE MD (in other words, diversified connection-point demand), rather than considering the MD at each connection point.

When a 10% POE MD supply reliability limitation is identified, a potential solution is modelled. The solution generally involves transmission network augmentation, but in some cases a change to the location of new generation has been identified, if this results in a lower overall cost. Because the original generation location was an output of the least-cost expansion modelling, assuming a different location for new generation involves additional fuel costs. Moving new generation is justified if the value of the additional fuel costs is lower than the cost of the transmission network augmentation it defers or suspends.

There are two key inputs to the power system simulation studies:

- High-level, least-cost expansion modelling of new generation, generation retirement, and new transmission network interconnection(s).
- The demand forecast for each scenario.

A1.3.2 Key outputs

There are two key outputs from the power system simulation studies:

- Details about transmission network developments that support the generation expansion and demand projections.
- Potential changes to the location of new generation if a different location results in a lower overall cost.

These outputs are provided in increments of five years over the 20-year outlook period.

A1.4 Time-sequential market simulation studies

The objective of the time-sequential market simulation studies is to produce detailed market operation results, given a predefined set of generation and transmission expansion projects and generation retirements produced by MARKAL and the power system simulation studies.

The key simulated market operation requirements are that unserved energy (USE) does not exceed the Reliability Standard, and that generation dispatch results in a secure operating state that can sustain the loss of a single generation element or network element.

AEMO used the Prophet[73] modelling tool for the time-sequential market simulations for the 2010 NTNDP.

A1.4.1 Description of the model

Time-sequential market simulations attempt to represent the complex interactions between consumer and producer behaviours, technical infrastructure, and the variability of environmental factors (weather, wind, and solar radiation) by simulating hourly generation dispatch across a given time frame.

This method of market simulation mirrors studies performed by AEMO for the 2009 National NTS. The power system is modelled at hourly resolution with five pricing regions linked by interconnectors. The transmission network is modelled via a set of constraint equations, representing the inter-regional and intra-regional network, similar to those used by AEMO's National Electricity Market Dispatch Engine (NEMDE). These network constraint equations put bounds on the generation dispatch to ensure that the system is secure and can sustain single credible contingencies.

A Monte Carlo algorithm is used to model random generation forced outages under two distinct regional demand conditions (10% POE and 50% POE MD). Up to 32 simulations are performed for each demand forecast under each scenario.

[73] Electricity market modelling software developed by Intelligent Energy Systems (IES).

A1.4.2 Key outputs

The Prophet simulation delivers a wide range of detailed outputs at hourly resolution. Because it models an economic dispatch subject to system normal network constraint equations, it is able to provide information about:

- network utilisation and congestion
- violation of the network constraint equations
- simulated prices
- generation capacity factors and emissions levels
- generation operating costs, and
- unserved energy (USE) outcomes.

These results can identify additional triggers for augmentation. For example, violations of network constraint equations may result from insufficient transmission capacity resulting in system instability. Stability studies were not part of the scope of the power system simulation studies. Excessive unserved energy (USE) is another trigger for augmentation.

Where potential augmentation triggers were identified, further power system simulation studies were conducted to identify the causes and potential solutions.

The time-sequential market simulation results also identify remaining areas of transmission network congestion, which arises when transmission network capability has affected the economic generation dispatch. Reducing transmission network congestion can lead to market benefits and an augmentation is justified if these benefits outweigh the augmentation costs. The NTNDP identifies the key causes of the remaining transmission network congestion and advances potential options to address it. An economic analysis has not been performed, however, to quantify the market benefits delivered by these options and check that the benefits exceed the costs. Therefore, while these augmentations are discussed in Chapter 4, they do not form part of the various augmentations listed.

For the purposes of the NEMLink investigation (see Chapter 5), a with/without transmission network augmentation comparison is performed across the results of two time-sequential studies to estimate potential market benefits (reliability and operating cost benefits)[74].

A1.5 Network assumptions

This section describes the transmission network assumptions for modelling the NEM. This includes, for example, system conditions, planning criteria, ratings, and wind availability.

A1.5.1 General regional assumptions

The assumptions applied to every region include system conditions and general planning criteria.

[74] Capital deferral benefits are also calculated based on the outcomes of the least-cost and power system modelling.

System conditions

Transmission network adequacy was assessed as part of the load flow analysis for conditions matching regional 10% POE MDs. In some cases, spot checks were carried out for other conditions, such as high wind generation (with lower demand) and high interconnector power transfers.

Planning criteria

The planning criteria, which differ between regions, require the system to be robust under unplanned generation or transmission outages. The regional reliability criteria, however, generally require supply of the 10% POE MD when a single transmission network element is out of service (N-1), and that following such a contingency event, it must be possible to re-dispatch generation, ancillary services, and controlled load reduction to secure the system within 30 minutes in anticipation of a further outage.

Before a contingency event, transmission circuit ratings are defined in terms of the maximum load that may be carried continuously. This refers to the transmission circuit being able to be operated at this rating indefinitely, both safely and without physical damage. After an event, increased ratings may apply (either a short-term or a contingency rating) for the in-service transmission network for a limited time with safety and without physical damage. Transmission network circuits are studied at these pre- and post-contingency ratings.

Transmission network augmentation is identified if system normal continuous ratings are exceeded for the full transmission network in service, or if contingency ratings are exceeded in the event of a single network element or generating unit outage.

Region-specific assumptions

Table A1-3 lists the assumptions that are specific within a particular region.

Table A1-3 Region-specific assumptions

Region	Planning criteria	Ratings	Wind farm capacity availability at summer MD
Queensland	N-1 at time of region-wide summer 10% POE MD is adopted except for some studies conducted to check the adequacy under North Queensland 10% POE MD. N-1-G planning criteria under 10% POE conditions in South East Queensland and North Queensland have been used. 'G' represents Swanbank E (for SEQ) and Townsville (for NQ). Additional comment: • For NQ zonal studies, NQ 10% POE MDs are applied with remaining zonal loads scaled down to reflect historical diversity • AEMO has not assessed project timing based on the N-1-Secure criteria as undertaken by Powerlink	Ratings used reflect those used for reliability assessments, consistent with wind speed assumptions under peak load conditions (generally 0.5-0.7m/s for system normal and 1.0m/s for post-contingent planning) **Ratings source: Powerlink**	0%
New South Wales	N-1 at time of region-wide (diversified) summer 10% POE MD for most of the transmission level circuits. Additional comment: • TransGrid applies a modified N-2 criteria to circuits supplying the Sydney CBD - these are not studied by the NTNDP • Assessment for local summer 10% POE MD locations within New South Wales (undiversified) have not been performed	Loading with all network elements in service was assessed against normal summer ratings. Loading under contingency conditions was assessed against a higher contingency rating, which is a risk-based figure at which the plant can be operated long term with no damage. Some lines (particularly around Snowy and QNI) can operate to 15-minute ratings, as provided in limit advice **Ratings source: TransGrid**	5%

Region	Planning criteria	Ratings	Wind farm capacity availability at summer MD
Victoria	Transmission project planning is based on the expected benefits exceeding the cost of the project considered. Expected limitations are considered with the application of dynamic ratings and market simulations to quantify the market benefits of augmentation. For the purposes of the NTNDP studies, all credible contingencies were assessed. Transmission elements loaded above 110% of their continuous rating were identified for potential augmentation	Ratings used are continuous, short-term and dynamic. For the purpose of screening critically-loaded transmission lines, continuous rating at 40°C ambient temperature (pre-contingent) and continuous rating at 35°C ambient temperature (post-contingent) [75] with a static wind speed of 0.6 m/s were applied. **Ratings Source: the AEMO EMS database and ratings used for APR studies**	8%
South Australia	N-1 criterion at time of region wide summer 10% POE MD. Summer continuous ratings used. For the purpose of long-term studies, transmission elements that are loaded above 100% of summer continuous ratings are identified for potential augmentations	Summer continuous ratings are used for reliability assessment. **Ratings source: the AEMO EMS database for summer normal, summer post-contingent and winter normal. Other ratings are determined through sources provided by ElectraNet**	3%
Tasmania	Transmission projects are justified on the basis of expected constraint energy that exceeds limits set out by the Office of the Tasmanian Economic Regulator. The network is operated with dynamic ratings, which include measured ambient temperature and wind speed. Constraints: • Expected constraints are considered with application of dynamic ratings and market simulations • For the purposes of long-term studies, all credible contingencies are assessed. Transmission elements that are loaded above 110% of continuous rating are filtered as limitations	For the purpose of screening critically loaded transmission lines, continuous rating at : • 25°C ambient temperature is applied for summer MD conditions • 15°C ambient temperature is applied for winter MD conditions **Ratings source: the AEMO EMS database**	0%

[75] This assumes 40°C post-contingency dynamic and/or short-term ratings approximately equal to the continuous ratings at 35°C. If a transmission line post-contingency loading is identified to exceed the 35°C continuous rating, the loading of that line is then further compared with the appropriate short-term/dynamic ratings.

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Attachment 2 - Network Diagrams

A2.1 Introduction

This attachment provides diagrams showing a high-level overview of the main transmission networks and interconnections for each region of the National Electricity Market (NEM) high-voltage transmission network. These diagrams approximate the AEMO Energy Management System (EMS) network model, but do not precisely reflect AEMO's boundary of direct oversight. The NTNDP CD provides more detailed diagrams.

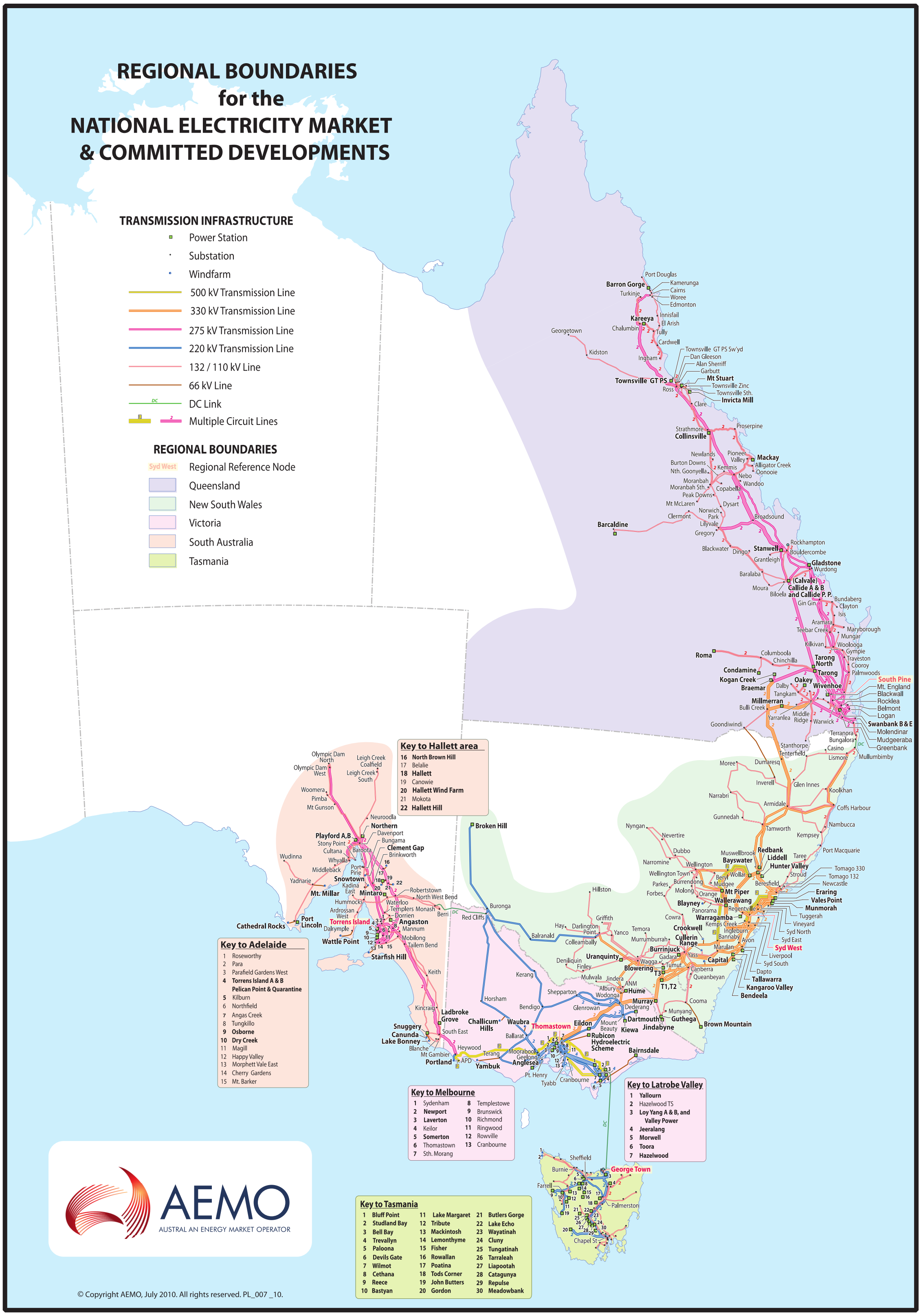
AEMO has also developed an interactive map of the high-voltage transmission network, power stations, and the gas transmission network, which is available from the NTNDP CD. This map also shows the approximate location of modelled committed projects and routine augmentations described in Chapter 3, Development by Scenario - Generation and Transmission Expansion, and Chapter 4, Development by Zone - Generation and Transmission Expansion.

These diagrams are indicative representations only and should not be relied on[76]. Interested parties should contact the relevant transmission network service provider (TNSP) to confirm a particular location's actual network configuration.

[76] AEMO has checked the diagrams for accuracy.

A2.2 Regional boundaries diagram

Figure A2-1 Regional boundaries



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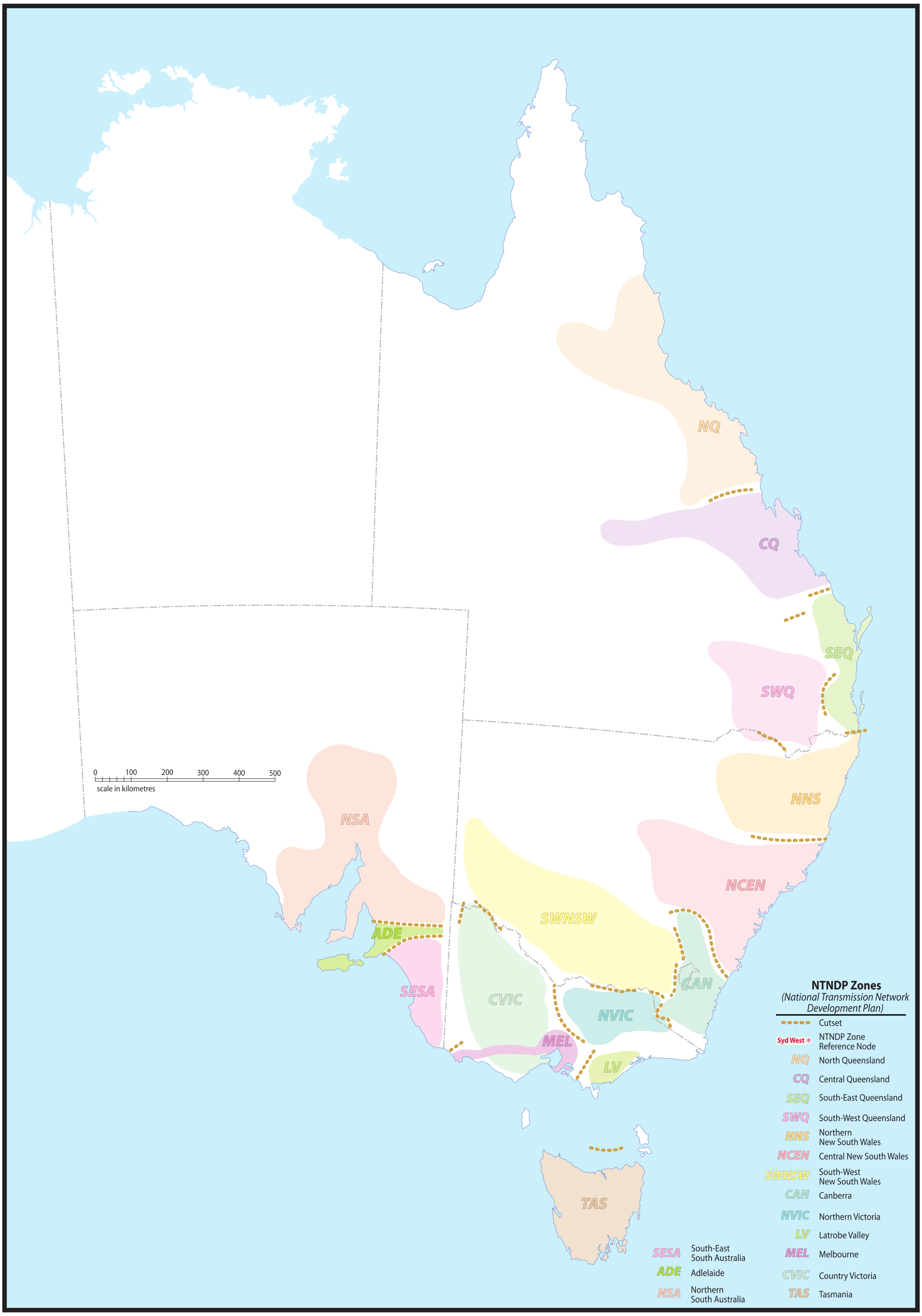
A2.3 NTNDP Zones

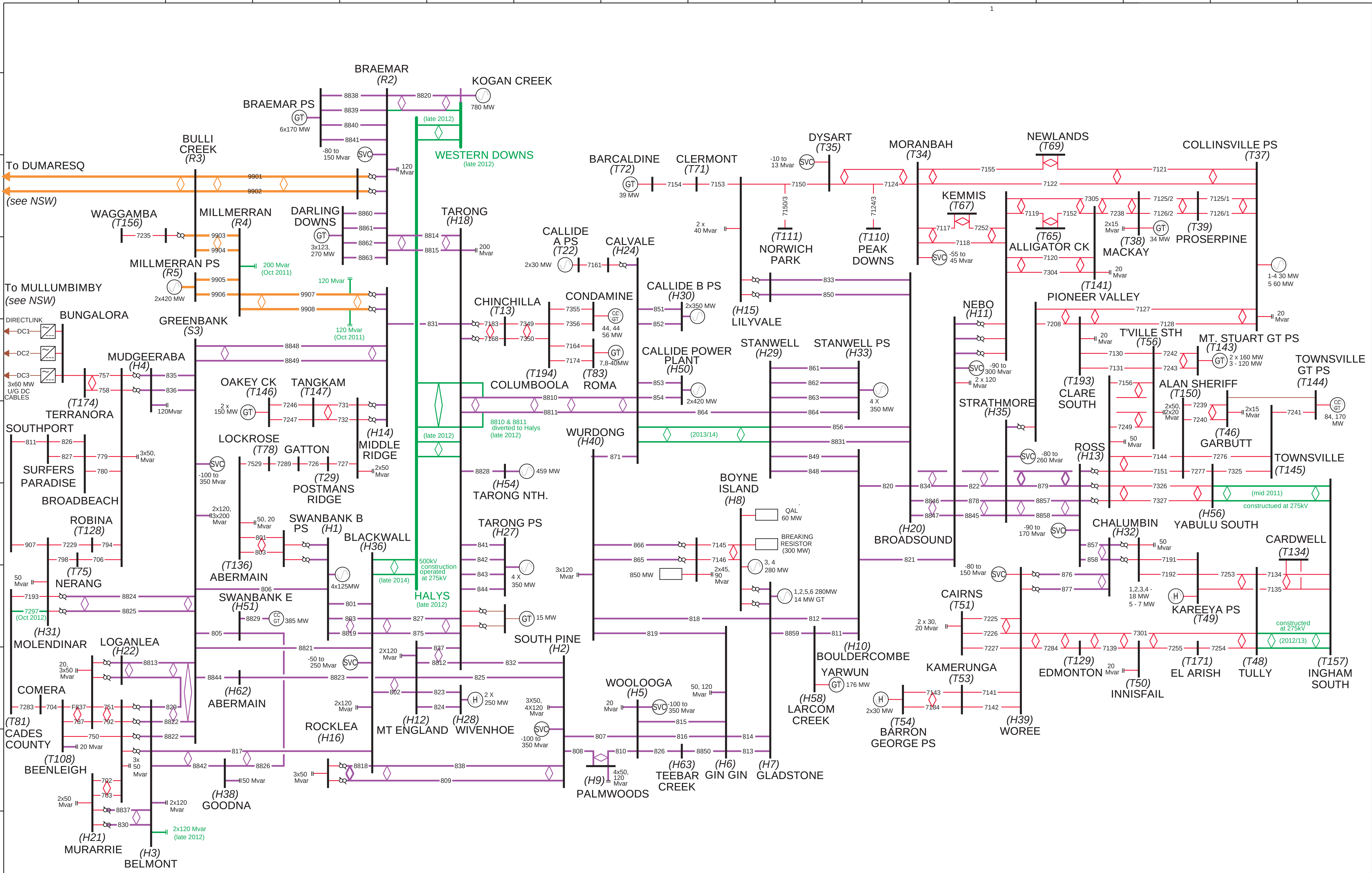
Table A2-1 lists the names and abbreviations of the NTNDP zones used in the 2010 NTNDP. Figure A2-1 shows the NTNDP zones and indicates their boundaries.

Table A2-1 NTNDP Zones

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

Figure A2-2 NTNDP Zones





AUSTRALIAN ENERGY MARKET OPERATOR
HIGH VOLTAGE NETWORK
MAIN GRID & INTERCONNECTIONS

QUEENSLAND

NSW | QUEENSLAND

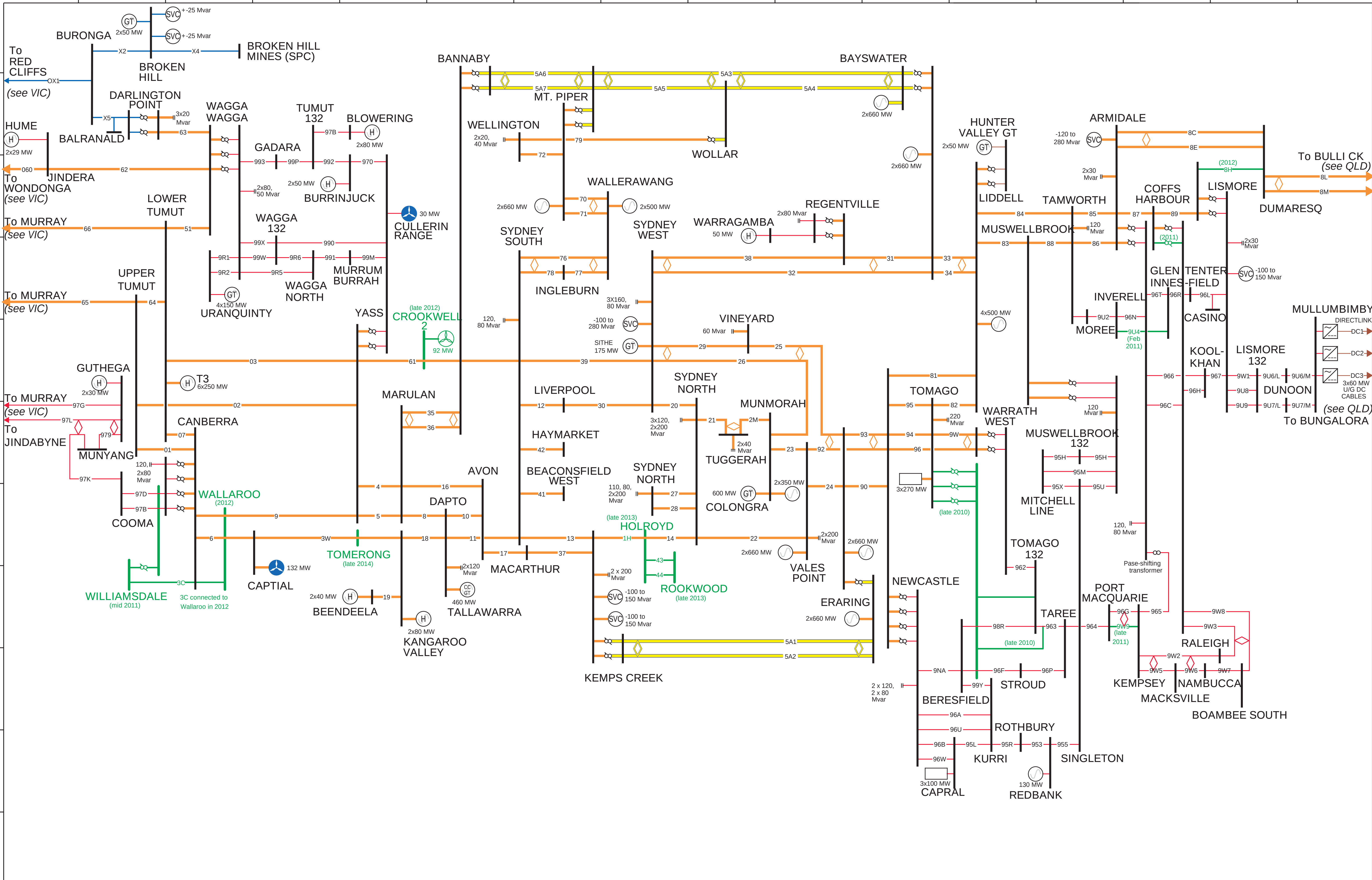
500kV
330kV
275kV
220kV
132 / 110kV
66kV and BELOW

Generator
Gas Turbine Generator
Hydro Generator
Combined Cycle Gas Turbine Generator
Windfarm

Static Var Compensator
Synchronous Condensor
Transformer
Capacitor Bank
Dual Circuit Towers

Convertor Station
Future Works

DATE : Dec. '10



AUSTRALIAN ENERGY MARKET OPERATOR
HIGH VOLTAGE NETWORK
MAIN GRID & INTERCONNECTIONS

NEW SOUTH WALES

VIC | NEW SOUTH WALES | QLD

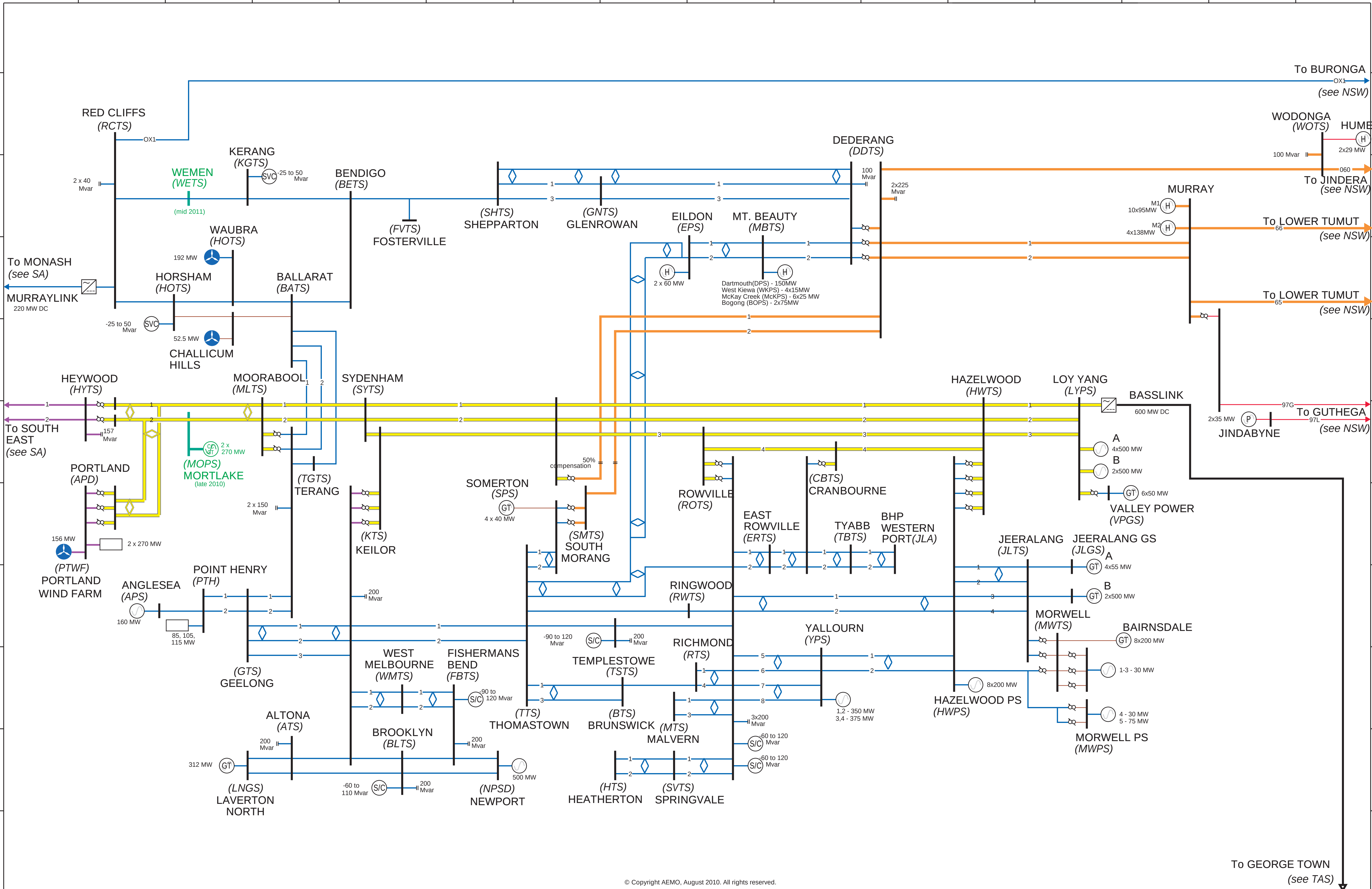
500kV
330kV
275kV
220kV
132 / 110kV
66kV and BELOW

Generator
Gas Turbine Generator
Hydro Generator
Combined Cycle Gas Turbine Generator
Windfarm

Static Var Compensator
Synchronous Condensor
Transformer
Capacitor Bank
Dual Circuit Towers

Convertor Station
Future Works

DATE : Dec. '10



AUSTRALIAN ENERGY MARKET OPERATOR
HIGH VOLTAGE NETWORK
MAIN GRID & INTERCONNECTIONS

VICTORIA

VICTORIA
TAS

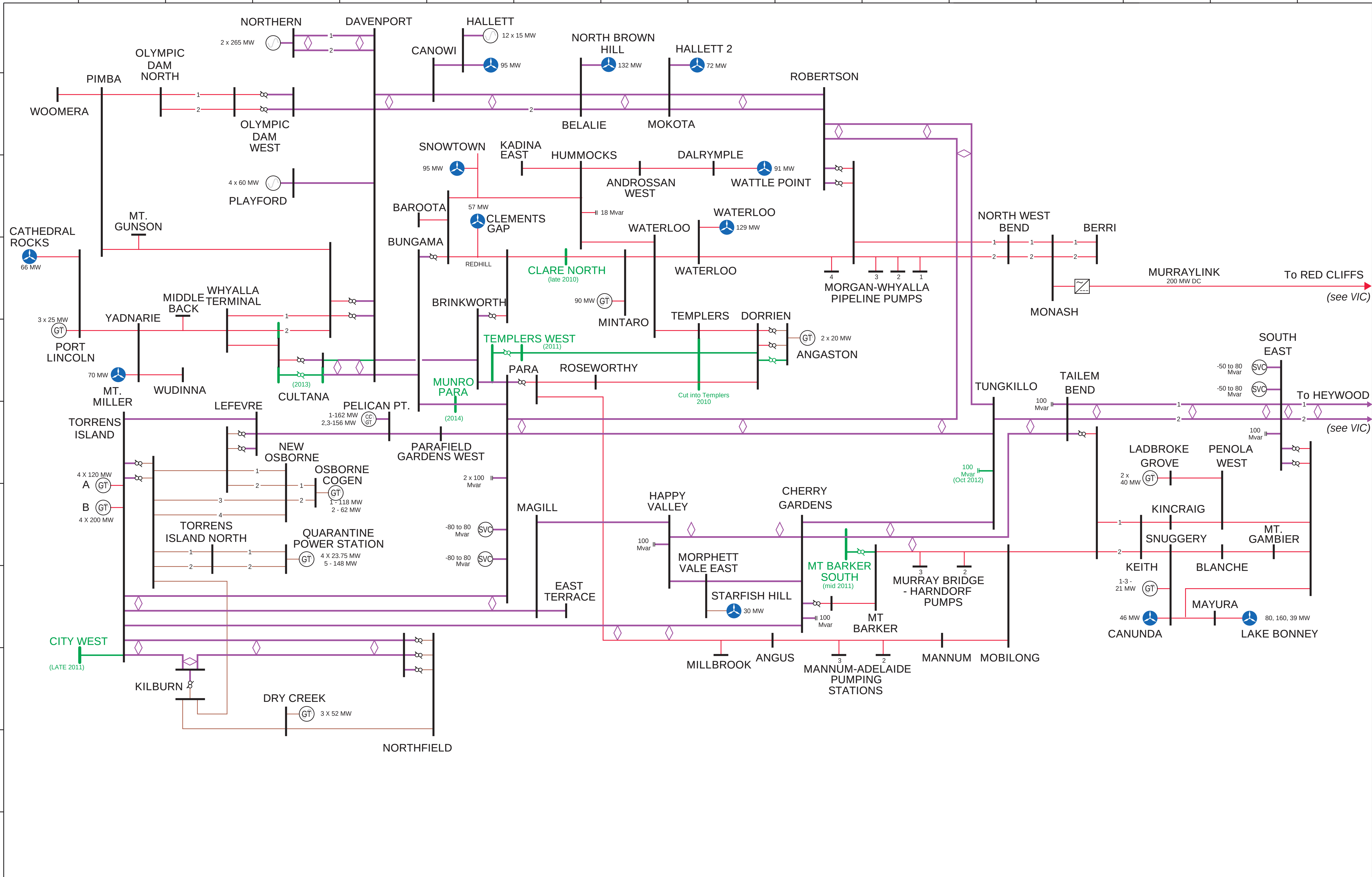
500kV
330kV
275kV
220kV
132 / 110kV
66kV and BELOW

Generator
Gas Turbine Generator
Hydro Generator
Combined Cycle Gas Turbine Generator
Windfarm

Static Var Compensator
Synchronous Condensor
Transformer
Capacitor Bank
Dual Circuit Towers

Convertor Station
Future Works

DATE : Dec. '10



AUSTRALIAN ENERGY MARKET OPERATOR
HIGH VOLTAGE NETWORK
MAIN GRID & INTERCONNECTIONS

SOUTH AUSTRALIA

SOUTH AUSTRALIA | VIC

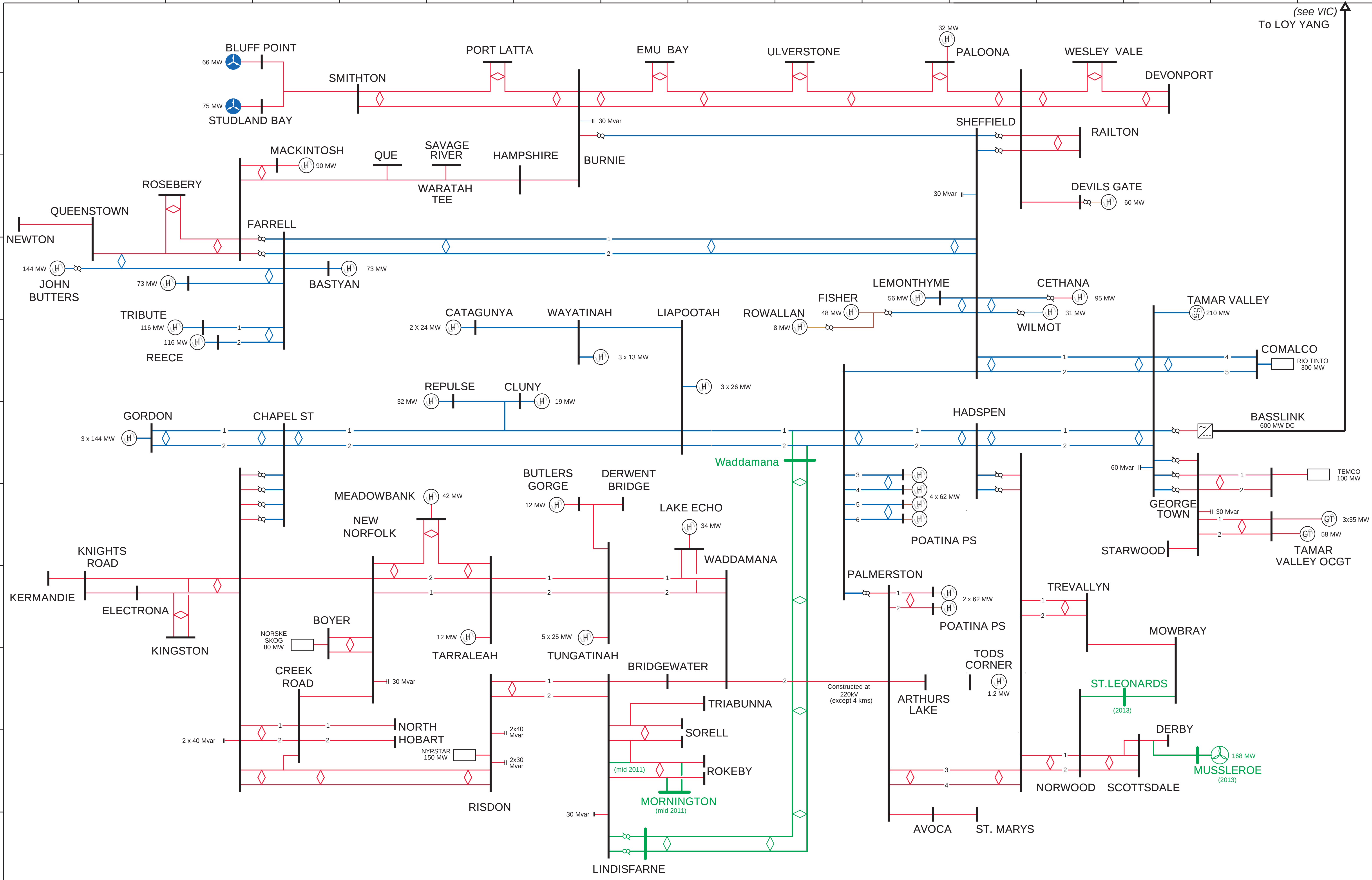
500kV
330kV
275kV
220kV
132 / 110kV
66kV and BELOW

Generator
Gas Turbine Generator
Hydro Generator
Combined Cycle Gas Turbine Generator
Windfarm

Static Var Compensator
Synchronous Condensor
Transformer
Capacitor Bank
Dual Circuit Towers

Convertor Station
Future Works

DATE : Dec. '10



AUSTRALIAN ENERGY MARKET OPERATOR
HIGH VOLTAGE NETWORK
MAIN GRID & INTERCONNECTIONS

TASMANIA

VICTORIA
TASMANIA

220kV
110kV
88kV
44kV
33kV
22kV
18kV
11kV
6.6kV

Generator
Gas Turbine Generator
Hydro Generator
Combined Cycle Gas Turbine Generator
Windfarm
Static Var Compensator
Synchronous Condensor
Transformer
Capacitor Bank
Dual Circuit Towers
Convertor Station
Future Works

DATE : Dec. '10

Glossary

The Glossary is divided into two sections. The first section lists abbreviations and provides the meaning of commonly used terms. The second section lists the company names used in the document, along with their full company names and ABN numbers.

Meanings

Some of the terms used in this document are already defined in the National Electricity Rules[77] (NER). For ease of reference, these terms are highlighted in yellow. Some terms, although defined in the NER, have been clarified here, and these terms are highlighted in orange.

Term	Meaning
absorbing RPAS	RPAS that can consume reactive power when required to suppress voltage in the power system
active power	See 'electrical power'
ADE	Adelaide
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
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 (APR)	An annual report providing forecasts of electricity or gas (or both) supply, capacity, and demand, and other planning information
APR	See Annual Planning Report
augmentation	Work to increase the capacity of a transmission or distribution network to transmit or distribute electricity
Binding constraint equation	A constraint equation that is actively influencing central dispatch process outcomes
Biomass	Electrical generation using organic material by various method
CAN	Canberra

[77] Version 30 used for reference. An electronic copy of the latest version of the NER can be obtained from http://www.aemc.gov.au/rules.php .

<table>
<tr><th>Term</th><th>Meaning</th></tr>
<tr><td>capacity factor</td><td>The output of generating units or systems, averaged over time, expressed as a percentage of rated or maximum output</td></tr>
<tr><td>capacity limited</td><td>A generating unit whose power output is limited</td></tr>
<tr><td>Capital Cost Benefit</td><td>A benefit deriving from the reduced capital costs resulting from being able to reduce (or defer) generation or transmission investment</td></tr>
<tr><td>CCGT</td><td>Combined Cycle Gas Turbine</td></tr>
<tr><td>CCS</td><td>Carbon Capture and Sequestration</td></tr>
<tr><td>central dispatch</td><td>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</td></tr>
<tr><td>COAG</td><td>Council of Australian Governments</td></tr>
<tr><td>CoGen / CoGeneration</td><td>A generation system that produces two forms of energy from the primary energy source: hot water, chilled water, and power generation (electrical energy)</td></tr>
<tr><td>committed project</td><td>A committed project is any new generation development or regulated transmission augmentation under development that meets a predefined set of criteria meant to indicate that the project is very likely to go ahead. To be classified as a committed project:

Generation development or non-regulated transmission development must satisfy all five criteria specified by AEMO for a committed project in Chapter 5 of the 2010 Electricity Statement of Opportunities.
regulated transmission augmentation must satisfy all of the following criteria:

Board commitment has been achieved (Board commitment also requires that the appropriate planning approvals and licences are in place)
Funding has been approved
The project has satisfied the Regulatory Test (or the RIT-T)
Construction has either commenced or a firm date has been set for it to commence

</td></tr>
<tr><td>connection point</td><td>The agreed point of supply established between network service provider(s) and another registered participant, non-registered customer or franchise customer</td></tr>
<tr><td>constrained</td><td>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</td></tr>
<tr><td>constraint</td><td>Any limitation on the operation of the transmission system that will give rise to unserved energy (USE) or to generation re-dispatch costs</td></tr>
<tr><td>constraint equation</td><td>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.
See also ‘binding constraint equation’, ‘FCAS constraint equation’, ‘invoked constraint equation’, and ‘network constraint equation’</td></tr>
<tr><td>constraint equation violation</td><td>Occurs when the requirements of a constraint equation are not met.
Under some power system operating conditions it might not be feasible to meet the requirements of all invoked constraint equations simultaneously in the central dispatch process.
Measured in megawatts (MW), the constraint equation violation represents the amount by which a constraint equation’s requirements are exceeded</td></tr>
<tr><td>contingency event</td><td>An event affecting the power system, such as the failure or unplanned</td></tr>
</table>

Term	Meaning
	removal from operational service of a generating unit or transmission network element.
CO2-e	carbon dioxide equivalent
CPI	consumer price index
CPRS	Carbon Pollution Reduction Scheme
CQ	Central Queensland
credible contingency event	A contingency event AEMO considers reasonably possible, given the circumstances in the power system
critical contingency	The specific forced or planned outage that has the greatest potential to impact on the electricity transmission network at any given time
CVIC	Country Victoria
demand	See 'electricity demand'
demand diversity	Referring to both intra and inter-regional demand diversity: • 'intra-regional' recognises that the maximum demands (MDs) at each connection point within a region might not occur at the same time, and the sum of the connection point MDs will exceed the regional MD, and • 'inter-regional' recognises that the MDs of different regions may occur at different times, and the sum of the individual regional MDs will exceed the total National Electricity Market (NEM) MD
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
dispatch algorithm	The algorithm used by AEMO to manage the central dispatch process. This algorithm is run before every dispatch interval. See also 'National Electricity Market Dispatch Engine (NEMDE)'
distillate	see Liquid-fuelled generation
distribution network	A network which is not a transmission network
distribution network service provider (DNSP)	A person who engages in the activity of owning, controlling, or operating a distribution system
DNSP	See distribution network service provider
DRET	Department of Resources, Energy and Tourism
DSP	See demand-side participation
DW-H	A Decentralised World, high carbon price
DW-M	A Decentralised World, medium carbon price
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

Term	Meaning
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 electrical power consumed by the consumer load • distribution and transmission losses, and • power station transformer losses and auxiliary loads. The ESOO reports demand as the average value over a 30-minute period
energy	See 'electrical energy'
energy limited	A generating unit that cannot operate at full capacity over the long term due to fuel or other energy source limitations. A typical example is a hydroelectric generating unit, the long-term output of which is limited by its water storage capacity
ERIG	Energy Reform Implementation Group
ESOO	Electricity Statement of Opportunities
FC-H	Fast Rate of Change, high carbon price
FC-M	Fast Rate of Change, medium carbon price
FCAS	See frequency control ancillary service
FCAS constraint equation	A constraint equation that reflects the need to obtain sufficient frequency control ancillary services (FCAS). See also 'frequency control ancillary services (FCAS)'
flow path	Those elements of the electricity transmission networks used to transport significant amounts of electricity between generation centres and major load centres. Se also 'national transmission flow path (NTFP)'
forced outage	An unplanned outage of an electricity transmission network element (transmission line, transformer, generator, reactive plant, etc)
frequency control ancillary service (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 plant	In relation to a connection point, includes all equipment involved in generating electrical energy
generating system	A system comprising one or more generating units and includes auxiliary or reactive plant that is located on the generator's side of the connection point and is necessary for the generating system to meet its performance standards
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

Term	Meaning
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, and includes (in megawatts (MW)): • consumer load • transmission and distribution losses • generating unit auxiliary load, and • generator transformer losses
GSOO	Gas Statement of Opportunities
GWh	Gigawatt hour
HVAC	high-voltage alternating current
HVDC	high-voltage direct current
IDGCC	Integrated Drying and Gasification Combined Cycle
IGCC	Integrated Gasification Combined Cycle
installed capacity	The generating capacity (in megawatts (MW)) of (for example): • a single generating unit, or • a number of generating units of a particular type or in a particular area, or • 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
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
JPB	See jurisdictional planning body
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). The JPBs are Powerlink Queensland (for Queensland), TransGrid (for New South Wales), AEMO (for Victoria), ElectraNet (for South Australia)and Transend Networks (for Tasmania).
km	Kilometres
kV	Kilovolts
LFRG	Load Forecasting Reference Group
Liquid-fuelled generation	Generation that utilises liquid fuel (usually in the form of distillate, kerosene, or fuel oil) as its primary fuel source

Term	Meaning
Liquefied Natural Gas	Natural gas that has been converted to liquid form for ease of storage or transport. The Melbourne LNG storage facility is located at Dandenong
LNG	Liquefied Natural Gas
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
loss factor	A multiplier used to describe the electrical energy loss for electricity used or transmitted
LRET	Large-scale Renewable Energy Target
LV	Latrobe Valley
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 price cap (MPC)	A price cap on regional reference prices as described in Clause 3.9.4 (of the NER). From July 2010, the market price cap is $12,500/ MWh
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
MCE	Ministerial Council on Energy
MD	See maximum demand
MEL	Melbourne
MILP	Mixed Integer Linear Programming
minimum reserve level (MRL)	The reserve margin (calculated under 10% probability of exceedence (POE) scheduled maximum demand (MD) conditions) required in a region to meet the Reliability Standard
MLF	See marginal loss factor
MMS	Market Management Systems
MPC	See market price cap
MRET	Mandatory Renewable Energy Target
MRL	Minimum Reserve Level
MVA	Megavolt amperes
MVAr	Megavolt amperes reactive
MW	Megawatts
MWh	Megawatt hours
N-1	Planning criterion requiring that the service be supplied with one element out of service
N-1-G	Planning criterion requiring that the service be supplied with one element out of service when a generator is not online

Term	Meaning
N-1-secure	Planning criterion associated with an N-1 criterion that requires that the system is capable of being brought to a secure operating state within 30 mins without the need for load shedding during the securing activity
National Electricity Market (NEM)	The wholesale exchange of electricity operated by AEMO under the NER
National Electricity Objective (NEO)	To promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to: (a) price, quality, safety, reliability and security of supply of electricity, and (b) the reliability, safety and security of the national electricity system. This is defined in Section 7 of the National Electricity Law (NEL)
National Electricity Market Dispatch Engine (NEMDE)	The software that calculates the optimum economic dispatch of the National Electricity Market (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 transmission flow path (NTFP)	That portion of a transmission network (or networks) used to transport significant amounts of electricity between National Transmission Network Development Plan (NTNDP) zones. See 'NTNDP zone'
National Transmission Network Development Plan (NTNDP)	An annual report produced by AEMO. Having a 20-year outlook, the NTNDP identifies transmission and generation development opportunities for a range of market development scenarios, consistent with addressing reliability needs and maximising net market benefits, while appropriately considering non-network options
National Transmission Statement (NTS)	An AEMO report replacing the Annual National Transmission Statement (ANTS) for 2009 only. The National Transmission Network Development Plan (NTNDP) replaces the NTS from December 2010
NCEN	Central New South Wales
NEM	See National Electricity Market
NEMDE	See National Electricity Market Dispatch Engine
NEMLink	A conceptual augmentation involving a high capacity link between all NEM regions for the purposes of conducting a pre-feasibility study into the benefits of such an augmentation (see Chapter 5)
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
network limit	Defines the power system's secure operating range. Network limits also take into account equipment/network element ratings. See also 'ratings'

Term	Meaning
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: • generating unit outputs • interconnector flows • transmission equipment ratings • demand at one or more connection points, and • 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)
network support agreement	An agreement between a network service provider and a market participant or any other person providing network support services to improve network capability by providing a non-network alternative to a network augmentation
Network Support and Control Ancillary Services (NSCAS)	Ancillary service for controlling active and reactive power flows, which assists with maintaining the power system in a secure operating state, and maintaining (or increasing) power transfer capabilities (see Chapter 6)
NNS	Northern New South Wales
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
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: • wind speed data from the Australian Bureau of Meteorology to produce wind speed traces, and • wind farm turbine characteristics (power curves) to convert wind speed traces into wind generation output availability traces
NPV	Net present value
NQ	North Queensland
NSA	Northern South Australia
NSCAS	Network Support and Control Ancillary Services
NSP	Network service provider
NTFP	See National Transmission Flow Path
NTNDP	See National Transmission Network Development Plan

Term	Meaning
NTNDP zone	A major generation or load centre defined for the National Transmission Network development Plan (NTNDP) for the purposes of reporting NTNDP results. Each NTNDP zone is joined by a national transmission flow path (NTFP)
NTP	National Transmission Planner
NTS	See National Transmission Statement
OCGT	open cycle gas turbine
Operating Cost Benefit	A benefit deriving from reduced fuel, operating and maintenance costs, indicating reduced operating costs
outage constraint equation	A constraint equation invoked when an outage has occurred due to maintenance or a contingency event. See also 'system normal constraint equation' and 'invoked constraint equation'
OS-L	Oil Shock and Adaptation, low carbon price
OS-M	Oil Shock and Adaptation, medium carbon price
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
POE	Probability of Exceedence
post-contingent	The timeframe after a power system contingency occurs
power	See 'electrical power'
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)
ppm	Parts Per Million
pre-contingent	The timeframe before a power system contingency occurs
pre-dispatch	Forecast of dispatch performed one day before the trading day on which dispatch is scheduled to occur
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

Term	Meaning
prior outage conditions	A weakened electricity transmission network state where a transmission element is unavailable for service due to either a forced or planned outage
probability of exceedence (POE) maximum demand	The probability, as a percentage, that a maximum demand (MD) level will be met or exceeded (for example, due to weather conditions) in a particular period of time. For example, for a 10% POE MD for any given season, there is a 10% probability that the corresponding 10% POE projected MD level will be met or exceeded. This means that 10% POE projected MD levels for a given season are expected to be met or exceeded, on average, 1 year in 10
PV	Present Value
QNI	Queensland-New South Wales interconnector
R&D	Research and Development
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 are dependant upon 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 condensors. 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
REC	Renewable Energy Certificate
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
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)

Term	Meaning
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 Australian Energy Regulator (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. From 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 Benefit	A benefit deriving from improved customer reliability as measured by reduced unserved energy (USE). See also 'unserved energy (USE)'
reliability of supply	The likelihood of having sufficient capacity (generation or demand-side participation (DSP) or both) to meet demand. See also 'electricity demand'
Reliability Panel	The panel established by the AEMC under section 38 of the National Electricity Law
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
reserve	See 'reserve margin'
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
RET	Renewable Energy Target - National Renewable Energy Target scheme
RIT-T	See regulatory investment test for transmission
RPAS	Reactive Power Ancillary Services
runback	A controlled reduction in the flow of electricity in a given network element, usually in association with a specific event. Murraylink has a runback system that rapidly reduces its power flow in response to the operation of an associated protection system
SASDO	South Australian Supply-Demand Outlook
satisfactory operating state	Operation of the electricity transmission network such that all plant is operating at or below its rating (whether the continuous or (where applicable) short-term rating)

Term	Meaning
SC-0	Slow Rate of Change, zero carbon price
SC-L	Slow Rate of Change, low carbon price
scale efficient network extensions (SENE)	A development model for connecting clusters of generation, proposed by the Australian Energy Market Commission (AEMC) as part of its review of energy market frameworks in light of climate change policies
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)
secure operating state	Operation of the electricity transmission network such that should a credible contingency occur, the network will remain in a 'satisfactory' state
SENE	Scale Efficient Network Extensions
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
SEQ	South East Queensland
SESA	South East South Australia
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
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'
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
SRG	Stakeholder Reference Group
SRMC	short run marginal cost
summer	In terms of the electricity industry, December to February of a given fiscal year
supply	The delivery of electricity
supplying RPAS	RPAS that can provide reactive power when required to boost voltage in the power system
SVC	static VAr compensator
SWNSW	South West New South Wales

Term	Meaning
SWQ	South West Queensland
system normal constraint	A constraint that arises even when all electricity plant is available for service
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)
system normal constraint equation	Constraint equations used in central dispatch when: • all transmission elements are in service, or • the network is operating in its normal network configuration
TAS	Tasmania
thermal generation	Generation that relies on the combustion of a fuel source. Thermal generation in the National Electricity Market (NEM) typically relies on the combustion of either coal or natural gas
TNSP	transmission network service provider
TUOS	Transmission Use of System
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: a) 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, b) 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	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'
USE	See unserved energy
UW-0	An Uncertain World, zero carbon price
UW-L	An Uncertain World, low carbon price
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. An assessment for the Victorian region, while AEMO uses a VCR of $55,000/MWh in Victoria, there is no nationally agreed VCR

Term	Meaning
VAPR	Victorian Annual Planning Report
VCR	See Value of Customer Reliability
violated constraint equation	A constraint equation for which the network attributes for a particular dispatch solution do not satisfy the equation's requirement
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	In terms of the electricity industry, June to August of a given calendar year
zone	See 'NTNDP zone'

Company names

This section lists the full name and Australian Business Number (ABN) number of companies that may be referred to in this document.

Company	Full company name	ACN / ABN
ACIL Tasman	ACIL Tasman Pty Ltd	68 102 652 148
AEMC	Australian Energy Market Commission	49 236 270 144
AEMO	Australian Energy Market Operator Ltd	92 072 010 327
AER	Australian Energy Regulator	
AGL Energy	AGL Energy Ltd	74 115 061 375
Alinta Energy	Alinta Energy Ltd	67 116 665 608
Australian Academy of Technological Sciences and Engineering (ATSE)	Australian Academy of Technological Sciences and Engineering Ltd	008 520 394
Australian National Low Emissions Coal Research And Development (ANLEC R&D)	Australian National Low Emissions Coal Research And Development Ltd	135 762 533
Australian Petroleum Production and Exploration Association (APPEA)	Australian Petroleum Production & Exploration Association Ltd	000 292 713
Australia Pipeline Industry Association (APIA)	Australia Pipeline Industry Association Ltd	098 754 324
Clean Energy Council	Clean Energy Council Ltd	127 102 443
CSIRO	Commonwealth Scientific and Industrial Research Organisation	126 447 489
ElectraNet	Electranet Pty Ltd	41 094 482 416
Energy Networks Association (ENA)	Energy Networks Association Ltd	106 735 406
Energy Retailers Association of Australia (ERAA)	Energy Retailers Association of Australia Ltd	103 742 605
Energy Supply Association of Australia (ESAA)	Energy Supply Association of Australia Ltd	052 416 083
Energy Users Association of Australia (EUAA)	Energy Users Association of Australia	814 086 707
Geodynamics	Geodynamics Ltd	55 095 006 090
IES	Intelligent Energy Systems	51 002 572 090
International Power	International Power (Australia) Pty Ltd	59 092 560 793

Company	Full company name	ACN / ABN
KPMG	KPMG Australia	51 194 660 183
Major Energy Users	Major Energy Users Inc	71 278 859 567
McLennan Magasanik Associates (MMA)	McLennan Magasanik Associates	33 579 847 254
Minerals Council of Australia (MCA)	Minerals Council of Australia	008 455 141
MirusWind	MirusWind Pty Ltd	103 586 778
National Generators Forum (NGF)	National Generators Forum Ltd	113 331 623
Origin Energy	Origin Energy Electricity Ltd	33 071 052 287
OEPC Tasmania	Office of Energy Planning and Conservation; Department of Infrastructure, Energy and Resources; Tasmania	
Powerlink Queensland	Queensland Electricity Transmission Corporation Ltd	82 078 849 233
SKM	Sinclair Knight Merz Pty Ltd	37 001 024 095
SP AusNet	SP Australia Networks (Transmission) Ltd	48 116 124 362
Transend Networks	Transend Networks Pty Ltd	57 082 586 892
TransGrid	TransGrid	19 622 755 774