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NATIONAL TRANSMISSION NETWORK DEVELOPMENT PLAN

For the National Electricity Market

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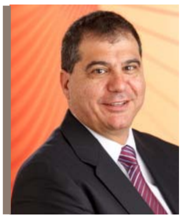
FOREWORD



The 2011 National Transmission Network Development Plan (NTNDP) has been produced against a background of a price on carbon, rising network charges and increasing investment in gas projects and renewable generation technologies.

There is general acceptance that the Australian Government's Clean Energy Future plan will change the commercial and economic considerations of how individuals use their energy. New policies, technology, and changing consumption patterns will determine how, where, and when new generation will connect to transmission and distribution networks.

In this environment of transformation it is vital that all Australians continue to have access to a secure and reliable electricity supply at affordable prices. To deliver wider economic benefits to the community, AEMO is exploring all nationally efficient transmission options.

AEMO takes a cohesive national view and provides a unique overview of regional developments and trends. The NTNDP looks at the costs and benefits of a stronger national transmission backbone, which would integrate new renewable generation sources in new locations. The NEMLink project represents a significant departure from the regional focus of the past. However, within the existing regulatory framework and current economic conditions, Australia cannot realise the full benefits NEMLink is capable of delivering.

To realise the benefits of NEMLink and coordinated gas and electricity investment, changes are required to the regulatory and transmission frameworks. The 2011 NTNDP shows there is considerable potential for gas pipelines to provide a viable alternative to electricity transmission lines under some circumstances, particularly where there is coordinated planning between gas and electricity transmission.

The NTNDP facilitates efficient long-term energy infrastructure investment in the National Electricity Market (NEM). The 2011 report builds on the outcomes of last year's report, and looks at key areas for transmission development over the next 20 years.

In the 2010 NTNDP, AEMO predicted that up to $120 billion of new generation will be required over the next 20 years to meet the NEM's energy requirements, the majority of which will be in the form of either gas powered generation or renewable energy, predominantly from wind generation.

Traditionally, transmission augmentation occurs around known load and generation centres but we are now seeing new generation based in more remote areas, and the nature of load profiles is changing along with the nature of the market. We need to take a new approach to future investments in transmission to maximise the benefits of this new generation.

To encourage a cohesive development strategy, the 2011 NTNDP looks at how the power system will accommodate large-scale investment in wind generation across the National Electricity Market. New generation technologies provide benefits as well as challenges, and AEMO's studies have examined both the economic and technical considerations associated with locating new wind farms.

The generation sector is competitive and investors will seek to maximise returns and manage their risks. Network congestion, marginal loss factors, and the ability to access markets are all drivers that investors take into account, and we are already seeing investors respond to these signals.

As Australia moves towards introducing more renewable energy generation, low carbon-intensive fuels become important to meet peak demand and provide a transitionary form of electricity generation. International prices have an impact on both coal and gas fuel costs. If the gas fuel cost is relatively high compared to coal, then this could slow the transition from coal-fired generation. Alternatively, relatively high coal costs will trigger earlier investment in renewable technologies. The outcomes will depend on gas and coal costs as impacted by a carbon price.

Being responsive to energy sector needs forms part of AEMO's Statement of Corporate Intent for 2011–12, and as a result, AEMO is reviewing its key planning documents, including the NTNDP, to improve the delivery of the key information the industry uses to make informed investment decisions.

In 2012, AEMO will publish its first national electricity forecasts, providing market participants and stakeholders with greater consistency and transparency, as well as being critical to market operations, transmission planning, and assessing the adequacy of supply.

The new national focus of these forecasts will help our industry meet the challenges of changing consumption patterns across Australia resulting from the introduction of new technologies and changing customer behaviour.

I look forward to continuing to work with all our stakeholders who are part of securing Australia's energy future.

M. Zema

Matt Zema

Managing Director and Chief Executive

DISCLAIMER

This publication has been prepared by the Australian Energy Market Operator Limited (AEMO) using information available at 1 November 2011, unless otherwise specified. AEMO must publish the National Transmission Network Development Plan in order to comply with Clause 5.6A.2 of the Rules.

The purpose of publication is to consider and assess an appropriate course for the efficient development of the national transmission grid over a period of at least 20 years.

Some information available after 1 November 2011 might have been included in this publication where it has been practicable to do so.

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LIST OF MEASURES AND ABBREVIATIONS

Units of Measure

Abbreviation	Unit of Measure
DD	Degree days
EDD	Effective degree days
GJ	Gigajoules
GW	Gigawatts
GWh	Gigawatt hours
HDD	Heating degree days
kPa	Kilopascals
kV	Kilovolts
kW	Kilowatts
kWh	Kilowatt hours
MJ/m^3	Megajoules per cubic metre
Mt	Megatonnes
MVA	Megavolt amperes
MVAr	Megavolt amperes reactive
MW	Megawatts
MWh	Megawatt hours
PJ	Petajoules
t	Tonnes
TJ	Terajoules
TWh	Terawatt hours
$	Australian dollars
$/GJ	Australian dollars per gigajoule
$/MWh	Australian dollars per megawatt hour
$/t	Australian dollars per tonne

Abbreviations

Abbreviation	Expanded Name
ABARE	Australian Bureau of Agricultural and Resource Economics
AC	Alternating current
ACRE	Australian Centre for Renewable Energy
ADE	Adelaide zone
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ANTS	Annual National Transmission Statement
APR	Annual planning report
ASI	Australian Solar Institute
AWEFS	Australian Wind Energy Forecasting System
BOM	Bureau of Meteorology
CAN	Canberra zone
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CEI	Clean Energy Initiative
COAG	Council of Australian Governments
CO2-e	Carbon dioxide equivalent
CPI	Consumer price index
CPRS	Carbon Pollution Reduction Scheme
CPT	Cumulative price threshold
CQ	Central Queensland zone
CVIC	Country Victoria zone
DB	Distribution business
DNSP	Distribution network service provider
DRA	Demand Response Aggregator
DRET	Department of Resources, Energy and Tourism
DSN	Declared Shared Network
DSP	Demand-side participation
DW-H	Decentralised World, high carbon price scenario
DW-M	Decentralised World, medium carbon price scenario
DW-L	Decentralised World, low carbon price scenario
EAAP	Energy Adequacy Assessment Projection

Abbreviation	Expanded Name
EDR	Economic demonstrated resources
EDT	Eastern Daylight-saving Time (see also EST)
EGS	Enhanced Geothermal Systems
EOD LP	End-of-day linepack
ESIPC	Electricity Supply Industry Planning Council (now part of the Australian Energy Market Operator - AEMO)
ESOO	Electricity Statement of Opportunities
EST	Eastern Standard Time (See also EDT)
ETS	Emissions Trading Scheme
EUR	Estimated ultimate recovery
FCAS	Frequency control ancillary service
FC-H	Fast Rate of Change, high carbon price scenario
FC-M	Fast Rate of Change, medium carbon price scenario
FCSPS	Frequency control Special protection scheme
FEED	Front-end engineering and design
GDP	Gross domestic product
GPG	Gas powered generation
GSOO	Gas Statement of Opportunities
GSP	Gross state product
HSA	Hot sedimentary aquifers
HVAC	High voltage alternating current
HVDC	High voltage direct current
IDGCC	Integrated drying and gasification combined cycle
IGCC	Integrated gasification combined cycle
IMF	International Monetary Fund
JPB	Jurisdictional planning body
LFRG	Load Forecasting Reference Group
LGC	Large-scale Generation Certificate
LNG	Liquefied Natural Gas
LOR (1, 2, or 3)	Lack of Reserve
LPG	Liquefied Petroleum Gas
LRC	Low reserve condition
LRET	Large-scale Renewable Energy Target
LRMC	Long-run marginal cost
LV	Latrobe Valley zone

Abbreviation	Expanded Name
MCE	Ministerial Council on Energy
MD	Maximum demand
MEL	Melbourne zone
MEPS	Minimum Energy Performance Standards
MLF	Marginal loss factor
MMA	McLennan Magasanik Associates
MMS	Market Management Systems
MNSP	Market network service provider
MPC	Market price cap
MPCCC	Multi-Party Climate Change Committee
MRET	Mandatory Renewable Energy Target
MRL	Minimum Reserve Level
MT PASA	Medium-term Projected Assessment of System Adequacy
NB	Nominal Bore
NCAS	Network control ancillary services
NCEN	Central New South Wales zone
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEO	National Electricity Objective
NER	National Electricity Rules
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NIEIR	National Institute of Economic and Industry Research
NLCAS	Network loading control ancillary services
NMNS	Non-market non-schedule
NNS	Northern New South Wales zone
NQ	North Queensland zone
NSA	Northern South Australia zone
NSCAS	Network support and control ancillary services
NSP	Network service provider

Abbreviation	Expanded Name
NTNDP	National Transmission Network Development Plan
NTP	National Transmission Planner
NTS	National Transmission Statement
NVIC	Northern Victoria zone
OCGT	Open cycle gas turbine
OPDMS	Operations and Planning Data Management System
ORER	Office of the Renewable Energy Regulator
OS-L	Oil Shock and Adaptation, low carbon price scenario
OS-M	Oil Shock and Adaptation, medium carbon price scenario
1P	Proved reserves
2P	Proved reserves + probable reserves
3P	Proved reserves + probable reserves + possible reserves
PASA	Projected Assessment of System Adequacy
POE	Probability of exceedence
PPI	Producer price index
PR	Proved reserves
PSA	Power System Adequacy – Two Year Outlook
PV	Present value
RBA	Reserve Bank of Australia
REC	Renewable Energy Certificate
REDP	Renewable Energy Demonstration Program
RERT	Reliability and Emergency Reserve Trader
RET	Renewable Energy Target - national Renewable Energy Target scheme
RIT-T	Regulatory Investment Test for Transmission
RPAS	Reactive power ancillary service
SASDO	South Australian Supply-Demand Outlook
SCADA	Supervisory Control and Data Acquisition system
SCER	Standing Committee on Energy and Resources
SC-0	Slow Rate of Change, zero carbon price scenario
SC-L	Slow Rate of Change, low carbon price scenario
SCO	Standing Committee of Officials
SENE	Scale efficient network extensions
SESA	South East South Australia zone
SRA	Settlements residue auction
SRAS	System restart ancillary service

Abbreviation	Expanded Name
SRES	Small-scale Renewable Energy Scheme
SRMC	Short-run marginal cost
STC	Small-scale Technology Certificates
ST PASA	Short-term Projected Assessment of System Adequacy
STTM	Short Term Trading Market for Gas
SVC	Static VAr compensator
SWNSW	South West New South Wales zone
SWQ	South West Queensland zone
TAS	Tasmania zone
TNSP	Transmission network service provider
UIGF	Unconstrained Intermittent Generation Forecast
USE	Unserved energy
UW-0	Uncertain World, zero carbon price scenario
UW-L	Uncertain World, low carbon price scenario
VAPR	Victorian Annual Planning Report
VCR	Value of Customer Reliability
VENCorp	Victorian Energy Network Corporation (now part of AEMO)
WACC	Weighted average cost of capital

KEY FINDINGS

Setting the scene for the next 20 years

The National Transmission Development Plan (NTNDP) provides a transparent and independent resource for the energy industry, policy makers, investors and the wider community to better understand Australia's energy needs and transmission requirements for its eastern and south eastern states over the next 20 years.

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

The NTNDP is an evolving document, and will change in response to market changes and requirements. This year's NTNDP validates and builds upon the work done in 2010. The NTNDP 20-year plans are expected to be shaped by changes to key drivers. These drivers include the carbon price, fuel costs, national Renewable Energy Target (RET) scheme, and the economic outlooks, which currently remain consistent with the 2010 NTNDP's predictions.

The 2011 NTNDP lays the foundations for the evolution of the power system to meet the challenges of renewable energy generation.

NEMLink

The NTNDP looks objectively at the costs and benefits of a stronger NEM backbone (the NEMLink project). NEMLink is the first national project of this kind to be considered and represents a significant departure from the regional focus of the past.

AEMO's NEMLink studies show that under current policies and given current expectations of economic and demand growth, NEMLink does not deliver positive net market benefits when only considering the more narrow focus of the current NEM benefit assessment.

NEMLink's net market benefits are limited under this assessment because it does not include the benefits from mitigating high impact low probability (HILP) events, or the strategic value in future-proofing against uncertainties that can be significant for a project like this that delivers high-capacity alternative network paths.

NEMLink would also deliver further benefits as it enables a truly national market for electricity, rather than a series of interconnected regional markets. An assessment that looks more widely at the economic impact of investments would find additional benefits beyond those obtained in the electricity market alone.

There are also likely to be some regional projects being planned by TNSPs, which could be deferred or avoided if NEMLink is built. These regional planning benefits have not been included in the economic assessment. An extension of the Sydney 500 kV ring network is an example of where benefits might accrue.

AEMO has extended its work on the NEMLink concept in 2011, giving increased confidence in the results and widening the study scope compared with the 2010 NTNDP. The 2011 analysis shows that deferring one of the incremental investments, a second Tasmanian link, improves NEMLink's viability. NEMLink's net electricity market benefits only eventuate, however, with the three remaining elements in place, strongly connecting the mainland regions of Queensland, New South Wales, Victoria, and South Australia (as shown in Table 1).

Under current expectations of economic conditions and demand, NEMLink could deliver gross benefits as high as $1.5 billion to the electricity market. NEMLink's wider economic benefits to Australia could be significant, potentially greater than the present value of the NEMLink costs at $3.5 billion.

Changes to the national regulatory and transmission frameworks are needed to enable wider economic benefits beyond the electricity market to be considered, to maximise the value of these investments to Australia.

Table 1 – Benefit to cost ratio assessment (in 2010 – 11 dollars)

NEMLink Option	Decentralised World, Low Carbon Price[a]		Fast Rate of Change, High Carbon Price[b]	
	Net Market Benefits ($ Billion)	Benefit to Cost Ratio	Net Market Benefits ($ Billion)	Benefit to Cost Ratio
NEMLink, all links	-2.52	0.4	-0.71	0.8
NEMLink, deferring QLD-NSW	-2.36	0.2	-0.96	0.7
NEMLink, deferring NSW-VIC	-3.17	0.1	-2.56	0.3
NEMLink, deferring VIC-SA	-2.25	0.2	-0.84	0.7
NEMLink, deferring VIC-TAS	-2.01	0.4	-0.40	0.9

a. Scenario assumptions include intermediate economic growth and medium population growth, with a low carbon price trajectory.

b. Scenario assumptions include high economic and population growth, with a high carbon price trajectory.

Towards a low carbon future

Integrating renewable investment

The 2010 NTNDP provided forecasts anticipating that up to $120 billion of new generation will be required over the next 20 years to meet Australia's energy requirements, the majority of which will be either gas powered generation (GPG) or renewable energy (predominantly wind).

The 2011 NTNDP looks at potential impacts on the network of large-scale investment in wind generation and other renewable technologies. As the cost of wind and carbon capture and storage technologies decrease over time, AEMO modelling, which incorporates the Australian Government's national Large-scale Renewable Energy Target (LRET) scheme, shows that investment in these newer forms of generation will increase. The modelling suggests that in the first 10 years, wind power is most likely to meet the target. The second 10 years of the 20-year NTNDP outlook anticipated the emergence of new technologies like geothermal and solar thermal generation.

With an assumed carbon price in the 2010 NTNDP starting at 23.92 $/tCO2-e, the LRET achieves its objectives, and our modelling indicates that up to up to 10 GW of new renewable generation, predominantly wind, may connect to the NEM by 2029–30.

AEMO investigated the way other countries with significant wind generation have integrated this technology. Unlike the NEM, parts of the United States and Europe use government-directed approaches to develop networks to support wind and other renewable generation.

AEMO will continue to apply an economic approach to transmission network development. Greater efficiencies, however, could be achieved through significant changes to the transmission development framework.

Investment drivers

A location is more attractive to investors if a wind farm's output is well matched with the size and shape of demand, therefore maximising its revenue. Other investment drivers include stable loss factors and congestion. In the NEM, this varies from region to region.

Flexible generation, such as open-cycle gas turbines and hydroelectric generation, is required to increase or decrease output to balance changes in demand and wind generation output. The NEM's five-minute dispatch interval facilitates wind integration because it can respond quickly to variable generation. Flexibility can also be provided by transmission capability that links areas with diversity of demand and wind output.

Congestion

The 2011 NTNDP examined the probability of congestion and controllable demand and its potential to limit wind generation and its profitability. The modelling indicates that the proximity of wind generation to strong transmission points improves profitability because of lower connection costs and reduced risk of congestion.

AEMO's studies also show network limitations, including the capability of the Victoria–South Australia interconnectors, will affect wind generation output in parts of South Australia.

Trends

Based on industry information, investors are increasingly focussing on New South Wales when developing new wind generation projects. This is consistent with the latest AEMO modelling, which shows New South Wales may become the region with the most wind generation capacity in the next 10 to 20 years.

Currently, South Australia is reaching very high penetration levels for wind generation. In the top three internationally, this high degree of wind penetration creates certain operational challenges.

Technical standards review

Wind generation is different from other more conventional forms of generation, primarily coal, gas, and hydroelectricity, and the existing technical standards must address the challenges of increasing variable energy inputs and capacity increases.

If wind generation displaces significant amounts of conventional generation then the performance of the power system will change. For example, the power system can become more sensitive to changes in generation and demand causing fluctuations in frequency and voltage.

Current technical standards were developed for conventional generation, but can accommodate low levels of variable generation, such as wind and certain types of solar generation. As the amount of variable generation increases, more substantive changes to the technical standards are required. In some locations, particularly South Australia, wind penetration levels are approaching levels at which standards may need to change.

A review of specific technical standards is proposed and would include the basis of negotiation with new generation proponents involving aspects of fault ride through (the ability of generation to stay on line during a large disturbance on the network) and minimum standards for reactive power.

Any changes to the negotiating framework should include consideration of the likely future levels of variable generation to minimise overall costs.

The way forward

A range of technical studies will be conducted to manage the safe and orderly integration of high levels of wind energy, the results from which will be released throughout 2012. The studies will look at frequency control and fault levels, and will progress existing work on high wind penetration in the NEM.

AEMO will refine its modelling to better understand the drivers of wind investment and take into account the differences between different turbine technologies. AEMO will also continue its discussions with wind turbine manufacturers about the potential capabilities of new designs.

Fuel cost impact on generation

Our modelling shows gas is the transitionary fuel source between coal and renewable electricity supply. Investment is highly dependent on fuel costs and the carbon price. CCGT development is extremely sensitive to gas fuel costs whereas, open-cycle gas turbine generation (OCGT) is not as sensitive to gas fuel costs as it only operates for relatively short periods of peak demand when electricity prices are high.

If gas fuel costs rise significantly relative to coal, investment in CCGTs is likely to be delayed and reliance on coal will be extended. The Clean Energy Future plan includes provision for closure of up to 2,000 MW of coal-fired plant. This base load capacity will most likely be replaced with CCGT plant and the timing will be linked to closure dates. Beyond the closure dates, additional CCGT investment will be affected by gas fuel costs.

Gas and electricity transmission cost comparison

As Australia moves towards a low carbon future, it will require a mix of generation types including CCGT generation. One challenge involves considering the most efficient way to deliver that energy, through a combination of gas pipelines and electricity transmission. Ultimately, the location of GPG is a decision for the investor. We have carried out a high level cost comparison but it should be noted the location of GPG depends on a number of factors.

The 2011 NTNDP compares the cost differences between using a gas pipeline to deliver gas to a CCGT plant near a load centre, with using electricity transmission lines to deliver electricity from a CCGT plant.

The study shows that under certain circumstances, gas transmission pipelines are more economically efficient over large distances than electricity transmission.

Based on indicative costs from publicly available information, the cost of long distance transmission (100 kilometres, 250 kilometres, and 500 kilometres) to supply gas to generation close to a load centre is approximately half the cost of supplying electricity to a load centre from generation close to a remote gas source. For example, over a distance of 250 kilometres, the cost of building gas pipelines ranges between $150 million and $305 million whereas electricity transmission lines will cost between $350 million and $480 million.

It should be noted that this study is indicative only, and looked at the capital costs of greenfield projects providing new capacity. It did not look at existing spare capacity or the potential for upgrading existing infrastructure, and it did it not include operating costs or losses.

The results show there is considerable potential for gas pipelines to provide a viable alternative to electricity transmission lines under some circumstances, highlighting the value of coordinated planning between gas and electricity transmission. This will be taken into account in future modelling, which will reflect the different costs for gas and electricity transmission more effectively when modelling the full costs of new entry generation.

The differences between the regulatory and commercial frameworks for gas and electricity transmission development, however, could prevent these benefits from being realised. Coordinated electricity and gas planning would identify where gas contractual arrangements and electricity transmission network plans are hampering optimal investments.

Marginal loss factors

Marginal loss factors (MLFs) are multipliers that describe electrical losses due to the distance between generation and loads. MLFs are applied to the electricity prices received by generators and affect the revenue received by generators for the energy produced.

Therefore generators bear the costs of losses due to their location, and this is potentially a disincentive for generation projects in remote areas, including renewable generation in those areas.

AEMO provides some indicative long-term MLFs for the NEM based on selected scenarios from the 2010 NTNDP, showing where loss factors are stable or likely to change. Depending on the scenario, MLFs in some zones could drop by up to 20% over the next 20 years, which would see a corresponding reduction in generator revenue.

Zones that are connected by high capability transmission lines to major load centres close to regional reference nodes (the point at which a region's reference spot price is determined) exhibited MLFs that were generally stable under the scenarios studied.

However, MLFs decreased at zones with increased average power transfers towards the regional reference node. Examples of NTNDP zones exhibiting these characteristics include Central Queensland (CQ), Northern New South Wales (NNS), Canberra (CAN), South West New South Wales (SWNSW), Northern South Australia (NSA), and Tasmania (TAS).

Changes in demand

Electricity consumption patterns are showing significant change in response to own-use electricity generation (for example, small-scale solar photovoltaic (PV) generation), increases in electricity prices resulting from rising network charges, expected price increases resulting from the Clean Energy Future plan, including energy efficiency schemes and new technologies (for example, plug-in electric vehicles). In the 2011 NTNDP, AEMO has assessed two potential future drivers of demand change involving small-scale solar PV generation and electric vehicles.

AEMO has also commenced a national forecasting project to ensure these and other important drivers of demand are considered on a nationally consistent basis.

Small-scale solar effects

With significant sustained increases in adoption over the next 20 years, small-scale solar PV generation has the potential to slightly reduce summer maximum demand, as well as contributing significantly to the energy produced on clear days.

A comparison of summer and winter solar PV generation profiles with the forecast demand profile for 2030 shows that encouraging owners to match their electricity consumption patterns to their power output may increase the contribution to meeting maximum demand and could delay network investment, especially in parts of the distribution network with high PV uptake. However, even with significant sustained increase in small-scale solar PV generation over the next 20 years, the change in demand may be insufficient to significantly affect transmission investment.

Plug-in electric vehicle impacts

Plug-in electric vehicles are one of several technologies that will have an impact on demand if there is sufficient uptake. The 2011 NTNDP focussed on this technology as part of AEMO's ongoing monitoring of the benefits of new technologies and their impact on demand.

Although there are currently few plug-in electric vehicles in Australia, several major car companies are planning to release all-electric models in the next few years. Widespread adoption and uncontrolled charging of plug-in electric vehicles has the potential to significantly affect both summer and winter maximum demand.

The 2011 study looks at the impact of a high level of uptake in a large city (Sydney). AEMO deliberately chose a high level of penetration to clearly demonstrate the impact of uncontrolled charging and the comparative benefit of controlled charging schemes or incentives for smart charging.

These studies show plug-in vehicle loads have the potential to significantly increase the energy required on summer and winter evenings, when demand is already at its highest levels. This increased maximum demand could potentially lead to additional high price periods in the NEM, resulting in investment in new peaking generation plants, and additional network expenditure.

The study also examines the potential benefits of controlled charging schemes and incentives for smart charging involving the following:

- Financial incentives that encourage certain customer behaviour.
- Standards for charging points programmed to charge only at certain times.
- The remote control of charging points by existing or new operators.

The impacts of uncontrolled charging and 50% smart charging (50% of vehicles commence charging at either 11:00 PM or 2:30 AM) on forecast summer and winter peak demand profiles for 2030 were assessed. The peak increases are greater in winter than in summer, because the winter peak tends to happen later in the day when the assumed plug-in electric vehicle load is higher.

In the longer term, there is potential to use plug-in vehicles as a source of power during demand peaks. This technology (sometimes referred to as Vehicle-to-Grid) involves smart charging points that can draw power from vehicle batteries to reduce network loading at peak times.

Although this technology is still in the early stages of development, it demonstrates potential to provide more dynamic demand and supply characteristics.

National forecasting

Electricity and gas demand forecasts are critical to market operations, transmission planning, and assessing supply adequacy. NEM forecasts are currently developed across different organisations, for varying purposes, with differing levels of detail, and a diversity of approaches and methodologies are used.

In 2012, AEMO will publish its first national electricity forecasts. This will provide a better understanding of growth drivers in all regions and a clearer picture of regional supply and demand outlooks considering changing energy consumption patterns. National gas forecasts are also being developed and the long-term forecasting strategy aims to combine gas and electricity forecasting processes.

Developing efficient transmission

The 2010 NTNDP's network plans provided a series of efficient network development outlooks for a range of scenarios, which remain valid because, while there were small movements in demand forecasts since 2010, load levels and project timings have remained consistent with the 2010 scenarios.

AEMO is committed to nationally efficient transmission and a series of key principles:

- National planning and consistent regulatory arrangements.
- A consistent platform for new connections regardless of location.
- Meeting the underlying needs for investment through a focus on delivering services to generators and consumers.

The NEM and the transmission networks have evolved through incremental investments that provide limited integration of regional networks and markets. The current approach of jurisdictional TNSPs is focussed on addressing regional redundancy (alternative network pathways) standards that ensure the security and reliability of electricity supply. The changing energy environment is leading to the development of new generation sources, specifically renewable energy, in new locations, and significant network investment will be needed to integrate them.

AEMO's 2010 NTNDP scenario modelling concluded that between $4 billion and $9 billion of transmission augmentation investment is required over the next 20 years across the NEM[1]. This investment is required to support new generation asset investments of between $35 billion under a low carbon price, low economic demand scenario, and $120 billion under a high carbon price, high economic growth scenario.

Electricity is an important input into the Australian economy and transmission network investment should be judged by its full effect on the economy. Current planning approaches assume that the investments that maximise net benefits to the electricity market are the same ones that will maximise net benefits to the Australian economy and community. This assumption should be tested, otherwise opportunities to increase the benefits to the economy and community, and aid in achieving national goals, may be missed.

[1] This includes committed TNSP expenditures.

NTNDP and APR alignment

The status and timing of projects listed in the 2011 APRs generally correspond with developments identified by the 2010 NTNDP as occurring in the first 10 years.

Cases where a proposed project or its timing differs from the NTNDP, however, are mainly due to APRs providing a more detailed consideration of local reliability issues, where the NTNDP takes a higher-level approach focussed on long-term national transmission network development. Other factors that led to differences included changes in load forecasts and near-term assumptions about the location of new generation.

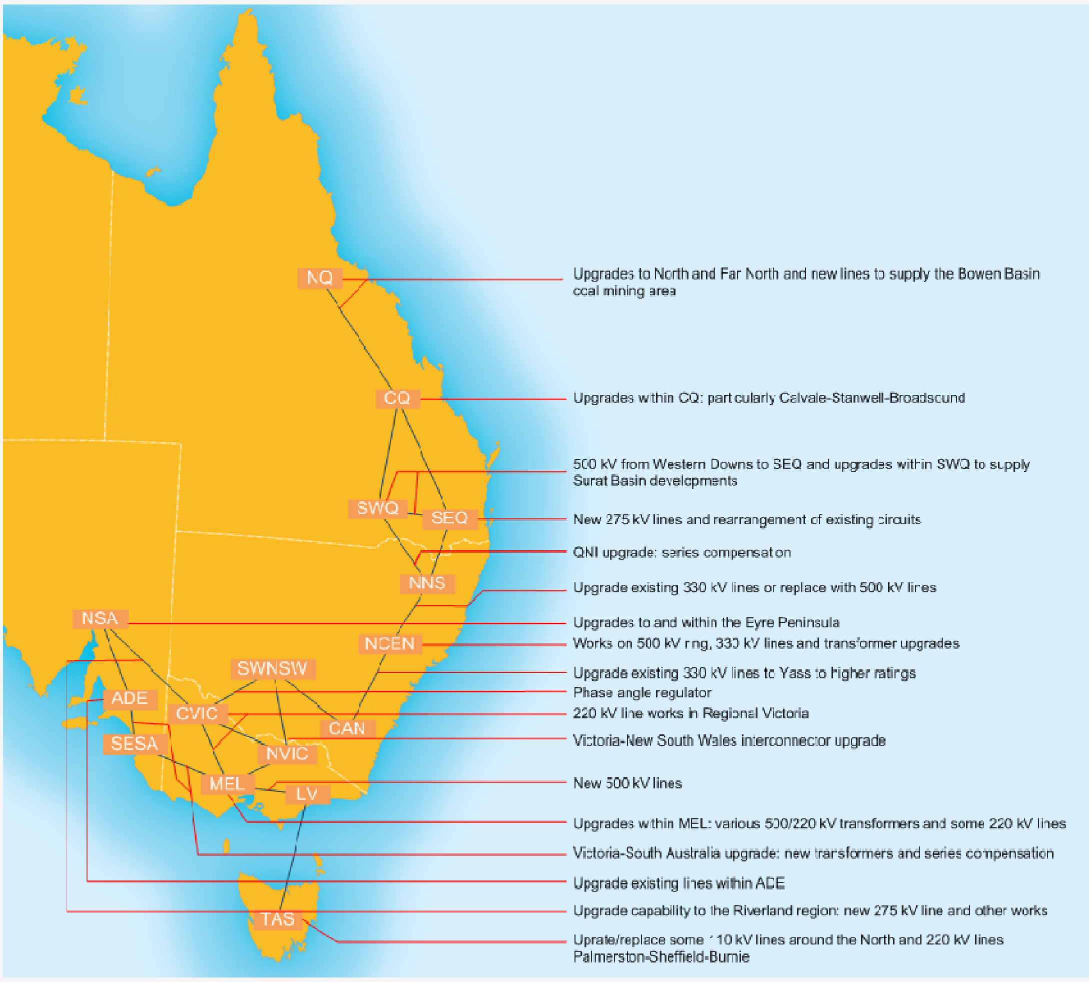
Figure 1 summarises the key regional transmission projects from the 2011APRs, as well as the first 10 years of the 2010 NTNDP's outlook period.

Noteworthy differences between the 2010 NTNDP and 2011 APRs relate to Queensland and Tasmania.

The 2011 Queensland APR identifies projects to support substantial load growth in the north west area of the Surat Basin, and the Bowen Basin coal mining area of Queensland, resulting from liquefied natural gas and coal mining activities. The load growth and network projects were not included in the 2010 NTNDP. Whether projects similar to the Queensland APR's are identified in future NTNDPs will depend on whether AEMO's national forecasting also identifies similar load growth.

Several projects in North West Tasmania identified in the 2010 NTNDP have been deferred because the 2011 Tasmanian APR did not identify firm proposals for significant wind generation in the area.

Figure 1 – Key regional transmission projects



Key projects

National projects identified in the 2010 NTNDP were further developed in 2011.

AEMO and ElectraNet studied projects to increase the capability to transfer power between South Australia and Victoria via the Victoria–South Australia (Heywood) interconnector. A joint Regulatory Investment Test – Transmission (RIT-T) will be published for consultation in 2012.

Powerlink and TransGrid are conducting joint studies on power transfer capability between Queensland and New South Wales.

The South Australian APR and the 2010 NTNDP have identified projects to support load growth in the Riverland region of South Australia. AEMO and ElectraNet have conducted preliminary studies, and plan to carry out further studies in consultation with TransGrid, exploring the best way to meet requirements irrespective of regional borders.

Network support and control ancillary services

Network support and control ancillary services (NSCAS) control active and reactive transmission network power flows, helping to maintain power system security and reliability, as well as delivering net economic benefits to the NEM by maintaining or increasing the power transfer capabilities of existing assets.

AEMO identifies the approximate quantity, duration, and location of NSCAS gaps so that transmission network service providers (TNSP) can develop investment proposals or establish operating arrangements to deliver these services. If TNSPs do not procure an adequate quantity of NSCAS, AEMO can contract for services or issue directions to maintain secure power system operations.

AEMO has reviewed the potential need for NSCAS for the next five years and identified the following:

- In New South Wales there is a need for reactive power ancillary services (RPAS) of up to 740 MVAr for the next five years to ensure acceptable voltage quality.
- In Victoria there is a need for network loading control ancillary services (NLCAS) of approximately 260 MW for the next five years to increase Victorian power transfer capabilities, and a need for RPAS of 160 MVAr in 2014–15 and 230 MVAr in 2015–16, to ensure voltage stability.
- In South Australia there is a likely need for RPAS of approximately 30 MVAr in 2013–14 to ensure voltage stability.
- In Queensland and Tasmania, no need for NSCAS has been identified.

CHAPTER 1 - INTRODUCTION

1.1 The 2011 National Transmission Network Development Plan

The annual National Transmission Network Development Plan (NTNDP) forms a key response to stakeholder requirements as well as being 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.

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.

In 2010, the NTNDP provided an independent appraisal of a 20-year strategic plan for the electricity transmission network within the National Electricity Market (NEM).[1] Delivering a comprehensive review of electricity transmission development needs for the next 20 years, it also included information about generation clusters, network support and control ancillary service (NSCAS) requirements, a review of transmission network service provider (TNSP) annual planning reports (APR) to ensure consistency with the NTNDP, and a high-level study of a large, inter-regional interconnection project for a high-capacity backbone (the NEMLink study).

Stakeholder feedback

In response to stakeholder feedback, the 2011 NTNDP builds on the work completed in 2010 by expanding and updating the results, and refining the planning approaches to provide new or improved ways for transmission planners and the industry generally to deal with the issues the 2010 NTNDP addressed.

For example, in relation to the way demand projections are being developed, and in particular the way the impacts from electric vehicles, small-scale generation, and the projected increase in wind generation.

Emerging planning issues

Responses to emerging planning issues are also explored in 2011. These issues involve the effective integration of wind generation in the NEM, considerations relating to gas and electricity transmission options, and refining the annual projections for energy and maximum demand.

In response to other stakeholder feedback, the 2011 NTNDP provides scenario sensitivity studies for certain 2010 NTNDP results, marginal loss factor outlooks for key connection points, and a further review of the transmission network projects in each region's APR for 2011 to ensure ongoing consistency with the NTNDP.

[1] For more information about this 20-year strategic study of the transmission network's future, see the 2010 NTNDP.

1.1.2 Background to the NTNDP

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

To achieve this, the NTNDP seeks to influence transmission investment in the following ways:

- Providing a consistent plan that considers the augmentations required under a range of scenarios, and delivering 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 network needs under those scenarios.
- Identifying network needs early to increase the time available to identify non-network options, including demand-side and generation options.
- Considering alternative network project timings, including alternatives resulting from the scenarios considered.

The NTNDP is one of a collection of key planning publications that AEMO issues annually. Together with the Electricity Statement of Opportunities (ESOO), the Gas Statement of Opportunities (GSOO), the Victorian Annual Planning Report (VAPR), 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.

The NEM transmission network

The NEM's transmission network supports the provision of power to most of Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania, and South Australia. In providing this support, the NEM transmission network:

- Supplies 19 million residents.
- Supplies 200,000 gigawatt hours (GWh) of energy to businesses and households each year.
- Extends over 5,000 km from Far North Queensland to Tasmania, and west to Adelaide and Port Augusta, and has approximately 40,000 km of transmission lines and cables.
- Is one of the longest alternating current (AC) systems 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.
- Presents challenges for transmission investment, because comparatively-priced fuels often present efficient alternatives.

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

Figure 1-1 — The National Electricity Market transmission network

Table 1-1 lists the NTNDP zones, their location names and abbreviations.

Table 1-1 — NTNDP zone abbreviations

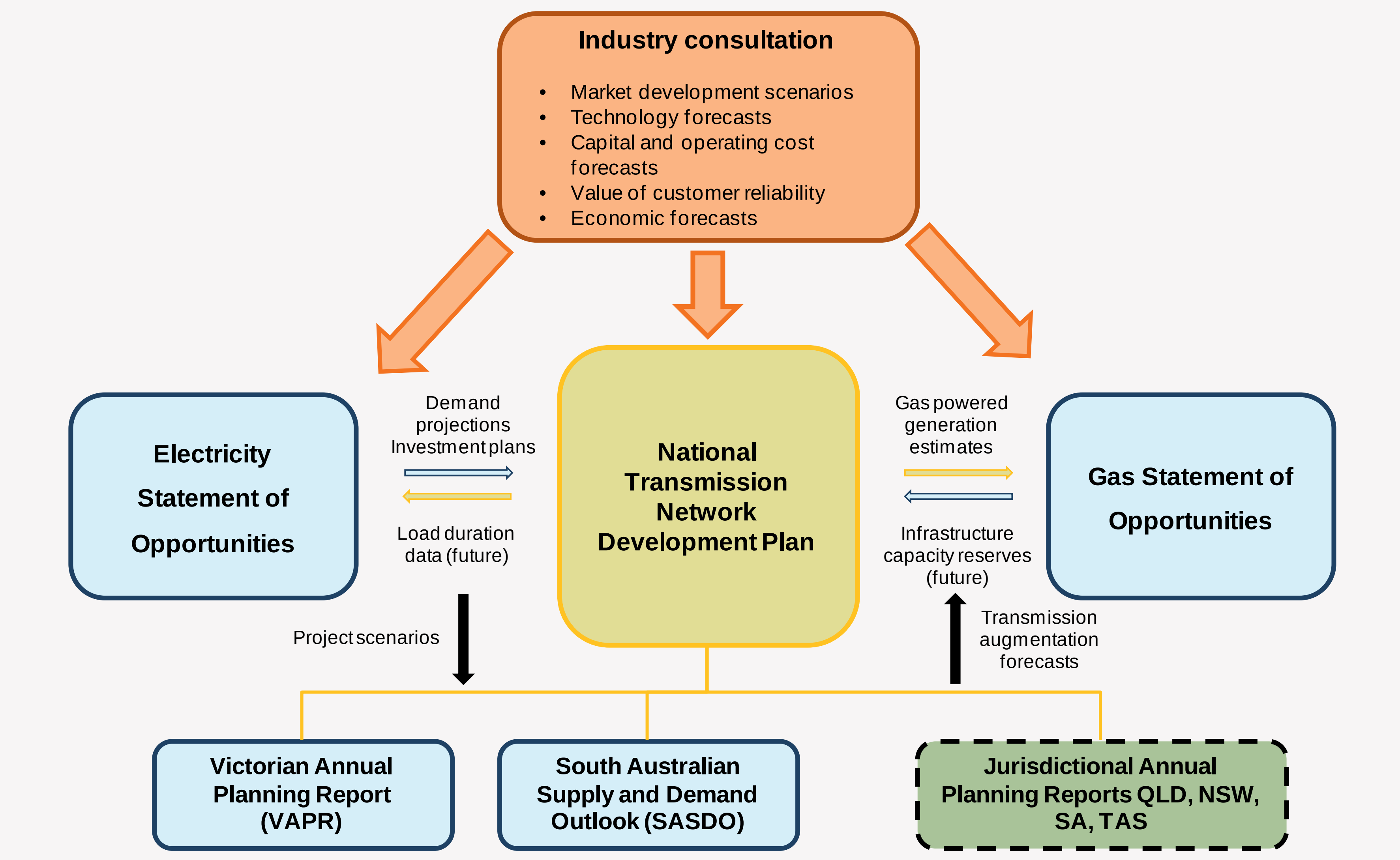
NTNDP Zone	Zone Abbreviation
North Queensland	NQ
Central Queensland	CQ
South West Queensland	SWQ
South East Queensland	SEQ
Northern New South Wales	NNS
Central New South Wales	NCEN
Canberra	CAN
South West New South Wales	SWNSW
Latrobe Valley	LV
Melbourne	MEL
Country Victoria	CVIC
Northern Victoria	NVIC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

Energy planning reports

Each region's jurisdictional planning body (JPB) produces an APR that provides information about existing NEM infrastructure and potential limitations arising within the next five years, while the ESOO and GSOO investigate supply-side reliability and provide information about energy resources affecting the NEM.

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

Figure 1-2 — The NTNDP in the energy planning context



1.1.3 The NTNDP planning criteria and the economic planning approach

The 2010 NTNDP established that NEM transmission network augmentations of up to $9 billion will be required over the next 20 years, and it is critical that these augmentations are efficient and economically justified.

The fundamental objective of transmission planning is to develop the power system as economically as possible while maintaining an acceptable level of reliability.

Acceptable reliability

Reliability is often judged by consumers as being a constant, uninterrupted electricity supply, and expectations differ about acceptable reliability levels. Transmission planners consider reliability in terms of capacity (sufficient transmission capability and generation to meet demand) and security (the transmission network's ability to withstand contingency events, like transmission or generation failures, and still remain within the power system's technical limitations).

The challenge for economic planning is to strike a balance between the costs of providing sufficient capability to cope with a range of potential contingency events while meeting consumer expectations, and the cost of not supplying electricity if a contingency event occurs.

The economic planning approach

The economic planning approach compares the costs and benefits of an investment, which will only proceed if the benefits exceed the costs. A failure to conform with these criteria inevitably leads to cost increases.

An investment's costs involve all the costs incurred, including capital, operating, and maintenance costs. An investment's benefits include the following:

- Reduced transmission losses.
- Reduced unserved energy.
- Enabling the efficient dispatch of generation, which involves reduced fuel costs, reduced carbon emissions (depending on the prevailing policy settings), and increased renewable generation.
- Enhanced market competitiveness.
- Efficient capital investment in generation and transmission, which involves capacity sharing for renewable generation and flexibility for future investments.

The economic planning approach is broadly viable, and can be confidently applied in other areas and jurisdictions without modification.

A national response

The economic planning approach provides the framework to consider cross-border solutions, where planning under different regionally-based deterministic reliability standards may lead to sub-optimal solutions. The economic planning approach also identifies optimal investments and timings by considering the costs and benefits regardless of where they are located. For example, if one region's standards are more conservative than another's then investment timings may occur earlier than necessary, even though a later investment in a neighbouring region may be the more efficient outcome for both regions.

As a result, where a national response is potentially more efficient than a local one, network limitation solutions are explored without regard for regional borders. For example, AEMO and ElectraNet are jointly considering the reliability of the South Australian Riverland area, and exploring cross-border solutions between Victoria and South Australia.

Competition benefits

Competition benefits derive from augmentations that increase competition between market participants, and lead to more efficient generation dispatch, and are one of the economic benefits expected to arise from transmission investments.

For example, AEMO considers an investment to increase the capacity of the interconnection between Victoria and South Australia (currently being assessed by AEMO and ElectraNet under a joint Regulatory Investment Test – Transmission) might lead to competition benefits.

HILP events

In terms of the economic assessment of new investment options, benefits can also derive from mitigating transmission network-related high impact low probability (HILP) events (although the benefits can be difficult to quantify due to the infrequent nature of their occurrence). HILP events are generally defined as events that lead to extensive and prolonged outages.

For example, AEMO (as the Victorian JPB) is reviewing areas that may have higher exposure to HILP events (including bushfire). The review is examining measures for reducing the risk associated with the HILP events, ranging from monitoring at times of high risk and implementing operational actions or control schemes, to implementing non-network options including demand-side participation or additional generation capacity, and additional transmission network investment.

1.1.4 Responses to the 2010 NTNDP

Following publication of the first NTNDP in 2010, AEMO published a consultation paper about the 2011 NTNDP's scope to better understand stakeholder priorities. The key themes emerging from this consultation involved the need to develop better data sets, further explore network development market benefits, assess the consultation process regarding generation costs, generate additional scenarios and sensitivities to test key inputs, and outline assumptions underpinning the modelling.[2]

In March 2011, AEMO held its first meeting of the Network Planning Forum, an executive-level leadership group comprising external stakeholders and industry participants, to consider current and future energy market issues and challenges. The forum canvassed the proposal that the NTNDP process may change from year-to-year with a focus on undertaking further in-depth analysis of key issues (as relevant).

AEMO also convened a series of interactive workshops throughout February 2011, where stakeholders provided feedback on uncertainties and risks introduced by the marginal loss factor arrangements, requested better information about assumptions made for the input data, and expressed support for further analysis of NEMLink and its benefits. Questions were also raised about the effects of increasing wind penetration on congestion levels in the NEM.

Conclusion

A key conclusion stemming from these responses is that annual updates and revisions for the 2010 NTNDP's 20-year outlook are not a priority, particularly given current levels of demand growth, which remain stable, and the now legislated price on carbon, which falls within the range of possible carbon price trajectories first examined in 2010. Alternatively, the NTNDP should challenge the energy industry (and the electricity transmission sector in particular) to find appropriate technical and structural solutions to efficiently deliver Australia's future power system.

[2] Submissions can be found on AEMO's website at http://www.aemo.com.au/planning/ntndp2011consult.html.

1.1.5 The ongoing validity of NTNDP modelling

The 2010 NTNDP's network plans provided a series of efficient network development outlooks for a range of scenarios, which remain valid because, while there were small movements in demand projections since 2010, load levels and project timings have remained consistent with the 2010 scenarios.

Results from sensitivity studies conducted in 2011 to analyse developments with the potential to affect the 2010 NTNDP's conclusions show that the Australian Government's Clean Energy Future plan's fixed three-year carbon price is sufficiently similar to the 2010 NTNDP medium carbon price scenarios that long-term modelling outcomes have been left substantially unchanged, provided that the emissions trading scheme results in a return to medium carbon prices from 2015 onwards.

1.2 Content and structure of the 2011 NTNDP

The NTNDP is available as a printed report and can also be downloaded from AEMO's website.

1.2.1 Main document

Key Findings provides an overview of the 2011 NTNDP's findings.

Chapter 1, Introduction, describes the background to the NTNDP, planning criteria and the economic planning approach, and responses to the 2010 NTNDP.

Chapter 2, Network development updates for 2011, provides information about AEMO's latest view of transmission development. This includes a review of the projects from the 2011 regional APRs, and examines how changes predicted in the APRs impact the NTNDP's conclusions.

Chapter 3, Network support and control ancillary services, provides information about the NEM's NSCAS requirements, based on a review of potential national and regional requirements for the next five years.

Chapter 4, Integrating large-scale wind generation in the NEM, provides information about technical issues arising from the large-scale integration of wind generation.

Chapter 5, NTNDP outlook marginal loss factors, provides information about how generation connection marginal loss factors change over time as generation and transmission develop under a number of NTNDP scenarios.

Chapter 6, NEMLink: further study results for a high-capacity backbone, provides the results from further studies that refine the scope and impact of a NEMLink-style project to further understand the potential costs and benefits of transmission backbone projects.

Chapter 7, Scenario sensitivity studies, provides information about generation and interconnector development for a range of sensitivities to the 2010 NTNDP scenarios.

Chapter 8, Gas and electricity transmission comparative case study, provides information about a comparative case study for connecting a hypothetical 1,000 MW combined-cycle gas turbine (CCGT), using either significant gas or electricity transmission infrastructure.

Chapter 9, The changing nature of demand, provides an analysis of the potential impact on demand from widespread adoption of plug-in electric vehicles and rooftop solar photovoltaic (PV) generation.

1.2.2 Appendices

The appendices are only available from the AEMO website.

Appendix A, s**upplementary information about marginal loss factor trends**, provides supporting information about marginal loss factor trends in respect of generation and transmission development under a number of NTNDP scenarios.

Appendix B, Annual Planning Report supplementary project information, provides information about the 2011 APRs and network developments that the 2010 NTNDP studies assumed would proceed, 2011 APR network developments that relate to the second 10 years of the NTNDP 20-year outlook period and are within the NTNDP scope, and network developments identified in the 2011 APRs that are outside the NTNDP scope (see Chapter 2).

Appendix C, NEMLink methodology and generation and transmission development results, provides information about improvements to the modelling methodology behind the 2011 review of NEMLink and the NEMLink options, resulting in a more accurate assessment of the net market benefits.

1.2.3 Other resources

The AEMO interactive map is available from the AEMO website. The interactive map enables users to select information for display, including the location of existing energy infrastructure, the approximate location of committed and modelled transmission network development projects for the 2010 NTNDP scenarios, and market simulation outputs for the scenarios.

Users can also select the area to display, choosing between high-level and detailed views of the transmission network.

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CHAPTER 2 - NETWORK DEVELOPMENT UPDATES FOR 2011

Summary

This chapter provides information about AEMO's 2011 transmission development outlook, representing AEMO's latest view of network developments for the next 10 years. It includes a review of the projects from the 2011 regional annual planning reports (APRs) developed by the jurisdictional planning bodies (JPB), summarises the correlation between the 2011 APRs and the 2010 NTNDP, and examines how changes predicted by the JPBs impact the NTNDP's conclusions.

Appendix B extends this analysis to projects considered committed and projects relating to the second 10 years of the NTNDP 20-year outlook period.

The status and timing of projects listed in the 2011 APRs generally correspond with developments identified by the 2010 NTNDP as occurring in the first 10 years.

Queensland

The 2010 NTNDP outlook for Queensland was based on new South West Queensland (SWQ) zone generation, with load growth largely occurring elsewhere in the region, requiring extensive transmission network augmentation from the SWQ to the South East Queensland (SEQ) zone within the 20-year outlook period. The 2011 APR is consistent with this outlook, and identified the following:

- New substations at Wandoan South and Columboola, and a new 275 kV transmission line from the Nebo Substation to Moranbah to address substantial load growth in the Surat and Bowen Basins.
- Projects to address thermal limitations between Queensland's central west and Gladstone, including a new 275 kV transmission line between Calvale and Stanwell (consistent with the 2010 NTNDP).
- Some shorter-term network limitations identified in the SEQ and SWQ zones in the 2010 NTNDP are addressed by line replacements and network rearrangements.

The 2010 NTNDP and the 2011 Queensland and New South Wales APRs all included an increase in the Queensland–New South Wales (QNI) interconnector's capability.

New South Wales

The 2010 NTNDP outlook for New South Wales featured the further development (to be completed in two stages) of the 500 kV transmission line ring around the Sydney–Wollongong–Newcastle load centre. The 2011 APR also featured this development but prioritised its development stages differently to the 2010 NTNDP. The 2011 APR also identified the following:

- A project to increase the thermal ratings of the Bannaby–Yass and Marulan–Yass 330 kV lines if new generation is developed in the South West New South Wales (SWNSW) zone.
- A project to include New South Wales sites in the Murraylink Runback Control System. This project is associated with other developments aimed at maximising Murraylink's power transfer capability and supporting the South Australian Riverland region's load.

Victoria

The 2010 NTNDP outlook for Victoria featured upgrades to the 500 kV line capabilities to Melbourne, adding new 500/220 kV transformers, and upgrading the 220 kV lines (also required to support export to South Australia over Murraylink) due to expected growth. The 2011 APR identified the following:

- The deferral of a number of projects identified in the 2010 NTNDP in the first 10 years, including 500 kV lines from potential new generation sources at Loy Yang or along the Moorabool–Mortlake–Heywood line.
- A number of developments for Regulatory Investment Test-Transmission (RIT-T) evaluation, including upgrading the capability between Victoria and South Australia, new transformation capability for the Melbourne Metropolitan Area, and upgrading the capability of some circuits in Regional Victoria.
- AEMO and ElectraNet, in consultation with TransGrid, intend to jointly assess efficient options for Riverland area supply, potentially involving augmentations in Regional Victoria. AEMO and ElectraNet are jointly undertaking a RIT-T application on options to increase the Victoria–South Australia (Heywood) interconnector's capability.

South Australia

The 2010 NTNDP outlook for South Australia included projects to increase interconnector capability, reinforcing the 275 kV network's capability between the Northern South Australia (NSA), Adelaide (ADE) and South East South Australia (SESA) zones, and reinforcing the 275 kV network in the Adelaide Metropolitan Area, which is generally consistent with the 2011 APR. The 2011 APR identified extension of the 275 kV network from Cultana to Port Lincoln (not included in the 2010 NTNDP due to the unavailability of relevant connection enquiry information).

Tasmania

The 2010 NTNDP outlook for Tasmania included projects to extend and reinforce the 220 kV transmission network, including replacing the existing Burnie–Sheffield 220 kV single circuit line and building a new Sheffield–Palmerston 220 kV double circuit line to accommodate new wind generation in Tasmania's north west. The 2011 APR did not identify any firm proposals for significant wind generation development in the north west, deferring the upgrades until after the first five years of the NTNDP's outlook period.

2.1 NTNDP 2010 and 2011

As a 20-year strategic study, the NTNDP's key value is in setting out credible views about the transmission network development in the long term. A key element of this strategic study is the linkage between the shorter-term regional plans and the longer-term national outlook. In this respect, the NTNDP forms a national outlook by extrapolating on the existing transmission system while accounting for planned regional developments, while the Jurisdictional Planning Bodies (JPBs) develop plans that account for the national outlook outlined in the NTNDP.

Committed projects (that the NTNDP studies assume will be built under all scenarios) are listed in Appendix B, along with their current status, as reported in the relevant annual planning report (APR) for 2011.

2.1.1 Changes since 2010

This section highlights changes in the 2011 APRs for each region with the potential to trigger further NTNDP studies. While showing minor differences in every region, the scope and anticipated timing of potential network developments remains compatible with the 2010 NTNDP's long-term strategy. Differences include the following:

- In Queensland, the 2011 APR identified substantial load growth in the Surat Basin's north west area and Bowen Basin coal mining area of Queensland, resulting from LNG and coal mining activities. This load growth and the associated network projects were not included in the 2010 NTNDP. Some network limitations identified in the 2010 NTNDP are also addressed by line replacements and network rearrangements.
- In New South Wales, differences between the 2010 NTNDP and the 2011 New South Wales APR relate mainly to differing assumptions about the location of new generation developments. This affects the order of the 500 kV ring developments around the Newcastle–Sydney–Wollongong area.
- In Tasmania, several projects in North West Tasmania identified in the 2010 NTNDP have been deferred because the 2011 APR did not identify firm proposals for significant wind generation in the area.

2.2 Regional annual planning report project reviews

This section compares transmission network developments identified in the 2010 NTNDP with the 2011 APRs for each region. The comparison is made in two parts:

- Developments identified in the 2010 NTNDP in the first 10 years of the 20-year outlook period. The current 2011 APR status of each of these projects is also given. The development numbers used in this table correspond to the development numbers used in Chapters 3 and 4 of the 2010 NTNDP.
- Other developments identified in the 2011 APRs that fall within the first 10 years of the 20-year outlook period that are also within the scope of the NTNDP.[1]

Additional information about APR projects is provided in Appendix B, which includes three tables for each region that provide the following information:

- The 2011 APR status for the network developments that the 2010 NTNDP studies assumed would proceed.
- The 2011 APR network developments that relate to the second 10 years of the NTNDP 20-year outlook period and are within the NTNDP's scope.
- The network developments identified in the 2011 APRs that are outside the NTNDP's scope.

AEMO categorised developments in the first 10 years of the NTNDP outlook period on the basis of development trigger timeframes, how sensitive the development triggers are to future conditions, and the potential risks from inaction.

Table 2-1 lists the criteria AEMO used to categorise these developments.

[1] Unless otherwise stated, minor developments, such as capacitive compensation to meet increasing reactive demand, connection projects, and augmentation of lines at voltages below those considered in the NTNDP are excluded.

Table 2-1 — 2010 NTNDP network development categories for 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 undertaken (or there are limited or expensive workarounds).
Preparatory work	Development is generally triggered in the second five-year period in most scenarios but maybe later in others.	High opportunity cost if eventually required and there is a long lead time (for example, easement acquisition).
Monitoring	Development is triggered in the first or second five-year period in some scenarios.	Likely to have workarounds if the triggering conditions unfold (there is a relatively low opportunity cost if the development is delivered late).

2.2.1 Queensland

Developments identified as occurring in the first 10 years

The status and timing of projects listed in the 2011 APR generally correspond with developments identified by the 2010 NTNDP as occurring in the first 10 years.

Transmission line replacements and network rearrangements that were not modelled in the 2010 NTNDP have contributed to relieving some constraints identified in the NTNDP, and have deferred the need for certain projects (see developments Q1, Q10, Q14, and Q16 in Table 2-2) by several years. The trigger timing for these projects depends on factors such as the location of future generation developments, rate of demand growth, and other network developments.

Table 2-2 — 2010 NTNDP developments and their 2011 APR status – Queensland

Dev' No.	Transmission Development	2010 NTNDP Rating/Timing	2011 APR Status	Project Costs APR 2011 ($ Million)	Comments
QN1	Series compensation on Armidale–Dumaresq 330 kV circuits and Dumaresq–Bulli Creek 330 kV circuits.	Early attention.	Powerlink and TransGrid are actively investigating upgrade impacts and benefits, and outcomes will be released in 2011. (Powerlink 2011 APR, Section 5.2.2).	120	The 2011 APR assessment is consistent with the 2010 NTNDP.
Q1	New Ross–Chalumbin double circuit line (single circuit strung).	Preparatory work.	Works planned by Powerlink to upgrade the 132 kV system north of Yabulu may also address this issue. (Powerlink 2011 APR, Section 4.4.1).	Not listed.	Committed line replacements in Far North Queensland were only partially modelled in the 2010 NTNDP. The replacement works described in the 2011 APR relieve the limitations identified in the NTNDP, deferring the need for this development.
Q2	Stanwell–Broadsound 275 kV stringing of a second circuit.	Monitoring.	Powerlink is considering implementing this augmentation within five years. (Powerlink 2011 APR, Section 4.5.3).	45	The 2011 APR assessment is consistent with the 2010 NTNDP. Demand growth and potential market benefits may drive the need for advancing this project.
Q3	Broadsound–Nebo 275 kV series capacitors.	Monitoring.	This is listed as a potential network project for monitoring. (Powerlink 2011 APR, Appendix F, Table F.2).	45	The 2011 APR assessment is consistent with the 2010 NTNDP.
Q4	New Calvale–Stanwell 275 kV double circuit line.	Preparatory work.	This double circuit line is being constructed and is expected to be completed by summer 2013–14. (Powerlink 2011 APR, Section 4.7.1).	104.7	The 2011 APR assessment is consistent with the 2010 NTNDP.
Q10	New Halys–Greenbank 500 kV double circuit line (initially operating at 275 kV).	Preparatory work.	This is listed as a potential network project for monitoring. (Powerlink 2011 APR, Section 4.5.6 and Appendix F, Table F.2).	430	Powerlink's proposed rearrangement of circuits connecting the Blackwall, Swanbank, Greenbank, and Belmont Substations, which was not incorporated in the 2010 NTNDP analysis, may defer the need for this project by several years.

Dev' No.	Transmission Development	2010 NTNDP Rating/Timing	2011 APR Status	Project Costs APR 2011 ($ Million)	Comments
Q11	New Western Downs–Halys 500 kV double circuit line (northern route first build) initially operating at 275 kV.	Preparatory work.	Powerlink considers this development as a possible augmentation in 2016–17. The project's timing, however, will depend on future generation development in the region. (Powerlink 2011 APR, Section 4.5.5).	250–300	The 2011 APR assessment is consistent with the 2010 NTNDP.
Q14	New Blackwall–Belmont 275 kV double circuit line.	Early attention.	This is listed as a possible network augmentation after summer 2016–17. (Powerlink 2011 APR, Section 4.5.6).	50–70	The 2011 APR assessment is consistent with the 2010 NTNDP. Powerlink is proposing rearrangement of circuits connecting the Blackwall, Swanbank, Greenbank, and Belmont Substations, which was not incorporated in the 2010 NTNDP analysis and may defer the need for this project by several years.
Q15	New Blackwall–South Pine 275 kV double circuit line.	Early attention.	This is listed as a project involving re-arranging the existing circuits to form dedicated double circuit lines to the Blackwall and South Pine Substations by summer 2014–15. (Powerlink 2011 APR, Section 4.5.6).	70–80	The 2011 APR assessment is consistent with the 2010 NTNDP.
Q16	New Loganlea–Greenbank 275 kV double circuit line (one circuit strung).	Preparatory work.	This project is not specifically listed in the 2011 APR.	Not listed.	Powerlink's proposed rearrangement of circuits connecting the Blackwall, Swanbank, Greenbank, and Belmont Substations, which was not incorporated in the 2010 NTNDP analysis, may defer the need for this upgrade. Powerlink also advises that an overhead transmission line cannot be implemented due to a lack of available easements.

Commentary on developments occurring in the first 10 years

(Q1) Ross–Chalumbin upgrade

Powerlink's line replacements in Far North Queensland[2], which have not been incorporated in the 2010 NTNDP analysis, will defer the need for this upgrade beyond the NTNDP's outlook period. Nevertheless, the 2010 NTNDP noted that limitations between Ross and Chalumbin will be influenced by this replacement project, and future limitations could be relieved by energizing the 132 kV circuits to their design voltage of 275 kV.

Subsequent analysis confirms that the line replacements in Far North Queensland will relieve transmission limitations and defer the proposed upgrade beyond the NTNDP's outlook period.

(Q10) Halys–Greenbank upgrade and (Q16) Loganlea–Greenbank upgrade

Powerlink's proposed rearrangement of circuits connecting the Blackwall, Swanbank, Greenbank, and Belmont Substations, which was not incorporated in the 2010 NTNDP analysis, will defer the need for these upgrades.

Powerlink also advises that the Q16 Loganlea–Greenbank upgrade cannot be implemented due to a lack of available easements, and alternative projects will be proposed in future NTNDPs.

Other developments identified in the 2011 APR for the first 10 years, within NTNDP scope

Table 2-3 lists network projects from the 2011 APR for Queensland relating to the first 10 years of the outlook period, which are within the scope of the NTNDP.

For information about the status of augmentations the 2010 NTNDP studies assumed were proceeding, and information about the APR augmentations that relate to the second 10 years of the NTNDP outlook period, see Appendix B.

Table 2-3 — Other 2011 APR developments in the first 10 years, within NTNDP scope - Queensland

No	Transmission Development	2011 APR Anticipated Timing	Comments
1	New 275 kV transmission lines between Western Downs and Columboola (near Miles), and Western Downs and Wandoan South. New substations at Wandoan South and Columboola to increase transfer capability into the Surat Basin's north west area. (Powerlink 2011 APR, Section 4.5.5 and 4.7.1).	2013 to 2014.	This is a committed project. Powerlink anticipates substantial load growth in the area that was not available for the 2010 NTNDP load forecast.
2	Supply to the Bowen Basin coal mining area. A new 275 kV transmission line (initially operated at 132 kV) from Nebo Substation to the Moranbah area. (Powerlink 2011 APR, Section 4.5.3).	Summer 2014–15. To be consulted on within the next 12 months.	Powerlink anticipates substantial load growth in the area that was not available for the 2010 NTNDP load forecast.
3	Switch Gladstone–Gin Gin 275 kV circuit into Wurdong 275 kV (Powerlink 2011 APR, Section 4.5.4).	Approximately five years or more.	Project timing is sensitive to location of new generation connections. Identified in the second 10-year period in the 2010 NTNDP, project reference: Q5.

[2] Powerlink is implementing a condition-based, staged development of the coastal 132 kV lines between the Yabulu South and Woree Substations. The replacement lines are being built as a dual voltage, double circuit line (275 kV and 132 kV). Both circuits will initially operate at 132 kV. Replacement lines for the southern sections from Yabulu South to Tully are to be progressively rebuilt with the continuity of the coastal link re-established by summer 2013–14.

2.2.2 New South Wales

Developments identified as occurring in the first 10 years

The status of projects listed in the 2011 APR for New South Wales generally corresponds with developments identified by the 2010 NTNDP as occurring in the first 10 years.

Differences involve developments that depend on two 2010 NTNDP study assumptions, which relate to the location of new generation developments in either the Northern New South Wales (NNS) zone or the South West New South Wales (SWNSW) zone.

Table 2-4 lists the network developments identified in the 2010 NTNDP as occurring in the first 10 years of the outlook period, and their 2011 APR status. The development numbers used in the table are from the 2010 NTNDP.

Table 2-4 — 2010 NTNDP developments and their 2011 APR status – New South Wales

Dev' No.	Transmission Development	2010 NTNDP Rating/Timing	2011 APR Status	Project Costs APR 2011 ($ Million)	Comments
QN1	Series compensation on the Armidale–Dumaresq 330 kV circuits and the Bulli Creek–Dumaresq 330 kV circuits.	Early attention.	TransGrid and Powerlink are actively investigating upgrade impacts and benefits, and outcomes will be released in 2011. (TransGrid 2011 APR, Section 3.3, Section 6.2.3).	120	The 2011 APR assessment is consistent with the 2010 NTNDP.
NV1	A new 220 kV, 250 MVA phase angle regulator on the Buronga–Red Cliffs 220 kV circuit.	Early attention.	The feasibility of a phase angle regulator installation is under investigation. TransGrid and AEMO will investigate the impacts on the power systems in New South Wales and Victoria from increasing Murraylink power transfer capabilities. (TransGrid 2011 APR, Section 3.3, Section 6.3.8).	Not listed.	In the 2010 NTNDP, this augmentation was needed to maintain a 200 MW export capability from Victoria to South Australia via Murraylink at times of high summer demand in Victoria and high import from New South Wales to Victoria The 2011 APR assessment is consistent with the 2010 NTNDP.
NV2	A Victoria–New South Wales interconnector upgrade.	Preparatory work.	TransGrid and AEMO would jointly undertake this work. (TransGrid 2011 APR, Section 3.3, Section 6.3.1, and Section 6.3.8).	Not listed.	This augmentation arose for one of the 10 future scenarios as a result of new generation and transmission optimisation. The 2011 APR assessment is consistent with the 2010 NTNDP.
N4	A Hunter Valley–Eraring (via Newcastle) 500 kV development.	Early attention.	TransGrid is actively working on this development, with possible timing within the next decade, due to the impact of potential NNS zone generation development. (TransGrid 2011 APR, Section 3.3, Section 6.3.5).	Not listed.	The 2010 NTNDP studies linked this development to the timing and development of future gas powered generation (GPG) in Northern New South Wales. No new generation developments have been announced for this region. The 2011 APR assessment is consistent with the 2010 NTNDP.
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.	A second transformer is expected to be required soon. (TransGrid 2011 APR, Section 3.3, Section 6.1.8).	Not listed.	The 2011 APR assessment is consistent with the 2010 NTNDP.

Dev' No.	Transmission Development	2010 NTNDP Rating/Timing	2011 APR Status	Project Costs APR 2011 ($ Million)	Comments
N7/8	Hunter Valley–Northern New South Wales zone 500 kV developments.	Monitoring.	TransGrid is considering 500 kV line developments as an option for upgrading the Northern New South Wales 330 kV system capability.[a] Prior to the 500 kV development, and dependent on load growth in the Northern New South Wales zone and interconnector power flow, TransGrid expects to upgrade one or both sections of the Hunter Valley–Tamworth–Armidale 330 kV link. (TransGrid 2011 APR, Section 3.3, Section 6.3.2).	Not listed.	The 2010 NTNDP studies linked this development to the timing and development of future GPG in Northern New South Wales. No new generation developments have been announced for this region. The 2011 APR assessment is consistent with the 2010 NTNDP.
N9	Upgrade terminal equipment on the Ingleburn–Wallerawang Power Station 330 kV circuit to achieve the full line rating. Address attendant voltage control issues for Sydney's 330 kV transmission network.	Monitoring line issues and early attention to voltage control issues.	These are minor works to be undertaken if economic in advance of any potential limitations. The existing line rating is adequate. (TransGrid 2011 APR, Section 3.3, Section 6.2.4).	Not listed.	The 2011 APR assessment is consistent with the 2010 NTNDP.
N10	An additional Mt Piper – Wallerawang 330 kV circuit.	Early attention.	TransGrid is investigating the need for this line and potential options. (TransGrid 2011 APR, Section 3.3).	Not listed.	The 2010 NTNDP studies linked this development to retirement of units at the Wallerawang C Power Station. This development might be implemented between the announcement of the intention to retire units at Wallerawang and the actual retirement of plant. No announcements have yet been made. This development is linked to a retirement of generation, is not committed, and is under investigation only. The 2011 APR assessment is consistent with the 2010 NTNDP.

a. The requirement is based on the development of power stations in Northern New South Wales according to the TransGrid Strategic Network Development Plan 2008.

Commentary on developments occurring in the first 10 years

The NTNDP identified two options for further development of the 500 kV transmission line ring around the Sydney–Wollongong–Newcastle load centre (depending on the location of new generation). Table 2-5 summarises the staging of these developments under the different NTNDP scenarios (for more information about these scenarios see Chapter 7).

Table 2-5 — 2010 NTNDP development options for the Sydney–Wollongong–Newcastle load centre 500 kV transmission line ring[a]

Transmission Development	FC-H	FC-M	UW-L	UW-0	DW-H	DW-M	OS-M	OS-L	SC-L	SC-0
N3 - Bannaby–Sydney 500 kV double circuit line development (South)[b, c]	3	3		3			4	3		
N4 - Hunter Valley–Eraring (via Newcastle) 500 kV development (North)[b]			3	3	2	2			2	

a. The numbers and shading relate to augmentation trigger timeframes (as observed in the 2010 NTNDP modelling).

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

b. ‘North’ and ‘South’ refer to the location of the transmission development in relation to the Sydney load centre.

c. The N3 option is not listed in Table 2-4 as it falls outside the 2010 NTNDP’s 10-year outlook.

In terms of the location of new generation developments in either the NNS zone or the SWNSW zone, the N4 development corresponds to scenarios where New South Wales new entry generation occurs mostly in the NNS zone. The N3 development corresponds to scenarios where New South Wales new entry generation occurs mostly in other New South Wales zones. Under the Uncertain World’s zero carbon price sensitivity, new entry generation is divided evenly between the NNS zone and the other New South Wales zones. As a result, new entry generation developments under this scenario are spread relatively evenly across the region.

The New South Wales APR describes the N3 and N4 developments (both listed as conceptual)[3] as follows:

- The N3 development, which is required to supply the Sydney area and accommodate GPG development in the south, is expected to be released for consultation in 2011–12.
- TransGrid is actively working on the N4 development, has acquired property for it, and views its possible timing as being within the next decade to manage the impact of potential NNS zone generation development.

3 TransGrid. “New South Wales Annual Planning Report 2011” Section 3.3, Section 6.3.5.

The APR indicates a primary need to develop the southern 500 kV link to supply the Sydney area and to accommodate GPG development in the south. This is consistent with a number of NTNDP scenarios, and TransGrid's choice of location for the 500 kV development was made on the same basis as the NTNDP.

In terms of generation retirements, one development identified in the 2010 NTNDP (N10) is linked to a retirement of generation. This retirement was not committed as at the release of the 2011 APR, and the APR reports that the related transmission development is only under investigation.

Other developments identified in the 2011 APR for the first 10 years, within NTNDP scope

Table 2-6 lists network projects from the 2011 APR for New South Wales relating to the first 10 years of the outlook period, which are within the scope of the NTNDP.

For information about the status of augmentations the 2010 NTNDP studies assumed were proceeding, and information about the APR augmentations that relate to the second 10 years of the NTNDP outlook period, see Appendix B.

Table 2-6 — Other 2011 APR developments in the first 10 years, within NTNDP scope – New South Wales

No	Transmission Development	2011 APR Anticipated Timing	Comments
1	Supply to southern Sydney. Reinforce the 330 kV transmission network supplying the Sydney South, Liverpool, Ingleburn, Beaconsfield, and Haymarket Substations. (TransGrid 2011 APR, Section 6.1.1).	Consultation process may be initiated by 2011–12.	These projects were required in the second 10 years of the 2010 NTNDP outlook period in some scenarios (2010 NTNDP project references: N11 and N12). Two reasons that the APR timing may differ from the 2010 NTNDP are: • TransGrid uses a more stringent reliability standard for the Sydney CBD and inner metropolitan area[a] than is used for the NTNDP. • TransGrid allows for un-diversified, localised maximum demands whereas the NTNDP studies do not.
2	Bannaby–Yass and Marulan–Yass 330 kV circuits. Upgrading the existing lines to higher thermal ratings by modifying towers and other line work. (TransGrid 2011 APR, Section 6.3.1).	Approximately five years for initial developments.	The need for the upgrade of the Bannaby–Yass and Marulan–Yass 330 kV circuits is based on the expectation of new generation being developed in the SWNSW zone. The 2010 NTNDP assumed less new generation being installed in this zone than the TransGrid 2011 APR. This is a possible alternative to 2010 NTNDP project N1.
3	Bannaby–Sydney (South Creek) 500 kV double circuit line. (TransGrid 2011 APR, Section 6.3.5).	Consultation process may be initiated by 2011–12.	See commentary above for more information. 2010 NTNDP project reference: NEMLink, N3.
4	Murraylink Runback Control System: Inclusion of New South Wales sites in a scheme that already operates for Victorian circuits. Will allow Murraylink flows to take account of post-contingent flows on the New South Wales 220 kV transmission network between Darlington Point and Buronga. (TransGrid 2011 APR, Section 6.1.11).	The timing of the project depends on the owners of Murraylink completing communication links.	Not reported in the 2010 APR. The substation controls were also installed at sites in New South Wales but the communication links between the sites and Murraylink have not been completed. It is proposed to complete these communication links and the owners of Murraylink have undertaken to carry out these works. May affect timing of augmentation projects in the South West New South Wales area.

a. See the TransGrid Strategic Planning Review 2008.

2.2.3 Victoria

Developments identified as occurring in the first 10 years

The status of projects listed in the 2011 APR for Victoria generally corresponds with developments identified by the 2010 NTNDP as occurring in the first 10 years.

Table 2-7 lists the network developments identified in the 2010 NTNDP as occurring in the first 10 years of the outlook period and their 2011 APR status. The development numbers used in the table are from the 2010 NTNDP.

Table 2-7 — 2010 NTNDP developments and their 2011 APR status – Victoria

Dev' No.	Transmission Development	2010 NTNDP Rating/Timing	2011 APR Status[a]	Projects Costs APR 2011 ($ Million)	Comments
V1	A new 500 kV Loy Yang–Hazelwood line.	Monitoring.	Timing is subject to significant new generation connected to Loy Yang or an increase in import via Basslink. (2011 VAPR, Section 5.4.2 and Table 5-2).	68	The 2011 APR assessment is consistent with the 2010 NTNDP.
V5	A new 500/220 kV 1,000 MVA transformer at Ringwood, Rowville, or Cranbourne.	Early attention.	Augmentation timing approximately 2017–18. AEMO identified this for RIT-T assessment commencing in 2011–12. (2011 VAPR, Section 5.4.5 and Table 5-2).	66[a]	The 2011 APR assessment is consistent with the 2010 NTNDP.
V6	A new (additional to V5) 500/220 kV 1,000 MVA transformer at Ringwood, Rowville, or Cranbourne.	Preparatory work.	AEMO identified this for further assessment. (2011 VAPR, Section 5.4.5 and Table 5-2).	84[b]	The 2011 APR assessment is consistent with the 2010 NTNDP.
V7	Re-conductor the 220 kV Rowville–Springvale line.	Preparatory work.	The market benefits from augmenting the Rowville–Springvale–Heatherton 220 kV line are currently insufficient to justify an augmentation. Alternative options are being investigated. (2011 VAPR, Section 5.4.5).	Not listed.	The 2011 APR overload assessment is consistent with the 2010 NTNDP. Timing is based on a cost benefit analysis undertaken for the 2011 APR.
V8	A new 500 kV Moorabool–Mortlake line (third line).	Monitoring.	This augmentation will be triggered bysignificant new generation connections along the 500 kV Moorabool–Mortlake/Heywood line. (2011 VAPR, Section 5.4.3 and Table 5-2).	Not listed.[c]	The 2011 APR assessment is consistent with the 2010 NTNDP.
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.	The 2011 APR assessment found that an additional transformer is not likely to be economically justified within the next 10-year period. AEMO identified this augmentation for further investigation. (2011 VAPR, Section 5.4.5 and Table 5-2).	45	The 2010 NTNDP timing of this augmentation was linked with additional import from New South Wales to Victoria. Without additional import, the timing was after the first 10 years. The 2011 APR assessment is consistent with the 2010 NTNDP.

Dev' No.	Transmission Development	2010 NTNDP Rating/Timing	2011 APR Status[a]	Projects Costs APR 2011 ($ Million)	Comments
V15	An additional 500/220 kV 1,000 MVA transformer in the western part of the Greater Melbourne Metropolitan Area.	Monitoring.	Augmentation is not expected to be required within the next 10 years. (2011 VAPR, Section 5.4.5).	40[d]	The 2010 NTNDP timing of this augmentation was linked with high demand growth in Victoria and significant new generation in South West Victoria. For other scenarios, the 2010 NTNDP identified the timing after the first 10 years. The 2011 APR assessment is consistent with the 2010 NTNDP.
NV2	A New South Wales–Victoria interconnector upgrade.	Preparatory work.	AEMO has not assessed the benefits of upgrading the New South Wales–Victoria interconnector in detail for the 2011 VAPR. AEMO will continue to work with TransGrid on potential augmentations as part of the NTNDP.	Not listed.	The 2010 NTNDP timing of this augmentation within the first 10 years was linked with additional import from New South Wales to Victoria. The 2011 APR assessment is consistent with the 2010 NTNDP.
V16	Cut-in on the 220 kV Eildon–Thomastown line at South Morang.	Monitoring.	These augmentations will be triggered by a significant increase in import from New South Wales, plus Murray generation. (2011 VAPR, Section 5.4.4).	Not listed.	The 2010 NTNDP timing of these augmentations within the first 10 years was linked with additional import from New South Wales to Victoria.
V22	A new 330/220 kV Dederang transformer (fourth).	Monitoring.	These augmentations will be triggered by a significant increase in power transfers from New South Wales, plus Murray generation. (2011 VAPR, Section 5.4.4).	23	The 2010 NTNDP timing of these augmentations within the first 10 years was linked to additional power transfers from New South Wales to Victoria. The 2011 APR assessment is consistent with 2010 NTNDP findings.

Dev' No.	Transmission Development	2010 NTNDP Rating/Timing	2011 APR Status[a]	Projects Costs APR 2011 ($ Million)	Comments
V28	A new 220 kV Ballarat–Moorabool line (third line).	Early attention.	The 2011 APR identified the optimal timing of this augmentation in approximately 2017–18. AEMO identified this for RIT-T assessment commencing in 2011–12. (2011 VAPR, Section 5.4.6 and Table 5-2).	26	The 2011 APR assessment is consistent with the 2010 NTNDP.
NV1	A new 220 kV, 250 MVA phase angle regulator on the 220 kV Buronga–Red Cliffs interconnection.	Early attention.	The 2011 APR has not assessed the need for this augmentation in detail. AEMO will continue to work with ElectraNet and TransGrid on potential augmentations as part of the NTNDP.	Not listed.	In the 2010 NTNDP, this augmentation was needed to maintain a 200 MW export capability from Victoria to South Australia via Murraylink at times of high summer demand in Victoria and high import from New South Wales to Victoria.
V29	Replace the existing, single circuit 220 kV Ballarat–Bendigo line with a 220 kV double circuit line.	Early attention.	The 2011 APR identified this augmentation as part of an indicative augmentation plan with timing between 2015–16 and 2025–26. AEMO identified this for RIT-T assessment in 2011–12 as part of transmission development V31. (2011 VAPR, Section 5.4.6).	205	The 2011 APR assessment is consistent with the 2010 NTNDP.
V31	Uprate the existing 220 kV Ballarat–Bendigo line.	Early attention.	This augmentation could be economically justified by 2017–18. AEMO identified this for RIT-T assessment in 2011–12. (2011 VAPR, Section 5.4.6).	Not listed.	The 2011 APR assessment is consistent with the 2010 NTNDP.

Dev' No.	Transmission Development	2010 NTNDP Rating/Timing	2011 APR Status[a]	Projects Costs APR 2011 ($ Million)	Comments
V32	Replace the existing, single circuit 220 kV Bendigo–Kerang line with a new 220 kV double circuit line.	Monitoring.	This augmentation is not expected to be required within the next 10 years, and will be studied in more detail as part of investigations into the ongoing requirements for South Australian imports over Murraylink.	Not listed.	In the 2010 NTNDP, this augmentation was needed to maintain a 200 MW export capability from Victoria to South Australia via Murraylink. With reduced export, the identified timing will be deferred until after the first 10 years.
V34	Replace the existing 220 kV Kerang–Wemen–Red Cliffs single circuit line with a new 220 kV double circuit line.	Monitoring.	This augmentation is not expected to be required within the next 10 years, and will be studied in more detail as part of investigations into the ongoing requirements for South Australian imports over Murraylink. (2011 VAPR, Section 5.4.6).	450	In the 2010 NTNDP, this augmentation is needed to maintain a 200 MW export from Victoria to South Australia via Murraylink. With reduced export, the identified timing will be deferred until after the first 10 years.
V30	Uprate the existing 220 kV Geelong–Moorabool lines.	Early attention.	The Geelong–Moorabool 220 kV line loading limitation has been removed, as the line traps limiting the line ratings were removed after the publication of the 2010 VAPR. (2011 VAPR, Section 5.4.6).	Completed.	Completed.

a. This cost is for an additional transformer at Cranbourne.

b. This cost is for a new transformer at Ringwood, including a 500 kV substation development.

c. The 2011 APR provided a cost estimate of $410 million for a double circuit line between Moorabool and Heywood.

d. This cost is for an additional transformer at Keilor.

e. Projects also listed in 2011 VAPR, Attachment A1.

Other developments identified in the 2011 APR for the first 10 years, within NTNDP scope

Table 2-8 lists network projects from the 2011 APR for Victoria relating to the first 10 years of the outlook period, which are within the scope of the NTNDP.

For information about the status of augmentations the 2010 NTNDP studies assumed were proceeding, and information about the APR augmentations that relate to the second 10 years of the NTNDP outlook period, see Appendix B.

Table 2-8 — Other 2011 APR developments in the first 10 years, within NTNDP scope – Victoria

No	Transmission Development	2011 APR Anticipated Timing	Comments
1	Uprating the Rowville–Malvern 220 kV line (2011 VAPR, Section 5.4.5).	Between 2015–16 and 2020–21.	The 2011 APR load forecast at Malvern Terminal Station is approximately 10% higher than the load forecast published the previous year. As a result, the 2011 APR identified the timing of this development as within the next five years. Adding real-time wind speed to the line rating calculation is likely to defer the uprating option.
2	A new Cranbourne–Heatherton 220 kV double circuit line (2011 VAPR, Section 5.4.5).	Between 2015–16 and 2025–26.	This augmentation is an alternative option to reconductoring the Rowville–Springvale 220 kV line, which was identified in the 2010 NTNDP (2010 NTNDP project reference: V7). This augmentation also addresses the reliability of supply to Springvale and Heatherton Terminal Stations.
3	Connection of Rowville-Thomastown 220 kV line at Ringwood.	2014–15.	This augmentation was identified in the 2010 NTNDP as required between 2020–21 and 2024–25 (2010 NTNDP project reference: V12). In the 2011 APR, it was brought forward due to increased load forecast at Ringwood, and AEMO has identified it for RIT-T assessment in 2011–12. A 500/220 kV transformer at Ringwood (2010 NTNDP project references: V5 and V6) would defer this augmentation.
4	East Rowville-Rowville 220 kV line uprating or a new East Rowville-Rowville 220 kV line.	2017–18.	AEMO has identified this augmentation for RIT-T assessment in 2011–12 as part of the next eastern metropolitan 500/220 kV transformer development. A 500/220 kV transformer at Cranbourne (2010 NTNDP project references: V5 and V6) would defer this augmentation.
5	A new 500/275 kV transformer at Heywood (third).	Between 2013 and 2017.	This augmentation was proposed in the 2011 APR, with timing to be refined in conjunction with the Heywood Interconnector upgrade RIT-T assessment, which is in progress. For South Australian network development associated with this augmentation, see item 5 of Table 2.10. 2010 NTNDP project references: VS1 and VS2.

2.2.4 South Australia

Developments identified as occurring in the first 10 years

The status of projects listed in the 2011 APR for South Australia generally corresponds with developments identified by the 2010 NTNDP as occurring in the first 10 years.

Table 2-9 lists the network developments identified in the 2010 NTNDP as occurring in the first 10 years of the outlook period and their 2011 APR status. The development numbers used in the table are from the 2010 NTNDP.

Table 2-9 — 2010 NTNDP developments and their 2011 APR status – South Australia

Dev' No.	Transmission Development	2010 NTNDP Rating/Timing	2011 APR Status	Projects Costs APR 2011 ($ Million)	Comments
S4	Establish the second 275 kV Davenport–Cultana line and reinforce the 275/132 kV transformation capability at Cultana. Rearrange the 132 kV Davenport–Whyalla and Whyalla–Middleback–Yadnarie lines.	Early attention.	Work in progress, targeted for commissioning in 2013. (ElectraNet 2011 APR, Section 12.5.1).	66	The 2011 APR assessment is consistent with the 2010 NTNDP.
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 project is one of the proposed 10-year network augmentation projects and may be required as early as 2016 or as late as 2021. (ElectraNet 2011 APR, Section 9.4.2).	158	The 2011 APR assessment is consistent with the 2010 NTNDP. The project timing depends on regional (the mid-North region) load growth.
S8	Install 275 kV series compensation between the South East Substation and the Tailem Bend Substation.	Monitoring.	This project is associated with the Heywood Incremental Augmentation and will be considered as part of the RIT-T assessment, which is being undertaken jointly between AEMO and ElectraNet in 2011–12. (ElectraNet 2011 APR, Section 3.1.1, Appendix A and Table A.2).	Not listed.	The 2011 APR assessment is consistent with the 2010 NTNDP.
NV1	A new 220 kV, 250 MVA phase angle regulator on the 220 kV Buronga–Red Cliffs interconnection.	Early attention.	ElectraNet and AEMO intend to proceed with joint planning to develop augmentation options and undertake preliminary market simulation studies, in consultation with TransGrid, during 2011–12. (ElectraNet 2011 APR, Section 10.2 and Appendix A).	Not listed.	In the 2010 NTNDP, this augmentation is needed to maintain a 200 MW export capability from Victoria to South Australia via Murraylink at times of high summer demand in Victoria and high import from New South Wales to Victoria. See commentary on developments occurring in the first 10 years following this table for more information.

Commentary on developments occurring in the first 10 years

AEMO, in consultation with ElectraNet, carried out studies on the Victoria-South Australia (Murraylink) interconnector capability required to support load growth in the Riverland region of South Australia (2010 NTNDP project reference NV1). Long-term network options in the Riverland region and regional Victoria are also being investigated jointly by AEMO and ElectraNet. AEMO will carry out further investigation in consultation with TransGrid and ElectraNet to address the limitations in Southern New South Wales in relation to high transfer from Victoria to South Australia via Murraylink and alternative options to a phase angle regulator on the Buronga-Red Cliffs 220 kV line.

Other developments identified in the 2011 APR for the first 10 years, within NTNDP scope

Table 2-10 lists network projects from the 2011 APR for South Australia relating to the first 10 years of the outlook period, which are within the scope of the NTNDP.

For information about the status of augmentations the 2010 NTNDP studies assumed were proceeding, and information about the APR augmentations that relate to the second 10 years of the NTNDP outlook period, see Appendix B.

Table 2-10 — Other 2011 APR developments in the first 10 years, within NTNDP scope – South Australia

No	Transmission Development	2011 APR Anticipated Timing	Comments
1	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. (ElectraNet 2011 APR, Section 7.4.2).	2012.	This was proposed in the 2010 APR. The timing identified in the 2011 APR is earlier than the 2010 NTNDP, as this project is primarily driven by local demand and local generation assumptions that are not fully captured in the NTNDP modelling. (2010 NTNDP project reference: S1)
2	Increase the rating of the 275 kV Northfield–Kilburn circuit to the line design rating by relevant protection and selected plant modifications. (ElectraNet 2011 APR, Section 7.4.2).	2012.	This was proposed in the 2010 APR. The timing identified in the 2011 APR is earlier than the 2010 NTNDP, as this project is primarily driven by local demand and local generation assumptions that are not fully captured in the NTNDP modelling. (2010 NTNDP project reference: S2)
3	Construct a 275 kV double circuit transmission line from Robertstown to Monash. Establish a 275/66 kV substation at Monash with one 50 MVAr 275 kV reactor, two 225 MVA 275/66 kV transformers and one 240 MVA 275/132 kV transformer. Construct a high capability double circuit 66 kV line from Monash to Berri, and remove all significant transmission infrastructure from Berri. (ElectraNet 2011 APR, Section 10.4.2).	2016–2020.	This was proposed in the 2010 APR, and reported in the 2010 NTNDP as a potential option to relieve the limitation associated with the 132 kV transmission network supplying the Riverland region. This is not a 2010 NTNDP project. In the 2010 NTNDP network analysis studies, it was assumed that South Australia is importing from Victoria via Murraylink to meet the supply-demand balance in South Australia at times of peak demand. Recent studies showed that the Victorian network might not be able provide the level of Murraylink transfer into South Australia to support the load growth in the Riverland region, avoiding the need of augmentations in the Riverland region. Further studies are being carried out to identify the most economical options.
4	Install additional 275/132 kV transformer capability in the South East region together with associated supporting 275 kV and 132 kV line works, as required. The optimal location of the additional capability to support this emerging limitation is currently under investigation. (ElectraNet 2011 APR, Section 11.4.2).	2013–2018.	This was proposed in the 2010 APR. Timing and scope to be refined in conjunction with the RIT-T analysis for the Victoria-South Australia (Heywood) interconnector incremental upgrade. (2010 NTNDP project references: S9, VS1, VS2).
5	Install a third Heywood transformer and associated work, such as a static voltage controller (SVC), series compensation, and reconfiguration of the South East 132 kV transmission network. (ElectraNet 2011 APR, Section 11.4.3).	N/A.	This was proposed in the 2010 APR. Timing and scope to be refined in conjunction with the RIT-T analysis for the Victoria-South Australia (Heywood) interconnector incremental upgrade. (2010 NTNDP project references: S8, VS1, VS2).

No	Transmission Development	2011 APR Anticipated Timing	Comments
6	Reinforce the Eyre Peninsula south of Cultana by constructing a high capability double circuit 275 kV line from Cultana–Yadnarie–Port Lincoln and establishing a 275/132 kV substation at Yadnarie. Install a 100 MVAr capacitor bank at Yadnarie and a static VAr compensator at Port Lincoln. In the future, convert the Port Lincoln to Yadnarie 132 kV line for sub-transmission purposes. (ElectraNet 2011 APR, Section 12.5.2).	2018–2020.	This was proposed in the 2010 APR. The need and timing of this project is subject to the growth of load and new generation development assumptions on the Eyre Peninsula. As a result, it was not reported in the 2010 NTNDP. After publishing the 2010 NTNDP, ElectraNet received connection enquiries for significant loads on the Eyre Peninsula.

2.2.5 Tasmania

Developments identified as occurring in the first 10 years

The status of projects listed in the 2011 APR for Tasmania generally corresponds with developments identified by the 2010 NTNDP as occurring in the first 10 years.

Table 2-11 lists the network developments identified in the 2010 NTNDP as occurring in the first 10 years of the outlook period and their 2011 APR status. The development numbers used in the table are from the 2010 NTNDP.

Table 2-11 — 2010 NTNDP developments and their 2011 APR status – Tasmania

Dev' No.	Transmission Development	2010 NTNDP Rating/Timing	2011 APR Status	Projects Costs APR 2011 ($ Million)	Comments
T1	Configure Waddamana switching, and upgrade the 110 kV Palmerston–Waddamana line to 220 kV operation.	Early attention.	Configuration of Waddamana switching is scheduled by June 2013, subject to a RIT-T. Further options are being investigated to implement a preferred option for Waddamana–Palmerston 220 kV transmission capability by mid-2016. (Transend 2011 APR, Section 5.2.5).	Not listed.	The 2011 APR assessment is consistent with the 2010 NTNDP.
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 is investigating an additional 110 kV line between Scottsdale and Derby, and rearrangement of this new line with the existing 110 kV lines to form a Norwood–Derby 110 kV line and a Norwood–Scottsdale–Derby 110 kV line, with possible implementation by 2015. Augmentation of the existing Norwood–Scottsdale 110 kV lines depends on the requirements of future generation connections. (Transend 2011 APR, Section 2.3.2).	Not listed.	The 2011 APR assessment is consistent with the 2010 NTNDP.
T3	Replace the existing 220 kV Burnie–Sheffield single circuit line with a new 220 kV double circuit line.	Early attention.	Replacement of the existing 220 kV Burnie–Sheffield single circuit line with a new double circuit 220 kV line is being investigated, with possible implementation by 2019. (Transend 2011 APR, Section 2.3.2).	Not listed.	The 2010 NTNDP assessment accommodated significant wind generation in North West Tasmania within the next five years. The 2011 APR, however, did not identify any firm proposals for wind generation in this location within the next five years.

Dev' No.	Transmission Development	2010 NTNDP Rating/Timing	2011 APR Status	Projects Costs APR 2011 ($ Million)	Comments
T4	A new 220 kV Sheffield–Palmerston double circuit line.	Early attention.	Replacement of the existing 220 kV Sheffield-Palmerston single circuit line with a new double circuit 220 kV line is being investigated, where the existing 220 kV line will be converted to 110 kV operation to enable additional connection points, with possible implementation by 2017. (Transend 2011 APR, Section 2.3.2).	Not listed.	The 2010 NTNDP assessment accommodated significant wind generation in North West Tasmania within the next five years. The 2011 APR, however, did not identify any firm proposals for wind generation in this location within the next five years.
T5	A new 220/110 kV transformer in the Hobart area.	Monitoring.	An additional transformer is not likely to be needed until 2020 at the earliest. Load growth in the area will be monitored closely. (Transend 2011 APR, Section 2.3.2).	Not listed.	The 2010 NTNDP identified this transformer within the next 10 years for high demand projection scenarios. The 2011 APR assessment was based on a 10% probability of exceedence medium economic growth forecast, and did not identify this augmentation within the next ten years.

Other developments identified in the 2011 APR for the first 10 years

There are no network projects from the 2011 Tasmanian APR relating to the first 10 years of the outlook period that are within the scope of the NTNDP.

For information about the status of augmentations the 2010 NTNDP studies assumed were proceeding, and information about the APR augmentations that relate to the second 10 years of the NTNDP outlook period, see Appendix B.

CHAPTER 3 - NETWORK SUPPORT AND CONTROL ANCILLARY SERVICES

Summary

This chapter provides information about National Electricity Market (NEM) requirements for network support and control ancillary services (NSCAS). NSCAS controls active and reactive transmission network power flows, helping to maintain power system security and reliability, as well as delivering net economic benefits to the NEM by maintaining or increasing the power transfer capabilities of existing assets.

The process for identifying NSCAS requirements and procuring NSCAS is due to change in 2012. This chapter also explains these changes and provides information about how AEMO expects to review NSCAS requirements under the new framework.[1]

AEMO identifies the approximate quantity, duration, and location of NSCAS gaps so that transmission network service providers (TNSP) can develop investment proposals or establish operating arrangements to deliver these services. If TNSPs do not procure an adequate quantity of NSCAS, AEMO can contract for services or issue directions to maintain secure power system operations.

To provide the market with sufficient notice to enable these services to be met through orderly investment, AEMO has reviewed the potential need for NSCAS for the next five years:

- In New South Wales there is a need for reactive power ancillary services (RPAS) of up to 740 MVAr for the next five years to ensure acceptable voltage quality.
- In Victoria there is a need for network loading control ancillary services (NLCAS) of approximately 260 MW for the next five years to increase Victorian transmission network power transfer capabilities, and a need for RPAS of 160 MVAr in 2014–15, and 230 MVAr in 2015–16, to ensure voltage stability.
- In South Australia there is a likely need for RPAS of approximately 30 MVAr in 2013–14 to ensure voltage stability.

From 2012, AEMO will also investigate limitations in the NEM, where increasing the transmission capacity by procuring NSCAS has the potential to increase net economic benefits, and an assessment of the expected increase.

As required under the new NSCAS rules, AEMO has been consulting with relevant stakeholders and preparing the NSCAS Descriptions and NSCAS Quantity Procedure publications, which describe the types of NSCAS to be procured by the TNSPs or AEMO, and AEMO's approach to assessing NSCAS gaps and economic benefits.

The consultation documents, submissions received, and the final determination (when available) will be published on the AEMO website.[2]

[1] For more information about the new NSCAS Rules, see the National Electricity Amendment (Network Support and Control Ancillary Services) Rule 2011 No.2. http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Rules-Made.html. Accessed 1 November 2011.

[2] http://www.aemo.com.au/electricityops/0168-0011.html.

3.1 Reporting future NSCAS needs

In April 2011, the Australian Energy Market Commission (AEMC) amended the arrangements for the identification and procurement of network support and control ancillary services (NSCAS). These changes will take effect in April 2012.

In anticipation of these changes, the 2011 NTNDP provides a preliminary NSCAS assessment before the 2012 commencement date. The 2012 NSCAS reporting will fully comply with the new National Electricity Rules (NER) requirements, and will incorporate the following information:

- An assessment identifying annual NSCAS that involves determining:
  - Needs (the NSCAS required to maintain security and reliability, and maintain or increase power transfer capability to maximise net economic benefits), which will be identified by power system and market simulation studies
  - Gaps (any NSCAS need AEMO forecasts within the next 5 years)
  - The relevant NSCAS trigger dates (the date an NSCAS gap first arises) and tender dates (the date AEMO needs to call for offers to acquire NSCAS in time to meet a trigger date)
- The NSCAS acquired by AEMO in the previous year.

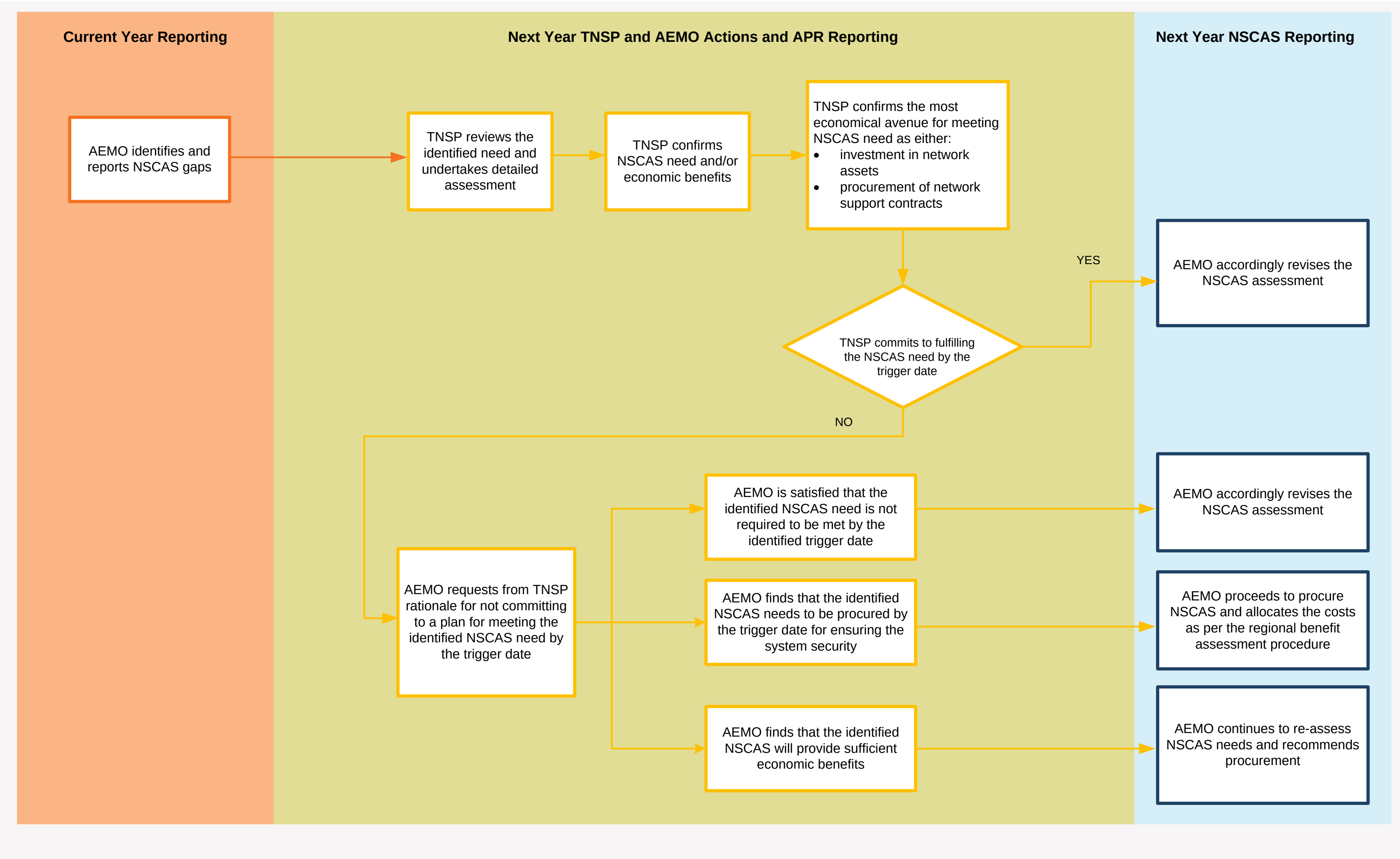
From 2012, AEMO will investigate limitations in the NEM, where increasing the transmission capacity by procuring NSCAS has the potential to increase net economic benefits, and an assessment of the expected increase.

The new NSCAS Rules also require AEMO to develop and publish descriptions of the types of NSCAS and quantity procedures for determining future needs. This will provide guidance on how to determine the most appropriate NSCAS needs for ensuring system security and reliability, and delivering net market benefits. AEMO is currently consulting on this requirement, with publication of its findings scheduled by the end of 2011. As a result, current NSCAS descriptions and procedures may differ from the NSCAS description and NSCAS quantity procedure to be published in 2011.

In the future, the TNSPs will be required to consider the NSCAS gaps identified by AEMO, and act to meet them through their network planning and investment processes.

Figure 3-1 shows a summary of the process for addressing NSCAS needs identified by AEMO.

Figure 3-1 — Process for meeting the NSCAS needs forecast by AEMO within the next five years



3.2 Types of network support and control ancillary services

NSCAS comprises a wide range of services that can be provided by TNSPs, generators, market participants and non-market participants. According to the new NSCAS Rules, any non-market ancillary service able to control active and reactive power flows into or out of a transmission network to maintain power system security and reliability of supply, or to maintain or increase power transfer capabilities to deliver net economic benefits to the NEM, can be classified as NSCAS.

NSCAS is required when there is a shortage of existing and planned network control and support services delivered by TNSPs using their regulated assets. When a shortage occurs, TNSPs are expected to procure NSCAS. Without this procurement, AEMO can contract for services if they are available, or issue directions to maintain secure power system operations.

Two types of NSCAS are assessed:

- Network loading control ancillary services (NLCAS).
- Reactive power ancillary services (RPAS).

3.2.1 Network loading control ancillary services

NLCAS reduces the loading on selected transmission lines by controlling active power flows into or out of the transmission network.

Types of NLCAS may include, but are not limited to, customer load reductions, standby or small-scale generation increases, and the use of phase shift transformers and other equipment to control active power flow.

3.2.2 Reactive power ancillary services

RPAS controls reactive power flows into or out of the transmission network, and can be provided by several means:

- Generating unit (including wind farms) reactive power capacities.
- Capacitors and reactors.
- Synchronous condensers, static synchronous compensators, and static VAR compensators.
- Control of customer reactive power consumption.

3.3 Procedure for assessing future NSCAS needs

The procedure for assessing future NSCAS needs involves four main steps:

- Indentifying key issues for further NSCAS assessment.
- Collecting the data necessary for the simulation studies and assessment.
- Developing study cases for simulation.
- Conducting power system simulation studies.

3.3.1 Identifying key issues

A key issue identified for NSCAS assessment is an issue that is presently being managed by existing Network Control Ancillary Service (NCAS) contracts, or that may not have been sufficiently addressed by the relevant TNSP in its latest annual planning report (APR), and for which NSCAS is a likely resolution option.

AEMO identifies key issues by reviewing previous APRs and AEMO planning and operational documents (like the NTNDP and Power System Adequacy - Two Year Outlook), as well as from operational experience. AEMO may also identify or confirm key issues by carrying out power system simulation studies.

3.3.2 Collecting data

AEMO collects information necessary to enable a more detailed investigation of key issues and their potential solutions. This includes (but is not limited to) the following:

- Continuous and short-term ratings of existing transmission assets from the relevant TNSP.
- Existing and future maximum fault levels from the relevant TNSP.
- Historical power system snapshots representative of high and low demand conditions.
- Committed transmission network developments, new generation proposals, or existing generation retirements as identified in the APRs and the Electricity Statement of Opportunities (ESOO).
- Connection point MW and MVAr forecasts from the most recent relevant APR (or equivalent).
- Generating unit reactive power performance standards.
- NSCAS previously procured and dispatched by AEMO.
- Technical details of existing network support agreements.

3.3.3 Developing study cases

AEMO develops study cases using the data collected for each key issue. The study cases, which assess NSCAS requirements by modelling the relevant power system operating conditions, consider peak load flows each year for the next five years (to 2015–16), and light load scenarios.

3.3.4 Conducting power system simulation studies

Various power system simulation studies (including load flow studies and voltage stability studies) are carried out for the five-year outlook. The results determine the NSCAS quantities required to satisfy NER security and reliability requirements.

3.4 Common assumptions for power system simulation studies

This section lists the common assumptions applied to the NSCAS assessment. Region-specific assumptions are listed with the relevant regional assessments in Section 3.5.

3.4.1 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% probability of exceedence (POE) maximum demand (MD), and all committed new generating units (as identified in the most recent ESOO) are in service.
- Some proposed generation will be in service if required to meet the 10% POE MD.[3]
- When simulating credible contingency events, the critical generating unit may be out of service as a prior outage (treated as N-g-1) to enable the examination of variations in total generation availability.[4]
- Generating unit capacities are as identified in the 2011 ESOO.
- Generating unit reactive power outputs are capped to the values specified in their performance standards.
- The existing NCAS contracts with generators can be renewed with the same capacity if required.
- The maximum interconnector power transfer limits will remain unchanged for the next five years unless specifically advised otherwise.
- Future generation dispatch patterns derive from the short-run marginal costs (as used in the NTNDP market simulations) and operational experience of existing generating units.

3.4.2 Load and demand assumptions

Assumptions about load and demand include the following:

- A 10% POE MD medium economic growth projection as developed by the TNSPs for the 2011 APRs.
- The 10% POE MD connection point active and reactive load forecasts provided by the TNSPs.
- When determining reactive power absorption requirements, minimum regional demand (which refers to actual minimum demand conditions over the past 12 months[5]) remains constant for the outlook period.
- For all loads, the active and reactive power consumed by the loads remains constant and is not dependent on the supply voltage.

[3] Proposed generation is identified in the ESOO, and its availability is determined in consultation with the relevant TNSP.

[4] This is only the case if remaining generation still meets the 10% POE MD, the situation is realistic and has occurred before, and corresponds with criteria given in the relevant TNSP's APR or as agreed by the TNSP.

[5] Established from Operations and Planning Data Management System (OPDMS) power system snapshots.

3.4.3 Other assumptions

General assumptions include the following:

- When determining RPAS requirements, only committed transmission network augmentations are modelled.
- Existing network support agreements remain in place, unless the relevant TNSP has confirmed otherwise.
- All installed reactive plant is available and can be switched in or out of service under system normal conditions.
- Only credible contingency events are considered.[6] The worst contingency event modelled is based on contingency analysis outcomes.
- Prior (planned) transmission network outages do not affect RPAS requirements for maintaining security.[7]
- When evaluating reactive power margins, transformer taps will remain in their pre-contingency positions after a contingency event.
- All available capacitor banks can be switched under system normal conditions during 10% POE condition unless this results in overvoltages.

[6] AEMO simulates an N-1 credible contingency. Other contingencies, however, may also be checked.

[7] This is because they would not be permitted to proceed if power system security can not be maintained.

3.5 Assessment results from power system simulation studies

This section provides a summary of each region's need for NSCAS, as identified by the power system simulation studies. It also includes any assumptions specific to a particular region. Although no tender dates have been identified, AEMO is currently consulting on the tender process, and anticipates the tender dates will be approximately six months earlier than the trigger dates.

3.5.1 Queensland assessment

The analysis of the key regional issues, involving a voltage stability limit for power transfers within Queensland, identified no need for NSCAS (of either type) for the period 2011–12 to 2015–16.

These results are consistent with the 2010 NTNDP assessment.

3.5.2 New South Wales assessment

The analysis of the key regional issues, involving voltage stability and voltage control associated with supplying major load centres from the region's major generating centres during peak load conditions, and high voltage at Upper Tumut and Kangaroo Valley during light load conditions, identified the following:

- No need for NLCAS.
- No need for the existing supplying RPAS for the next five years (procured to ensure acceptable voltage quality and sufficient voltage stability margins for supplying major load centres in Sydney during peak load conditions).[8]
- A need for absorbing RPAS for the next five years to avoid overvoltage under light load conditions, with a July 2012 trigger date.[9]

Table 3-1 summarises NSCAS needs for the next five years.

Table 3-1 — Indicative NSCAS needs for New South Wales[a] (MVAr)

Type of NSCAS	2011–12	2012–13	2013–14	2014–15	2015–16
Absorbing RPAS[b]	720	740	740	740	740

a. "Indicative" refers to the timing and quantity required, which are approximate.

b. These values reflect the current service, which is RPAS from Snowy Hydro generating units running as synchronous condensers. An alternative service may result in different values.

The 2011 NSCAS assessment indicates a significantly lower supplying reactive power need than identified in 2010 for two reasons:

- The 10% POE MD forecast provided by TransGrid is significantly lower than the 2010 forecast, in both MW and MVAr.
- New committed network reactive power supply augmentation projects, and particularly the two 160 MVAr capacitor banks at Beaconsfield West and the additional 80 MVar capacitor in Sydney West.

8 Assuming all committed augmentation projects advised by TransGrid, particularly the two 160 MVAr capacitor banks at Beaconsfield West (or the equivalent quantity of reactive power support at another location such as Sydney South), will be completed on schedule, and Munmorah Unit 3 may be out of service during peak demand periods.

9 This is an existing need for absorbing reactive power, the contract for which will expire in July 2012. The trigger date is the month a new contract will be required.

Absorbing reactive power needs have increased compared with the 2010 assessment for the following reasons:

- Less scheduled loads (pumps) at the Kangaroo Valley Hydroelectric Power Station are assumed (a reduction of 80 MW compared to 2010).
- The newly committed Wallaroo 330 kV switching station (which includes a new 330 kV line) is scheduled to be in service by July 2012.

3.5.3 Victorian assessment

The analysis of the key regional issues, involving a review of the load inter-tripping requirement associated with 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 voltage quality and voltage stability issues in the regional Victoria area, identified the following:

- An ongoing need for NLCAS 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 MVA, with a July 2012 trigger date.[10] This is currently provided by inter-tripping the loads at the Portland Aluminium smelter.
- A need for supplying RPAS in the Eastern Melbourne Metropolitan Area for the period 2014–15 and 2015–16 (if supplied at the Rowville Terminal Station, this will be equivalent to 160 MVar in 2014–2015, increasing to 230 MVAr in 2015–2016), to provide a sufficient reactive power margin and maintain voltage stability in the area of the Cranbourne and Rowville Terminal Stations, with a December 2014 trigger date.

Table 3-2 summarises NSCAS needs for the next five years.

Table 3-2 — Indicative NSCAS needs for Victoria[a] (MW and MVAr)

Type of NSCAS	2011–12	2012–13	2013–14	2014–15	2015–16
NLCAS (MW)	260	260	260	260	260
Supplying RPAS (MVAr)	0	0	0	160[b]	230[b]

a. “Indicative” refers to the timing and quantity required, which are approximate.

b. Equivalent RPAS from a capacitor bank at Rowville.

These results are consistent with the 2010 NTNDP assessment.

[10] This is an existing need for network loading control, the contract for which will expire in July 2012. AEMO is assessing its net market benefit, and the trigger date is the month a new contract will be required if this need is found to be economically justified.

3.5.4 South Australian assessment

The analysis of the key regional issues did not identify any NLCAS-related issues. Analysis involving low voltage or voltage stability in the South East, Eyre Peninsula, Eastern Hills, and mid-North areas, however, identified a need for RPAS of approximately 30 MVAr in the vicinity of Middleback on the Eyre Peninsula for 2013–14, with a December 2013 trigger date.[11]

Table 3-3 summarises NSCAS needs for the next five years.

Table 3-3 — Indicative NSCAS needs for South Australia[a] (MVAr)

Type of NSCAS	2011–12	2012–13	2013–14	2014–15	2015–16
Supplying RPAS	0	0	30[b]	0	0

a. “Indicative” refers to the timing and quantity required, which are approximate.

b. This will not be required if the main parts of the Cultana 275/132 kV augmentation project can be completed prior to summer 2013–14, before a forecast step load increase on the Eyre Peninsula.

The 2010 NSCAS assessment did not identify the Eyre Peninsula reactive power requirements because the new step load increase on the Eyre Peninsula for 2013 was only forecast by ElectraNet in 2011.

3.5.5 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 need for NSCAS (of either type) for the next five years.[12]

These results are consistent with the 2010 NTNDP assessment.

[11] This requirement can be avoided if the main project scope of the Cultana 275/132 kV augmentation is complete prior to summer 2013–14, before a forecast step load increase on the Eyre Peninsula. The main project scope includes duplicated 275 kV lines between Davenport and Cultana, duplicated 200 MVA 275/132 kV transformers at Cultana, a Cultana–Yadnarie line, and two 132 kV lines from Cultana to Whyalla Central and Whyalla Terminal Station.

[12] AEMO found an RPAS requirement only when southern area generation is very low and power transfer in a southerly direction is high during winter peaks, which is unlikely.

CHAPTER 4 - INTEGRATING LARGE-SCALE WIND GENERATION IN THE NEM

Summary

This chapter presents an analysis of the issues arising from the large-scale integration of wind generation in the National Electricity Market (NEM). Some considerations also apply to other forms of intermittent generation such as solar photovoltaic (PV) generation.

The analysis reviewed the technical issues relating to large-scale wind generation both here and overseas, including the results of international wind integration studies. This also considered the way these issues are addressed by Australia's National Electricity Rules (NER) and international grid codes.

The modelling used to analyse the impacts of increased wind generation included drivers of wind generation investment, network congestion and its impact on wind generation, the correlation between wind generation output and demand, the diversity of output between locations, and the way demand and wind generation changes over short timeframes.

The key findings from this analysis include the following:

- The NER technical standards for generation connections covering wind generation are largely consistent with international standards. Some potential improvements have been identified for integrating large-scale wind generation.
- Advantages stem from a positive correlation between generation and demand, maximising energy output during high demand periods while minimising the need for transmission augmentation.
- The NEM is well-designed for integrating large amounts of wind generation. Favourable characteristics include short dispatch intervals, semi-dispatch of wind generation, wind forecasting that is integrated into the dispatch process, and flexible frequency control markets.
- Displacing conventional generation with wind and other asynchronous generation will reduce inertia, with implications for fast frequency control, stability, and the management of load shedding for frequency recovery following a loss of supply.

Initiatives to be pursued by AEMO resulting from this analysis include the following:

- Reviewing relevant aspects of the technical standards for connecting new generation.
- Further analysis of increasing wind penetration and the implications for inertia and stability (such as voltage stability) and ongoing network operations.
- Refining market modelling to better understand the drivers of wind investment and to account for different cost structures for wind turbines designed for higher and lower wind speeds.
- Discussions with wind turbine manufacturers involving the potential capabilities of new turbine designs.
- Understanding the implications of using generic rather than detailed turbine models for power system analysis.
- Monitoring trends relating to wind and other intermittent generation, and anticipating network impacts.

4.1 The changing generation mix

The NEM's generation mix is changing[1], with government policies and incentives leading to significant increases in renewable generation, particularly wind farms and rooftop solar photovoltaic (PV) installations.

The 2010 NTNDP presented a range of scenarios projecting significant future renewable generation (the majority from wind), growing to between 4 GW to 6 GW by 2019–20, and up to 10 GW by 2029–30. The 2011 ESOO listed over 15 GW of proposed wind generation projects[2], not all of which will go ahead, supporting the scale of development projected in the NTNDP.

As wind generation grows, it poses certain challenges in relation to its intermittent nature, the types of technologies adopted to interface with the transmission network, and its relative concentration in the NEM. As a result, AEMO commenced a review of wind integration issues as part of the 2011 NTNDP.

Integrating asynchronous generation technologies

Most wind generation is asynchronous[3], using power electronic devices to either wholly or partly interface with the transmission network. These devices have significantly different characteristics from conventional thermal and hydroelectric generation (which are synchronous[4]), and so securely accommodating wind generation presents different challenges to conventional thermal and hydroelectric generation.

Concentrations in the NEM

The NEM's overall wind penetration (at approximately 2% – 3%) appears low when compared with the national Renewable Energy Target (RET) scheme's goal of 20% for all renewables by 2020.[5] This penetration is not evenly reflected in all regions, with South Australia already averaging wind energy penetration of 20%[6], and with instantaneous penetration (the ratio of wind generation to demand plus exports) exceeding 80%. This puts South Australia a close second (with Ireland), to the Iberian Peninsula, which has the highest wind energy penetration in the world.

The 2010 NTNDP predicted that South Australia and Tasmania are likely to have the largest growth in wind generation. These regions experience the lowest demand of all the NEM regions and have limited ability to export to other regions. This suggests that with low demand and high wind speeds, there will be periods when wind generation exceeds demand. For example, South Australia currently has approximately 1,200 MW of installed wind capacity, which might exceed the lowest demand, which is typically below 1,000 MW.

1 As indicated in the Electricity Statement of Opportunities (ESOO) AEMO. "Electricity Statement of Opportunities for the National Electricity Market". Version 2. 2011. Available http://www.aemo.com.au/planning/esoo2011.html.

2 These will depend on appropriate government incentives, as well as market and positional factors such as expectation of market price, the expected amount of network limitations, connection point loss factors, and the cost of achieving the required technical performance requirements.

3 An asynchronous generator has a rotational speed that is unrelated to the power system frequency.

4 A synchronous generator has a rotational speed that is related to the power system frequency, typically as a constant multiple of the frequency.

5 Department of Climate Change and Energy Efficiency. "Renewable Energy Target". Available http://www.climatechange.gov.au/government/initiatives/renewable-target.aspx. 15 August 2011.

6 Average wind energy penetration is the number of installed MW divided by the peak demand for the region.

AEMO's wind integration review

AEMO's 2011 review of wind integration issues comprised five studies:

- **International Practice** is a general review of wind integration experience and technical issues observed or discussed internationally.[7]
- **Review of Grid Codes** is a wind integration-focused review of international grid codes and the NER.[8]
- **Simulation Using Historical Wind Data** is a review of issues related to wind variability and diversity of wind resources using historical wind measurements around the NEM.[9]
- **Analytical Studies** is a review of the international study experience and the way these studies relate to the Australian context.[10]
- **Congestion Study** is a review focusing specifically on expected wind resource congestion.[11]

These studies, which form the basis for the information presented in this chapter, will be available from the AEMO website.

Study results

This chapter presents study results that consider the following issues:

- Wind generation characteristics and their implications for integrating wind.
- Impacts of increased wind generation on power system characteristics and operational issues.
- Technical standards and any implications from increased wind generation.
- Wind generator revenue.
- Network planning for large-scale integration of renewable generation.
- Emerging technical issues and future reviews that could address them.

7 ECAR Energy "Wind integration in electricity grids: International Practice and Experience". 2 October 2011.
8 ECAR Energy "Wind integration: International Experience. WP2: Review of Grid Codes". 2 October 2011.
9 Forthcoming AEMO publication.
10 Ackermann T.A., Kuwahata R. "International Experience in Wind Integration. Studies: AEMO Wind Integration WP4(A) 2011.
11 Forthcoming AEMO publication.

4.2 Wind generation characteristics

Characteristics that maintain or enhance the performance of the power system[12] make the integration of any new generation plant or technology easier, as does a strong correlation between output and demand, which improves the efficiency of investment.

The correlation comes from either dispatch controllability, or output and demand having the same drivers (for example, sunny summer weather increases both local demand and solar PV generation output).

Beneficial characteristics related to technical issues include the following:

- A high level of power system support (involving aspects such as voltage, frequency, inertia, and stability) and performance during faults that does not worsen a fault situation.
- A high level of coordination with other generating systems and their systems of control and protection. This includes avoiding harmful interaction, like oscillatory instability and sub-synchronous resonance.

4.2.1 Correlation with demand

Wind generation is wind dependent, so peak wind generation does not necessarily correlate with peak electricity demand. Wind Integration: international practice and experience[13] reported better correlation between wind and demand in New South Wales than South Australia. It also analysed the historical performance of existing wind farms over the 2010–11 summer period. AEMO has since repeated this analysis based on eighteen years of data, and a broader range of sites.

To assess wind generation's correlation with demand and contribution to peak demand, a statistical analysis was performed using synthetic hourly wind generation profiles[14] for 148 locations across the NEM. This analysis was undertaken for existing and proposed wind farm sites identified in the 2010 ESOO, for a period from 1 January 2002 to 1 January 2011, at a hub height of 60 metres.

The wind profiles were subsequently translated to expected electrical power using wind turbine power curves. No allowances were made for factors that might reduce the potential wind energy available (such as network limitations, temperature, turbine maintenance, and differences between turbine output within the same wind farm).

On the basis of this new analysis, little correlation was found between the aggregate wind output and demand in any region. Nevertheless there are likely to be potential wind farm sites with better correlation between local or regional demand and wind. A positive correlation benefits both the wind farm owner, from a revenue perspective, and the electricity market, by reducing the network capital expenditure needed to support the additional wind generation.

Wind contribution to peak demand

Table 4-1 shows the contribution factors (as a percentage of installed capacity) calculated both from historical data from existing wind farms, and from simulated wind data. Although international experience suggests that high levels of wind penetration might reduce overall contributions from wind, the results suggest a higher contribution from wind in the future. This might be due to the inclusion of more wind farms in each region, increasing the geographical diversity.

Limitations in the simulated data (such as network limitations, temperature, turbine maintenance, and differences between turbine output within the same wind farm), however, might reduce the appropriateness of a direct comparison with the historical results, and are likely to show a higher contribution than will be seen in practice.

[12] See note 7 in this chapter.
[13] See note 7 in this chapter.
[14] Generated by the Commonwealth Scientific and Industrial Research Organisation (CSIRO) meso-scale atmospheric wind model.

Table 4-1 — Comparison of wind contribution factors[a]

	Queensland	New South Wales	Victoria	South Australia	Tasmania
Wind summer peak contribution (ESOO historical) based on existing wind farms	-	9.2%	7.7%	5.0%	1.0%
Wind summer peak contribution based on CSIRO wind model[b]	13%	15%	13%	14%	6%

a. These wind contribution factors are based on synthetic data and do not replace the data or findings published in the 2011 ESOO.

b. These contribution factors represent the minimum level of output available at least 85% of the time during the top 10% of the seasonal demands in each region.

Wind diversity between regions

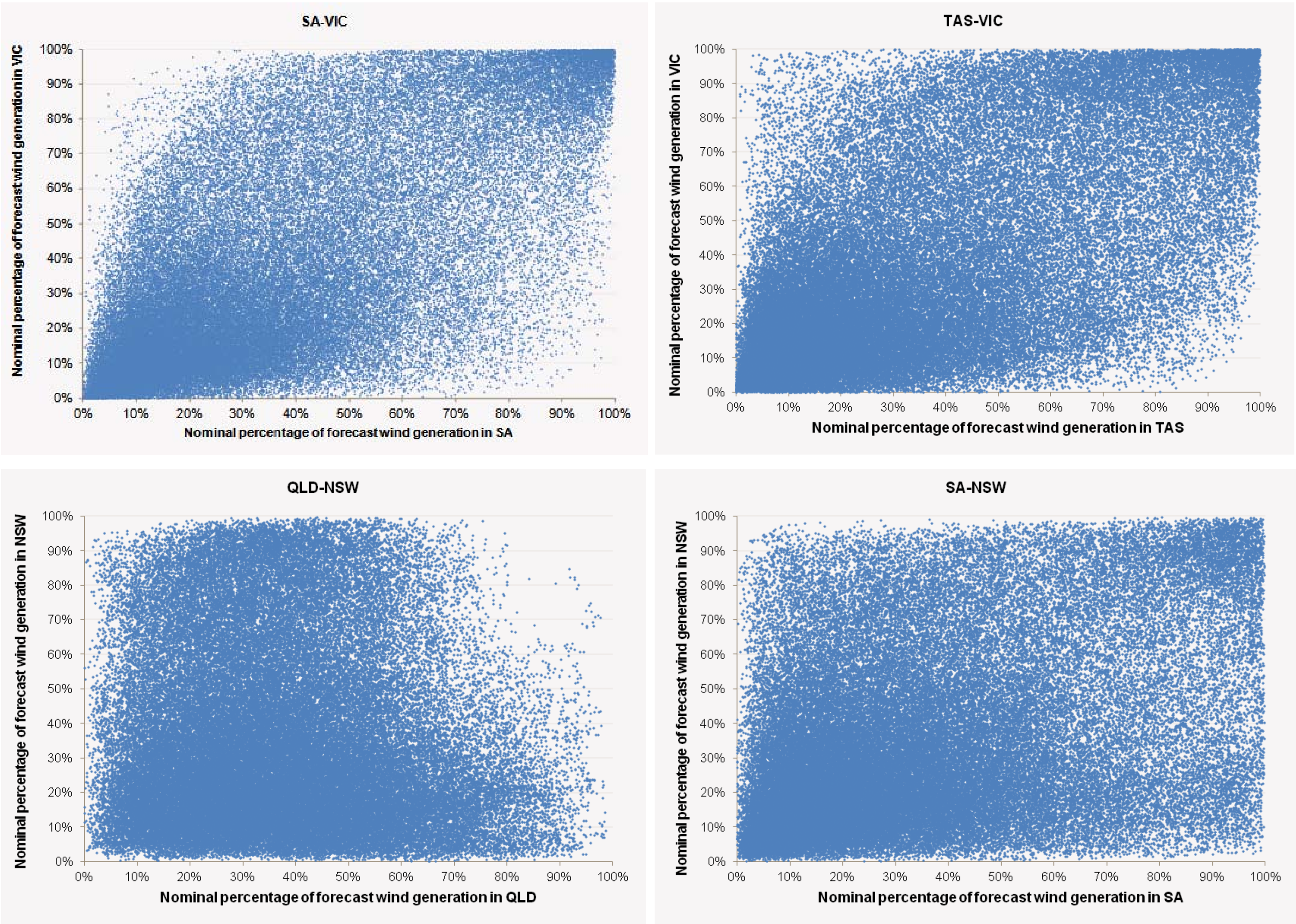
Figure 4-1 shows a series of scatter diagrams that display wind diversity between various regions (South Australia–Victoria, Tasmania–Victoria, Queensland–New South Wales, and South Australia–New South Wales).

Scatter patterns showing greater density from the bottom left corner to the top right corner of each chart demonstrate correlation between the subject regions. Patterns showing greater density from the top left corner to the bottom right corner show anti-correlation. Generally more evenly distributed patterns show generally low correlation.

The figures demonstrate some correlation between South Australia and Victoria, with weaker correlation between Tasmania and Victoria, and South Australia and New South Wales, with a slight anti-correlation between Queensland and New South Wales. The concentration of data points around the bottom left corner indicates there are many occasions when the wind strength is low in all regions at the same time.

These observations potentially indicate that as wind penetration increases, some benefit might derive from upgrading certain interconnectors to enable excess generation to be more broadly shared between the regions.

Figure 4-1 — Regional wind diversity



Variability and rates of change

Variability is a key characteristic of wind generation, which arises from the intermittent nature of the energy source. Using the simulated data, AEMO examined the predicted hourly change in both demand and wind for the wind penetration levels predicted under the 2010 NTNDP's Decentralised World, medium carbon price scenario (DW-M) for the year 2019–20.

Table 4-2 lists the projected installed capacity under the DW-M scenario by 2019–20. Table 4-3 lists the projected maximum hourly variability of wind and demand, and the net aggregate of the two. For example, the maximum increase in wind generation output from one hour to the next in New South Wales is projected to be 375 MW, and the maximum decrease in output is projected to be 392 MW.

These variations represent the possible scale of the power system management issues that might arise as a result of the wind penetration levels forecast in the 2010 NTNDP. South Australia and Tasmania have the largest wind variation, significantly larger than the variation of demand, as a consequence of their considerable local wind development.

Table 4-2 — Projected installed wind capacity under DW-M, 2019–20 (MW)

	Queensland	New South Wales	Victoria	South Australia	Tasmania	NEM
Wind generation installed capacity	0[a]	919	2,340	3,404	1,540	8,203

a. No wind capacity was installed in Queensland under this scenario.

Table 4-3 — Maximum hourly variability under DW-M, 2019–20 (MW)

	Queensland	New South Wales	Victoria	South Australia	Tasmania	NEM
Maximum hourly increase (wind)	0	375	590	914	604	1,517
Maximum hourly increase (demand)	1,137	1,996	1,082	413	262	4,472
Maximum hourly increase (wind and demand)[a]	1,137	2,025	1,365	1,006	545	4,539
Maximum hourly decrease (wind)	0	392	677	893	522	1,709
Maximum hourly decrease (demand)	697	1,153	930	347	372	2,281
Maximum hourly decrease (wind and demand)[a]	697	1,222	1,031	924	565	2,753

a. This number represents the net aggregate of wind generation output and demand.

Figure 4-2 shows the variability of demand, and wind and demand in the NEM. Based on the 2010 NTNDP's projections for 2019–20, the NEM-wide hourly variability of wind in combination with demand is not significantly different from the variability of demand alone.

Therefore, if hourly changes in wind demand can be accurately predicted, and in the absence of network limitations, this variability should not add significantly to the difficulty of NEM-wide power system management.

Figure 4-3 shows the variability of demand, and wind and demand in South Australia. In regions such as South Australia, where further wind generation development is expected, the frequency of large hourly changes in wind generation can be significantly greater than demand. This places particular focus on the importance of dependable wind forecasting, particularly for the magnitude and timing of rapid changes. This also potentially offers additional value for fast response generation or additional interconnection.

Figure 4-2 — NEM hourly variability of demand, and wind and demand

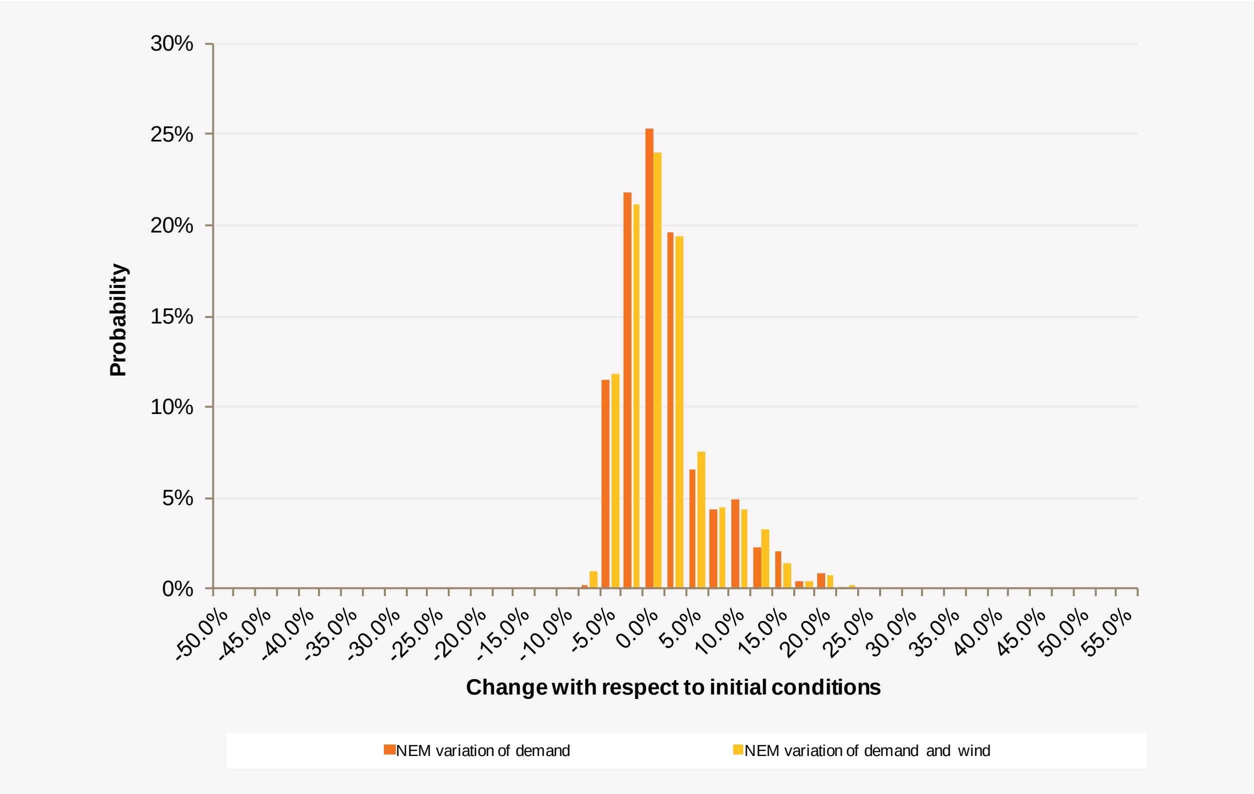
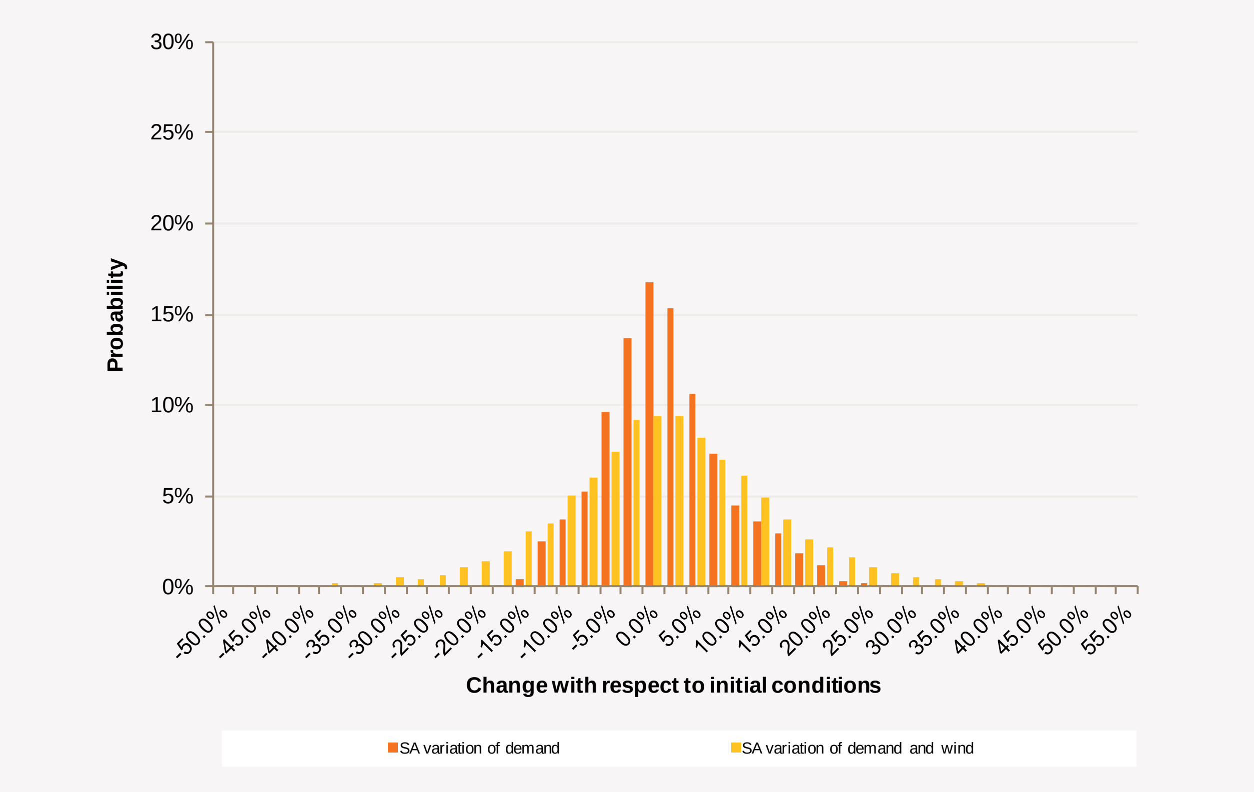


Figure 4-3 — South Australian variability of demand, and wind and demand



Dispatch controllability

Wind generation is readily controllable when it comes to reducing generation output. Increasing generation on dispatch, however, requires it to be initially operating at reduced output (spilling energy). While this is technically possible, the value associated with frequency control services (the Raise ancillary service) has been insufficient to make them an attractive option for wind generators to date. However, some voluntary reductions in the output of wind in response to negative price have been observed.

The ability to reduce generation output through dispatch is important for managing power system security. In Australia this is implemented through the semi-dispatch of generation registered as semi-scheduled, to maintain generation output at or below a specific level.

4.2.2 The level of power system support

Wind generation can generally provide reactive power support (for voltage control) and frequency control capabilities. The extent to which it is required to do so depends on technical performance standards and the level of participation in network support control ancillary services (NSCAS) and frequency control ancillary services (FCAS).

Performance during faults and other contingency events

Generation has to remain operating to support the power system during faults and other contingency events (such as tripping a load or a transmission line) to avoid load shedding or a black system condition.

In the NEM, generating systems greater than a certain size (usually 5 MW) are required to comply with technical standards for performance during contingency events. These technical standards cover all large-scale generation, including wind generation, but distributed generation (such as residential and small commercial solar PV installations) are excluded due to the size threshold.

Wind generation is less likely to cause a power system event than conventional generation, because it comprises multiple small units, and the loss of a unit is unlikely to cause a major power system disturbance. Under certain circumstances, however, a large number of wind generating units can trip or rapidly change output at the same time, causing a major disturbance. This requires special consideration where large-scale integration is anticipated.

There are few, if any, reported incidents internationally where wind generation has caused a major power system event, but there have been occasions when it behaved in an unexpected way that exacerbated an existing event.[15]

[15] See note 7 in this chapter.

4.3 Power system characteristics and operational issues

Higher levels of wind generation increase the importance of some power system characteristics and lead to operational issues that include the following:

- Power system flexibility.
- Forecasting.
- Response to ramp events.
- Frequency control ancillary services.

4.3.1 Power system flexibility

A flexible power system is one that can adapt to changing requirements over a range of timescales.

Considerations about flexibility are primarily driven by the nature of wind as an energy source, particularly its intermittent nature (other supply sources must compensate) and availability (the wind does not blow on demand).

Flexibility can be provided through coordination of ancillary services (with some possible enhancements) and flexible generation dispatch, and supported by a robust transmission network design in the following ways:

- Flexibility can be provided through transmission augmentation, which enables a wider range of supply sources to compensate for the intermittent nature of renewable generation.
- A controllable portfolio of energy sources (for example hydroelectric, solar thermal, biofuel, geothermal, and storage technologies[16]) can provide complementary characteristics that support and enhance the integration of intermittent generation.
- Shorter generator dispatch intervals enable rapid changes in generation output to be compensated for from one dispatch cycle to the next. The NEM's five-minute cycle, supported by the semi-dispatch requirement, is well suited to intermittent generation.
- A mix of intermittent generation technologies close to loads can supply local load, efficiently making use of the different characteristics of these sources and minimising losses.
- Flexibility can be enhanced by appropriate use of renewable energy to support the network. It might be reasonable, for example, to constrain renewable sources (to spill renewable energy) to supply ancillary services.
- Demand management can be used in conjunction with renewable generation to provide more flexible ways to match supply and demand.

4.3.2 Forecasting

The ability to produce intermittent generation forecasts plays an important role in the effective and efficient operation of the NEM. Since 2008, AEMO has employed the Australian Wind Energy Forecasting System (AWEFS) in conjunction with the semi-dispatch of wind generation to predict and manage the output of wind farms.

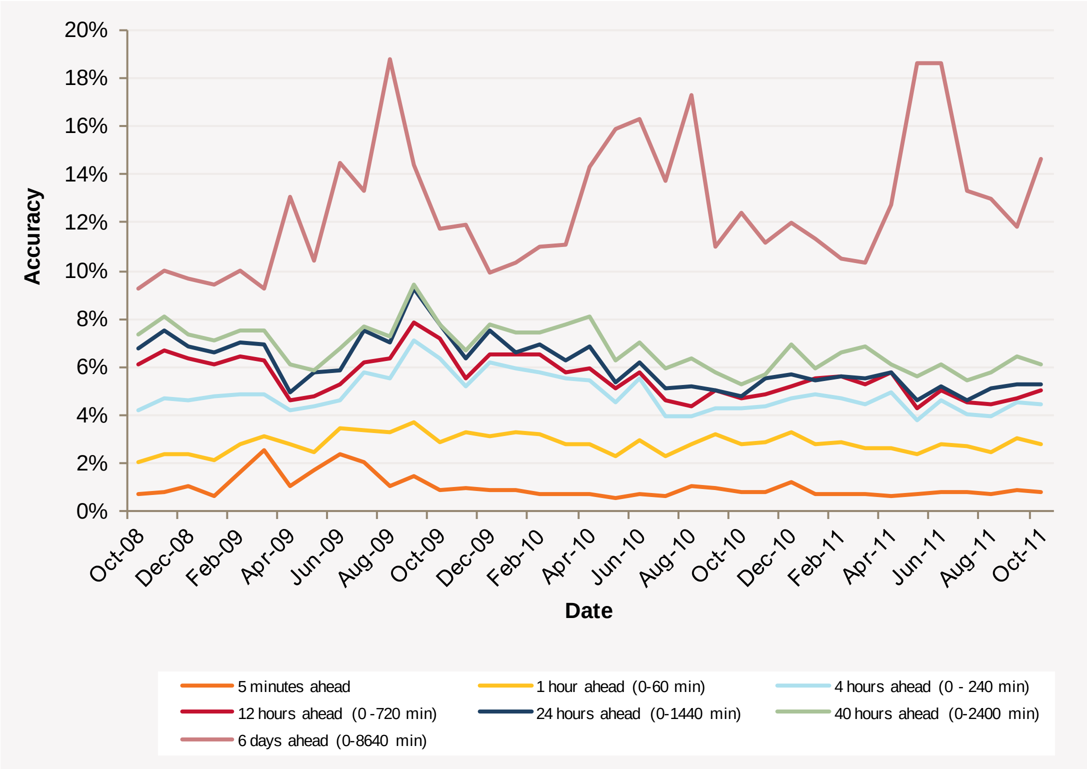
Figure 4-4 shows the AWEFS performance accuracy assessment from its inception to October 2011. This shows that AWEFS wind generation forecasts are, on average, accurate over a range of time periods.

The Australian Government is supporting additional research in wind energy forecasting through the Wind Energy Forecasting Capability Initiative, which is expected to deliver improved forecasts over time.[17]

[16] According to one Irish study, current storage technologies are not considered viable below approximately 50% energy penetration of intermittent renewables (well above the Australian Government's 20% target), and might even result in higher carbon emissions. Considering the nature of the NEM network (long and lightly interconnected) compared with more compact networks, it might be that the threshold where storage becomes viable is lower and potentially more regionally dependent.

[17] Department of Resource, Energy and Tourism, Wind Energy Forecasting Capability Initiative. http://www.ret.gov.au/energy/clean/cei/wind_energy_forecasting_capability_initiative/Pages/WindEnergyForecastingCapabilityInitiative.aspx . 14 July 2011.

Figure 4-4 — AWEFS NEM-wide performance accuracy, normalised mean absolute error (%)



4.3.3 Response to ramp events

Ramp events relate to significant changes in intermittent generation over a wide area (for example, as a weather front passes).

Ramp event magnitudes can be predicted to some extent, but their timings can be uncertain, potentially resulting in significant supply and demand imbalances. As a result, ramp events are driving attempts internationally to quantify whether existing reserve provisions are adequate for reliability. In Ireland, for example, due to forecast uncertainty, wind generation growth is increasing the need for longer-term generation reserves (for example, generation with recall times of approximately four hours).

With growing renewable generation, and considering the large-scale integration of renewable generation, the NEM's operational treatment of future ramp events requires review.

4.3.4 Frequency control ancillary services

The large-scale integration of intermittent renewable generation is likely to result in increases in the magnitude and frequency of rapid changes in generation output, which might require increased FCAS.

The timing and extent of FCAS increases might depend on the level of renewable generation in a particular region, and the extent of interconnection with other regions.

The displacement of synchronous generation with asynchronous generation is also likely to increase the rate of change of frequency following a contingency event, which has implications for Fast Raise and Fast Lower FCAS and other operational issues such as the management of load-shedding for frequency recovery following a loss of supply.

4.4 Technical standards

Technical standards define the performance requirements for generation connected to the network. They dictate generation's performance during contingencies, power system support, and the ability to co-ordinate with other plant.

A particular generating system's performance standards depend on many factors. Factors relating to generation penetration include the following:

- The amount of generation connected to the transmission network.
- The performance of existing generating plant (particularly other plant electrically connected in close proximity). If existing plant performs poorly, the technical requirements for later tranches of generation (as well as the associated costs) will be higher to compensate.

The cost of retrofitting to meet new, higher standards is typically much higher than the cost of building to meet them initially. As a result, to provide investor certainty when new requirements are introduced, older plant in the NEM has generally been permitted to continue operating to earlier technical standards. Technical standards therefore need to consider the ultimate level of new generation over a reasonable planning period.

In light of the high levels of wind generation seen in the 2010 NTNDP modelling, the national RET scheme and the Australian Government's Clean Energy Future plan potentially give rise to the need to review some aspects of the existing technical standards.

As a result, the 2011 NTNDP features a review of international standards and a comparison with the technical standards in the NEM, to ascertain whether the existing NEM technical standards are similar to those in other countries, and are sufficient to support the connection of large amounts of wind generation to the network. This review highlighted certain issues, and AEMO will review relevant aspects of the technical standards for connecting new generation.

4.4.1 Negotiation of standards

Typically, the NEM's technical standards are specified as an automatic standard (beyond which a network service provider cannot require additional performance) and a minimum standard (below which the generating plant may not be connected).

A generator can negotiate to meet a standard between the automatic and minimum standards, and in this respect the NEM might be unique. In all other countries surveyed, the technical standards were either at a fixed level or at a level determined by the transmission system operator.

The differences in access framework provide both advantages and challenges for connecting large amounts of wind generation:

- The negotiated access standard regime provides the benefit of avoiding unnecessary costs associated with mandating the highest level of performance conceivably required anywhere in the transmission network.
- Current rules for the future scenarios that can be considered when negotiating performance limits the scope for speculation on what the future will look like (for example, while there is commitment at government level to a particular level of renewable generation, there is no scope for considering it in the access standards).

  The consequence is that higher levels of performance might be required from later tranches of connecting generators rather than sharing the (lesser) burden across a greater proportion of the generation fleet. In the worst case this might limit the amount of generation that can be connected to certain parts of the power system, resulting in overall higher energy supply costs.

While the negotiated access standard regime provides certain benefits, there needs to be a way to ensure that future needs can be taken into account when setting the requirements for generating plant connecting today.

The specification of future needs

The specification of future needs is not necessary in other countries where the standards are mandatory and set at levels suitable for future requirements. The implication is that setting the levels for standards requires some understanding of how much generation (and what type) might be required to connect in that part of the network. For example, in Spain, inadequate performance requirements for wind generation required many wind farms to retro-fit plant upgrades, paid for through an incentive scheme.

Alternatively, if future requirements are difficult to determine, a negotiated access standard regime that requires performance standards to be set at the highest level the generating system can achieve might help to avoid excessive technical requirements and costs for later connections.

4.4.2 Automatic access standards

Some aspects of the automatic access standards are higher than international standards for wind power.

The NEM technical standards cover all generation technologies, and scope might exist to moderate some aspects of the automatic access standards, if they are unreasonably high for the full range of generation technologies. AEMO intends to explore this possibility.

4.4.3 Fault ride through and contingency performance

Investigations suggest that in some respects, the automatic standards are higher than mandatory standards internationally (for example, for fault ride through). The NER, however, does not require (transmission connected) generation to stay connected for a 3-phase fault, unlike most other international standards that were surveyed. Three-phase faults are rare in Australia, and historically this level of requirement has not been an issue.

4.4.4 Reactive power

Investigations suggest that while the automatic standard for reactive power is high by comparison with other grid codes for wind generation, the minimum standard may fall below a “do no harm” level if it allows a generating plant to absorb reactive power in the event of a depressed voltage.

The current wording of the minimum access standard is ambiguous, and potentially the requirements for reactive power generation could be changed to reflect the capability inherently available in modern generating plant, including wind turbines.

4.4.5 Requirements for dynamic models

Internationally, the requirements for wind turbine manufacturers to provide plant operation models appear to vary between jurisdictions, although many grid codes include some requirements. This can include the development of standard models in addition to detailed models. Standard models are typically less accurate than detailed models, but are sometimes required for modelling very large power systems where simulation tool limitations prevent simultaneous use of large numbers of detailed models. Use of standard models is also favoured by wind turbine manufacturers as a way of protecting the intellectual property associated with operating their control systems.

Compared with other countries, the NEM’s unique negotiated access standard framework and long, lightly interconnected network creates a greater need for accurate modelling. Connection applicants need to be able to accurately model the performance of the power system and their plant to be able to determine appropriate performance standards. It is unclear under what circumstances provision of standard models would be adequate for this purpose. Provision of two sets of models would also be a significant overhead both for the generator, which provides the models, and for AEMO, which needs to maintain the model.

With the power system operated to the levels defined by the models, it is important to ensure that models are validated and monitoring systems put in place to confirm that actual performance is consistent with the models provided.

4.5 Wind generator revenue

Wind generator revenue is impacted by a series of market incentives for generation to locate in particular places, including spot market prices, marginal loss factors and network congestion, so that the quality of the energy source is not the only consideration for renewable generation investors.

To better understand wind generator revenue, the 2011 NTNDP expands on the 2010 NTNDP simulation of wind generation operation in the NEM by focussing on the analysis of wind generation and congestion (any network limitation that reduces the output of generators[18]), using a number of years of wind measurements to examine the potential impact of wind generation in 2019–20 under the Fast Rate of Change, high carbon price (FC-H) scenario, the Decentralised World, medium carbon price (DW-M) scenario, and the Oil Shock and Adaptation, low carbon price sensitivity. The analysis considers spot market prices and network congestion, with a focus on network congestion that limits power transfers from wind farms to evaluate the degree of congestion and determine how congestion varies between network locations.[19]

Spot market prices

Spot market prices reflect the generation bidding in a region and the presence (or absence) of interconnector congestion.

All generators operating at a particular time receive their region's spot market price and might also receive additional payments from contracts or renewable energy certificates (RECS). These additional payments can lead to generators bidding at low or even negative prices at times of low demand. Combined with the need for some thermal generation to be bid at negative prices[20], this situation can lead to negative spot prices.

At times of lower wind generation output, less generation is available and higher priced generation must be dispatched while there is less competition for other generation to stay online, leading to higher spot market prices. This effect has led to lower average prices for wind generation in South Australia than conventional generation, as reported in the 2011 South Australia Supply and Demand Outlook.

Spot market prices become more uniform across the NEM if interconnector congestion is reduced by changes to patterns of generation or demand or by augmentation of an interconnector that experiences congestion.

Network congestion

Network congestion is a consequence of power flows being constrained by system limits, which can be related to avoidance of line overloading or associated with various types of stability limits. Network congestion can also limit generation output.

The extent of network congestion a generator will experience depends on where in the network it is connected, and typically relates to the level of loading of the transmission lines in that area, at least for thermal (overload) and voltage stability limits.

With larger-scale integration of renewable generation, the correlation between local demand and generation output will also impact the extent of congestion experienced by some generating plant.

Conclusions

The analysis found that only wind farms in South Australia are impacted by network congestion, from both intra-regional and inter-regional network limitations. This is mainly a reflection of the larger amount of new entry wind generation in South Australia compared to local demand, than in other regions.

The most wind generation installed by 2019–20 occurs under the DW-M scenario, a large amount of which is installed in South Australia. The proliferation of wind generation in South Australia contributes to a number of low

[18] Radial and common point network limitations.

[19] The generation expansion schedule, wind bubble definitions, and indicative wind farm constraint equations are consistent with the 2010 NTNDP studies.

[20] To avoid shutting the plant down and incurring a start-up cost the following day or potentially missing out on higher prices later on.

price events in the region, and the South Australian spot prices fall below 5 $/MWh under this scenario approximately 15% of the time. The congestion results also show a large average capacity factor reduction for South Australia.

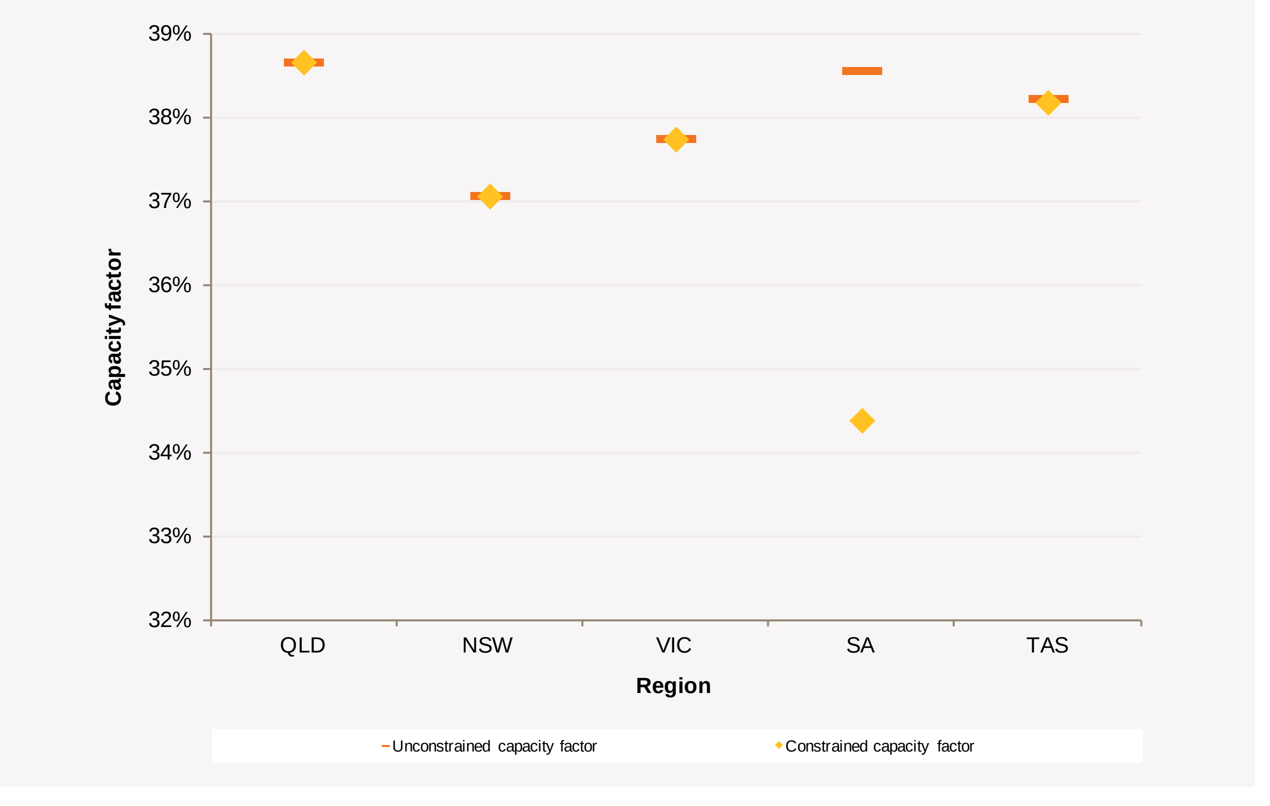
Figure 4-5 shows the expected (best case results assuming an unconstrained network) and simulated (based on the 2010 NTNDP network modelling and taking into account existing committed as well as reliability-driven future network augmentations) averaged capacity factors under the DW-M scenario for each region.

Figure 4-6 shows volume weighted average wind generator prices as a percentage of the average pool price[21] for each region, where wind new entry generation is modelled (excluding Queensland). Key features include the following:

- South Australia is the only region significantly constraining off wind generation and experiencing low spot prices.
- Wind generation in other regions is able to generate at expected capacity factors.
- Wind farm revenues vary significantly depending on their location.

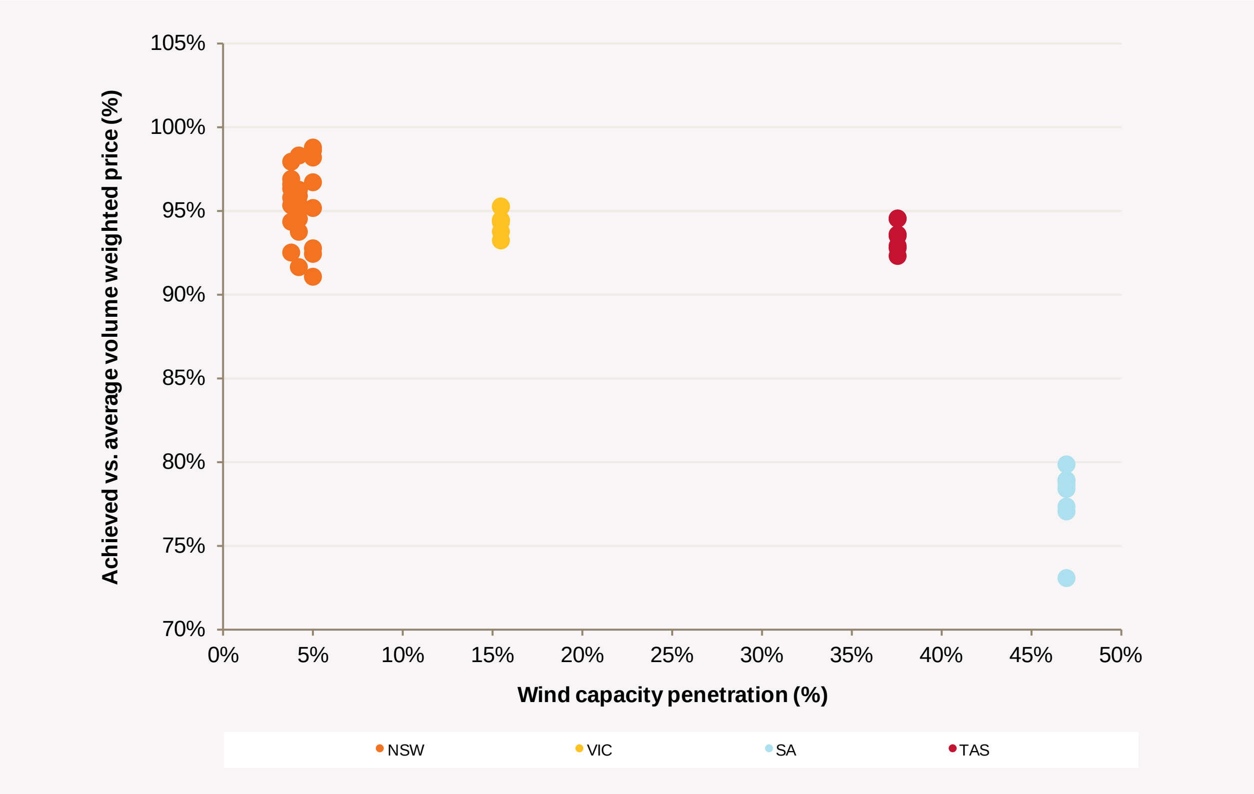
These results only relate to the scenarios and modelled network conditions, and are indicative only.

Figure 4-5 — Regional average wind capacity factors (%)



[21] Results are shown for a range of scenario-based simulations.

Figure 4-6 — Volume weighted average wind generator price as a percentage of average pool price by region (%)



4.6 Planning for large-scale integration of renewable generation

This section presents information about the planning implications from large-scale integration of renewable generation. It also considers the international experience and how that relates to (or differs from) the NEM's situation.

A range of specific uncertainties introduce complexities in transmission network planning:

- Government policy timing and changes.
- The implementation of government policy and the resulting growth in renewable generation can change faster than transmission can be built.
- Open access and the speed at which generation (for example, wind and gas turbines) can be built means that local networks might be initially unable to support new generation. To date, this has resulted in potentially less efficient renewable generation being built close to transmission networks, rather than transmission being extended to areas offering superior renewable resources.

This section considers the lessons that can be learned from international experience in relation to the following general considerations:

- Government policies relating to transmission network augmentation.
- The speed of response to policies and policy advice.
- Investigating the impact of wind and demand on the optimal location of new wind generation.

4.6.1 Government policies relating to transmission network augmentation

Transmission network investments in the NEM are justified by a cost-benefit comparison[22]. Other countries do not necessarily use this approach, in some cases requiring network owners to augment the network so that renewable generation is unconstrained, as well as potentially requiring renewable generators to be compensated for curtailed energy.

Several factors should be taken into account when reviewing international wind integration studies and applying them to the NEM:

- The assumptions underlying the studies implicitly account for the regulatory arrangements and policies in the countries to which they apply.
- Most studies assume a certain penetration of renewable generation, and that transmission will be built to ensure that renewable targets will be met, given that in several cases the government mandates both the amount of renewable generation and a transmission system operator (TSO) requirement to make renewable generation work.

  As a result, in most European studies, transmission is constructed to meet policy objectives, not on the basis of an economic test. This has implications for local and potentially regional-level transmission network development.

In the case of the NEM, the transmission network service provider (TNSP) must justify the development of transmission augmentations to support renewable generation or for any other purpose, on a net market benefits assessment under the Regulatory Investment Test for Transmission (RIT-T).

As a result, the results of any studies conducted in the NEM may differ from those conducted internationally.

4.6.2 The speed of response to policies and policy advice

International experience has shown that the amount of renewable development can exceed levels anticipated by TSOs, potentially resulting in less than optimal solutions.[23] This is because generating units, including wind generation, can be built faster than electricity transmission, and because renewable generation development is often driven by government policy, which can change. For example, in Australia:

- A minimum of one to two years are required to conduct a grid integration study (coupled with the lead times required to plan the study and obtain funds).
- Three years are required to make relevant NER changes.
- Grid augmentations (if required) typically take five to seven years to complete once plans are finalised.

TSO studies therefore need to look beyond current settings and consider a broad range of possible futures.

4.6.3 Investigating the impact of wind and demand on the optimal location of new wind generation

AEMO uses market modelling in conjunction with network modelling for its long-term NEM-wide planning functions and its planning obligations for Victoria.

Market modelling for the 2010 NTNDP applied a combination of least-cost modelling for generation capacity expansion and time sequential Monte Carlo simulations to assess congestion, unserved energy and operating costs.

As part of the 2011 NTNDP, AEMO has investigated ways to improve future modelling techniques, with a view to improving long-term NEM planning.

[22] Where the proposed investment is for reliability corrective action, a preferred option may have a negative net economic benefit (that is, a net economic cost).

[23] This has occurred in several international studies, but also appears in a number of Australian studies where the amount of renewable generation installed has caught up with the study assumptions within approximately five years.

The increasing importance of statistical analysis and probabilistic assessment

The large-scale integration of renewable generation places increasing emphasis on statistical analysis and probabilistic assessments, rather than deterministic standards for planning.

Investigating the impact of modelling using different reference years

AEMO assessed the modelling outcomes for new entry wind generation's sensitivity to wind and demand data. Several indicators, such as NEM carbon dioxide equivalent (CO2-e) emissions intensity, NEM operating cost, regional unserved energy, and constraint equation binding hours were used to compare results for wind and demand data profiles using reference years from 2002–03 to 2009–10 under the Fast Rate of Change, high carbon price (FC-H) scenario, the Decentralised World, medium carbon price (DW-M) scenario, and the Oil Shock and Adaptation, low carbon price (DW-L) sensitivity.

All three scenarios saw similar results, with no reference year consistently providing results that were close to the average for the period.

The reference year 2005–06, which was used for the 2010 NTNDP studies, generally provided results closer to the average for most indicators, confirming that data for 2005–06 can be used for broader market modelling studies.[24] For studies that focus on system reliability, however, more detailed comparisons might need to be conducted, and these findings will be applied when developing future studies.

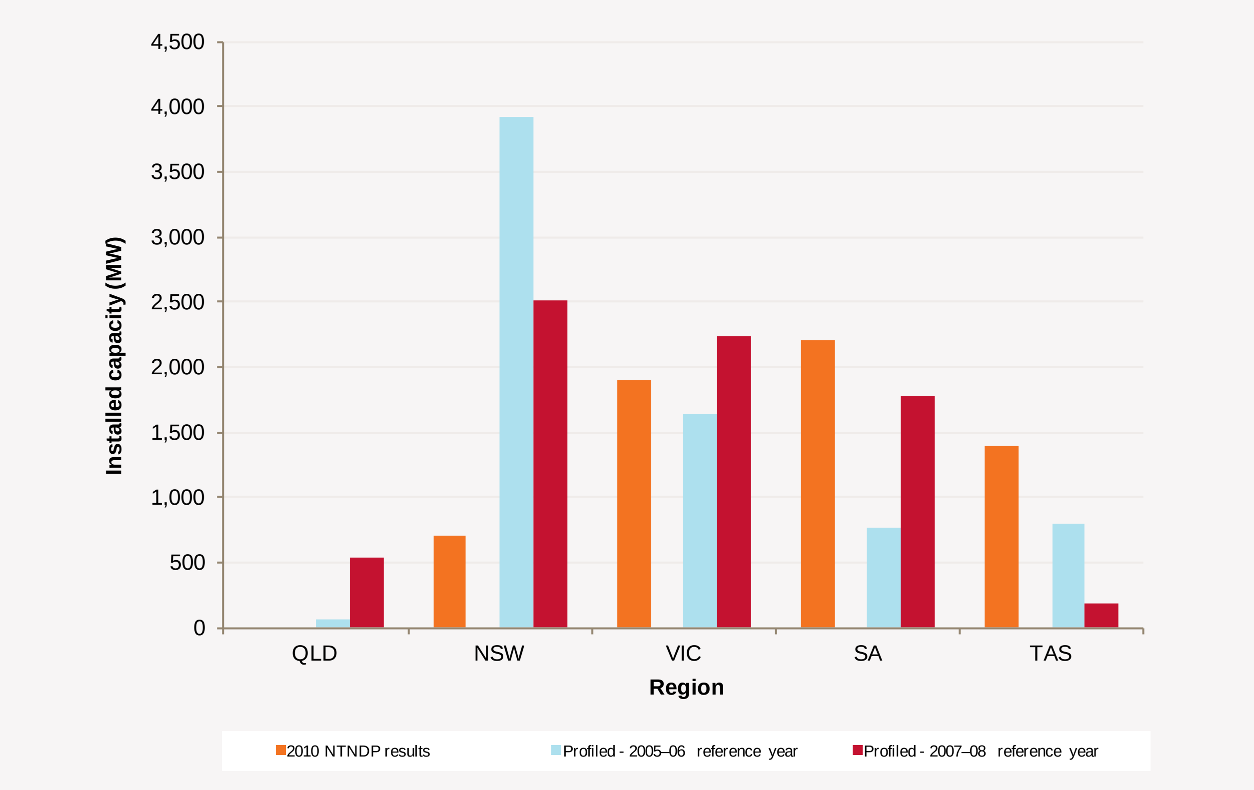
Investigating the impact of wind and demand on the optimal location of new wind generation

Figure 4-7 shows wind generation expansion by 2019–20 under two least-cost long-term expansion models:

- A static wind capacity factor model that models future wind farm output at the same capacity factor all the time (2010 NTNDP results).
- A profiled wind contribution model that bases wind farm contributions on the historical correlation of wind and regional demand. Two sets of forecast results for 2019–20 are shown, based on the reference years 2005–06 and 2007–08.

[24] Modelling shows that wind generation expansion can be highly sensitive to the choice of reference year, as demonstrated in Figure 4-7.

Figure 4-7 — Comparison of wind expansion results for 2019–20



The results show that capturing the correlation of wind and regional demand:

- Changes new entry generation to favour wind farms with better wind and demand correlation.
- Gives different results depending on the reference year used.

With significant anticipated growth in intermittent renewable generation, this investigation highlights the need to include intermittent energy source and demand correlation impacts in the least-cost expansion modelling. A suitable reference year also needs to be identified. The modelling undertaken for the 2011 NEMLink study review applies some of these improvements (for more information, see Chapter 6).

4.7 Emerging technical issues and future reviews

Increasing levels of wind generation utilising the types of technologies currently being installed will alter the power system's existing characteristics.

At lower levels of instantaneous penetration, the network is synchronous with some asynchronous generation. Very high levels of instantaneous penetration, however, introduce sufficient asynchronous plant to require changes in power system design and operation.

In some cases, high instantaneous penetration is seen at the local level. Regionally, this could apply to South Australia and Tasmania (based on forecast wind generation growth), South Australia having already experienced instantaneous penetration in excess of 80%, which is one of the highest levels by world standards.

As a result, AEMO and the TNSPs will need to consider the need for specific technical studies to investigate changes resulting from high levels of wind generation. Emerging technical issues that are likely to arise as the power system transitions to a greater application of asynchronous technologies include the following:

- As wind generation is often connected to the power system through power electronics devices[25], and consequently has a lower fault level than the synchronous generation it displaces, the fault level might vary significantly depending on instantaneous penetration, with implications for protection, voltage control, and coordination.
- As wind generation is asynchronous, there might be periods when total power system inertia is very low, with implications for frequency control, load shedding performance, generator power imbalance protection, and the rate-of-change of frequency protection. Some of the latest wind turbine designs, however, offer simulated inertia features.
- Displacement of synchronous generation with power stabilisers might have implications for power system stabilisation.
- In the presence of series compensated lines and HVDC network elements, power electronic devices can give rise to sub-synchronous resonance, which can cause damage to generating plant.
- Methods of restarting the system from a black system condition might require review.
- The operation of islanded transmission networks, where parts of the power system have been electrically separated from the rest of the system, might require review.
- The performance of plant under unbalanced fault conditions and the rapid performance of power electronic devices might require changes to modelling and analysis methods.

The technical characteristics of wind turbine design continue to evolve, with the latest designs performing better than older ones, and AEMO will need to work with the wind turbine manufacturers to ensure that any identified issues are managed efficiently.

[25] Such as thyristors or insulated gate bi-polar transistors, which are switches for large currents within ACDC converters.

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CHAPTER 5 - NTNDP OUTLOOK MARGINAL LOSS FACTORS

Summary

This chapter presents information about how marginal loss factors (MLFs), which are multipliers describing marginal electrical energy losses for electricity used or transmitted, potentially change over time as generation and transmission develop. The analysis, which only considers MLFs for generation connection points, derives from stakeholder feedback about the impact MLFs have on generation business cases, and the potential investment risks arising from MLF uncertainty and volatility.

Based on a mix of historical and forecast information, MLFs reflect the losses from transporting electricity from generation to load centres. AEMO calculates and fixes operational MLFs annually for the following 12 months. Reflecting the different value of generation from different locations, operational MLFs are applied in the dispatch and market clearing process and directly impact generator revenues. For generators, higher MLFs provide an advantage over lower MLFs.

Uncertainty about future MLFs can affect generator investment decisions. A range of interacting factors that impact MLF trends include existing generation and demand, the amount of new generation, its output patterns, and location in the network, projected demand growth, the regional reference node's location, and the strength of the interconnection with other NTNDP zones.

AEMO estimated the MLFs for 2019–20 and 2029–30[1] for generation and transmission development under three NTNDP scenarios (aggregated by NTNDP zone) that include the Fast Rate of Change, high carbon price (FC-H), Decentralised World, medium carbon price (DW-M), and Oil Shock and Adaptation, medium carbon price (OS-M). The following trends were observed:

- MLFs were generally stable under all scenarios in zones connected by high capability transmission lines to major load centres close to the regional reference node.

  Zones with these characteristics include South East Queensland (SEQ), South West Queensland (SWQ), Central New South Wales (NCEN), Latrobe Valley (LV), Melbourne (MEL), and Adelaide (ADE). MLFs were also generally stable in Country Victoria (CVIC), despite a lack of high capability transmission lines.

- MLFs decreased under all scenarios in zones with increased average power transfers towards the regional reference node.

  Zones with these characteristics include Central Queensland (CQ), Northern New South Wales (NNS), Canberra (CAN), South West New South Wales (SWNSW), Northern South Australia (NSA), and Tasmania (TAS).

  Decreasing MLFs indicate that generation becomes less attractive over time in these zones.

[1] These dates refer to the middle and the end of the 2010 NTNDP outlook period.

- Some MLF changes varied by scenario. Zones with these characteristics include North Queensland (NQ) and South East South Australia (SESA).

  NQ's MLF decreased in the first 10 years under all scenarios, but recovered in the second 10 years under the FC-H and DW-M scenarios.

  SESA's MLF increased slightly in the first 10 years under the FC-H and DW-M scenarios. In the second 10 years it continues to increase under FC-H but to decrease under DW-M. Under the OS-M scenario, there is a small decrease in the MLF in the first 10 years followed by a larger increase in the second 10 years.

- MLFs increased in Northern Victoria (NVIC) under all scenarios. Generation developments within Victoria and South Australia lead to increased power transfers through NVIC and into New South Wales (away from the Victorian regional reference node).

  Increasing MLFs indicate that generation becomes more attractive over time in this zone.

Under certain scenarios some zones saw MLF decreases of approximately 10% – 20%, representing a potential reduction of 10% – 20% in generator revenues (per MWh) at those locations.

5.1 Marginal loss factors

This section describes the purpose of MLFs, how the value of MLFs change in response to changes in the National Electricity Market (NEM), and the use of scenarios in this analysis.

Spot pricing and MLFs

The MLFs represent an adjustment to the price a generator receives to account for electrical energy losses.

Electricity spot prices reflect the incremental cost of generation added in each spot market interval in each region. Each region has a reference spot price, which is determined for each regional reference node.[2]

The price a generator may receive at other locations within the region is then calculated by multiplying each location's MLF and the regional reference node price.

Power transfers and MLFs

The MLF reflects average power transfers over a year and will generally be less than 1.0 at locations with power transfers towards the regional reference node, and greater than 1.0 at locations with power transfers away from the regional reference node. To a generator, a higher MLF is more attractive than a lower MLF.

Changes to the MLF reflect increases or decreases in power transfers towards or away from the regional reference node as a result of the following:

- The level of new entry generation and demand changes relative to the level of existing generation and demand.
- Changes to network capability within a zone, and between a zone and neighbouring zones, in particular the capability of the network between a zone and the regional reference node.

Figure 5-1 shows the location of the NTNDP zones in each region.

Specifically, MLFs tend to:

- Increase in zones where new entry generation in the zone or in neighbouring zones results in increased power transfers away from the regional reference node.
- Decrease in zones where new entry generation in the zone or in neighbouring zones results in increased power transfers towards the regional reference node.

In this analysis, indicative MLFs for generation connection points in each zone are shown for the years 2019–20 (the end of the first 10 years of the 2010 NTNDP's 20-year outlook period) and 2029–30 (the final year of the outlook period) under three scenarios. MLFs for the year 2011–12 (published by AEMO for operational purposes[3]) are provided as a reference point.

2 The MLF at each regional reference node is 1.0. The MLF for each zone, however, is a weighted average of the MLFs for each connection point in the zone. As a result, the MLFs for some zones that contain regional reference nodes do not equal 1.00.

3 AEMO. "List of Regional Boundaries and Marginal Loss Factors for the 2011–12 Financial Year v3.1". Available http://www.aemo.com.au/electricityops/0172-0009.pdf. 25 October 2011.

The NTNDP scenarios and MLF reference points

To facilitate the scenario analysis, AEMO applied a number of assumptions that resulted in a series of indicative MLF trends based on the three NTNDP scenarios considered (FC-H, DW-M, and OS-M).[4]

The MLF reference points for 2011–12 were calculated in accordance with Clause 3.6 of the National Electricity Rules (NER), and the 2019–20 and 2029–30 indicative MLFs were calculated using a method that approximates Clause 3.6 requirements. As a result, caution should be exercised when interpreting the calculated MLFs or comparing them with the reference point MLFs for 2011–12. For more information about the methodology and assumptions see Appendix A, Section A.2.

The new entry generation assumptions considered under the three NTNDP scenarios, involving the type and amount of new entry generation in each zone, are summarised in Appendix A, Section A.4. This is an outcome of the optimised generation and transmission modelling for each scenario.

The indicative MLFs reported in this chapter reflect outcomes of specific NTNDP scenarios. Differing generation, load, or network development outcomes will result in different MLFs.

[4] For more information about scenarios see Chapter 7, Section 7.1.2 and 2010 NTNDP Chapter 2. Available http://www.aemo.com.au/planning/0410-0066.pdf. 25 October 2011.

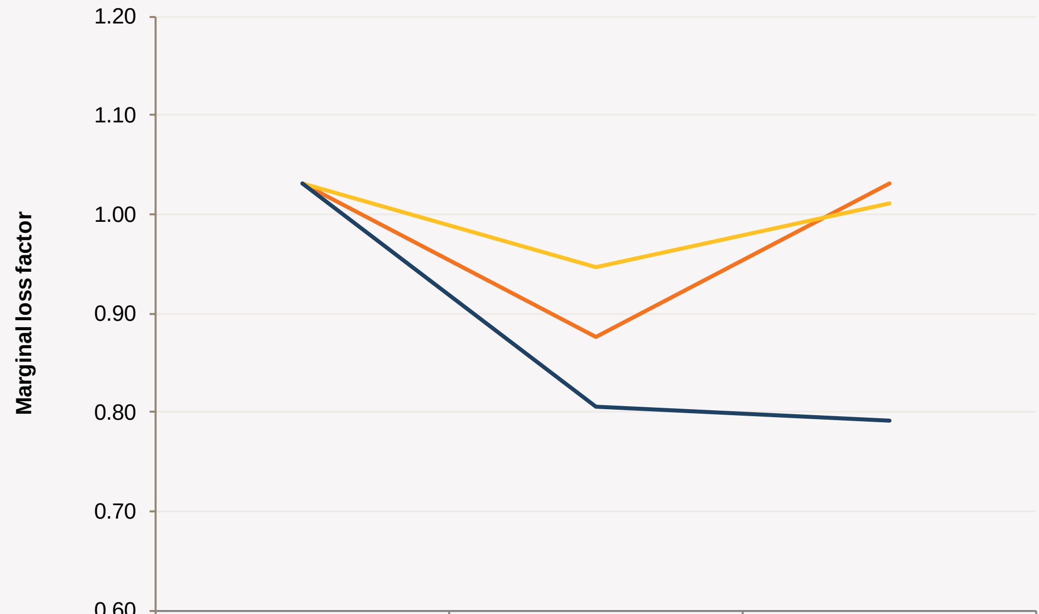
Figure 5-1 — NTNDP zones

5.2 Indicative MLFs by zone

This section presents a summary outcome of the MLF study for each scenario and study year. For more detailed information, see Appendix A.

For the purpose of presenting indicative MLF trends, a zonal MLF has been calculated as the volume-weighted average MLF of all generation in each NTNDP zone. Figure 5-2 to Figure 5-17 show the indicative MLFs for the years 2011–12 (provided as a reference point), 2019–20, and 2029–30.

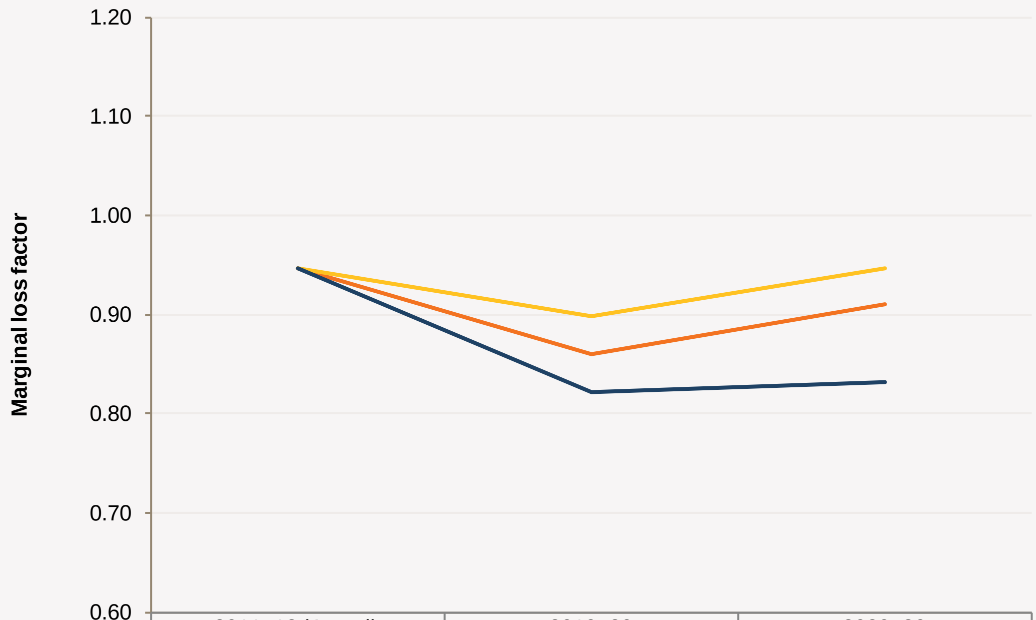
Figure 5-2 — Variation of indicative MLFs for the North Queensland (NQ) zone



	2011–12 (Actual)	2019–20	2029–30
FC-H	1.03	0.88	1.03
DW-M	1.03	0.95	1.01
OS-M	1.03	0.81	0.79

Zone	Indicative MLF Trends	Factors Influencing the Outcome
North Queensland (NQ)	The MLFs tend to decrease under all scenarios in the first 10 years and under the OS-M scenario in the second 10 years. The MLFs increase again (returning to current values) under the FC-H and DW-M scenarios in the second 10 years.	In the first 10 years, new entry generation in the NQ zone results in lower imports from the CQ zone, and lower indicative MLF values. In the second 10 years, high and medium demand growth under the FC-H and DW-M scenarios coupled with low levels of new entry generation results in increased imports towards the NQ zone, and increased indicative MLFs in both scenarios. The OS-M scenario has the highest level of new entry generation and lowest demand in comparison to the FC-H and DW-M scenarios. As a result, power flow towards the NQ zone has either decreased or reversed, leading to an initial reduction in MLFs followed by subsequent stabilisation.

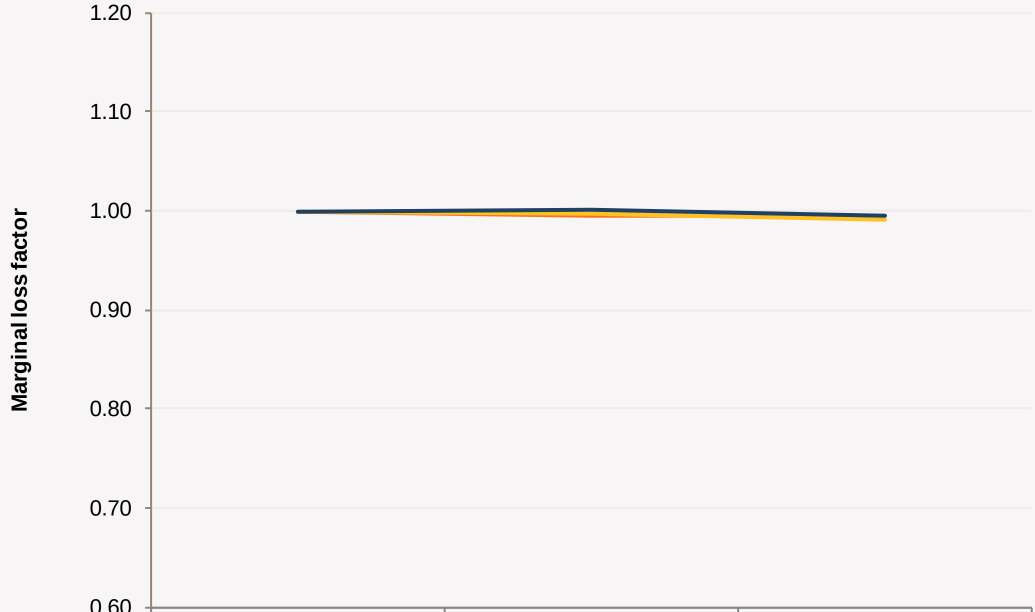
Figure 5-3 — Variation of indicative MLFs for the Central Queensland (CQ) zone



	2011–12 (Actual)	2019–20	2029–30
FC-H	0.95	0.86	0.91
DW-M	0.95	0.90	0.95
OS-M	0.95	0.82	0.83

Zone	Indicative MLF Trends	Factors Influencing the Outcome
Central Queensland (CQ)	The MLFs experience large variations over time, with a tendency to decrease in the first 10 years and to increase in the second 10 years to a value at or below the current values.	New entry generation within CQ occurs under all three scenarios, leading to increasing power transfers from CQ to SEQ. Decreasing power transfers from the CQ zone due to demand growth result in increased indicative MLFs in the second 10 years.

Figure 5-4 — Variation of indicative MLFs for the South East Queensland (SEQ) zone

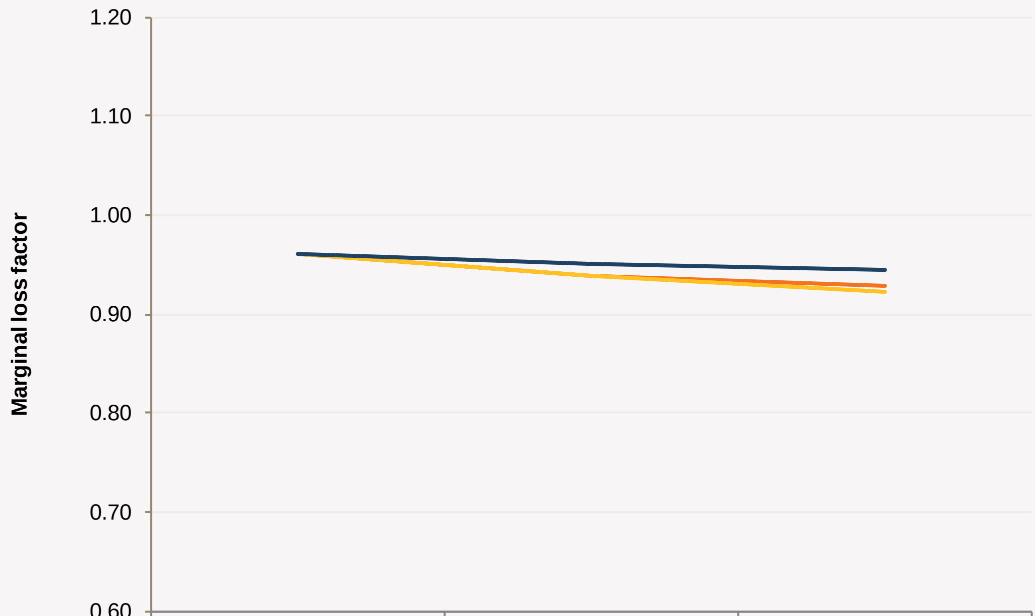


	2011–12 (Actual)	2019–20	2029–30
FC-H	1.00	1.00	0.99
DW-M	1.00	1.00	0.99
OS-M	1.00	1.00	0.99

Zone	Indicative MLF Trends	Factors Influencing the Outcome
South East Queensland (SEQ)[a]	The MLFs remain relatively unchanged over time under all scenarios.	MLFs have less impact from new entry generation due to the regional reference node being located within the zone (at the South Pine 275 kV node) and the high capability of the transmission network within the zone and with neighbouring zones (SWQ in particular).

a. The location of the regional reference node for Queensland.

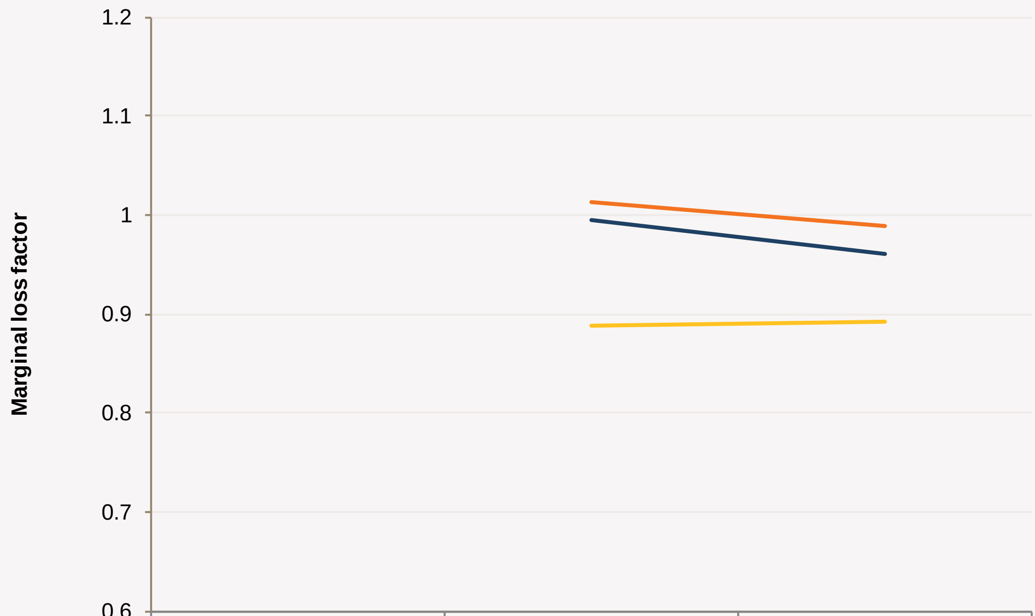
Figure 5-5 — Variation of indicative MLFs for the South West Queensland (SWQ) zone



	2011–12 (Actual)	2019–20	2029–30
FC-H	0.96	0.94	0.93
DW-M	0.96	0.94	0.92
OS-M	0.96	0.95	0.94

Zone	Indicative MLF Trends	Factors Influencing the Outcome
South West Queensland (SWQ)	The MLFs remain relatively unchanged over time under all scenarios.	The strength of the existing and augmented transmission system within the zone and connecting to the SEQ zone (the regional reference node's location), makes the SWQ zone's indicative MLFs less sensitive to significant new entry generation.

Figure 5-6 — Variation of indicative MLFs for the Northern New South Wales (NNS) zone

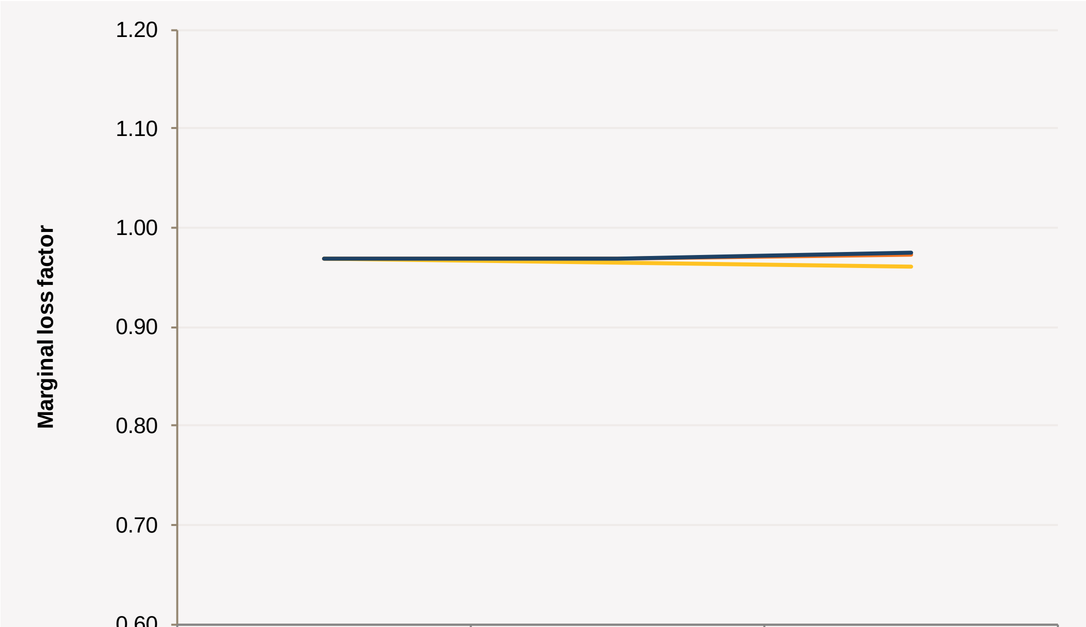


	2011–12 (Actual)	2019–20	2029–30
FC-H	-	1.01	0.99
DW-M	-	0.89	0.89
OS-M	-	1.00	0.96

Zone	Indicative MLF Trends	Factors Influencing the Outcome
Northern New South Wales (NNS)	The MLFs experience small variations under the FC-H and OS-M scenarios, and remain relatively unchanged under the DW-M scenario.	New entry generation appearing in all three scenarios and increasing imports from Queensland lead to increased power transfers from NNS[a] to NCEN. In the first 10 years, the FC-H and OS-M scenarios have little new entry generation. As a result, the indicative MLFs are close to 1.0. The DW-M scenario has significant new entry generation leading to a lower initial MLF. In the second 10 years, new entry generation appears under all three scenarios, resulting in lower indicative MLFs. Under the DW-M scenario, however, the indicative MLFs remain relatively constant. This is despite significant new entry generation reaching 7,000 MW due to the scenario-based 500 kV transmission development between NCEN and NNS.

a. There are no actual MLFS for 2011–12 because this zone has no generation that is directly grid connected.

Figure 5-7 — Variation of indicative MLFs for the Central New South Wales (NCEN) zone

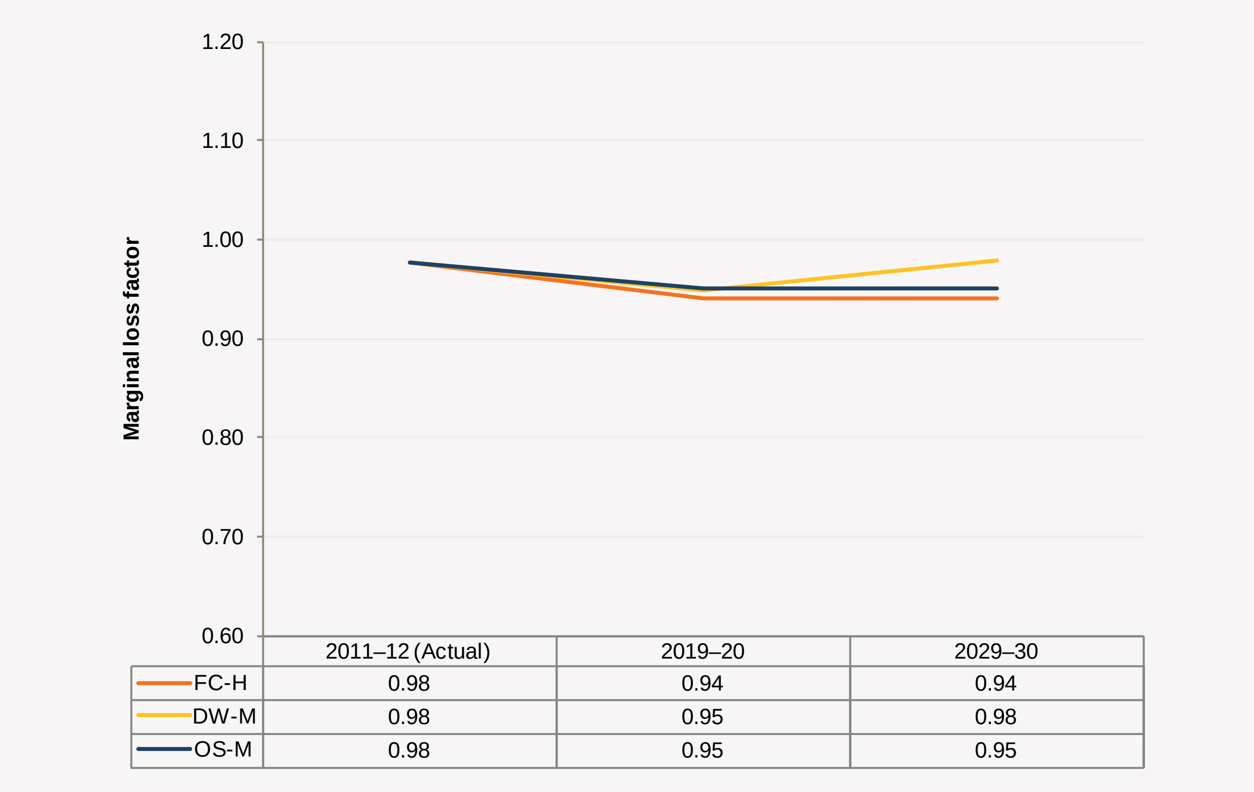


	2011–12 (Actual)	2019–20	2029–30
FC-H	0.97	0.97	0.97
DW-M	0.97	0.97	0.96
OS-M	0.97	0.97	0.98

Zone	Indicative MLF Trends	Factors Influencing the Outcome
Central New South Wales (NCEN)[a]	The MLFs remain relatively unchanged over time under all scenarios.	MLFs have less impact from new entry generation due to the regional reference node being located within the zone (at the Sydney West 330 kV node) and the high capability of the transmission network within the zone and connecting with neighbouring zones.

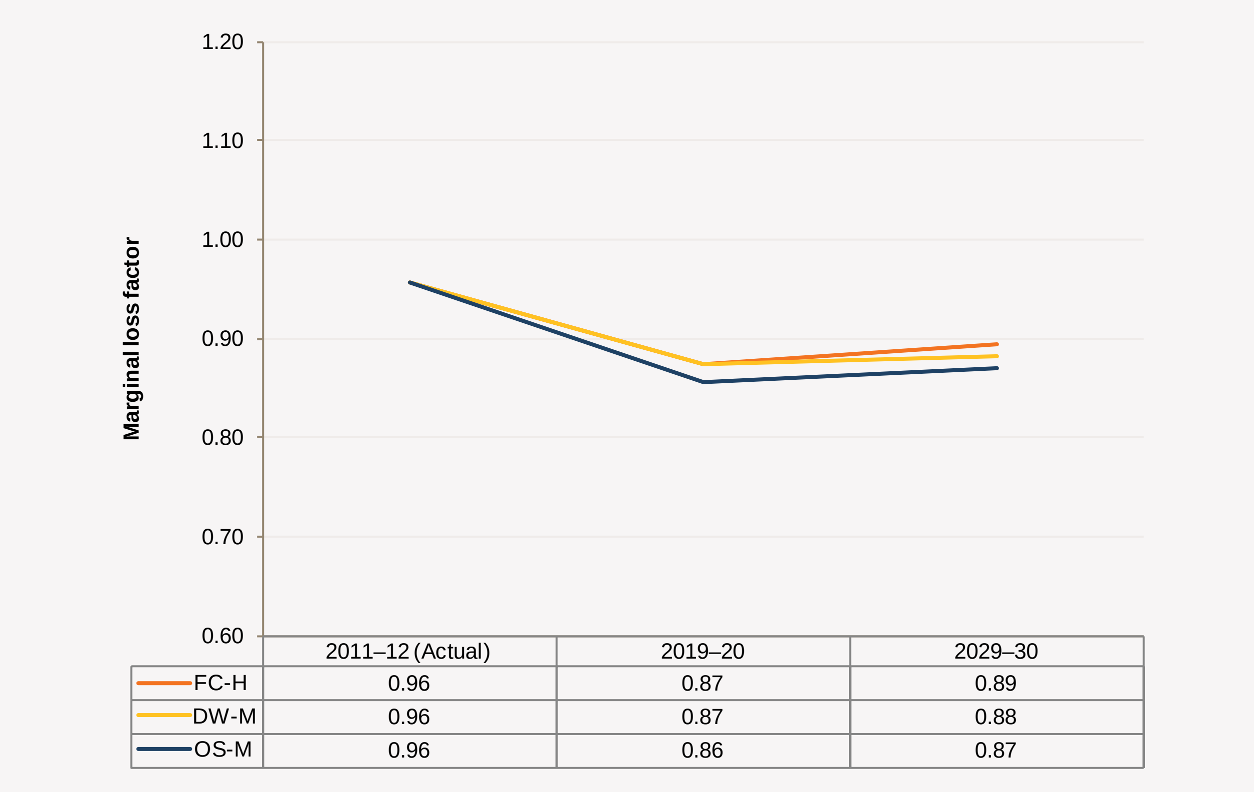
a. The location of the regional reference node for New South Wales.

Figure 5-8 — Variation of indicative MLFs for the Canberra (CAN) zone



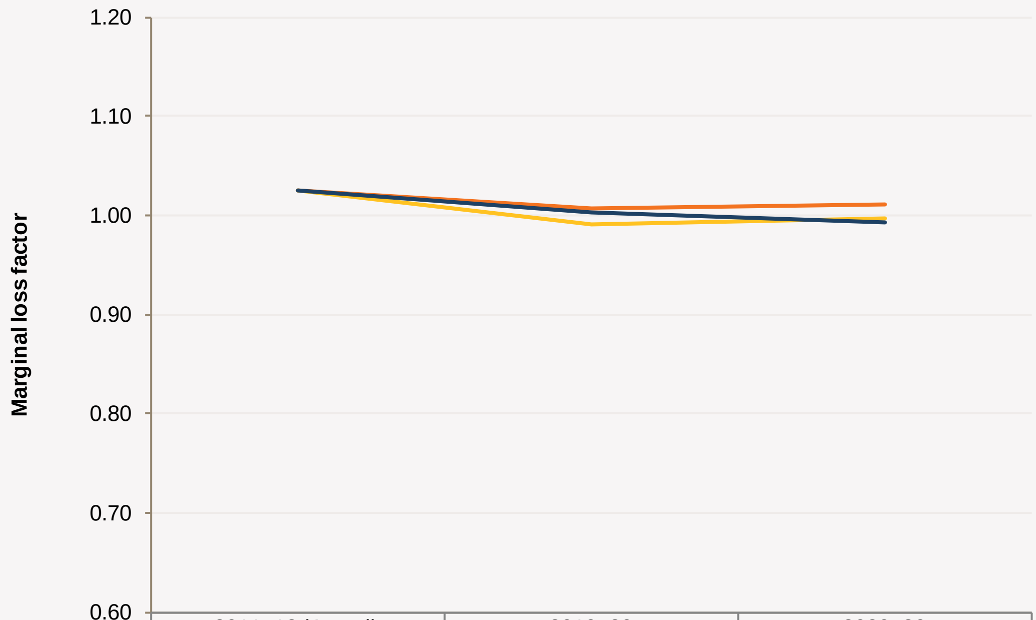
Zone	Indicative MLF Trends	Factors Influencing the Outcome
Canberra (CAN)	The MLFs experience small variations, with a tendency to decrease.	New entry generation appearing in all three scenarios and increasing imports from Victoria lead to increased power transfers from CAN to NCEN (towards the regional reference node).

Figure 5-9 — Variation of indicative MLFs for the South West New South Wales (SWNSW) zone



Zone	Indicative MLF Trends	Factors Influencing the Outcome
South West New South Wales (SWNSW)	The MLFs experience large variations, with a tendency to decrease.	New entry generation appearing in all three scenarios and increasing imports from Victoria leads to increased power transfers from SWNSW to NCEN (towards the regional reference node). The dominant driver in the first 10 years is increased imports from Victoria, which causes the initial reduction in MLFs. In the second 10 years, decreasing imports and new transmission in some scenarios act to increase the MLFs, while increased wind generation in the zone acts to decrease them. The combined effect results in relatively little change over the second 10-year period.

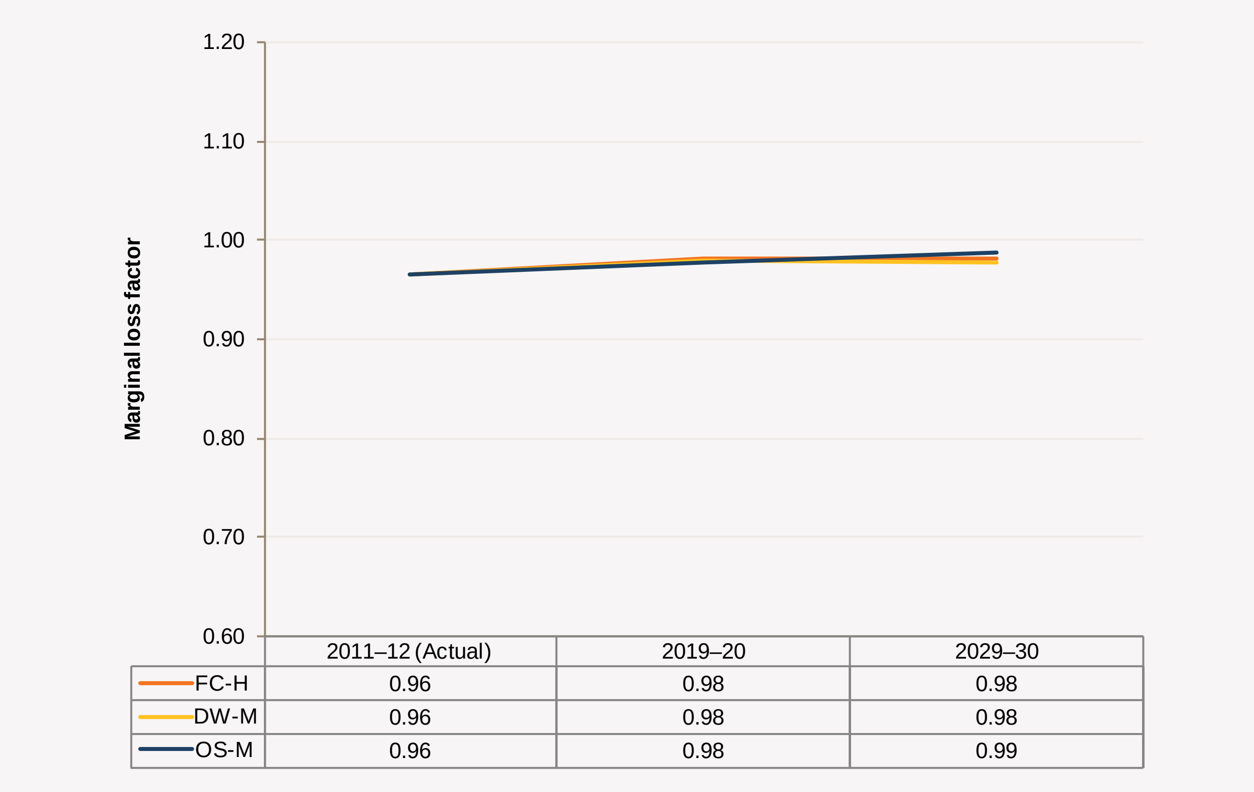
Figure 5-10 — Variation of indicative MLFs for the Country Victoria (CVIC) zone



	2011–12 (Actual)	2019–20	2029–30
FC-H	1.02	1.01	1.01
DW-M	1.02	0.99	1.00
OS-M	1.02	1.00	0.99

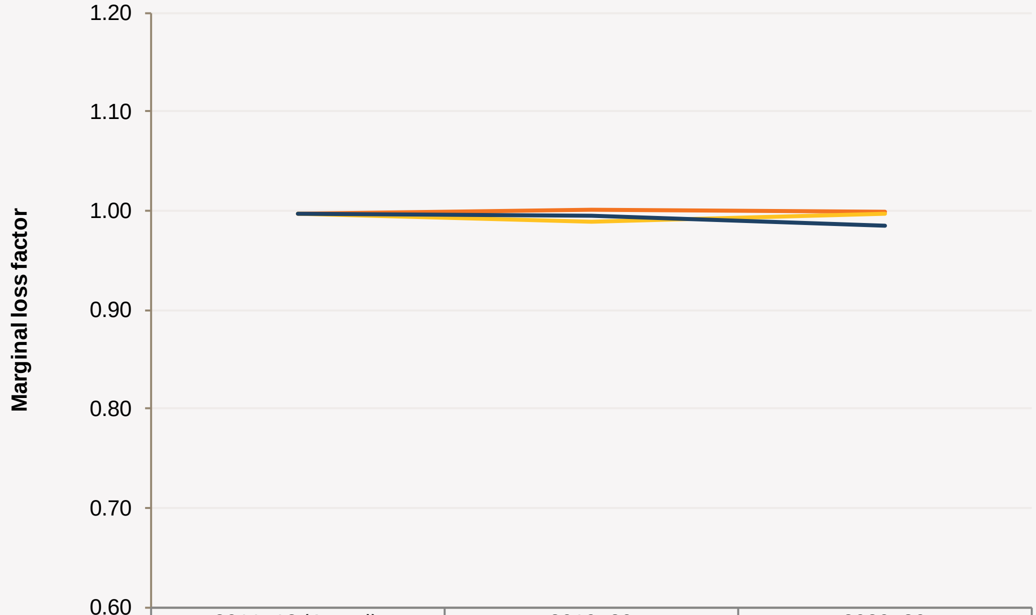
Zone	Indicative MLF Trends	Factors Influencing the Outcome
Country Victoria (CVIC)	The MLFs remain relatively unchanged over time under all scenarios.	New entry generation appearing in all three scenarios leads to small increases in power transfers towards the MEL zone (and the regional reference node).

Figure 5-11 — Variation of indicative MLFs for the Latrobe Valley (LV) zone



Zone	Indicative MLF Trends	Factors Influencing the Outcome
Latrobe Valley (LV)	The MLFs remain relatively unchanged over time under all scenarios.	MLFs are less sensitive to new entry generation due to the strength of the existing and augmented transmission network within the zone and connecting to the MEL zone (the regional reference node's location).

Figure 5-12 — Variation of indicative MLFs for the Melbourne (MEL) zone

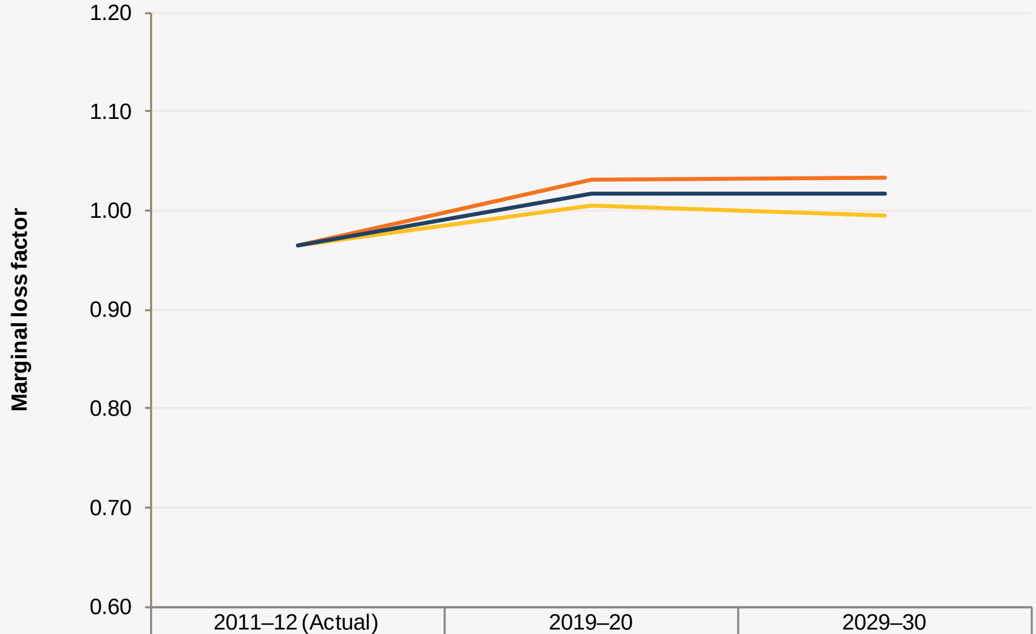


	2011–12 (Actual)	2019–20	2029–30
FC-H	1.00	1.00	1.00
DW-M	1.00	0.99	1.00
OS-M	1.00	1.00	0.98

Zone	Indicative MLF Trends	Factors Influencing the Outcome
Melbourne (MEL)[a]	The MLFs remain relatively unchanged over time under all scenarios.	MLFs have less impact from new entry generation due to the regional reference node being located within the zone (at the Thomastown 66 kV node) and the high capability of the transmission network within the zone and with neighbouring zones.

a. The location of the regional reference node for Victoria.

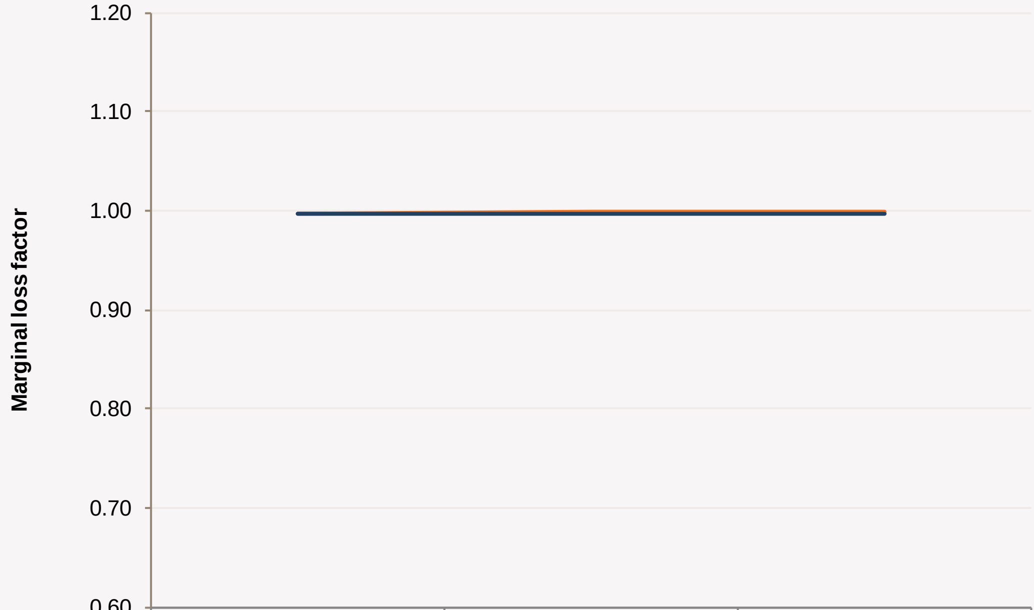
Figure 5-13 — Variation of indicative MLFs for the Northern Victoria (NVIC) zone



	2011–12 (Actual)	2019–20	2029–30
FC-H	0.96	1.03	1.03
DW-M	0.96	1.01	0.99
OS-M	0.96	1.02	1.02

Zone	Indicative MLF Trends	Factors Influencing the Outcome
Northern Victoria (NVIC)	The MLFs experience large variations, with a tendency to increase.	No new entry generation appears in any of the scenarios. However, power transfers from MEL to New South Wales (away from the regional reference node) increase through this zone.

Figure 5-14 — Variation of indicative MLFs for the Adelaide (ADE) zone

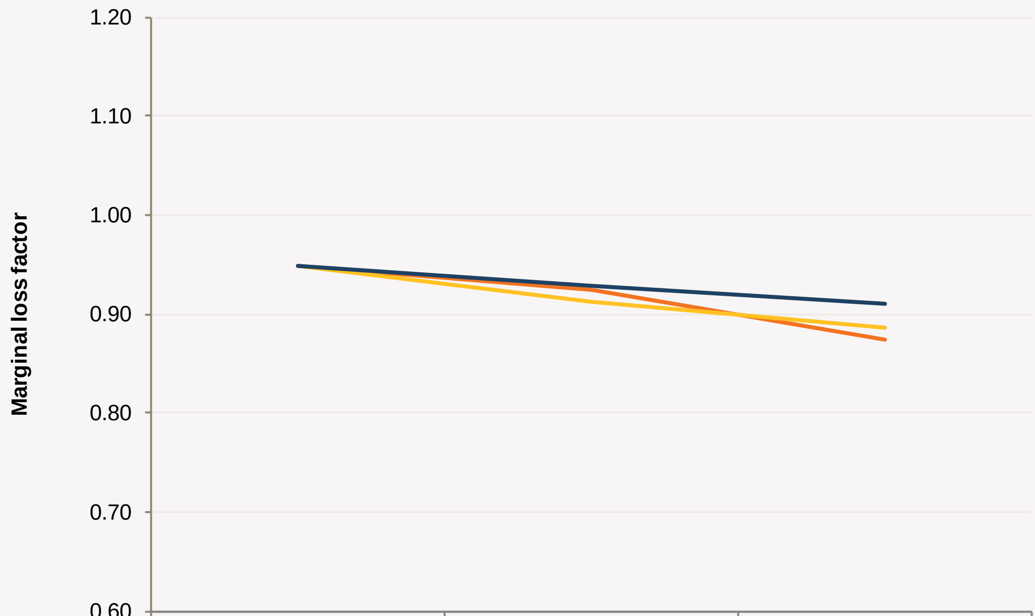


	2011–12 (Actual)	2019–20	2029–30
FC-H	1.00	1.00	1.00
DW-M	1.00	1.00	1.00
OS-M	1.00	1.00	1.00

Zone	Indicative MLF Trends	Factors Influencing the Outcome
Adelaide (ADE)[a]	The MLFs remain relatively unchanged over time under all scenarios.	MLFs are less sensitive to new entry generation due to the regional reference node being located within the zone (at the Torrens Island 66 kV node) and the high capability of the transmission network within the zone and with neighbouring zones.

a. The location of the regional reference node for South Australia.

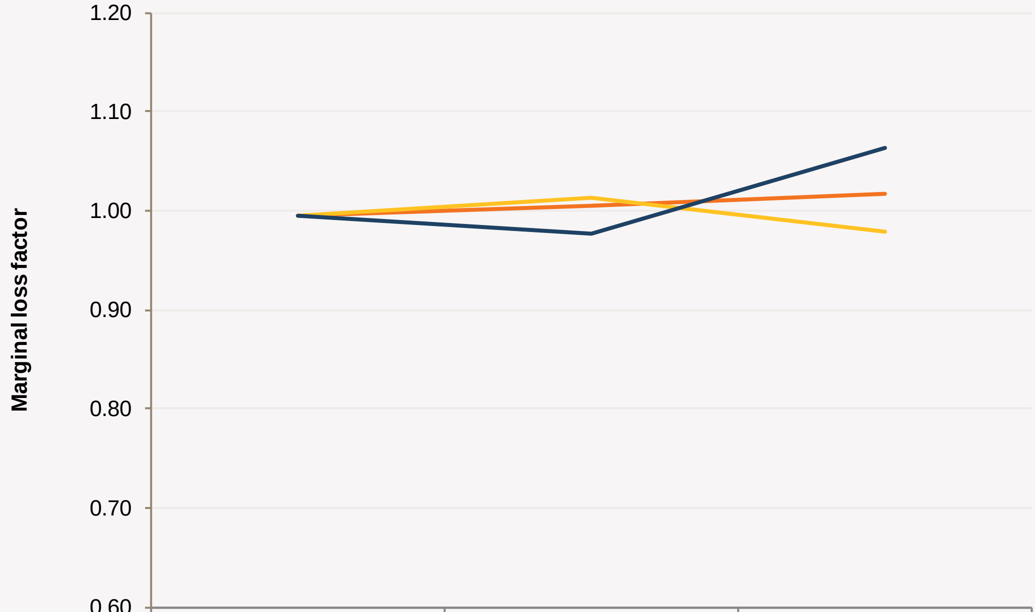
Figure 5-15 — Variation of indicative MLFs for the Northern South Australia (NSA) zone



	2011–12 (Actual)	2019–20	2029–30
FC-H	0.95	0.92	0.88
DW-M	0.95	0.91	0.89
OS-M	0.95	0.93	0.91

Zone	Indicative MLF Trends	Factors Influencing the Outcome
Northern South Australia (NSA)	The MLFs experience large variations, with a tendency to decrease.	New entry generation appearing in all three scenarios leads to increasing power transfers towards the ADE zone (and the regional reference node).

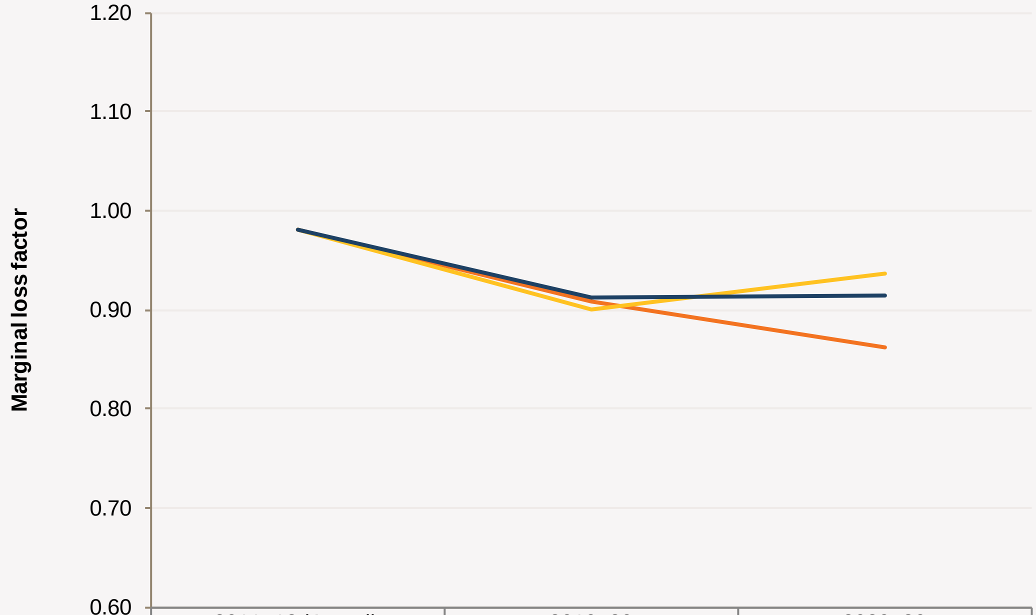
Figure 5-16 — Variation of indicative MLFs for the South East South Australia (SESA) zone



	2011–12 (Actual)	2019–20	2029–30
FC-H	0.99	1.01	1.02
DW-M	0.99	1.01	0.98
OS-M	0.99	0.98	1.06

Zone	Indicative MLF Trends	Factors Influencing the Outcome
South East South Australia (SESA)	The MLFs slightly increase under the FC-H and DW-M scenarios in the first 10 years. The MLFs continue to increase under FC-H but decrease under DW-M in the second 10 years. The MLFs slightly decrease under the OS-M scenario in the first 10 years, followed by a larger increase in the second 10 years.	New entry generation and changes in demand within the SESA zone vary significantly between all scenarios, leading to no consistently identifiable MLF trend.

Figure 5-17 — Variation of indicative MLFs for the Tasmania (TAS) zone



	2011–12 (Actual)	2019–20	2029–30
FC-H	0.98	0.91	0.86
DW-M	0.98	0.90	0.94
OS-M	0.98	0.91	0.91

Zone	Indicative MLF Trends	Factors Influencing the Outcome
Tasmania (TAS)	The MLFs experience large variations, with a tendency to decrease.	High levels of new entry generation appear in all three scenarios, leading to increased power transfers from Tasmania to Victoria.

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CHAPTER 6 - NEMLINK: FURTHER STUDY RESULTS FOR A HIGH-CAPACITY BACKBONE

Summary

This chapter presents the results from a review of the 2010 NTNDP study involving increased inter-regional power transfer capabilities in the National Electricity Market (NEM), with the aim of providing a more accurate view of potential market benefits.

Central to the 2010 NTNDP study was a conceptual project called NEMLink, involving significant transmission investment in a high-capacity backbone that linked the regions. The study found that the project's market benefits were significant, and under an optimistic set of assumptions approached breakeven in terms of the project's costs.

The 2011 NTNDP continues this prefeasibility study by examining whether the net market benefits can be improved by deferring individual NEMLink components (each of which links two regions) until after the NTNDP's 20-year outlook period.

The 2011 NTNDP review found the following:

- Individually deferring any of the NEMLink components, other than the Victoria to Tasmania component, substantially reduces the benefit to cost ratio, indicating maximum net benefits are achieved when combining all three mainland components (Queensland to New South Wales, New South Wales to Victoria, and Victoria to South Australia).

  This suggests there are significant synergies to be gained from augmenting all the mainland region links. This finding is consistent with the 2011 NTNDP review's approach, based on valuing NEMLink while deferring individual components, rather than valuing individual components.
- The most economic NEMLink option defers the Victoria to Tasmania component until beyond the 20-year outlook period. This link has the highest capital cost per unit of capacity of any NEMLink component, and these costs outweigh the market benefits from allowing additional wind investment in Tasmania, and leveraging the Tasmanian hydroelectric generators to stabilise the intermittency of wind generation in the southern mainland regions.
- NEMLink (with or without the Victoria to Tasmania component) may approach economic viability by approximately 2020–21 under high demand growth and high carbon price conditions.
- Using the current benefit assessment approach, under conditions that more closely resemble the current NEM policy and economic environment, no modelled NEMLink projects are likely to be viable by 2020, and future work should consider a longer study period with a view to staged NEMLink completion by 2025 or 2030.
- Any future work on NEMLink (and similar NEMLink alternatives) should refine the cost benefit results through a more detailed network representation, a longer outlook period, a broader set of modelling scenarios, and an optimisation of the staging for individual NEMLink components.

The 2010 study also made several modelling assumptions that have been revised and improved to provide a more accurate view of the potential market benefits.

Detailed generation investment, transmission costs, and cost benefit analysis results are included in Appendix C.

6.1 2010 NEMLink study results

The NEMLink concept was originally developed with input from the transmission network service providers (TNSP), and represents one view of a logical future extension to existing and planned 500 kV regional transmission networks.

As an initial scoping study, its purpose was to assess whether the project's economic outcomes were sufficient to warrant further examination. The modelling assumed that the entire project would be commissioned by 2019–20. Modelling was conducted under the Fast Rate of Change, high carbon price scenario (FC-H), and the Uncertain World scenario's zero carbon price sensitivity (UW-0). For a description of the scenarios, see Chapter 7, Section 7.1.2.

Both the scenario and the scenario sensitivity represent high economic growth with a requirement for significant new generation. The different carbon price trajectories result in substantially different generation investment patterns in terms of location and technology.

The study's results provided information about the technical characteristics, estimated costs, and potential market benefits that a high-capacity backbone project might carry. These benefits were significant, and under an optimistic set of assumptions approached breakeven against the project costs.

Modelling results

Table 6-1 lists the discount rate, transmission costs, gross market benefits, and benefit to cost ratio for the NEMLink project under the two scenarios considered. For more information about the discounted cash flow calculation (present value), see Appendix C, Section C.4.

Table 6-1 — 2010 NEMLink discount rate, transmission capital costs, gross market benefits, and benefit to cost ratio (2010–11 dollars)

Scenario	Discount Rate (%)	Present Value Transmission Capital Costs ± 30% ($ Billion)	Present Value Market Benefits ($ Billion)	Benefit to Cost Ratio[a]
Fast Rate of Change, high carbon price (FC-H)	8.78	4.4	3.9	0.9
Uncertain World, zero carbon price sensitivity (UW-0)	11.37	3.3	1.7	0.5

a. This is the ratio of the present value of market benefits to the present value of transmission costs. A value greater than 1.0 indicates that market benefits outweigh transmission costs, and the project carries positive net market benefits.

The modelling results indicated that, while the benefit to cost ratio remains less than one in both scenarios, it was sufficiently high under FC-H to warrant further analysis. In addition, some NEMLink components were expected to provide more market benefits than others, although the extent of these differences was not quantified as part of the 2010 study.

Augmentations as large as NEMLink's would be expected to be built in stages. The 2011 NTNDP continues the prefeasibility study begun in the 2010 NTNDP by examining the net market benefits from a number of alternative NEMLink projects that defer individual NEMLink components, and assessing impacts under both optimistic and moderate assumptions.

6.2 Methodology

6.2.1 Technical features of the NEMLink concept

The NEMLink conceptual network augmentation was intended to enable large-scale power transfers within and between the regions. The original NEMLink project comprised the following:

- A high capacity, 500 kV double circuit, alternating current (AC) transmission backbone connecting the mainland regions.
- A 400 kV high voltage direct current (HVDC) connection between Tasmania and the mainland, similar to the existing Basslink interconnector.
- Necessary intermediate substations, switching stations, and devices for reactive compensation and power flow control.

AEMO engaged consulting engineers[1] and consulted with TNSPs to obtain high-level cost estimates for each component as appropriate for a prefeasibility assessment. This estimate assumes that the conditions will be generally favourable along the length of the augmented transmission lines, and an allowance of 10% has been made to the route length to account for potential deviations from the most direct path. AEMO has not investigated issues associated with acquiring the necessary easements.

Figure 6-1 shows the original NEMLink concept modelled in 2010.

Table 6-2 lists the NEMLink options and their associated costs, which are consistent with this network structure, although each option represents a case that defers an inter-regional link beyond the outlook period (except for the no deferrals option). Deferring individual components and assessing the net market benefits of the remaining augmentations (rather than assessing each component separately) is consistent with the original study's purpose of exploring the benefits from significantly increasing power transfer capabilities across the NEM.

Table 6-2 — NEMLink options studied in the 2011 NTNDP (2010–11 dollars)

NEMLink Option	Estimated Capital Cost (± 30%) ($ Billion)
NEMLink, no deferrals	8.3
NEMLink, deferring QLD-NSW	6.1
NEMLink, deferring NSW-VIC	7.3
NEMLink, deferring VIC-SA	5.7
NEMLink, deferring VIC-TAS	7.3

[1] Sinclair Knight Merz Pty Ltd.

6.2.2 Market modelling for NEMLink

The 2010 NEMLink studies were conducted under the FC-H and the UW-0 scenarios. The market benefits achieved under FC-H, however, were sufficiently close to the NEMLink project costs to warrant further study. As a result, the 2011 NTNDP studies focus on the FC-H scenario, where high demand and high carbon prices are likely to lead to the largest requirement for new generation.

In addition, the Decentralised World, low carbon price scenario (DW-L) has also been considered because it represents a scenario that is most similar to the Australian Government's Clean Energy Future plan carbon price modelling, which introduces a carbon pricing scheme and payments for closure mechanism over the next 10 years.[2]

Several changes were made for the 2011 studies to improve the accuracy of the market benefit results, which involved network impact representations, formulation of generation build targets, and time-resolution of the least-cost expansion model. These improvements also helped to better capture the implications of demand diversity between regions, the correlation between wind and demand, and some remaining intra-regional congestion even with NEMLink in place.

The market benefits were determined under each scenario by comparing the results of a modelled case (with a NEMLink option) with a base case (without a NEMLink option).

The modelling framework comprised a combination of least-cost expansion modelling and time-sequential market simulations.

For a summary of the market benefit calculation approach, see Section 6.4. For more information about the NEMLink market modelling, see Appendix C, Section C.2.

[2] Australian Government. “Clean Energy Future”. Available http://www.cleanenergyfuture.gov.au. 27 July 2011.

Figure 6-1 — The original NEMLink concept

6.3 Generation and transmission development

6.3.1 Generation development

Least-cost modelling generally attempts to meet regional demand growth using the most economic selection of new generation from across the NEM, up to the limits imposed by the transmission network. It also provides flexibility in the mix of peaking and base load generation to meet maximum demand and energy requirements for the lowest cost.

Most of the NEMLink options result in a significant reduction in total new generation investment compared with the base case (without a NEMLink option). The option deferring QLD-NSW shows the largest reduction of 4% and 12% under the FC-H and DW-L scenarios, respectively. This suggests that the NEMLink options enable a better use of generation capacity without sacrificing power system reliability.

The exception is the option deferring NSW-VIC, which has more new generation installed than under the base case (without a NEMLink option), largely in the form of wind generation in New South Wales and combined-cycle gas turbine (CCGT) generation in the same region to mitigate wind generation's intermittent output. This least-cost result occurs because operating cost savings outweigh the increased capital costs of new generation, which indicates the importance of connecting New South Wales and Victoria as part of NEMLink, to better utilise the generation in both regions.

Increased transmission network capabilities allow the NEMLink modelling more freedom to share capacity between regions, and to select cheaper, though potentially more distant generation investment options to meet regional demand. This results in significant shifts in new generation timing, location, and technology.

The 2011 NEMLink modelling shows a consistent pattern of new generation spread across zones where new investment did not occur under the base case:

- Under the FC-H scenario, the Northern New South Wales (NNS) and South West New South Wales (SWNSW) zones become leading zones for CCGT investments.
- Under the FC-H scenario, deferring VIC-TAS or deferring VIC-SA could promote CCGT carbon capture and storage (CCS) technology in the Latrobe Valley (LV) zone.
- Under the DW-L scenario, Country Victoria (CVIC), NNS, and South West Queensland (SWQ) become popular zones for geothermal and solar thermal generation.

For more detailed results, see Appendix C, Section C.3.

6.3.2 Transmission development

For the purposes of the NEMLink studies, each NEMLink option was assumed to proceed from 2020–21, and alternate timings were not permitted. Intra-regional augmentations were assumed to be consistent with those modelled in the 2010 NTNDP, because despite NEMLink's high capacity, the need for intra-regional augmentations is driven by intra-regional load centres rather than inter-regional bulk power transfers.

In the underlying base case (without a NEMLink option), the model was able to select from major inter-regional augmentations studied in the 2010 NTNDP. Subsequently, the base case modelling resulted in the following:

- Augmentation of the Queensland–New South Wales (QNI) interconnector in 2014–15 under FC-H.
- Augmentation of the Victoria–South Australia (Heywood) interconnector in 2014–15 under FC-H.
- No inter-regional augmentations under DW-L.

Intra-regional augmentation options in the base case were again consistent with those modelled in the relevant 2010 NTNDP scenario.

6.4 2011 NEMLink market benefit comparisons

The 2011 NTNDP study market benefits have been calculated using the same discounted cash flow calculation methodology used in the 2010 studies (for more information see Appendix C, Section C.4). Costs are discounted using generator-weighted average cost of capital (WACC) assumptions, which were 8.78% under the FC-H scenario and 9.79% under the DW-L scenario.[3]

Market benefits are calculated by comparing study results for each NEMLink option with the results from the base case (without a NEMLink option). Market benefits accrued from differences in the following areas:

- Capital costs and avoided fixed costs, determined for the following:
  - For generation by comparing generation capital and fixed operating costs from the least-cost expansion.
  - For transmission by comparing the cost of transmission projects deferred (or brought forward).
- Operating costs, determined by comparing the total operating costs (including emission costs) from the time-sequential modelling.
- Transmission network losses, determined by comparing the cost of interconnector losses from the time sequential modelling (for more information about how the value of losses was determined, see Appendix C).
- Reliability benefits, determined by comparing the unserved energy from the time-sequential modelling, and valuing the difference at an assumed value of customer reliability of 55,000 $/MWh.

AEMO has not sought to quantify other relevant market benefits that may exist, such as competition benefits and option values.

The study results indicate the following:

- Under the FC-H scenario, the NEMLink option deferring VIC-TAS shows the highest net market benefits.
- Under the FC-H scenario, no augmentation options show positive net market benefits, though several projects have cost benefit ratios approaching one.
- Under the DW-L scenario, the market benefits are significantly lower than the transmission capital costs for all studied NEMLink options.

Figure 6-2 and Table 6-3 show the net market benefits and additional benefit-to-cost information for the NEMLink project (no deferrals) and the four NEMLink options under the FC-H scenario.

Figure 6-3 and Table 6-4 show the same information for the DW-L scenario.

[3] These were the generator WACC assumptions provided by ACIL Tasman for the 2010 NTNDP. “Preparation of energy market modelling data for the Energy White Paper”. Available http://www.aemo.com.au/planning/0400-0019.pdf. Accessed 27 October 2011.

Figure 6-2 — Net market benefits, FC-H scenario

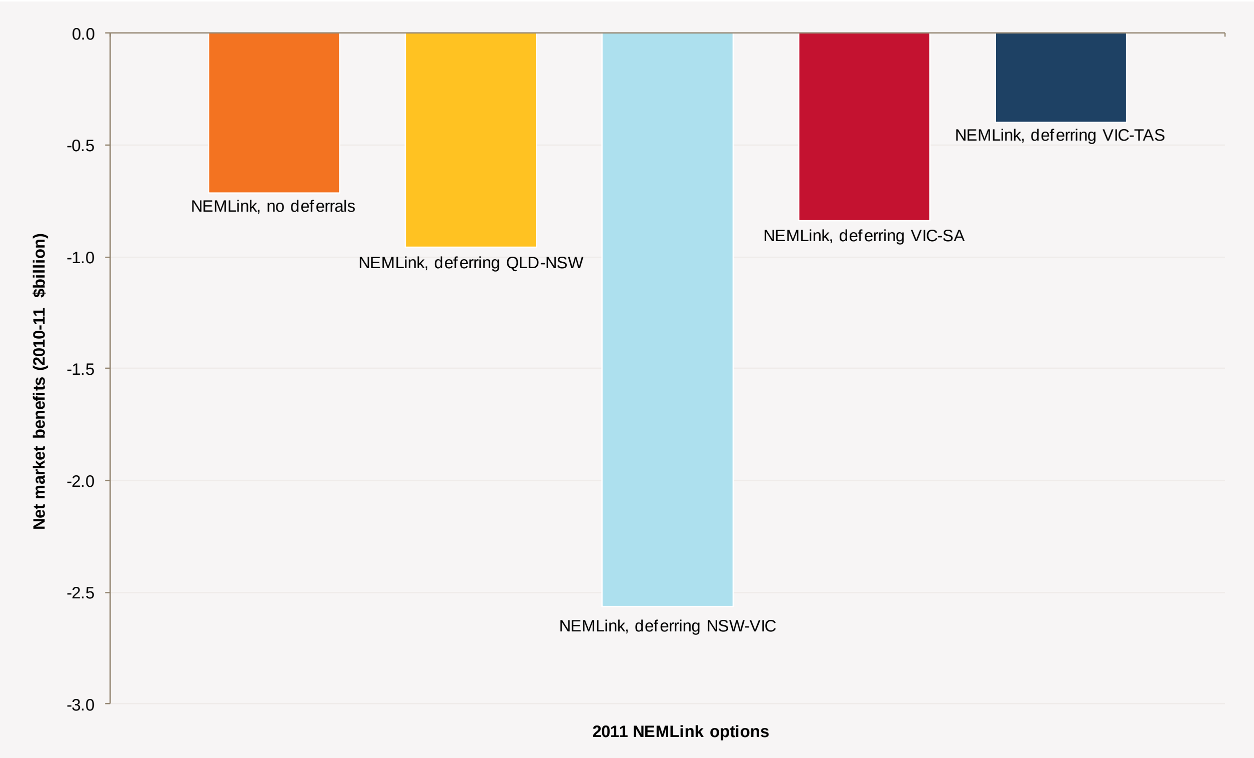


Table 6-3 — Benefit-to-cost ratio assessment, FC-H scenario (2010–11 dollars)

NEMLink Option	Present Value of Transmission Costs ±30% ($ Billion)	Present Value of Market Benefits ($ Billion)	Net Market Benefits ($ Billion)	Benefit to Cost Ratio
NEMLink, no deferrals	4.35	3.64	-0.71	0.8
NEMLink, deferring QLD-NSW	3.15	2.19	-0.96	0.7
NEMLink, deferring NSW-VIC	3.82	1.26	-2.56	0.3
NEMLink, deferring VIC-SA	2.91	2.07	-0.84	0.7
NEMLink, deferring VIC-TAS	3.79	3.39	-0.40	0.9

Figure 6-3 — Net market benefits, DW-L scenario

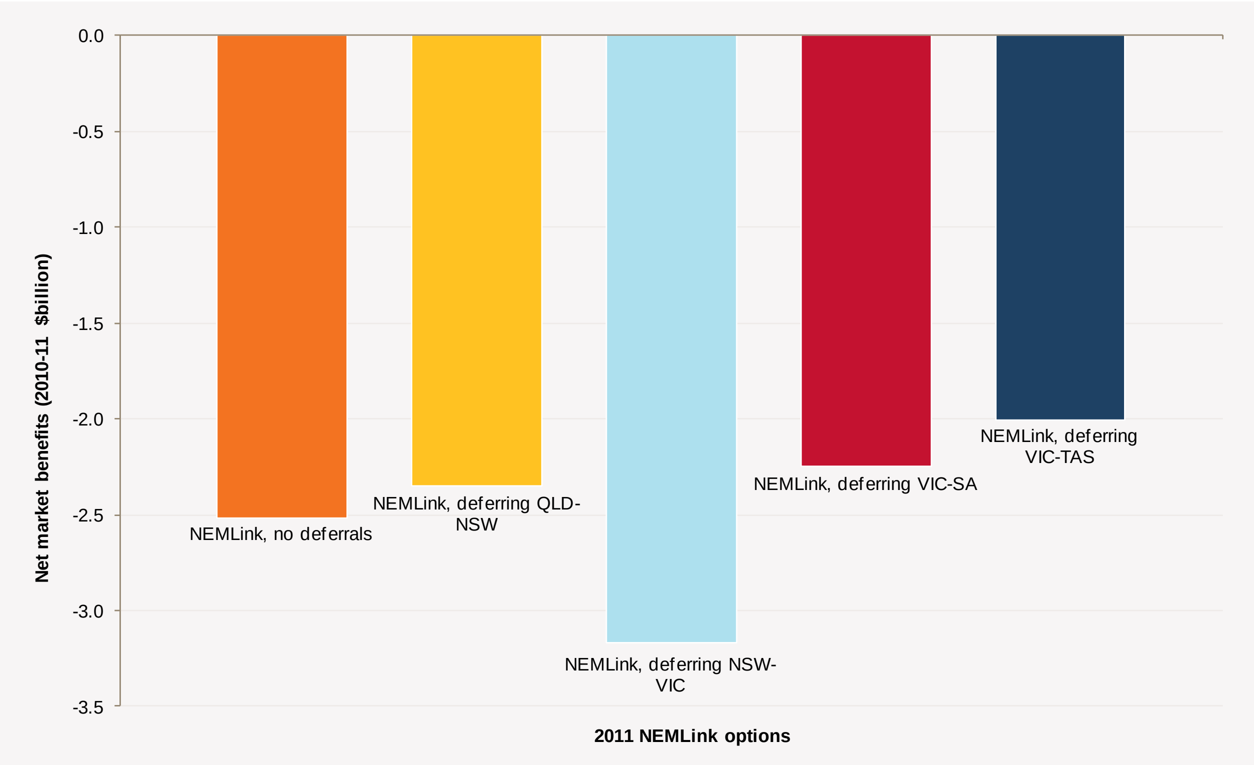


Table 6-4 — Benefit-to-cost ratio assessment, DW-L scenario (2010–11 dollars)

NEMLink Option	Present Value of Transmission Costs ±30% ($ Billion)	Present Value of Market Benefits ($ Billion)	Net Market Benefits ($ Billion)	Benefit to Cost Ratio
NEMLink, no deferrals	4.01	1.49	-2.52	0.4
NEMLink, deferring QLD-NSW	2.94	0.58	-2.36	0.2
NEMLink, deferring NSW-VIC	3.54	0.37	-3.17	0.1
NEMLink, deferring VIC-SA	2.73	0.48	-2.25	0.2
NEMLink, deferring VIC-TAS	3.51	1.50	-2.01	0.4

6.4.1 A comparison of market benefit findings

Comparing the 2010 and 2011 NEMLink studies for the FC-H scenario shows that the 2011 modelling has not substantially changed the expected market benefits. While this net change is small, individual modelling improvements have acted to both increase and decrease the benefits, in particular through a more accurate representation of the following:

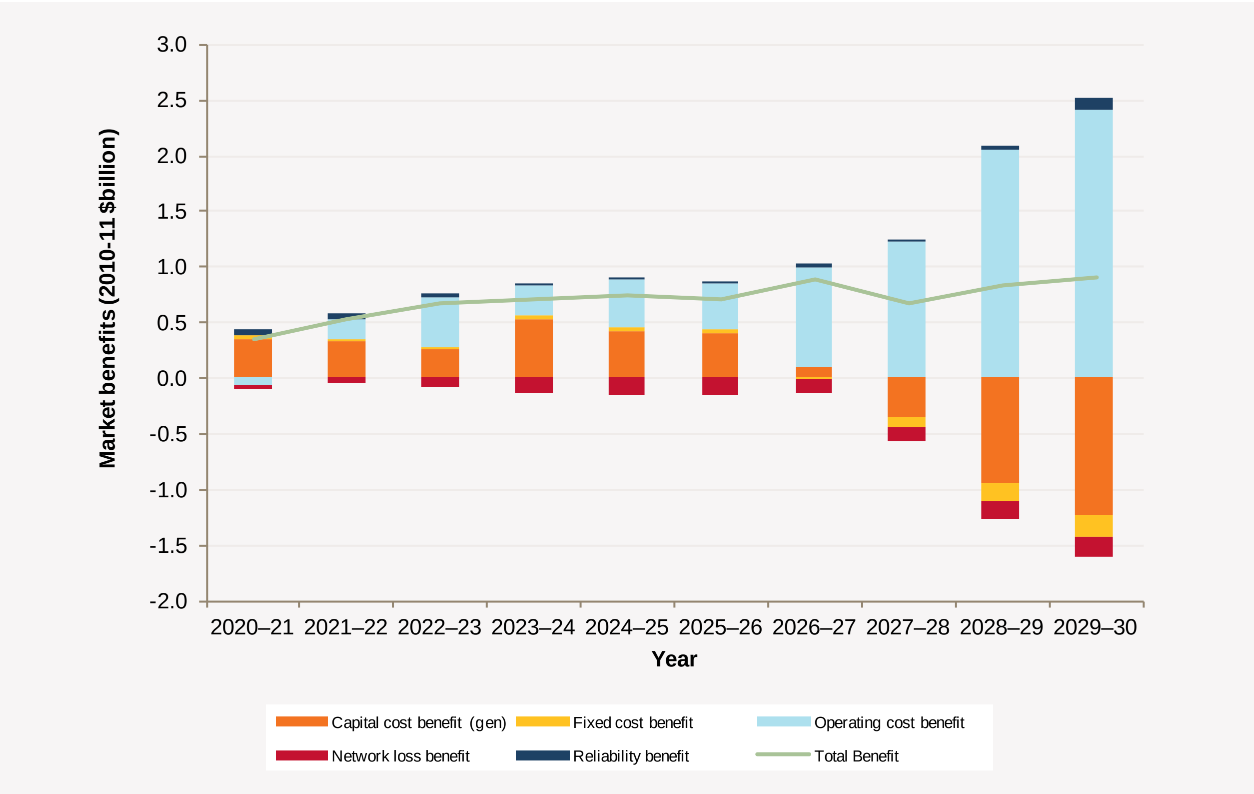
- Network limitations unaffected by commissioning the NEMLink projects (decreasing net benefits).
- Demand profiles and demand diversity between regions (increasing net benefits).
- The capability and limitations of the transmission network when facilitating reserve sharing between neighbouring regions at times of high demand (increasing or decreasing net benefits by balancing trade-offs between capital costs and operating costs within the net benefit calculations).

While annual NEMLink market benefits are similar in the 2010 and 2011 studies, the distribution across market benefit types is different. The 2010 NTNDP modelling resulted in negative capital cost benefits, due to more new generation with NEMLink than without it. The negative capital cost was offset with significant operating cost benefit, because the additional generation investment displaced existing generating units that were more expensive to run.

The 2011 NEMLink studies have better rationalised these trade-offs through improved modelling of generation build targets (see Appendix C, Section C.2), leading to largely positive annual market benefits across all types.

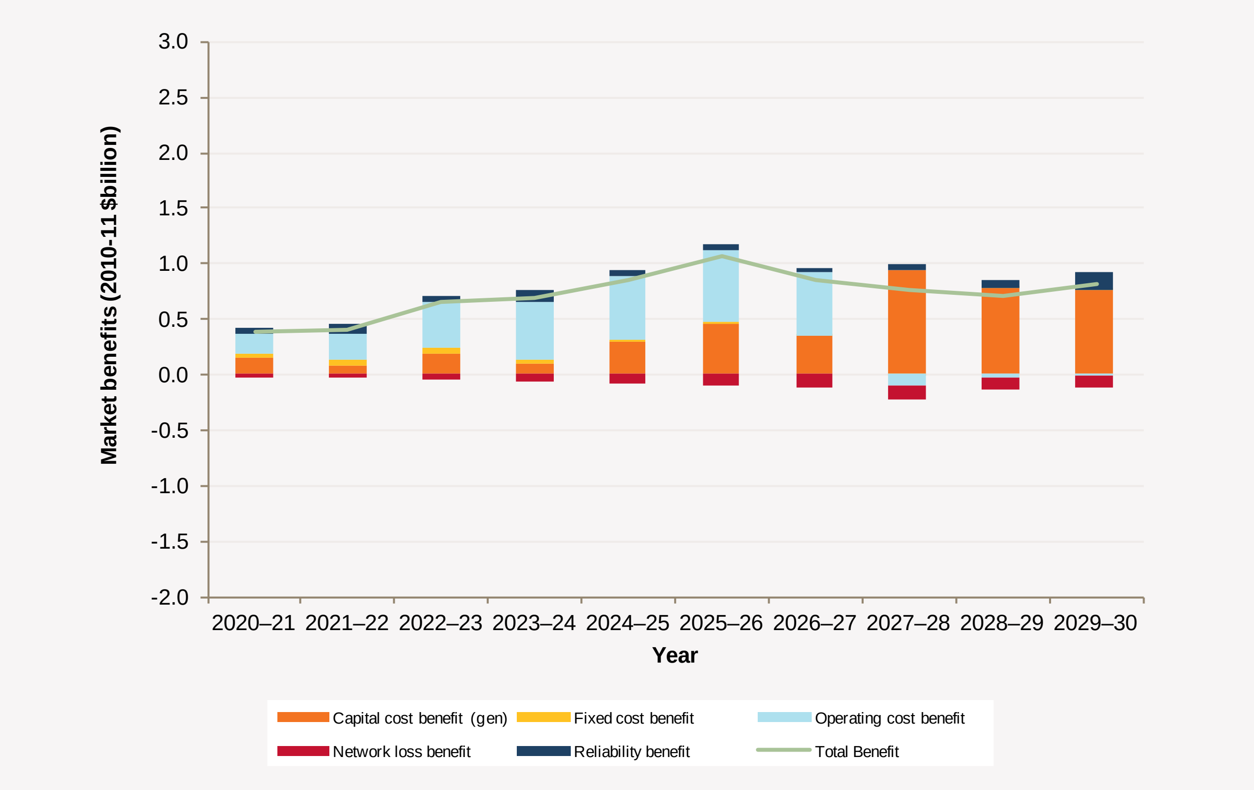
Figure 6-4 and Figure 6-5 show a comparison of the annual market benefits (by benefit type) for the 2010 and 2011 NEMLink studies (no deferral option) under the FC-H scenario, in 2010–11 dollars. Appendix C, Section C.4 presents market benefit charts for the other NEMLink options and the DW-L scenario.

Figure 6-4 — Annual NEMLink project market benefits under the FC-H scenario, 2010 study[4]



[4] This figure shows the annual market benefits from the year NEMLink is commissioned (2020–21) onwards. Some minor benefits, which are small by comparison, accrue prior to this because the modelling anticipates NEMLink.

Figure 6-5 — Annual NEMLink project market benefits under the FC-H scenario, 2011 study[5]



6.4.2 Assessing NEMLink options using different discount rates

Different cash flow discount rate assumptions can significantly impact the net market benefit results.

Table 6-5 lists the net market benefits given different discount rate assumptions. A discount rate of 6%[6] has been selected as a sensitivity. This rate is consistent with the lower bound sensitivity recommended by the Australian Energy Regulator (AER) when converted to a pre-tax real discount rate.

Under the FC-H scenario, a lower discount rate generally increases each option's net market benefits (by up to $700 million in one case).

Under the DW-L scenario, however, the opposite is true. This is because the annual benefits over the outlook period, though increasing over time, never exceed the annualised costs, and a lower discount rate increases the impact of the future negative cash flows.

[5] See note 4 in this chapter.

[6] This approximates the current TNSP-regulated WACC discount rate of 8.82%. See the Australian Energy Regulator. "Electricity transmission and distribution network service providers - Review of the weighted average cost of capital (WACC) parameters – Final Decision". May 2009.

Table 6-5 — Sensitivity of net market benefits to discount rate (2010–11 dollars)

NEMLink Option	FC-H		DW-L	
	PV of Net Market Benefits at 8.78% ($ Billion)	PV of Net Market Benefits at 6% ($ Billion)	PV of Net Market Benefits at 9.79% ($ Billion)	PV of Net Market Benefits at 6% ($ Billion)
NEMLink, no deferrals	-0.71	-0.35	-2.52	-3.80
NEMLink, deferring QLD-NSW	-0.96	-0.96	-2.36	-3.97
NEMLink, deferring NSW-VIC	-2.56	-3.33	-3.17	-4.77
NEMLink, deferring VIC-SA	-0.84	-0.76	-2.25	-3.55
NEMLink, deferring VIC-TAS	-0.40	0.30	-2.01	-2.88

6.5 Conclusions

Individually deferring any of the NEMLink components, other than the Victoria to Tasmania component, reduces the benefit-to-cost ratio, indicating maximum net benefits are achieved when completing the entire high-capacity backbone from Queensland to South Australia. This suggests there are significant synergies from augmenting capability that links all of the mainland NEM regions.

The no deferrals and deferring VIC-TAS options show the highest positive or marginal net market benefits, indicating that those NEMLink options may become approach economic viability around 2020–21 under high demand growth and high carbon price conditions (FC-H).

Using the current benefit assessment approach, under conditions that more closely resemble the current NEM policy and economic environment, no modelled NEMLink projects are likely to be viable by 2020, and future work should consider a longer study period with a view to staged NEMLink completion by 2025 or 2030.

Any future work on NEMLink (and similar NEMLink alternatives) would refine the cost benefit results through a more detailed network representation, a longer outlook period, a broader set of modelling scenarios, and an optimisation of the staging for individual NEMLink components.

CHAPTER 7 - SCENARIO SENSITIVITY STUDIES

Summary

This chapter presents the results of sensitivity studies conducted to analyse developments with the potential to affect the future generation and transmission plans developed for the 2010 NTNDP.

A total of eleven sensitivity studies were conducted for two 2010 NTNDP scenarios, the Decentralised World, medium price (DW-M) scenario, and the Fast Rate of Change, high carbon price (FC-H) scenario.

Nine sensitivities to the DW-M scenario were studied to determine the impacts of changed assumptions about carbon pricing, the Large-scale Renewable Energy Target (LRET), generation capital costs, generation technology availability, and gas fuel costs. This scenario was chosen as the reference scenario for these sensitivity studies because it is a mid-range scenario.

Two sensitivities to the FC-H scenario were also studied to determine the impact of changed assumptions about generator capital costs, generation technology availability, and gas fuel costs. This scenario was chosen as the reference scenario for these sensitivity studies because the scenario's 2010 NTNDP results included the highest levels of new technology and new entry gas powered generation (GPG).

Key results from the sensitivity studies include the following:

- The Australian Government's Clean Energy Future plan's fixed three-year carbon price is sufficiently similar to the 2010 NTNDP medium carbon price scenarios to leave long-term modelling outcomes substantially unchanged, provided that the emissions trading scheme results in a return to medium carbon prices from 2015 onwards.
- A low carbon price results in substantially fewer existing brown and black coal generation retirements, reducing GPG investments.
- Future least-cost investment patterns (in terms of quantity, technology, and locality) are particularly sensitive to gas fuel cost assumptions, with relatively small price changes resulting in significant changes to the optimal mix of generation and transmission investment.
- The 2010 NTNDP found that gas may act as a transitional fuel between base load coal and renewables. Increasing the gas fuel cost makes this transition more difficult, and results in slower emission reductions (as coal-fired generation has less incentive to retire) and higher capital costs (as costs are higher for newer, less well-developed renewable technologies).
- With medium carbon prices and economic growth, extending the existing LRET trajectory to 2030 will result in significant investment in wind (13 GW), geothermal (3 GW), solar thermal (1 GW), and biomass (1 GW) generation technologies, resulting in a 13.9 Mt reduction in annual carbon dioxide equivalent (CO2-e) emissions by 2030, at the expense of an additional $35 billion in generation capital expenditure.
- Future least-cost investment patterns are largely unaffected by 20% reductions in geothermal and solar thermal capital costs, but are highly sensitive to similar levels of reduction in wind and carbon capture and storage (CCS) capital costs.
- Delaying the availability of new renewable technologies tends to increase investment in wind generation (to meet the LRET) and GPG (to support energy and maximum demand growth).

7.1 Sensitivity study development

The sensitivity studies examined the impact a series of changes in key inputs had on the 2010 NTNDP results.

The key inputs included carbon pricing, the LRET, generation capital costs, generation technology availability, and gas fuel costs.

Table 7-1 lists the 2010 NTNDP reference scenarios and the 2011 NTNDP sensitivity studies.

Table 7-1 — 2010 NTNDP reference scenarios and 2011 NTNDP sensitivity studies

Reference Scenario	2011 NTNDP Sensitivity Study	
Decentralised World, medium carbon price	Carbon pricing.	Clean Energy Future plan prices for 2012–13 to 2014–15, followed by the 2010 NTNDP's medium carbon price trajectory.
		Clean Energy Future Plan prices for 2012–13 to 2014–15, followed by the 2010 NTNDP's low carbon price trajectory.
	Large-scale Renewable Energy Target.	Maintain the existing LRET trajectory to 2020 then extend it linearly to 2030, giving a target of approximately 61 TWh in 2030.
	Generation capital costs and technology availability.	CCS technology included, and capital costs reduced by 20%.
		Geothermal capital costs reduced by 20%.
		Solar thermal capital costs reduced by 20%.
		Wind farm capital costs reduced by 20%.
		CCS technology included.
	Gas fuel cost sensitivity.	Increased gas fuel costs.
Fast Rate of Change, high carbon price	Generation capital costs and technology availability.	CCS and geothermal excluded.
	Gas fuel cost sensitivity.	Increased gas fuel costs.

7.1.1 Methodology for modelling generation and transmission developments

The 2010 NTNDP modelling framework comprised 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 network capability upgrades, which minimises overall capital and operating costs subject to meeting predefined minimum reserve levels (MRLs).
- **Power system simulation studies** add to the least-cost expansion modelling by including intra-regional network augmentations based on meeting jurisdictional planning criteria at the 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.

Unlike the 2010 NTNDP modelling, AEMO has only considered high-level, least-cost expansion modelling for the 2011 sensitivity studies to allow a wide range of sensitivities to be explored. Several scenarios required for the 2011 Gas Statement of Opportunities (GSOO) have also been analysed in more detail through a time-sequential approach that simulates hourly electricity market dispatch, and allows the calculation of the amount of gas used by GPG.

Least-cost expansion modelling

Investment in new generation is modelled by a least-cost algorithm that aims to invest in and retire generation, or upgrade inter-regional network capability, to minimise the combined capital and operating cost expenses across the NEM. This optimisation is subject to satisfying the following points:

- The electricity supply-demand balance throughout the year across the NEM.
- A generation build target for reliability with a required reserve level above a summer and winter 10% probability of exceedence (POE) maximum demand.
- The LRET, which mandates an annual level of generation to be sourced from renewables.

In general, the supply-demand balance will be satisfied by a mixture of technologies (including renewables, base load coal, and combined-cycle gas turbines (CCGT)), while the generation build target for reliability will be met with peaking open-cycle gas turbines (OCGT) that are cheaper to install and are only required to run at times of high electricity demand.

In the short-term, LRET-driven renewable generation is likely to derive from wind, with alternatives such as large-scale geothermal and solar thermal units potentially becoming viable towards 2020, depending on electricity demand and the impact of carbon pricing on other generation sources.

Results of the least-cost modelling include 20-year projections of generation expansion and retirement, major transmission augmentations, total market capital costs, and approximate carbon emissions.

7.1.2 Reference scenarios

The 2010 NTNDP described future generation and transmission plans for five core scenarios with two differing carbon price trajectories, providing a series of plausible future socio-economic outcomes:

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

Under the **FC-H** scenario, the electricity sector transforms rapidly to meet strong emissions targets. Australia remains globally competitive, benefiting from strong international growth. Governments have agreed on targets internationally, which are met by 2030. The transition to a carbon constrained future has been smooth, and there is sustained high economic and population growth. Demand for electricity is high, energy sources have diversified, emissions have reduced, energy efficiency has improved, and other forms of demand-side participation have emerged.

Under the **UW-L** scenario, carbon policy uncertainty creates barriers for emerging technologies. Strong international demand for Australia's resources drives high economic and population growth, resulting in high energy demand. Emissions targets have been agreed internationally but are constantly reviewed and debated. By 2020, a 20% target for renewable energy generation has been met but not significantly exceeded. Overall, demand for electricity continues to grow and, while consumers support the notion of a low-carbon future, they remain resistant to change.

Under the **DW-M** scenario, demand-side technologies and distributed generation emerge as low-cost alternatives. All sectors of the Australian economy do well, with intermediate economic growth and medium population growth. Moderate emission reduction targets have been implemented and met in Australia and internationally. Australia's energy network is highly decentralised by 2030 and there has been significant new investment in demand-side technologies. Overall, low gas fuel costs, demand for fuel cells and increased distributed generation result in high domestic gas demand.

Under the **OS-M** scenario, a global oil shortage creates high oil and gas fuel costs, leading to low international and domestic economic growth. Higher than expected CCS costs create greater reliance on centralised, renewable-energy options. Carbon policy is internationally agreed, with moderate emissions reduction targets set for 2050. A weak economy provides consumer incentives to improve energy efficiency, while price responsive demand-side participation remains at average levels and electricity demand is moderate to low.

Under the **SC-L** scenario, the electricity sector transforms slowly due to a low rate of international and domestic economic growth, and low population growth. Australia moves towards a service economy, with some manufacturing and energy-intensive industry moving offshore. Australia does not remain globally competitive. Boosting economic activity becomes a priority. Carbon policy is internationally agreed, with low emissions reduction targets set for 2050. Slow demand growth and a low carbon price produce low distributed generation investment and less incentive for governments to set ambitious emissions targets or for consumers to change their behaviour.

Table 7-2 identifies the key assumptions underpinning each NTNDP scenario. The second to last column (emissions targets below 2000 levels) identifies the carbon price and carbon price sensitivity each scenario explored.

Table 7-2 — Key assumptions underpinning the 2010 NTNDP scenarios

Scenario	Economic Growth	Population Growth	Global Carbon Policy	Centralised Supply-side Response	Decentralised Supply-side Response	Demand-side Response	Emissions Targets Below 2000 Levels	Scenario/ Sensitivity Abbreviation
Fast Rate of Change	High	High	Strong	Strong	Strong	Strong	-25%[c] (sensitivity -15%)	FC-H FC-M
Uncertain World	High	High	Weak	Strong	Weak	Weak	-5%[a] (sensitivity zero carbon price)	UW-L UW-0
Decentralised World	Medium	Medium	Strong	Weak	Strong	Strong	-15%[b] (sensitivity -25%)	DW-M DW-H
Oil Shock and Adaptation	Low	Medium	Moderate	Moderate (renewable)	Weak	Weak	-15%[b] (sensitivity -5%)	OS-M OS-L
Slow Rate of Change	Low (mixed)	Low	Weak	Moderate	Weak	Weak	-5%[a] (sensitivity zero carbon price)	SC-L SC-0

a. The -5% carbon emissions target (low carbon price) is associated with a carbon price trajectory from (zero) 0 to 44.80 $/t CO2-e.

b. The -15% carbon emissions target (medium carbon price) is associated with a carbon price trajectory from (zero) 0 to 62.33 $/t CO2-e.

c. The -25% carbon emissions target (high carbon price) is associated with a carbon price trajectory from (zero) 0 to 93.50 $/t CO2-e.

Table 7-3 shows the 2010 NTNDP carbon price trajectories for the high, medium, and low carbon price assumptions. Expressed in dollars per tonne of CO2-e emissions ($/t CO2-e), as used in the 2010 NTNDP scenarios, these trajectories form the basis for the 2011 sensitivity studies.

Table 7-3 — 2010 NTNDP carbon price trajectories (2010–11 $/t CO2-e)[a]

Year	High	Medium	Low
2010–11	0	0	0
2011–12	0	0	0
2012–13	0	0	0
2013–14	49.92	33.28	23.92
2014–15	51.92	34.61	24.88
2015–16	53.99	36.00	25.87
2016–17	56.15	37.44	26.91
2017–18	58.40	38.93	27.98
2018–19	60.74	40.49	29.10
2019–20	63.16	42.11	30.27
2020–21	65.69	43.79	31.48
2021–22	68.32	45.55	32.74
2022–23	71.05	47.37	34.05
2023–24	73.89	49.26	35.41
2024–25	76.85	51.23	36.82
2025–26	79.92	53.28	38.30
2026–27	83.12	55.41	39.83
2027–28	86.45	57.63	41.42
2028–29	89.90	59.94	43.08
2029–30	93.50	62.33	44.80

a. The 2010 NTNDP also included a zero carbon price trajectory.

To enable a comparison with the sensitivity study results (see Section 7.2 to Section 7.5):

- Figure 7-1 shows the projected capital costs for the 10 NTNDP scenarios and carbon price sensitivities.
- Figure 7-2 presents the annual NEM-wide CO2-e emissions by scenario over the 20-year outlook period.

Figure 7-1 — Projected capital costs per scenario by 2030 (2010–11 dollars)

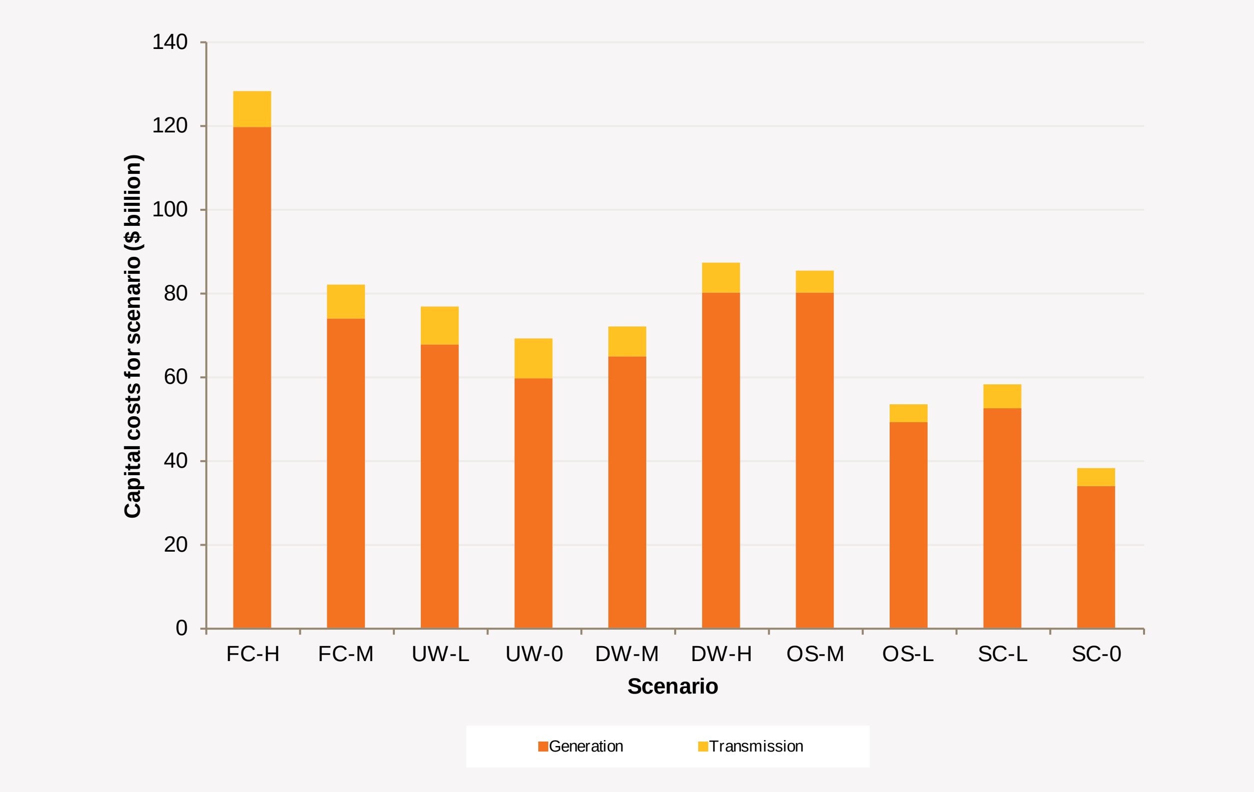
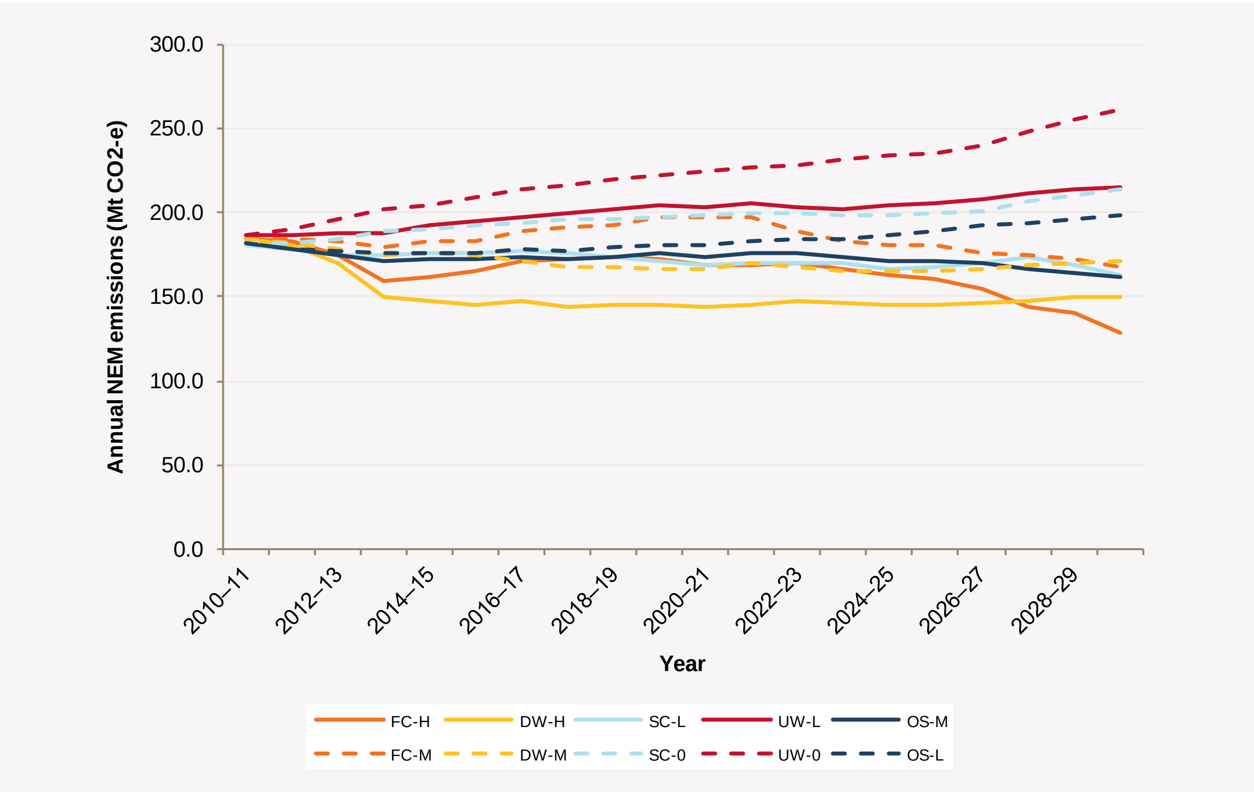


Figure 7-2 — Annual NEM-wide CO2-e emissions in the NEM by scenario



7.1.3 Key drivers for generation and transmission investment

Besides economic and demand growth, which were considered in detail by the 2010 NTNDP scenarios, there are four key areas (and associated assumptions) driving investment, retirement, and network augmentation across the NEM. Explored in more detail by the 2011 NTNDP sensitivity studies, these areas include the following:

- Carbon pricing, which influences generation technology operating costs, depending on their emissions intensity.
- The LRET, which mandates a national energy requirement that must be met from renewable sources.
- Capital costs and technology availabilities, which determine when new technologies become commercially viable.
- Fuel and operating costs, which affect the use of different types of installed generation and generation technologies to meet demand.

Presentation of results by NTNDP zone

Some results are presented for NTNDP zones. For a detailed list of the NTNDP zone location names and their abbreviations, see Chapter 1.

7.2 Sensitivities to carbon pricing

7.2.1 Recent carbon pricing announcements

On 10 July 2011, the Australian Government announced details of a carbon-pricing package developed through the Multi-Party Committee on Climate Change (MPCCC).[1] The Clean Energy Future plan proposes a price on CO2-e emissions from 1 July 2012, with some measures taking effect during the 2011–12 financial year.

The policy targets a reduction in CO2-e emissions to 5% below year 2000 levels by 2020, and up to 25% in the presence of equivalent international action. The policy allows for much of the reduction to be achieved via overseas abatement.

The policy also proposes an 80% reduction from 2000 levels by 2050.

The carbon price

The policy will introduce a fixed price for the first three years of 23.00, 24.15, and 25.40 nominal $/t CO2-e, respectively. There will be an unlimited quantity of single-year-only permits made available at the fixed prices.

After the third year a floating price will be introduced, appropriate for the emissions target to be set from May 2014. A fixed quantity of permits will progressively be auctioned. Permits may be banked for use in later years and emitters may borrow up to 5% from their following year's obligation. Firms will be able to import up to 50% of their liabilities using permits from similar international schemes with importing arrangements overseen by the scheme regulator. Exports of permits are prohibited.

The emissions target will be recommended by the new Climate Change Authority, taking account of international developments. If there is a lack of agreement at the parliamentary level, then the targets will revert to a default trajectory to achieve a 5% reduction from 2000 levels by 2020.

The target will be set such that voluntary action, such as GreenPower, will be accredited as being additional to the underlying target.

Until 2018, the floating price will have a ceiling starting at 20 $/t CO2-e above expected international price levels, increasing annually at 5% in real terms, and a floor starting at 15 $/t CO2-e, increasing annually at 4% in real terms.

The price ceiling will become the emissions charge (penalty) for non-surrender. Facilities that emit more than 25,000 tonnes of CO2-e per year are liable to pay the carbon price.

[1] Australian Government. "Clean Energy Future". Available http://www.cleanenergyfuture.gov.au. 27 July 2011.

Payment to close

Generation totalling up to 2,000 MW with as-generated emissions intensity over 1.2t CO2-e/MWh will be invited to tender for closure by 2020. The arrangement is to be negotiated during 2011–12, and will take into account AEMO's views on energy security. AEMO expects the closures to occur in the second half of the decade.

7.2.2 Selected sensitivities

To analyse the impact the carbon pricing policy has on the 2010 NTNDP results, two studies were undertaken based on the DW-M scenario, which most closely resembles the economic parameters in the Australian Government modelling.

Under the DW-M scenario there is a reasonably high level of base load retirement in response to the medium carbon price, with demand growth largely met by GPG developments, and the LRET resulting in substantial wind development across regions in the south and the south east.

The sensitivity studies apply the three years of fixed carbon pricing from 1 July 2012 to 30 June 2015, with either the medium or the low 2010 NTNDP carbon price trajectory continuing from 1 July 2015, representing the future emissions trading prices. The low carbon price trajectory (not studied for the DW-M scenario in 2010) is the closest to the Australian Government's carbon price modelling.

Table 7-4 describes the two sensitivity studies, and the adjustments required to the DW-M reference scenario's assumptions.

Table 7-4 — Carbon price trajectory sensitivity study

Sensitivity Study	Assumption Changes	Reference Scenario
Revised Medium Carbon Price Trajectory	A carbon price trajectory as per the Clean Energy Future plan for 2012–13 to 2014–15, followed by the 2010 NTNDP's medium carbon price trajectory. Non-committed retirements delayed until after 2015–16.	DW-M
Revised Low Carbon Price Trajectory	A carbon price trajectory as per the Clean Energy Future plan for 2012–13 to 2014–15, followed by the 2010 NTNDP's low carbon price trajectory. Non-committed retirements are delayed until after 2015–16.	DW-M

7.2.3 Results

Table 7-5 compares the capital costs and CO2-e emissions results for the DW-M reference scenario and the two sensitivity studies. It also shows those results for the Decentralised World, high carbon price (DW-H) sensitivity.[2] The Revised Medium Carbon Price Trajectory sensitivity indicates that, provided there is a return to medium carbon prices, the impacts of the Clean Energy Future plan align closely with the 2010 NTNDP's DW-M carbon price scenario. As a result, a number of investigations conducted as part of the 2011 NTNDP have applied the detailed results from that scenario.

Comparing the sensitivities shows that, while the Revised Low Carbon Price Trajectory sensitivity study results in capital cost savings, the long-term impact on NEM-wide emissions is substantial.

[2] Included as a point of comparison.

Table 7-5 — Generation capital costs and emissions by 2029–30 for the reference scenario and sensitivity studies

Reference Scenario/Sensitivity Study	Generation Capital Cost ($ Billion)	Emissions (Mt CO2-e)
Decentralised World, medium carbon price (reference scenario)	64.6	171.7
Decentralised World, high carbon price[a] (comparison point)	79.8	150.1
Revised Medium Carbon Price Trajectory (sensitivity study)	70.1	170.3
Revised Low Carbon Price Trajectory (sensitivity study)	62.5	208.4

a. This 2010 alternative price sensitivity is only included as a point of comparison.

Consistent with the DW-M reference scenario, the carbon price sensitivity studies did not result in a need for interregional transmission augmentations.

Figure 7-3 to Figure 7-5 show the sensitivity study results, which indicate that the fixed 3-year carbon price trajectory detailed in the Australian Government's Clean Energy Future plan is sufficiently similar to the trajectories modelled in the 2010 NTNDP's medium carbon price studies to leave long-term modelling outcomes substantially unchanged, provided that the emissions trading scheme results in a move towards medium carbon prices from 2015.

The assumed delay of non-committed retirements until after 2015–16 in both sensitivity studies results in delays to other new investments (specifically GPG), which are corrected once retirements are enabled, resulting in no long-lasting impact on the modelled outcomes.

The low carbon price trajectory

Comparing the two sensitivity studies indicates the prolonged reduction in carbon price trajectories (as seen in the Revised Low Carbon Price Trajectory) has a substantial impact on modelling outcomes. In particular, the lower carbon prices provide reduced incentive for retiring existing brown and black coal generation (4,000 MW less are retired), which leads to a significant reduction in GPG investment (2,000 MW of CCGT is not installed, and a further 5,500 MW of CCGT is substituted with OCGTs to meet growth in peak demand only).

Investment in renewable technologies remains largely unchanged with low or medium carbon prices, because at these levels renewable investment is primarily driven by the LRET.

The high carbon price trajectory

The 2010 NTNDP also considered a high carbon price sensitivity. While a sensitivity study with modified carbon prices and retirements before 2015 has not been done, the results indicate that a high carbon price (in the order of 93 $/t CO2-e by 2030 in real 2010–11 dollars) contributes to significant changes in investment patterns and technology utilisation across the NEM. In particular, higher carbon prices lead to significantly more retirement of existing units (more than 2,500 MW higher than the medium carbon price scenario), with the additional retirements being replaced by both GPG and renewable technologies. This mix resulted in a substantial reduction in emissions at the expense of a higher capital expenditure in new investments.

Figure 7-3 — Reference scenario (Decentralised World, medium carbon price scenario): cumulative new generation capacity in the NEM by technology type and year

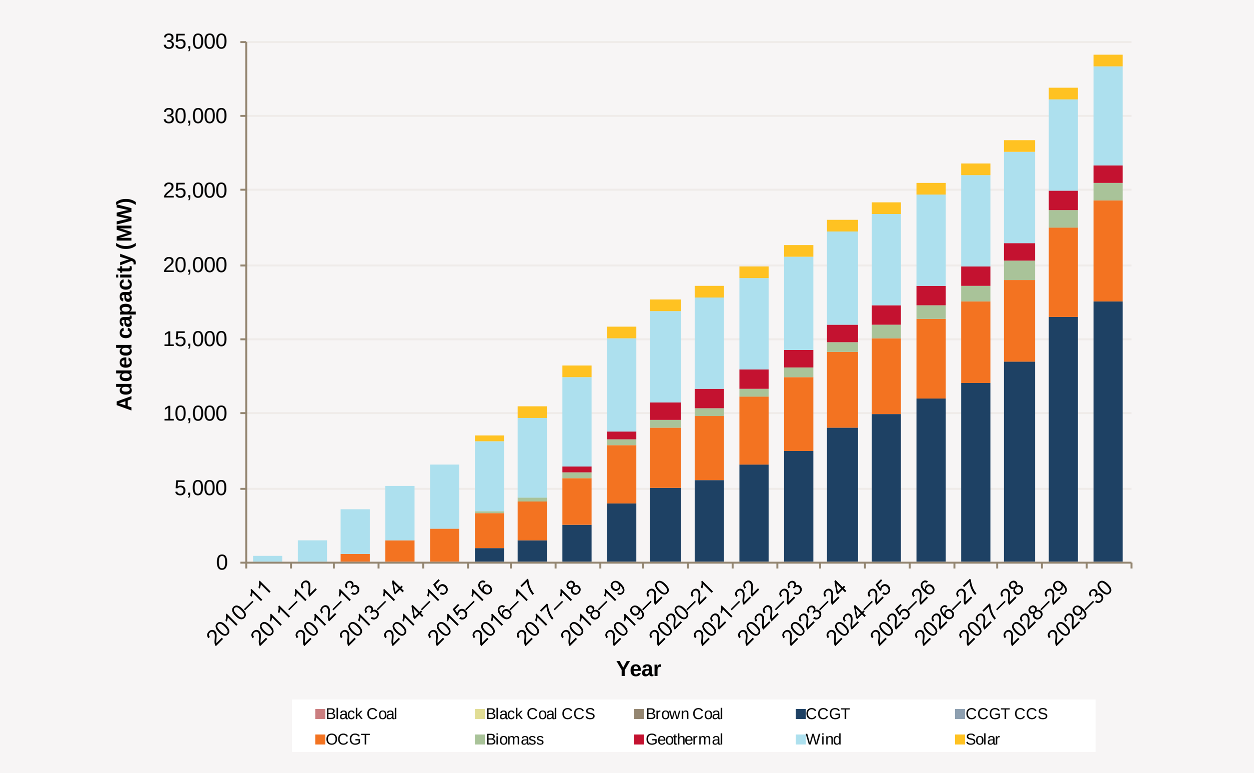


Figure 7-4 — Revised Medium Carbon Price Trajectory sensitivity: cumulative new generation capacity in the NEM by technology type and year

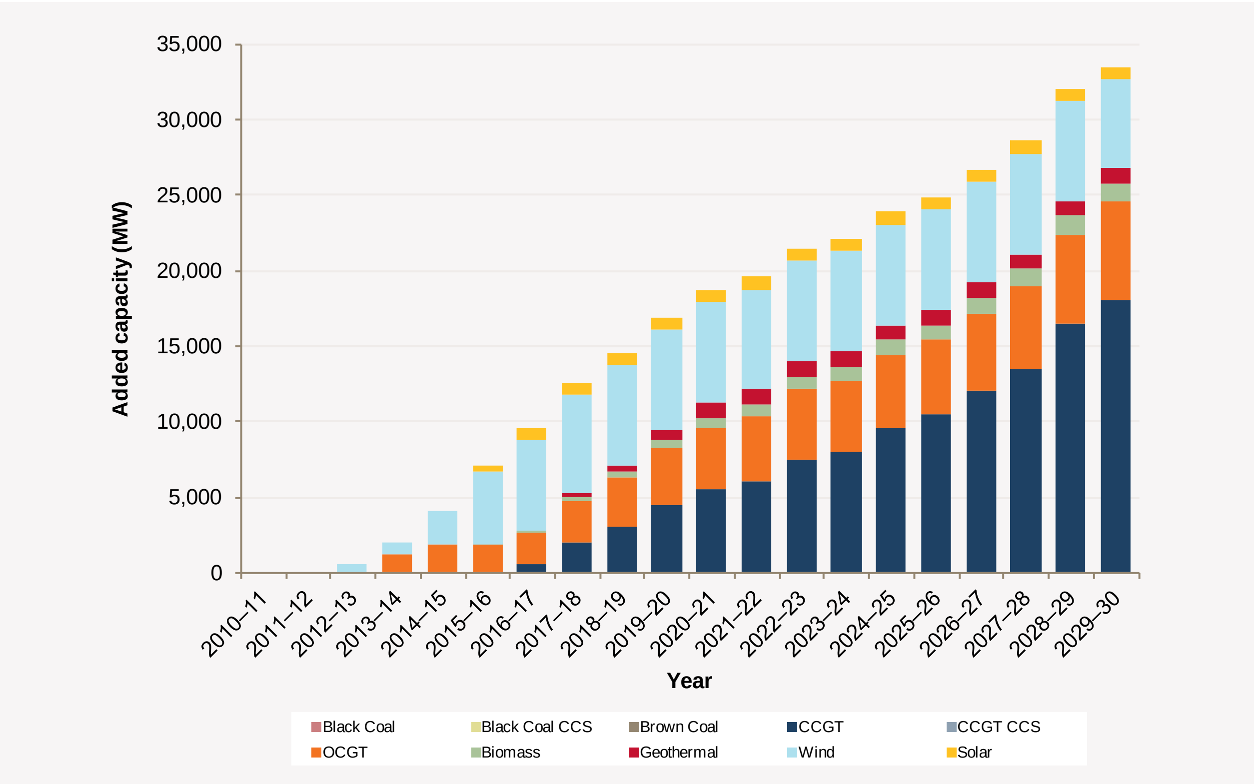
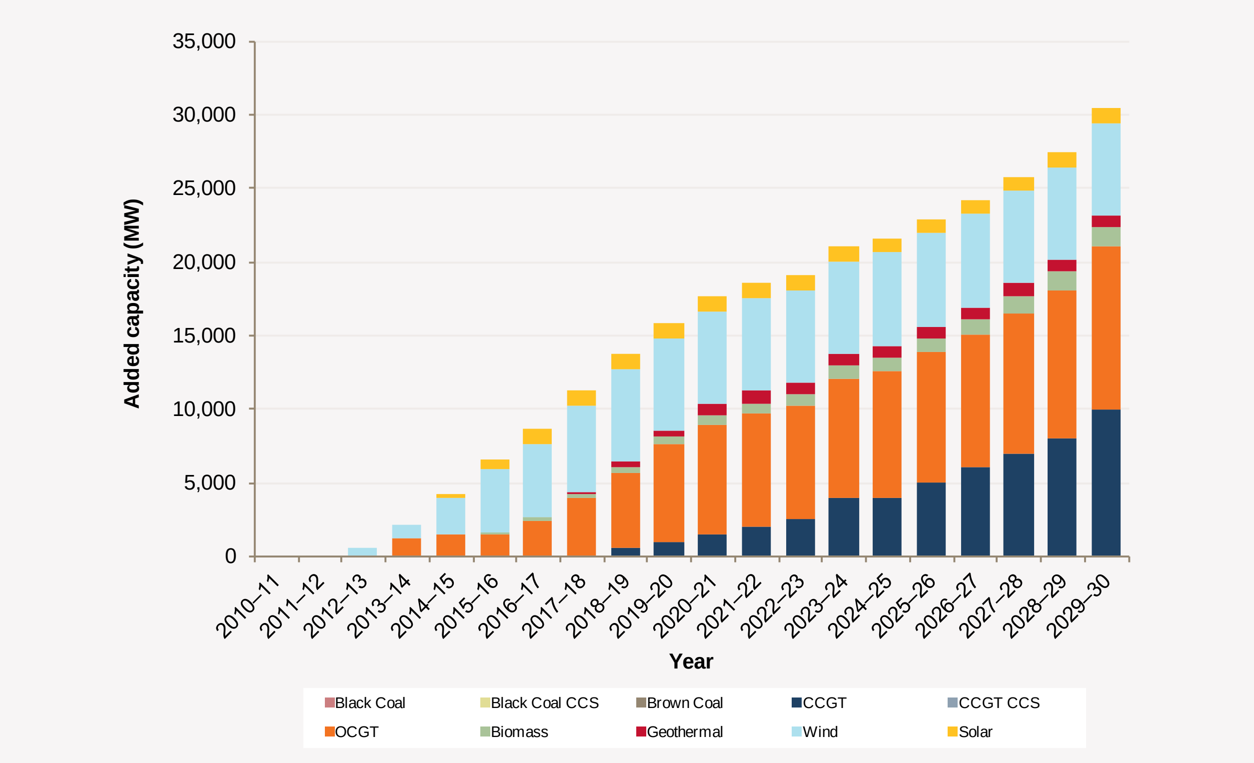


Figure 7-5 — Revised Low Carbon Price Trajectory sensitivity: cumulative new generation capacity in the NEM by technology type and year



7.3 Large-scale Renewable Energy Target (LRET) sensitivity

7.3.1 The LRET in the 2010 NTNDP

For the 2010 NTNDP scenarios, AEMO modelled the national Renewable Energy Target (RET) scheme as it applies to large-scale generation. The national RET scheme, which commenced in January 2010, aims to meet a renewable energy target of 20% by 2020[3], and requires electricity retailers to source a proportion of their electricity from renewable sources developed after 1997.

The national RET scheme has been implemented through Renewable Energy Certificates (RECs). Eligible renewable sources create RECs in proportion to their energy output, which can be traded, banked, or sold to retailers that must surrender an amount of RECs towards meeting the national target, in proportion to their share of national energy demand. In 2011, the RECs obligation totals 14,825 GWh, and will increase annually until it reaches 45,000 GWh in 2020.

[3] Department of Climate Change and Energy Efficiency. “Renewable Energy Target”. Available http://www.climatechange.gov.au/government/initiatives/renewable-target.aspx. 15 August 2011.

In January 2011, the national RET scheme was restructured into two parts[4]:

- The Small-scale Renewable Energy Scheme (SRES) is a fixed price, unlimited-quantity scheme available only to small-scale technologies (such as solar water heating), and is being implemented via Small-scale Technology Certificates (STC).
- The Large-scale Renewable Energy Target (LRET), which retains the REC's existing floating price, fixed-quantity structure, and is available only to large-scale power generation, such as hydroelectric, wind, solar, biomass, and geothermal. The objective of the LRET is 41,000 GWh of renewable energy by 2020 (4,000 GWh less than the total national RET scheme), which is being implemented via Large Generation Certificates (LGC).

For the purposes of the NTNDP, only the LRET component is modelled, two adjustments to which are required to model the national RET scheme for the NEM:

- The Australian-wide targets are scaled by 87%, representing the ratio of NEM energy consumption to Australian energy consumption based on the ABARE 2008 Energy Update.[5]
- The targets are expressed on a financial year basis by averaging the targets of the calendar years making up the financial year.

The 2010 NTNDP results showed the scheme to be a significant driver of renewable generation investment over the next 10 years. The 2010 modelling also predicted the following:

- Achievement of the LRET depends on a carbon price, and was not met in every year of the outlook period for studies with low or zero carbon prices.
- Wind power is the main renewable generation technology investment in the short term, with other technologies (like geothermal and solar generation investment) appearing towards the end of the decade to 2020.
- After 2020, renewable investment will slow for several years, because initially these technologies are not lowest cost investments in their own right. As technology costs fall and carbon prices rise, additional renewable generation investment occurs.

Under some NTNDP scenarios, high levels of installed wind generation were coupled with significant investment in OCGT generation. This is largely due to the variable nature of wind generation and its low contribution to reliably meeting peak demand. While wind generation is able to provide support for regional energy growth, it cannot provide the same level of reliable support at times of maximum demand. This leads to a growing opportunity for peaking capacity to capture high-priced demand peaks as maximum demand grows.

[4] Department of Climate Change and Energy Efficiency. "Fact Sheet: Enhanced Renewable Energy Target". Available http://www.climatechange.gov.au/government/initiatives/renewable-target/fs-enhanced-ret.aspx. 5 May 2011.

[5] ABARE. "2008 Energy Update". Available http://www.abareconomics.com/interactive/energyUPDATE08/index.html. 31 January 2011. (No longer available online.)

7.3.2 The sensitivity

The 2010 NTNDP results showed that renewable generation investment stopped following the end of the national RET scheme in 2020, recommencing only when renewable generation became cost competitive with other technologies.

To explore the possible impacts an extended LRET may have on the development of generation and transmission assets in the NEM, AEMO analysed an alternative trajectory that extends the target to 2030.

Table 7-6 describes the sensitivity study and the adjustments required to the Decentralised World scenario's assumptions.

Table 7-6 — LRET sensitivity study (Decentralised World, medium carbon price (DW-M))

Sensitivity Study	Assumption Changes	Reference Scenario
Extended LRET (Linear extension of 2020 target to 2030)	Maintain the existing LRET trajectory until 2020. Linearly extend the 20% LRET trajectory to 2030 (~61 TWh).	DW-M

7.3.3 Results

There is a substantial increase in renewable investment that primarily displaces GPG investment, given medium economic growth and medium carbon prices. Investment in wind generation reaches 13.2 GW by 2029–30, with the rest of the target being met by 3.0 GW of geothermal generation, 1.4 GW of solar thermal generation, and 1.2 GW of biomass generation.

The results show that additional renewable investments are spread across all regions, with wind and geothermal investment being highest in Victoria and South Australia, and solar thermal technology dominant in Queensland.

The geothermal expansion in both Victoria and South Australia is an optimal solution combining Victoria-South Australia (Heywood) interconnector augmentation (in 2023–24), which facilitates capacity sharing between the regions, reducing the reliance on local base load generation expansion.

Table 7-7 compares the capital costs and CO2-e emission results for the reference scenario and the sensitivity study. The results show that while increasing the LRET's target is an effective way of reducing emissions and ensuring a rapid transition towards renewable technologies, it comes at the expense of substantially higher capital costs.

Table 7-7 — Generation capital costs and emissions by 2029–30 for the reference scenario and sensitivity study

Reference Scenario/Sensitivity Study	Capital Cost ($ Billion)	Emissions (Mt CO2-e)
Decentralised World, medium carbon price (reference scenario)	64.6	171.7
Extended LRET[a] (sensitivity study)	100.0	157.8

a. A linear extension to 2030.

Figure 7-6 and Figure 7-7 show changes in installed capacity by location and technology between 2010–11 and 2029–30 under the DW-M scenario and the Extended LRET sensitivity study.

Figure 7-6 — Capacity changes between 2010–11 and 2029–30 by location and technology (Decentralised World, medium carbon price)

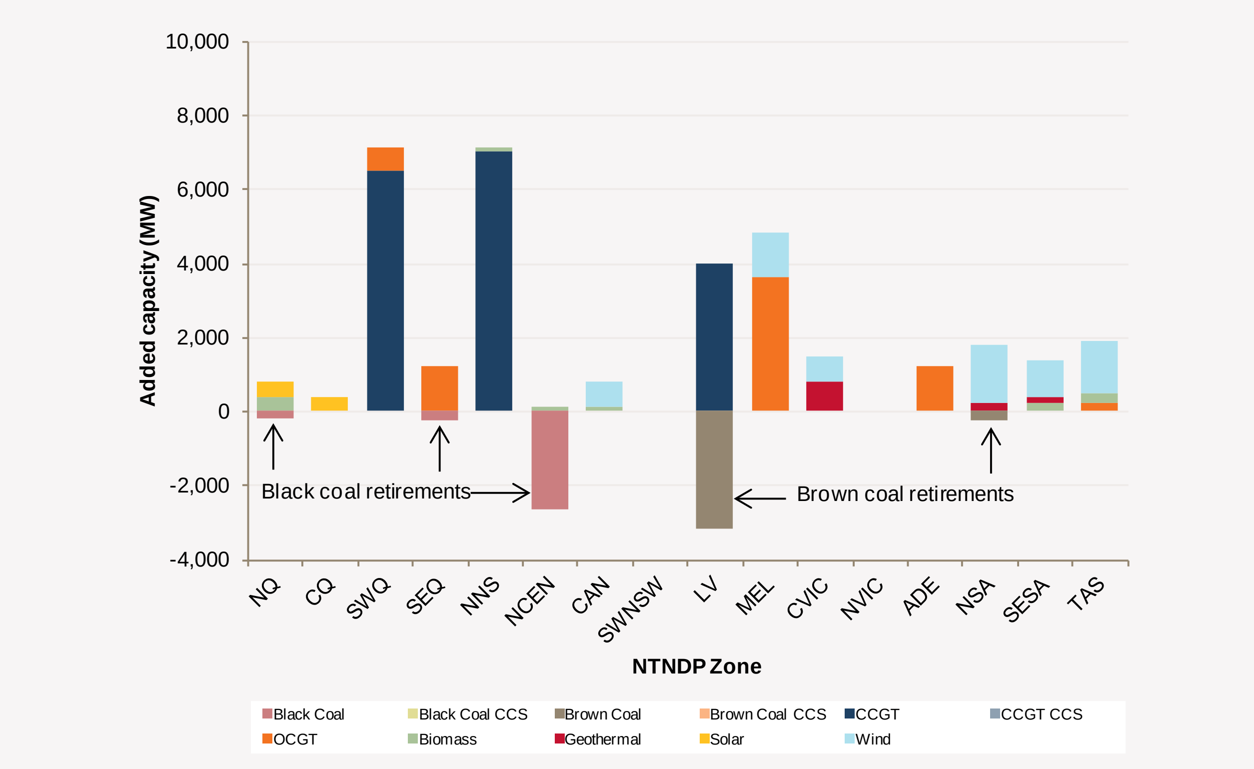
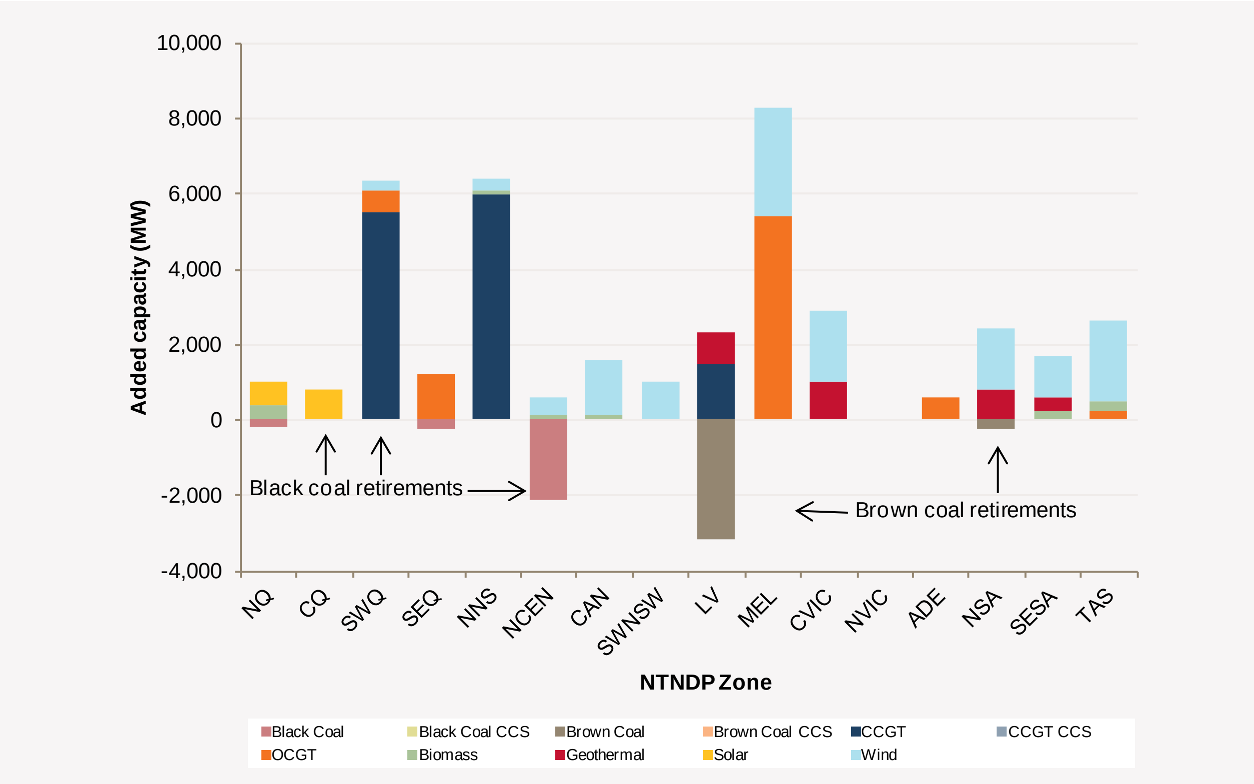


Figure 7-7 — Capacity changes between 2010–11 and 2029–30 by location and technology (Extended LRET)



7.4 Sensitivities to generation capital cost and technology availabilities

7.4.1 Capital costs and technology availabilities in the 2010 NTNDP

The 2010 NTNDP used technology capital costs and commercial viability dates based on advice from industry consultants, and a subsequent consultation process with industry in February 2010.[6] Cost and earliest build date information varies from scenario to scenario, based on the underlying scenario assumptions.

7.4.2 Selected sensitivities

The capital costs and availabilities of new investment options are subject to uncertainties and vary with assumptions about future exchange rates, commodity and productivity variations, and a rate of technological improvement for each technology type.

To explore the sensitivity of modelling outcomes to changes in capital costs, alternatives were analysed that modified the availability of technologies and lowered the capital costs of individual technologies by 20%.

Table 7-8 and Table 7-9 list the sensitivity studies and the changes required to the original scenario assumptions.

Table 7-8 — Technology cost sensitivity studies

Sensitivity Study	Assumption Changes	Reference Scenario
CCS Technology Capital Costs Reduction	CCS capital costs reduced by 20%.	DW-M.
Geothermal Technology Capital Costs Reduction	Geothermal capital costs reduced by 20%.	DW-M.
Solar Thermal Technology Capital Costs Reduction	Solar thermal capital costs reduced by 20%.	DW-M.
Wind Technology Capital Costs Reduction	Wind farm capital costs reduced by 20%.	DW-M.

Table 7-9 — Technology availability sensitivity studies

Sensitivity Study	Assumption Changes	Reference Scenario
Inclusion of CCS Technology	CCS technology included.	DW-M.
Exclusion of Geothermal and CCS Technologies	Geothermal and CCS technologies excluded.	FC-H.

[6] AEMO. "2010 National Transmission Network Development Plan Consultation". Available http://aemo.com.au/planning/ntndp2010consult.html. 6 September 2011.

7.4.3 Results

The impact of reducing an individual technology's capital costs varied significantly. The results are largely insensitive to 20% reductions in the capital costs of geothermal and solar thermal technologies, but are particularly sensitive to reductions in the capital costs for wind and CCS investments.

In particular, the results show the following:

- Reducing the capital costs of CCS technology by 20% allows 6,300 MW of new CCGT CCS investment to occur, replacing 4,500 MW of CCGT generation in the reference scenario. The difference between these two numbers is due to the higher auxiliary loads in CCS generation, which means additional capacity must be installed to achieve the same contribution towards meeting demand.
- Reducing the capital costs of geothermal and solar thermal technologies by 20% had little impact on the least-cost generation investment pattern in terms of quantity, location, and technology.
- Reducing the capital costs of wind technology by 20% allows over 5,000 MW of new wind investment to occur, completely displacing investment in geothermal and solar thermal generation technologies. The intermittent nature of wind means that additional OCGT capacity is required to reliably meet growing maximum demand.

Figure 7-8 to Figure 7-10 illustrate the quantity of new generation investments by technology for the DW-M scenario, the CCS Technology Capital Costs Reduction sensitivity study, and the Wind Technology Capital Costs Reduction sensitivity study, respectively.

Consistent with the reference scenario, the modelling did not result in a need for interregional transmission augmentations in the technology cost and technology availability sensitivity studies.

Figure 7-8 — Decentralised World, medium carbon price: capacity changes between 2010–11 and 2029–30 by technology

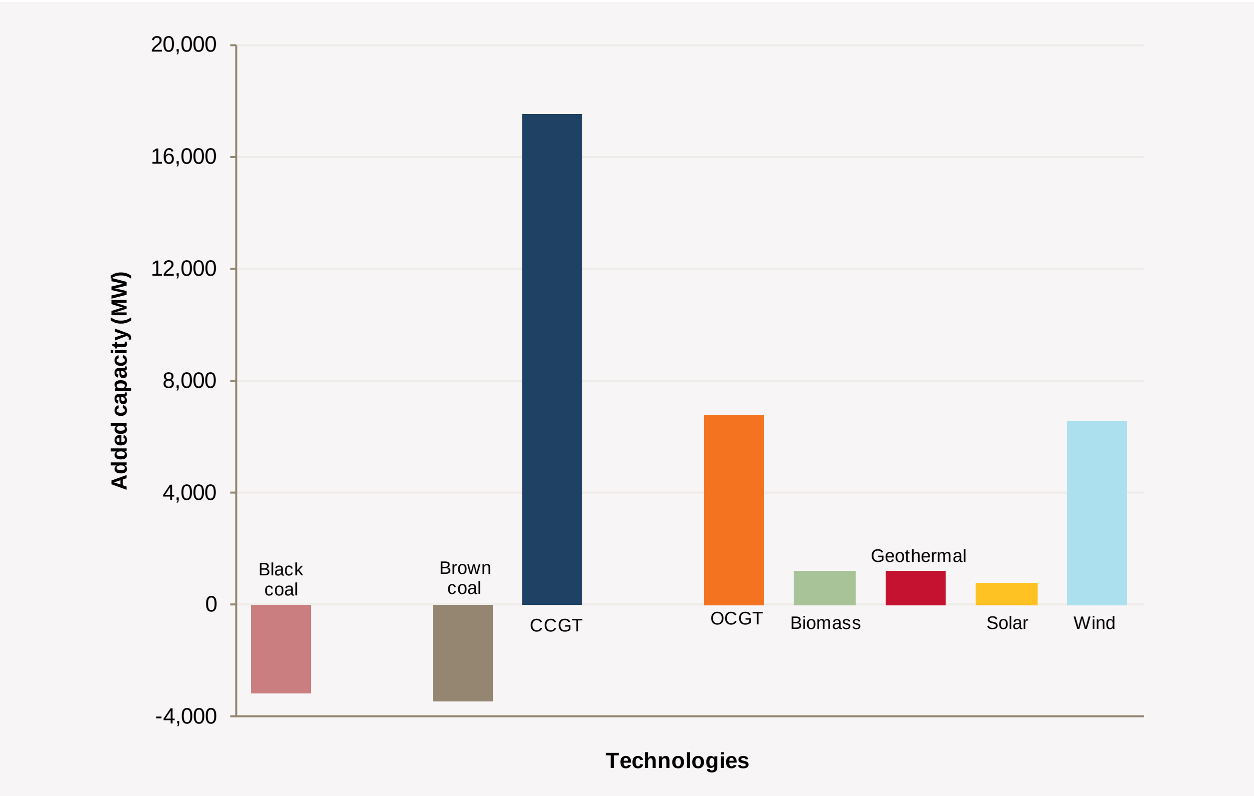


Figure 7-9 — CCS Technology Capital Costs Reduction sensitivity: capacity changes between 2010–11 and 2029–30 by technology

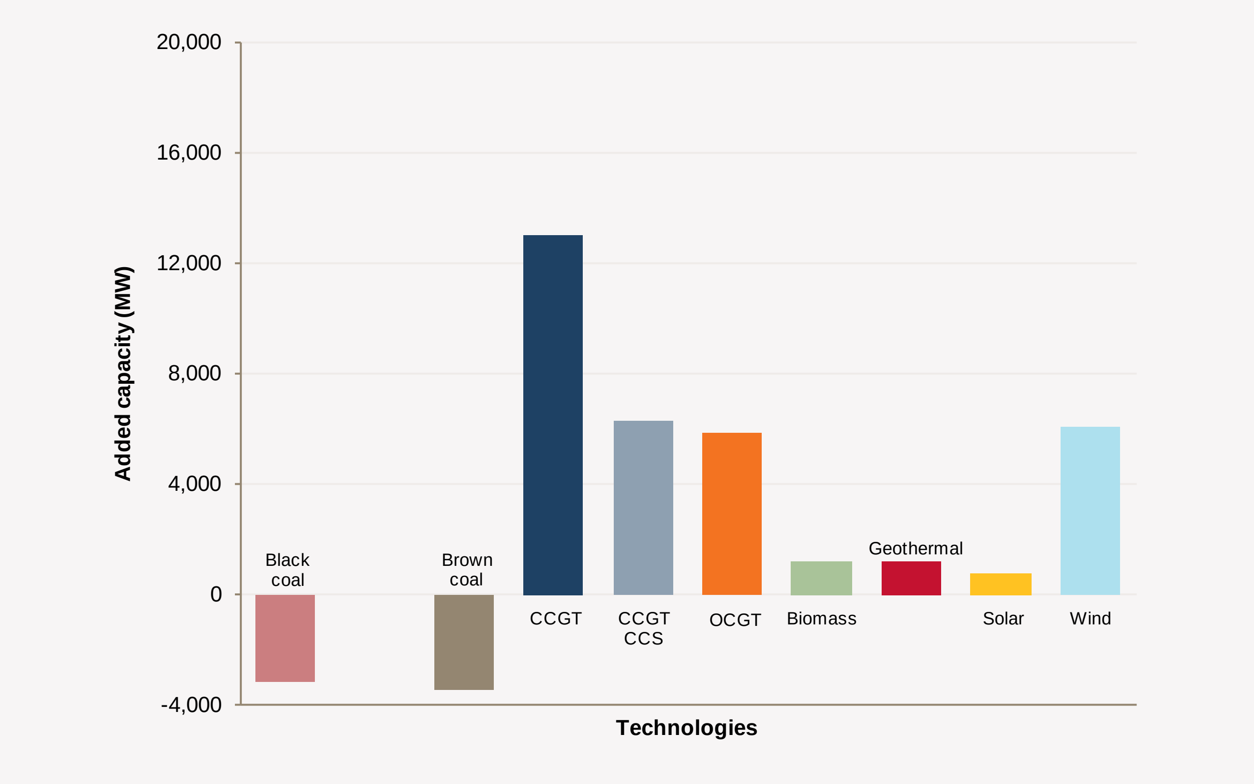
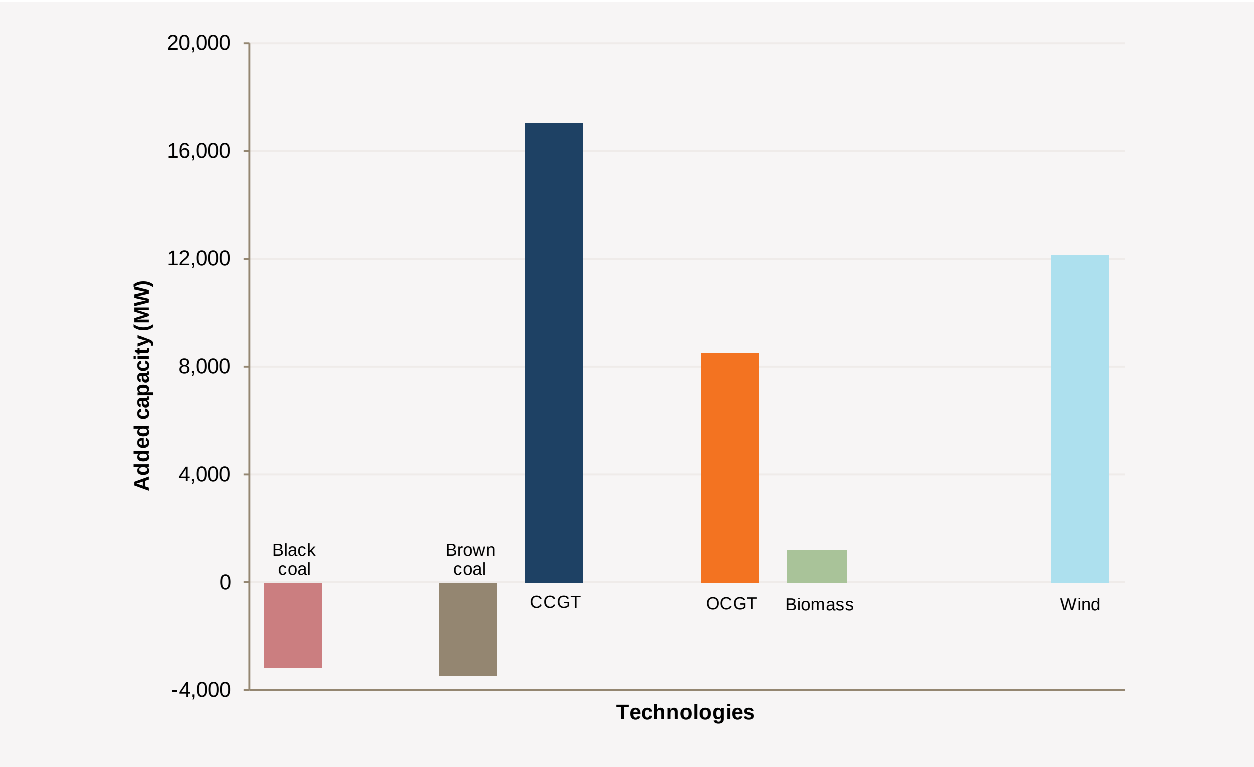


Figure 7-10 — Wind Technology Capital Costs Reduction sensitivity: capacity changes between 2010–11 and 2029–30 by technology



The 2010 NTNDP's DW-M scenario delayed the commercial viability of CCS technology until beyond the outlook period (after 2029–30). The Inclusion of CCS Technology sensitivity study is based on this, but represents a world where the viability of CCS technologies has been advanced to 2019–20. No results are presented for this sensitivity study, as the modelling did not result in any CCS technology investment or any other changes.

The Exclusion of Geothermal and CCS Technologies sensitivity study is based on the 2010 NTNDP's FC-H scenario, and represents a world where the commercial viability of geothermal and CCS technologies have been significantly delayed (beyond the outlook period).

The results show that delaying or removing the option to invest in geothermal and CCS technologies (which are used to meet the LRET) tends to increase investment in wind, solar thermal, and GPG (to support growth in energy and maximum demand).

An augmentation of the New South Wales–Queensland (QNI) interconnector proceeds in 2014–15 under this sensitivity study, which is consistent with the FC-H scenario. In both cases, demand in New South Wales relies heavily on support from generation in Queensland. Delaying geothermal expansion in South Australia will lower the generation support from South Australia to Victoria, deferring the need to augment the Victoria-South Australia (Heywood) interconnector, which proceeds under the FC-H scenario.

Figure 7-11 and Figure 7-12 illustrate the generation investment results, showing changes in installed capacity by location and technology between 2010–11 and 2029–30.

Figure 7-11 — Fast Rate of Change, high carbon price: capacity changes between 2010–11 and 2029–30 by location and technology

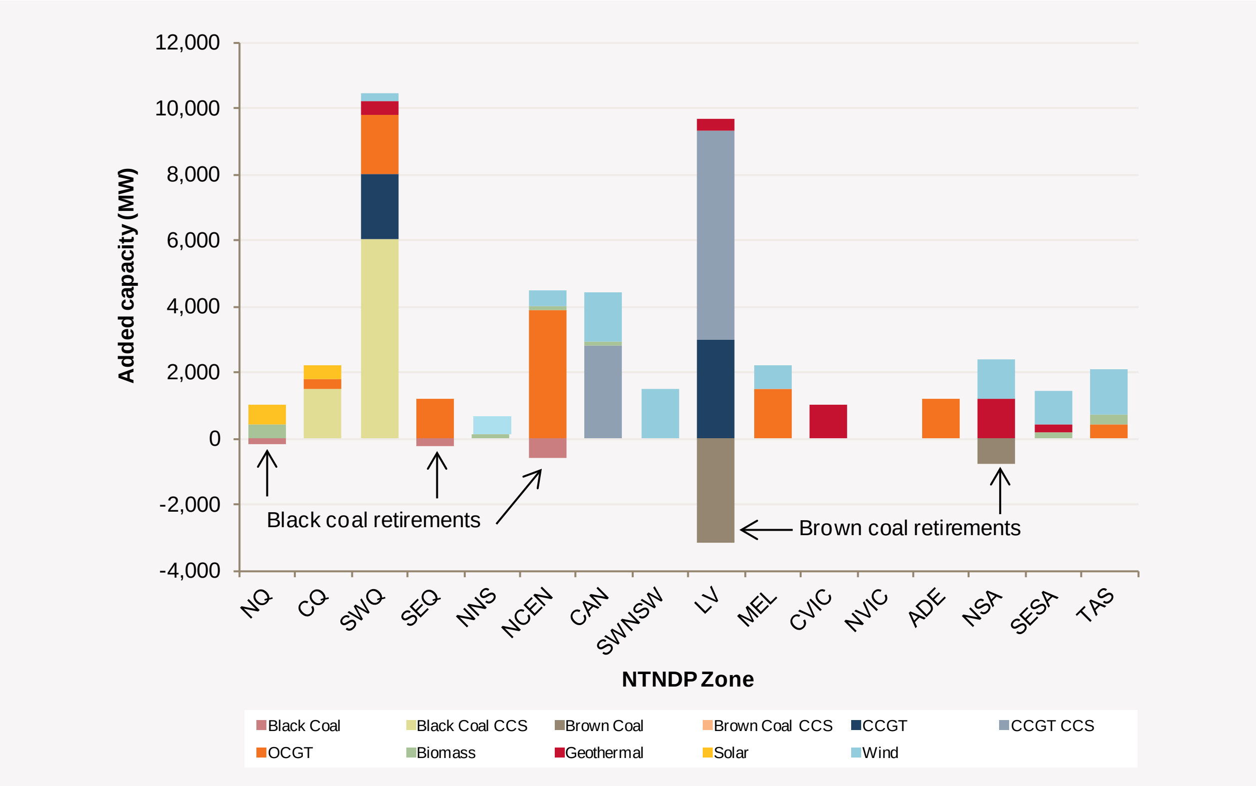
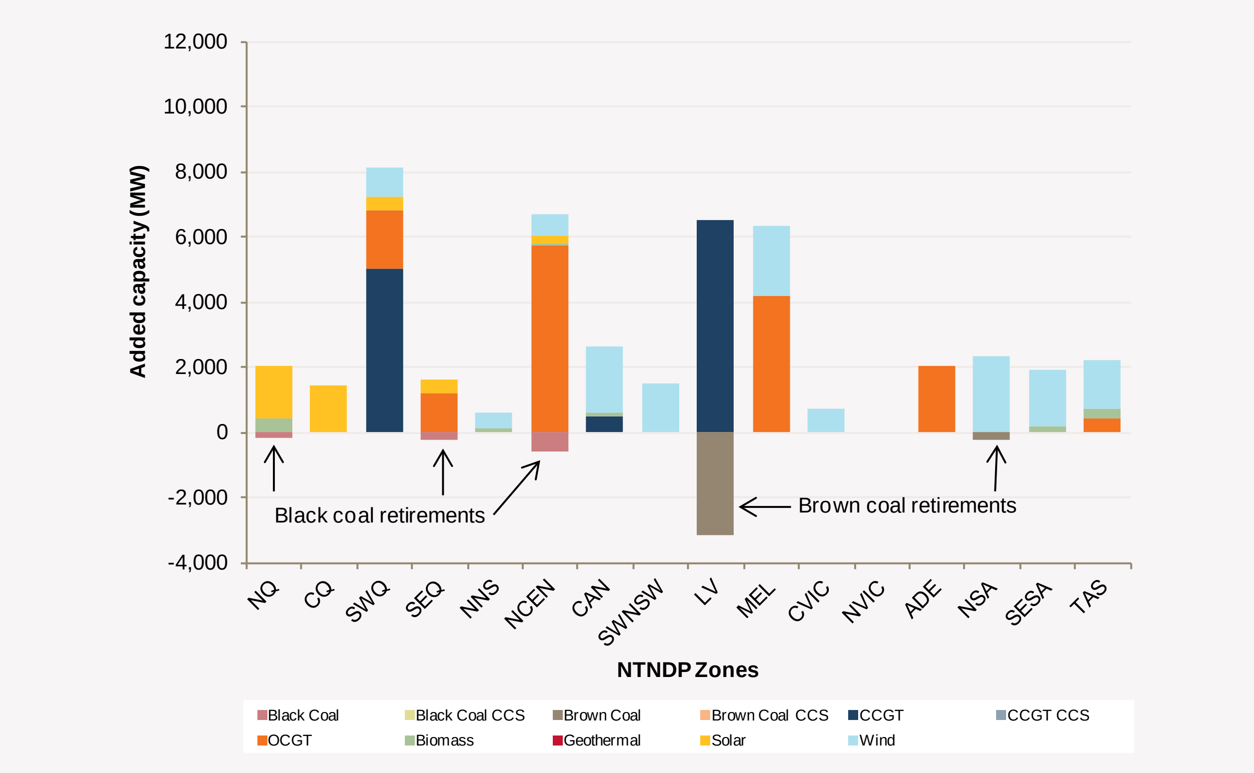


Figure 7-12 — Exclusion of Geothermal and CCS Technologies sensitivity: capacity changes between 2010–11 and 2029–30 by location and technology



7.5 Sensitivities to gas fuel costs

7.5.1 Gas fuel costs in the 2010 NTNDP

The 2010 NTNDP based gas fuel costs on advice from industry consultants and a subsequent consultation process with industry in February 2010.[7] These costs vary from scenario to scenario, based on the underlying scenario assumptions.

The 2010 NTNDP observed that gas could play an important role as a transitionary fuel between coal for base load generation (which is displaced first as carbon prices rise), and renewable resources (which, in the absence of the LRET, begin to become economic in their own right towards 2030).

7.5.2 Selected sensitivities

Given the important role gas may play in both meeting future demand and aiding the transition to renewable resources, AEMO has undertaken a sensitivity analysis on the impact of variations to gas fuel costs.

The 2010 NTNDP Oil Shock and Adaptation scenario's low carbon price sensitivity explored a low demand, low carbon price world under the influence of a high gas fuel cost. Similar studies, however, were not conducted with higher demand and higher carbon prices.

The 2011 NTNDP gas fuel cost sensitivity studies investigated the impact of a set of increased gas fuel costs for CCGT technology in the South West Queensland (SWQ), South East Queensland (SEQ), Northern New South Wales (NNS), and Latrobe Valley (LV) zones. Figure 7-13 shows the costs under the Increased Gas Fuel Cost sensitivity study.

[7] See note 5 in this chapter.

The increased costs were then applied to two reference scenarios: the Fast Rate of Change scenario (high demand, high carbon price) and the Decentralised World scenario (medium demand, medium carbon price). Figure 7-14 and Figure 7-15 show gas fuel costs for CCGT technology in the SWQ, SEQ, NNS, and LV zones under these scenarios.

Comparing these prices shows that the gas fuel costs applied in the sensitivity studies, while varying considerably across locations, averaged 1.37 $/GJ higher than the Fast Rate of Change scenario, and 2.45 $/GJ higher than the Decentralised World scenario.

Figure 7-13 — Increased Gas Fuel Cost: gas fuel cost in the SWQ, SEQ, NNS, and LV zones

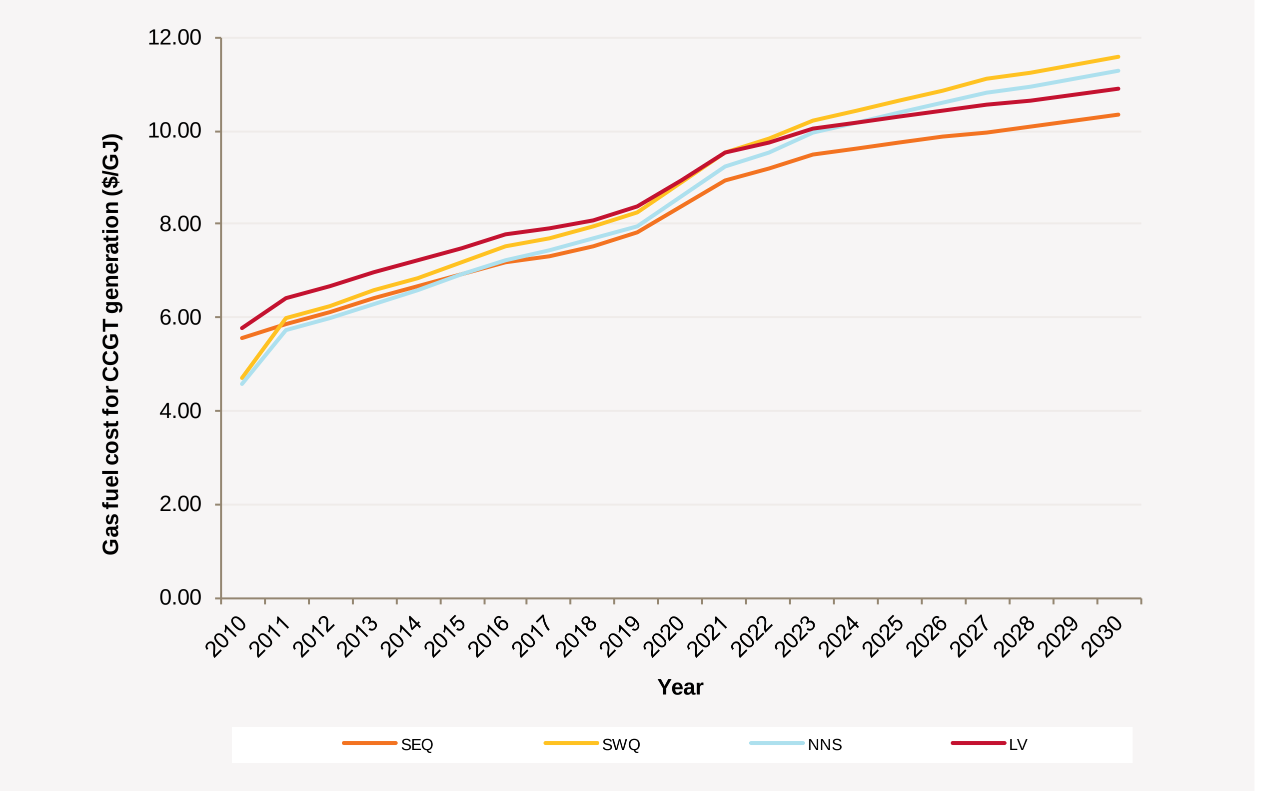


Figure 7-14 — Fast Rate of Change, high carbon price: gas fuel cost in the SWQ, SEQ, NNS and LV zones

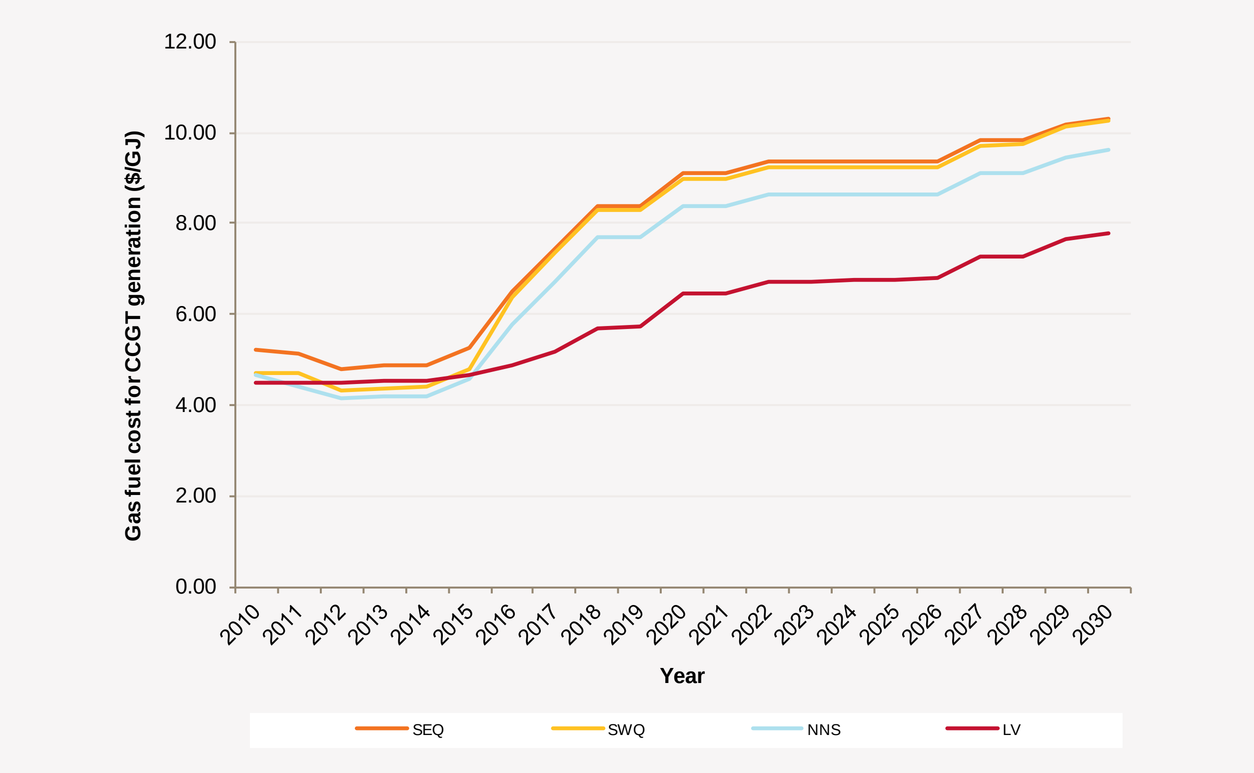
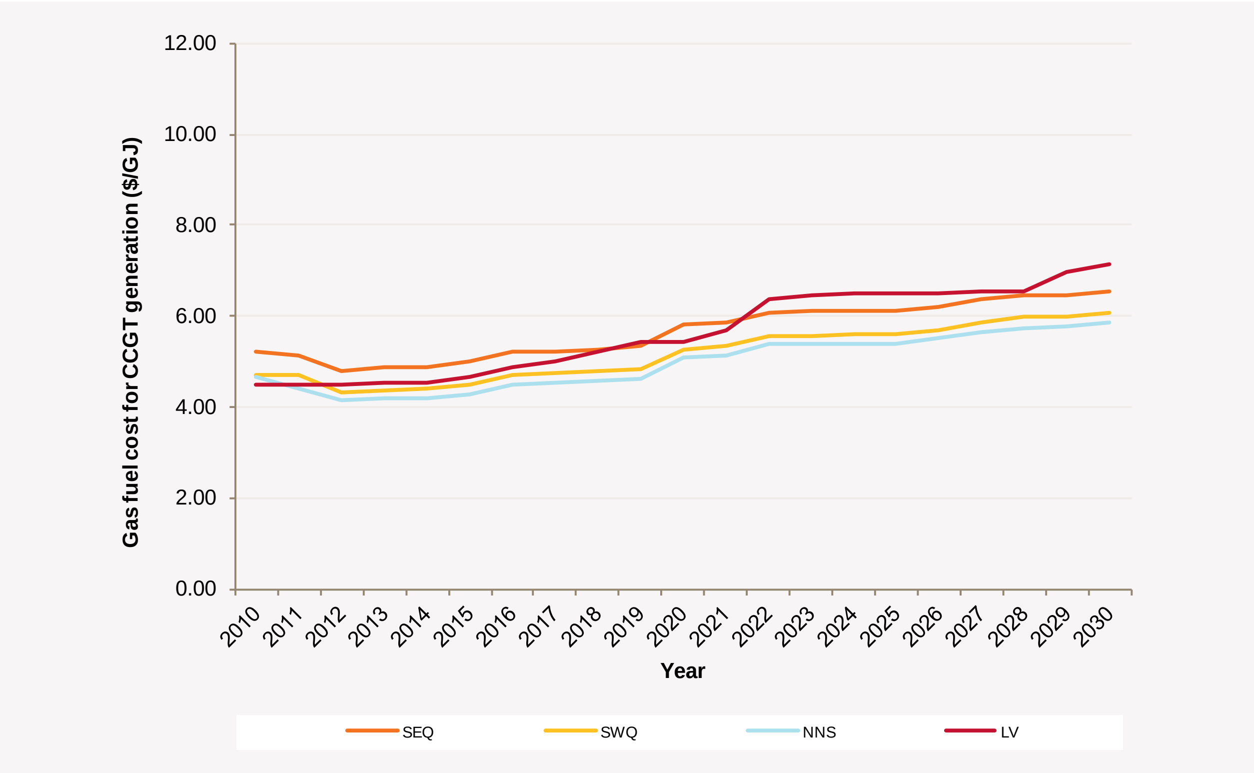


Figure 7-15 — Decentralised World, medium carbon price: gas fuel cost in the SWQ, SEQ, NNS, and LV zones



7.5.3 Results

The modelled least-cost investment patterns (in terms of generation capacity, technology, and locality) are particularly sensitive to gas fuel cost assumptions, resulting in dramatic shifts in the optimal mix of generation and transmission investment.

Capital costs and emissions

The 2010 NTNDP observed that gas could act as a transitional fuel. Increased gas fuel costs make this transition more difficult, with two main outcomes:

- Slower emissions reductions, as coal-fired generation has less incentive to retire.
- Higher capital costs, as more expensive renewable technologies are installed earlier in their technology learning curves when costs are higher.

Table 7-10 compares the capital costs and CO2-e emission results for the two scenarios and the gas fuel cost sensitivity studies.

Table 7-10 — Generation capital costs and emissions by 2029–30 for the reference scenarios and sensitivity studies

Reference Scenario/Sensitivity Study	Capital Cost ($ Billion)	Emissions (Mt CO2-e)
Fast Rate of Change, high carbon price (reference scenario)	119.7	152.3
Decentralised World, medium carbon price (reference scenario)	64.6	171.7
Increased Gas Fuel Cost (Fast Rate of Change) (sensitivity study)	148.7	158.4
Increased Gas Fuel Cost (Decentralised World) (sensitivity study)	97.8	198.9

Fast Rate of Change gas fuel cost sensitivity

In both the scenario and the price sensitivity study, significant investment is required to meet high demand growth. However, the sensitivity study's high gas fuel cost substantially changed the investment economics across the outlook period.

While total coal-fired generation retirements are similar by 2029–30, the higher gas fuel cost delays these retirements (compared to the reference scenario) until carbon prices have reached very high levels and the trade-off allows GPG investment to become economic.

To satisfy energy growth in Victoria with limited GPG investment, the modelling augments the transmission network between Victoria and South Australia and draws support from geothermal and wind generation in that region.

The scenario's simulation result was to augment the New South Wales–Queensland (QNI) interconnection in 2014–15, allowing Queensland demand to rely on support from GPG in regions to the south in earlier years and export coal-fired generation with CCS in later years. With much of this GPG investment removed in the sensitivity study, the interconnection upgrade is not considered optimal until 2029–30.

Figure 7-16 and Figure 7-17 illustrate these results, showing changes in installed capacity by location and technology between 2010–11 and 2029–30 for both the Fast Rate of Change scenario and the Increased Gas Fuel Cost (Fast Rate of Change) sensitivity study.

Figure 7-16 —Fast Rate of Change, high carbon price: capacity changes between 2010–11 and 2029–30 by location and technology

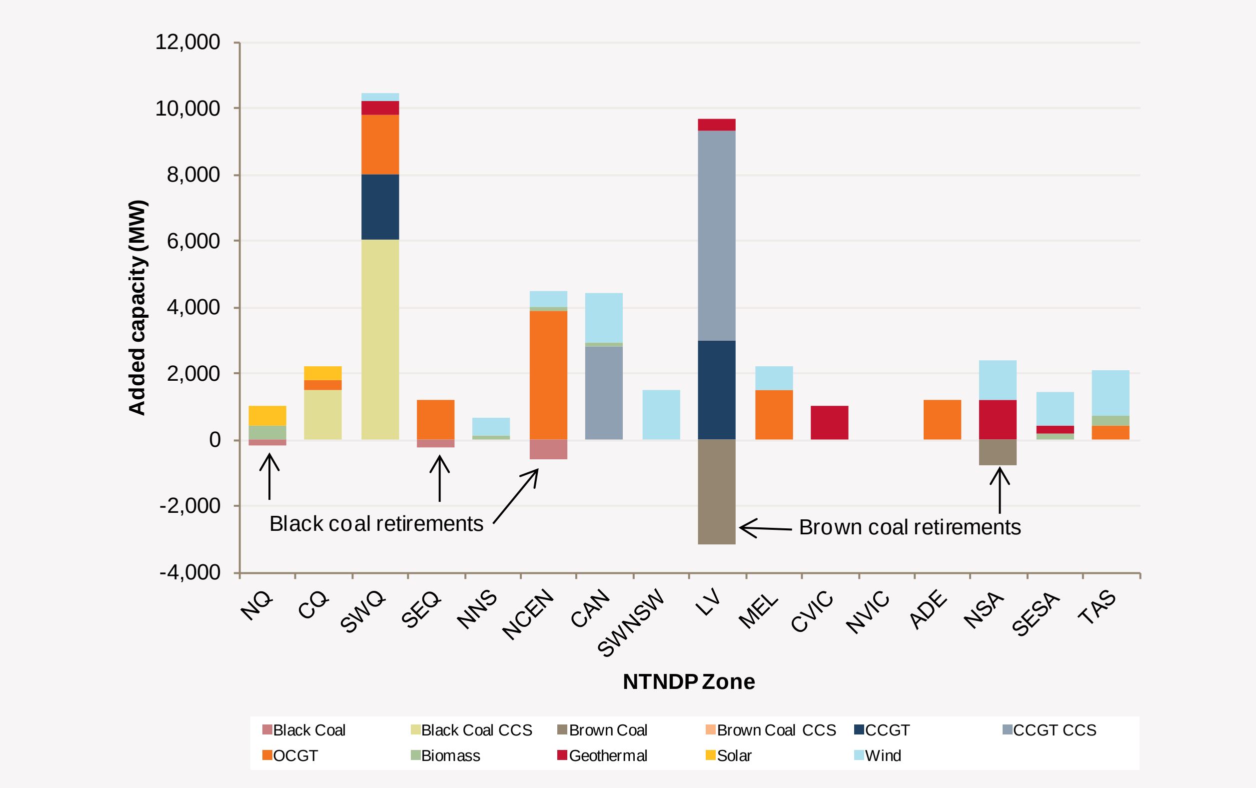
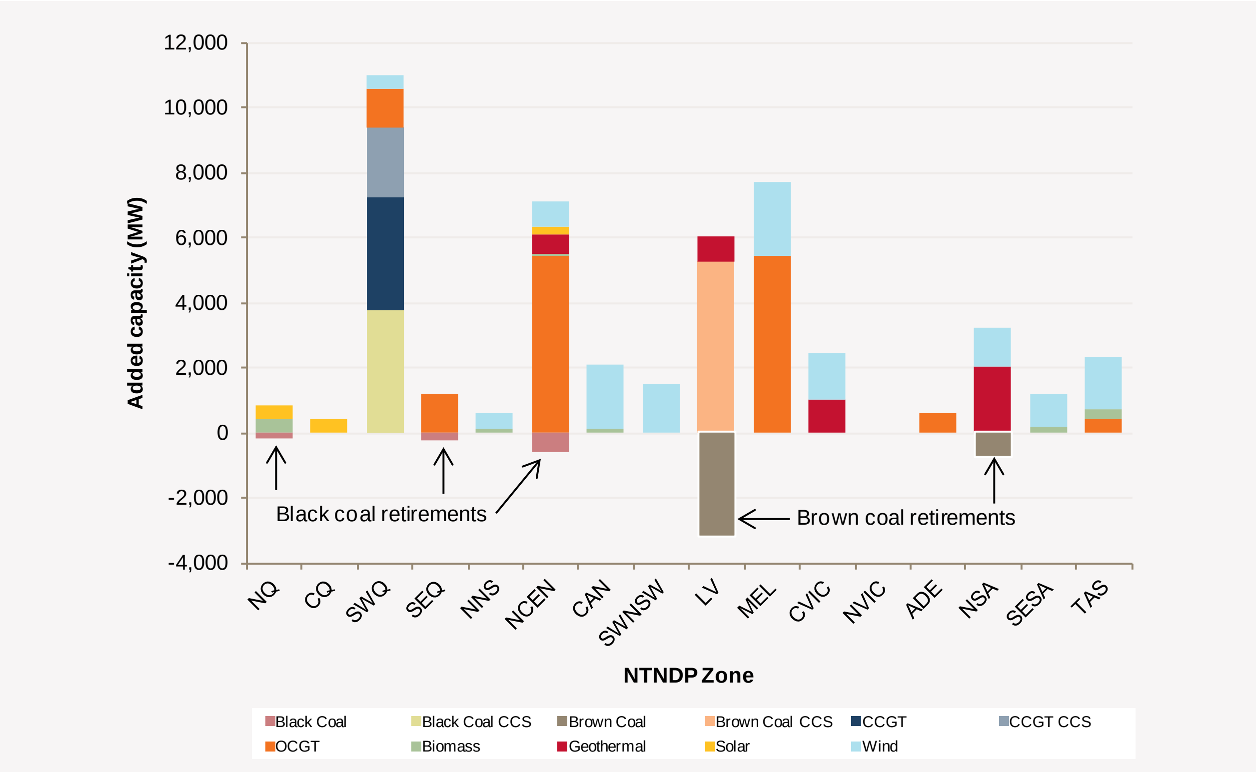


Figure 7-17 — Increased Gas Fuel Cost (Fast Rate of Change) sensitivity: capacity changes between 2010–11 and 2029–30 by location and technology



Decentralised World gas fuel cost sensitivity

The Increased Gas Fuel Cost (Decentralised World) sensitivity study has a higher increase in gas fuel costs than the Increased Gas Fuel Cost (Fast Rate of Change) sensitivity study. This higher variation in gas fuel costs has several outcomes:

- Substantially changed investment economics and coal-fired generation retirements across the outlook period.
- Demand growth is balanced by less coal-fired generation retirement, reducing the requirement for base load GPG.
- The stimulation of more renewable technology, especially wind and geothermal generation.

Figure 7-18 and Figure 7-19 illustrate these results, which show changes in installed capacity by location and technology between 2010–11 and 2029–30 for both the Decentralised World reference scenario and the Increased Gas Fuel Costs (Decentralised World) sensitivity study.

Figure 7-18 — Decentralised World, medium carbon price: capacity changes between 2010–11 and 2029–30 by location and technology

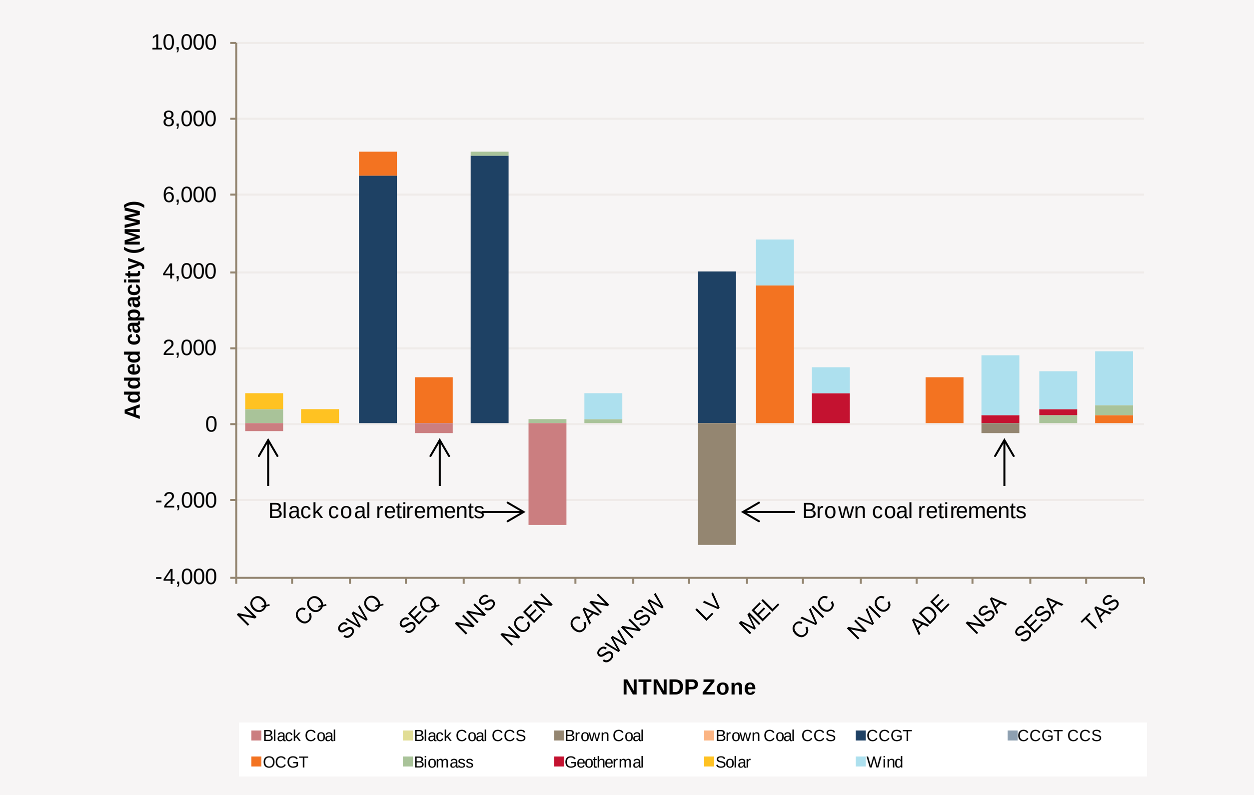
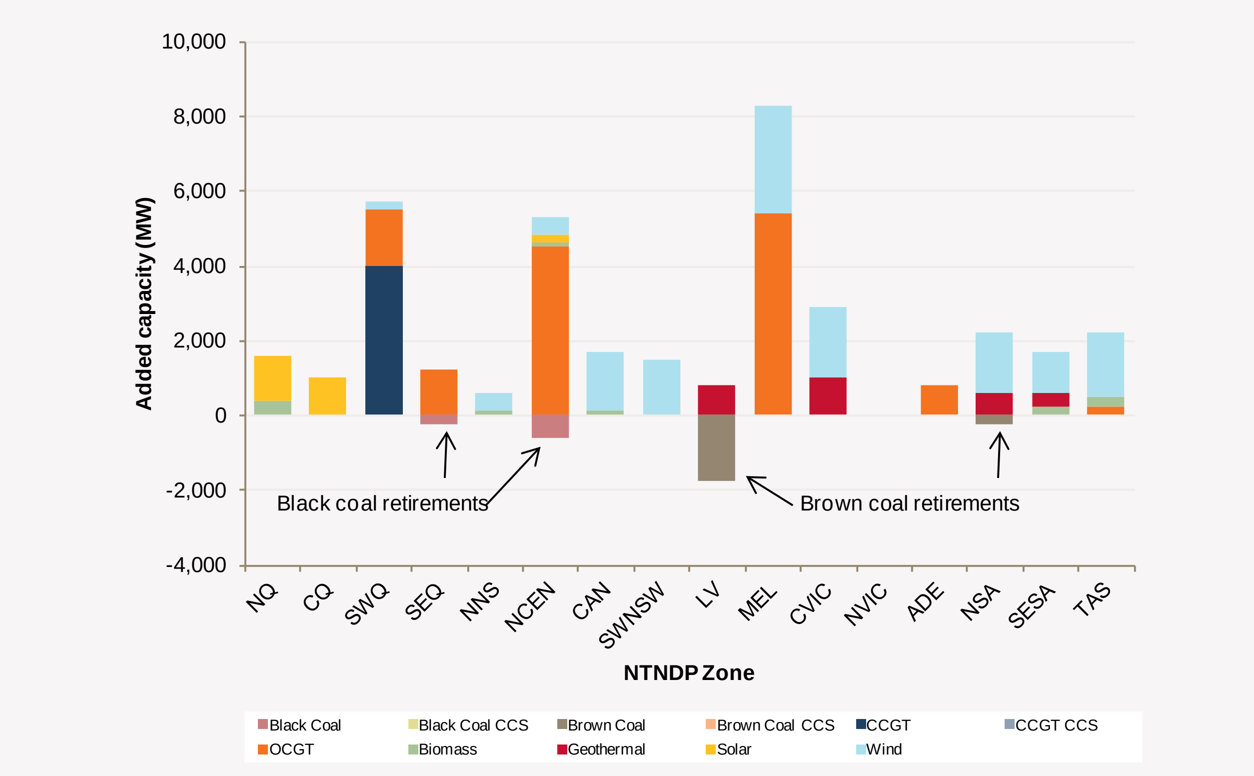


Figure 7-19 — Increased Gas Fuel Cost (Decentralised World) sensitivity: capacity changes between 2010–11 and 2029–30 by location and technology



7.6 The 2011 GSOO sensitivities

The most significant factor driving growth in domestic gas demand is GPG. To adequately investigate this segment, a more detailed modelling exercise was undertaken for the 2011 Gas Statement of Opportunities (GSOO) that explored future GPG outcomes under a selection of scenarios, which included both the 2010 NTNDP scenarios and several of the 2011 NTNDP sensitivity studies.

The GPG results across the scenarios show a wide range of gas consumption outcomes in terms of gas volumes, the pattern of locations, and the generation technologies being used. By the end of the outlook period, annual GPG demand may range between 170 PJ and 1,200 PJ, depending on carbon price, gas fuel cost, and national economic growth.

The highest gas demand for GPG occurs under the Uncertain World and Decentralised World scenarios, where moderate gas fuel costs, moderate-to-high carbon prices, and moderate-to-high economic growth produce an optimal economic environment for GPG investment and utilisation.

The Decentralised World, medium carbon price scenario and high carbon price sensitivity indicate that without high gas fuel costs, a carbon price increase results in significant GPG demand growth.

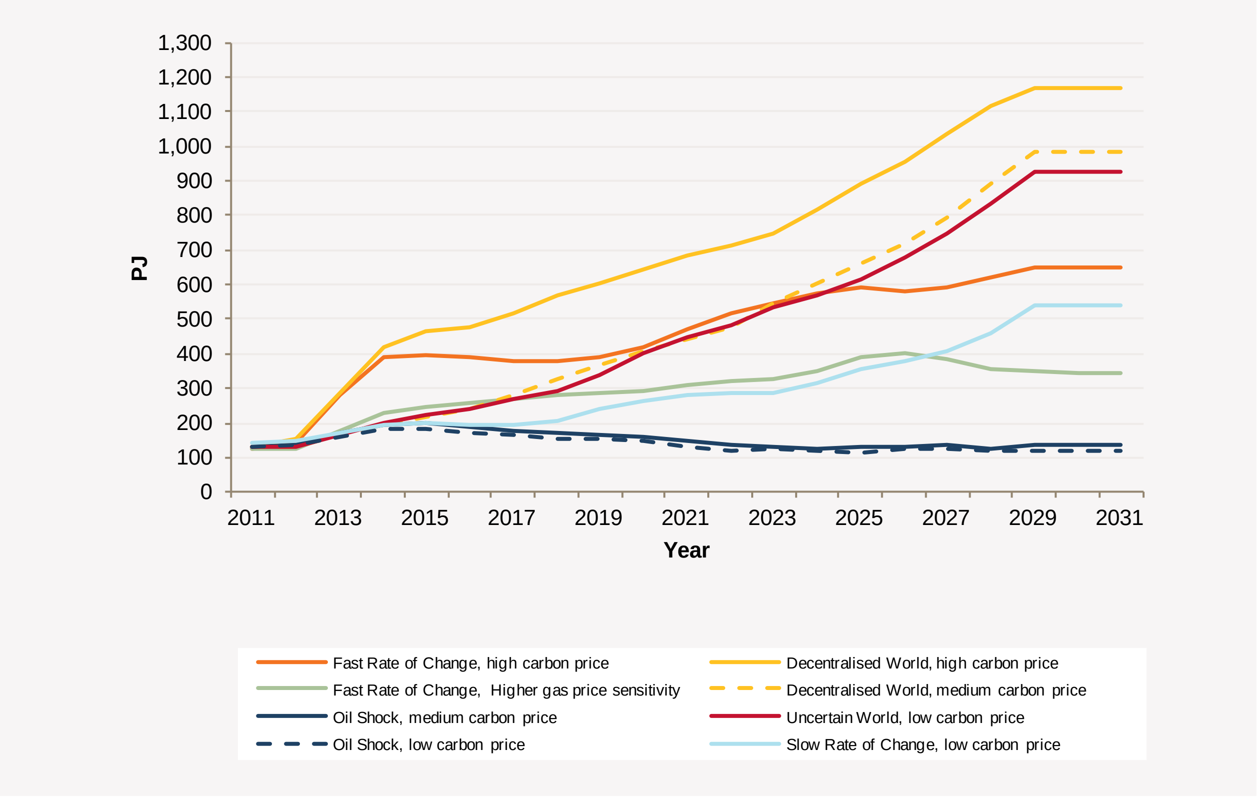
Alternatively, scenarios considering high carbon prices and high electricity demand (such as the Fast Rate of Change scenario) tend to show gas as a transitionary fuel. Under these scenarios, GPG demand significantly increases earlier on, to compensate for coal-fired generation retirement and prior to renewable investment becoming competitive with gas (which occurs towards the end of the outlook period), when it begins to displace GPG demand growth. This transition is also likely to occur in moderate and lower carbon price scenarios, but only after the 20-year outlook period.

The Fast Rate of Change scenario's Increased Gas Fuel Cost sensitivity study[8] suggests GPG investment and use is particularly sensitive to gas fuel cost assumptions. With the higher gas fuel costs, final GPG demand is just over half the demand under the Fast Rate of Change scenario.

If gas fuel costs rise significantly higher than current levels, the Oil Shock and Adaptation, medium carbon price scenario and its low carbon price sensitivity indicate that medium to low carbon prices are not sufficient to encourage GPG to displace higher-emitting generation technologies, and both the scenario and its sensitivity result in reductions in total GPG demand over the 20-year outlook period. By lowering the gas fuel costs (while holding electricity demand and carbon price fixed), the Slow Rate of Change, low carbon price scenario and its zero carbon price sensitivity results in a substantially higher GPG demand trajectory than Oil Shock and Adaptation.

Figure 7-20 illustrates these results, which compare NEM-wide GPG demand across the studied scenarios.

Figure 7-20 — Comparison of NEM-wide annual GPG demand results by scenario



8 Referred to in the 2011 GSOO as the "higher gas price sensitivity".

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CHAPTER 8 - GAS AND ELECTRICITY TRANSMISSION COMPARATIVE CASE STUDY

Summary

This chapter presents a cost analysis of building gas and electricity transmission infrastructure to support a 1,000 MW combined-cycle gas turbine (CCGT), highlighting the need to coordinate electricity and gas transmission expansion to deliver a national energy network with optimal gas and electricity transmission infrastructure.

The 2010 NTNDP identified gas powered generation (GPG) development as an important theme in the transition to a lower carbon dioxide equivalent (CO2-e) emission energy environment. Following on from this finding, the 2011 NTNDP compared electricity and gas transmission infrastructure characteristics and related issues (such as costs, timeliness, reliability, and environmental planning requirements).

Indicative capital cost estimates for electricity and gas connections were evaluated for three distances:

- At 100 kilometres, electricity connection costs $135 million to $185 million, and gas connection costs $60 million to $120 million.
- At 250 kilometres, electricity connection costs $350 million to $480 million, and gas connection costs $150 million to $305 million.
- At 500 kilometres, electricity connection costs $725 million to $975 million, and gas connection costs $305 million to $610 million.

Gas transmission infrastructure is cheaper and also has a smaller visual impact and typically shorter lead times between environmental planning and approvals, and practical completion.

A number of considerations arise from significant infrastructure investment of this scale:

- Opportunities to connect future generation capacity and loads.
- Gas resource depletion, which may reduce the useful life of a pipeline.
- Investment decisions based on efficient cost recovery may not deliver outcomes offering the greatest net energy market benefits.

AEMO will continue to work with industry to identify the best energy market outcomes in the following ways:

- By modelling gas and electricity transmission options to meet needs identified in the NTNDP.
- Through modelling scenarios that include depletion of particular gas sources to understand how this affects the relative net benefits of gas and electricity transmission augmentation.
- By using both the Electricity Statement of Opportunities (ESOO) and Gas Statement of Opportunities (GSOO) to examine gas and electricity transmission augmentation options to promote joint gas and electricity planning.

8.1 Introduction

The 2010 NTNDP identified GPG development as an important part of the transition to a lower CO2-e emission intensive environment, with the prominence of gas in every NTNDP scenario raising important issues relating to gas and electricity transmission interaction.

In recent years, gas pipelines have been built to transfer gas to GPG closer to existing electricity transmission networks. Exploring alternative approaches, AEMO subsequently examined the differences between building electricity transmission lines and gas pipelines to deliver GPG output to a major electricity load centre, providing high-level design and indicative cost estimates for the cases examined (and forming the basis for modelling gas generation in future NTNDP studies).

In terms of location, GPG can either be closer to gas production sources and its output transferred via electricity transmission lines, or it can be closer to the existing electricity transmission network and its fuel supplied by gas pipelines. Two case studies were considered involving a 1,000 MW combined-cycle gas turbine (CCGT) (corresponding to a typical configuration comprising two 500 MW generating units):

- The first case study examines a GPG-near-gas-source location requiring a 100 km, 250 km, or 500 km electricity transmission line.

  Figure 8-1 shows the diagram for the electricity transmission case study.
- The second case study examines a GPG-near-electricity-transmission-network location requiring a 100 km, 250 km, or 500 km gas pipeline.

  Figure 8-2 shows the diagram for the gas transmission case study.

Figure 8-1 — Electricity transmission case study configuration

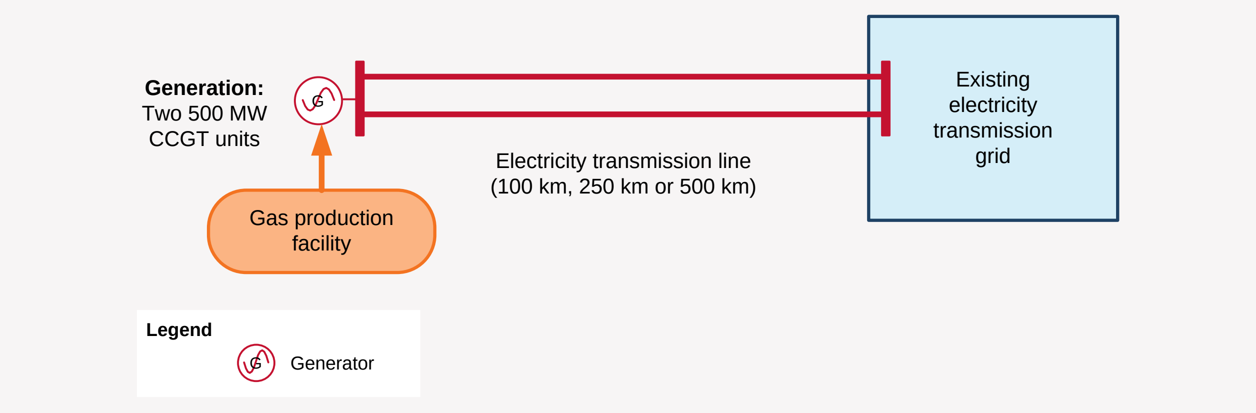
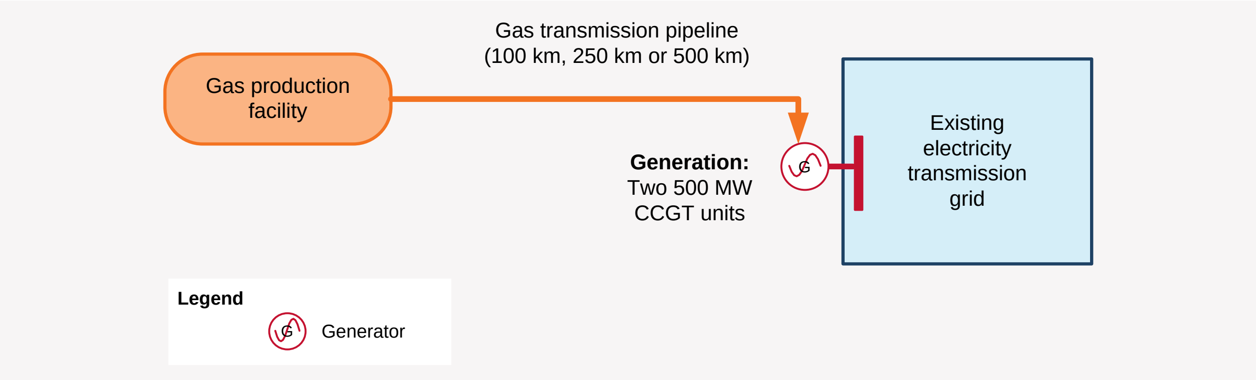


Figure 8-2 — Gas transmission case study configuration



Case study commonalities

Costs that have been excluded from the estimates because they are common to both the electricity and gas transmission case studies include the following:

- The cost of plant at the receiving end substation for transmission line connection (electricity transmission case study) and the cost of plant for generator connection (gas transmission case study).
- The capital costs of establishing the gas production facility, power station, generating units, and generating unit transformers.

Section 8.6 includes diagrams that identify the plant that is not common to both electricity and gas case studies. The costs of this plant have been included in the case study estimates.

8.2 Electricity transmission case study

8.2.1 Indicative cost estimates for electricity transmission

Table 8-1 lists the plant and indicative cost estimates for transmission line lengths of 100 km, 250 km, and 500 km, which derive from the 2010 NTNDP's NEMLink study and AEMO's own electricity cost estimate data. This case study applies a uniform cost per kilometre for electricity transmission line. The cost of transmission line is significant in terms of the overall cost, and as a result a range of unit costs for transmission line have been applied in the estimates.

Two options were also explored for the 250 km line. Option 1 has an intermediate switching station.[1] Option 2 has series capacitors at the receiving end, but no intermediate switching station.

Table 8-1 — Indicative electricity transmission cost estimates ($ million)

Plant	100 Kilometres	250 Kilometres		500 Kilometres
		Option 1	Option 2	
330 kV double circuit overhead transmission line with a capacity of 1,245 MVA for each circuit	100–150	250–375	250–375	500–750
Sending-end substation	30	30	30	30
Receiving-end substation, shunt capacitors, and dynamic reactive power compensation	5	45	10	45
Series capacitor compensation	-	-	60	120
Intermediate switching station	-	30	-	30
Total electricity transmission cost estimate	135–185	355–480	350–475	725–975

A detailed design may identify larger conductor sizes, and therefore a higher cost than assumed by these cost estimates. The longer the electricity transmission line, the greater the potential for economies of scale, which reduces a project's total cost.

[1] An intermediate switching station controls transmission line reactance and capacitance to control voltage drop or voltage rise (or both).

8.2.2 Electricity transmission design

The case study's 1,000 MW CCGT is connected by a double circuit transmission line. If a transmission circuit trips as a credible contingency, the remaining parallel circuit can transfer generation from both 500 MW generating units with no loss of supply. This reflects a typical NEM design approach.

The two transmission technologies currently in use involve:

- Alternating current (AC) transmission.
- High voltage direct current (HVDC) transmission.

AC transmission

New generation can be relatively easily accommodated by an AC transmission network. Significant power transfers over very long distances impose power system transient and voltage stability limitations, which can be overcome by adding series and shunt capacitor compensation or intermediate switching stations (or both).

At voltage levels of 330 kV or higher, significant issues are not expected for transfers of 1,000 MW over a distance of 500 km.

HVDC transmission

Over long distances, HVDC transmission is used in overhead, underground, or submarine cable applications, joining systems with different frequencies and augmenting AC transmission networks without increasing the fault levels.

While not imposing power system transient and voltage stability limitations, long-distance HVDC transmission presents other technical difficulties, and significant additional costs when adding one or more new connections along its route, with each new connection point requiring a direct current (DC) to AC converter and an inverter station.

In general, compared to AC transmission lines, HVDC lines become more cost effective over longer distances with no tapping points. As a result, the case study only considers an AC transmission option.

Transmission network connections

The connection configuration for the electricity transmission case study involves a 330 kV double circuit, AAAC (all aluminium alloy conductor) transmission line 100 km, 250 km, or 500 km long, with a summer rating of 1,245 MVA. Additional plant, such as an intermediate switching station, capacitors, or static VAr compensators (SVC) are included as required, depending on the length of the transmission line, to manage voltage stability and reactive power requirements.

Single line diagrams for each connection scenario are included in Section 8.6.1.

8.3 Gas transmission case study

8.3.1 Indicative cost estimates for gas transmission

Table 8-2 lists the plant and indicative gas pipeline cost estimates for pipeline lengths of 100 km, 250 km, and 500 km. Pipeline costs are based on industry feedback and publicly available information involving several Australian pipeline projects commissioned within the last five years (with lengths ranging from 60 km to 830 km).[2] This case study applies a uniform cost per kilometre for gas pipeline. The cost of gas pipeline is significant in terms of the overall cost, and as a result a range of unit costs for gas pipeline have been applied in the estimates.

For the 500 km gas pipeline, two options were explored. Option 1 excludes compressor stations. Option 2 includes compressor stations.

Table 8-2 — Indicative gas transmission cost estimates ($ million)

Plant	100 Kilometres	250 Kilometres	500 Kilometres	
			Option 1	Option 2
Pipeline[a]	60–120	150–305	305–610	245–485
Compressor station[b]	-	-	-	120
Total gas transmission cost estimates	60–120	150–305	305–610	365–605

a. Pipeline lengths may be larger than route lengths due to varying terrain, and although this has not been factored into the estimate, no material change is expected.

b. Compressor station cost estimates derive from industry feedback, a study undertaken in Australia[3], and a conceptual engineering impact study for a pipeline in North America.[4]

Pipeline building costs vary significantly according to the length and the physical characteristics of the route. The longer the pipeline, the greater the potential for economies of scale, which reduces a project's total cost. Specific factors affecting the cost include soil type, underground water level, the number of river or stream crossings, the vicinity to urban areas, and local climate and weather patterns during the construction.

The available pressure from the gas production facility at the start of the pipeline is assumed to be 15,000 kPa. Fuel for compression at the production facility is likely to incur further cost[5], which is not significant enough to change the magnitude of the cost estimate for a pipeline system, and so is excluded from the estimate.

[2] Lucas."Bonaparte gas pipeline". Available http://www.lucas.com.au//Projects/CompletedProjects/Bonaparte.htm . 24 October 2011;
AER. Sleeman consultancy report.pdf. "Estimate of Capital Cost of Corio Loop". March 2006. Available http://www.aer.gov.au/content/index.phtml/itemId/692907**.** 24 October 2011.
NSW Government. Environmental Assessment (Volume 1).pdf, "Young to Wagga Wagga Looping Pipeline Environmental Assessment-Stage 1, January 2010. Available http://majorprojects.planning.nsw.gov.au/index.pl?action=view_job&job_id=3113. 24 October 2011;
Queensland Hunter Gas Pipeline. Available http://www.qhgp.com.au/. 24 October 2011.
Bluescope Steel Australia."QSN Link Gas Pipeline". Available http://www.pipesteel.com.au/case-study/qsn-link-gas-pipeline. 24 October 2011.

[3] AER. Appendix F – Sleeman Consulting (Part 2) (February 2004).pdf."Sleeman Consulting Comments on Expansion Options for Existing Gas Pipelines". February 2004. Available http://www.aer.gov.au/content/index.phtml/itemId/681032. 24 October 2011.

[4] The Joint Pipeline Office. "Appendix 3-5, Compressor Cost Estimate, Conceptual Engineering/Socioeconomic Impact Study – Alaska Spur Pipeline". January 2007, Available http://www.jpo.doi.gov/SPCO/DOE%20Spurline%20Documents/Appendix%203-5%20Compressor%20Cost%20Estimate.pdf. 26 October 2011.

[5] Assuming a compressor unit operating throughout the year using gas at a rate of 1,600 standard cubic feet per minute (SCFM), and a gas price of 10 $/GJ, the fuel cost estimate is approximately $5.6 million a year. For a short distance pipeline, for example 100 km, the compression required at the production facility may be substantially less than the assumed pressure of 15,000 kPa.

8.3.2 Gas transmission design

Four gas transmission scenarios were considered:

- Scenario 1 is a 100 km, 400 mm Nominal Bore (NB) pipeline without compression.
- Scenario 2 is a 250 km, 400 mm NB pipeline without compression.
- Scenario 3 is a 500 km pipeline with two options:
  - Option 1 is a 400 mm NB pipeline without compression.
  - Option 2 is a 300 mm NB pipeline with two compressor stations of two compressors each (with a 4,500 kW capacity rating) with redundancy, at 200 km and 400 km.

Unlike electricity transmission lines, energy can be stored in a gas pipeline as linepack. As a result, a gas supply disruption is unlikely to result in instantaneous loss of generation, making a single gas pipeline a practical consideration.

Line diagrams for each connection configuration are included in Section 8.6.2.

The maximum pressure available at the supply point and the minimum pressure requirement at the CCGT plant determine the pipeline's diameter. For simplicity, the design is optimised for a uniform pipeline diameter for the entire distance.

The number and location of compressor stations is determined in conjunction with the pipe to minimise the compressor requirement and pipe diameter. Compressor units are considered with redundancy, with each compressor station having two compressors (one operating, another for back up).

The following additional key assumptions are made for the system design:

- The fuel is coal seam gas (CSG) with a heating value of 37.5 MJ/m^3 and specific gravity of 0.55.
- The load (demand) needs a consistent amount of gas, 24 hours a day (referred to as a flat profile).
- The two 500 MW generating units operate at the same time.
- The pipeline's maximum allowable operating pressure is 15,300 kPa.
- The supply pressure from the source (gas production facility) is available at 15,000 kPa (requiring significant compression at the gas production plant to compress gas from the low CSG field pressure to pipeline pressure).
- The minimum pressure requirement at the CCGT plant gate is 3,500 kPa.

8.4 Other considerations

This section provides information about other considerations in gas and electricity transmission designs including environmental considerations, reliability and access to additional new generation, ongoing operation and maintenance, and the possible impacts on the electricity transmission network.

8.4.1 Environmental

Electricity transmission

Overhead transmission lines can be constructed across most types of terrain. In general, a 60 metre wide easement is likely to be required to build a 330 kV double circuit transmission line[6], and the associated community consultation and planning permission may have a lead time of several years.

Locating GPG at a major load centre may also be environmentally unacceptable. Where this is the case, GPG can be located near a strong part of the existing electricity transmission network. In some cases, a short length of new transmission line may be required, adding to gas transmission option costs.

Gas transmission

Easements for building gas pipelines are generally 20 to 30 metres wide during construction, although extra space is usually required at road or stream crossings or for special soil conditions. The permanent easement is usually 15 to 25 metres wide.

Pipelines are generally underground (apart from their markers[7]), and the associated community and planning permission may have a shorter lead time compared to overhead electricity transmission lines. Compressor station noise and visibility can, however, affect communities. These are usually addressed by using sound-deadening materials for compressor buildings and planting trees around the compressor stations.

8.4.2 Reliability and access to additional new generation

Electricity transmission

Overhead transmission line forced outages are mainly influenced by extreme weather conditions such as lightning, cyclones, and bushfires. Local connection provides a more reliable supply than remote connection over long distances, and generally avoids power system transient and voltage stability limitations. Local connection can also increase fault levels due to low impedance between the generating end and receiving end. The effect of increased fault levels depends on the fault level capability and limitations of the existing plant. In some cases, fault level reduction at critical locations can add significant costs.

Remote connection has the advantage of enabling additional new generation (of any technology) and loads along the route. The most economic approach will involve estimating the extent of any additional generation, given this impacts transmission line design, requiring a potentially higher voltage level and current-carrying capacity.

The 330 kV voltage level and 1,245 MVA capacity for each circuit that the cases assume leaves little spare capacity to accommodate additional new generation.

6 Standards Australia. “AS/NZS 7000:2010 Overhead Line Design-Detailed Procedures” Appendix DD. Available http://infostore.saiglobal.com/store.

7 White-coloured posts to identify the location of the easement and pipeline that warn against unauthorised excavation.

Gas transmission

Gas pipeline forced outages are mainly influenced by corrosion and third party damage (for example, unauthorised digging). Unlike the electricity transmission network, however, energy can be stored in gas pipelines as linepack, which makes it likely that GPG can still be supplied for short periods if gas production stops.

Similarly, depending on the location of a rupture, supply is still possible for a short period while repair is underway, providing there is sufficient time to reschedule generation.

Although it is possible to connect additional GPG along a pipeline's route (via branching and using additional compressors to boost capacity), additional electricity transmission lines are still required for power transfer.

8.4.3 Operation and maintenance

For these high level studies, operation and maintenance costs and transmission losses have not been included in the cost estimates for either electricity or gas transmission, but would need to be considered when selecting a preferred option.

Typical electricity transmission network losses (in the form of heat) range from 4% – 5%.

Typical unaccounted for gas (UFG) is approximately 0.5%, including leakage and mismatched meter readings. A fraction of the gas injected into a pipeline (typically less than 2%) is often also used for compressor and heater fuel, which also reduces gas amounts at the receiving end.

8.4.4 Impact on the electricity transmission network

The electricity and gas transmission case studies deal with connecting a single generator to the electricity transmission network. In both cases, the associated electricity assets would be considered connection assets and the costs would be borne by the connecting generator.

However, the results can be extended to consider using gas transmission as an alternative to augmenting the shared electricity transmission network[8] in the case where the augmentation is driven by GPG.

For example, in the Northern New South Wales (NNS) zone, where there are significant gas reserves but limited electricity transmission capacity to connect significant amounts of new generation, the alternatives include the following:

- Augment the electricity transmission network from the NNS zone to Sydney.
- Build gas infrastructure that enables generation to connect closer to Sydney's 500 kV electricity transmission network.

As a result, future AEMO studies will (where appropriate) actively consider gas pipelines as well electricity transmission augmentation.

[8] This refers to transmission network assets that are not connection assets.

8.5 Differences between electricity and gas transmission

Table 8-3 contrasts the salient features of electricity and gas transmission for a 1,000 MW CCGT, supplied by a gas production facility 100 km, 250 km, or 500 km from the electricity transmission network.

Table 8-3 — Electricity and gas transmission

	Electricity Transmission	Gas Transmission
Type of construction	Overhead transmission line.	Underground gas pipeline with ground-level facilities.
Planning criteria	Double circuit transmission line.	Single gas pipeline.
Design – 100 km	A 100 km double circuit transmission line plus shunt capacitor at the receiving end.	A single gas pipeline without compressor stations.
Design – 250 km	Option 1 - a double circuit transmission line, one intermediate station, shunt capacitors, and SVC at the receiving end. Option 2 - a double circuit transmission line, series compensation, and shunt capacitor at the receiving end.	A single gas pipeline without compressor stations.
Design – 500 km	A double circuit transmission line, one intermediate station, series compensation, shunt capacitors, and SVC at the receiving end.	**Option 1** – a continuous, larger diameter pipeline. **Option 2** – a smaller diameter pipeline with compressor stations.
Indicative capital cost estimate – 100 km	$135 million to $185 million.	$60 million to $120 million.
Indicative capital cost estimate – 250 km	$350 million to $480 million.	$150 million to $305 million.
Indicative capital cost estimate – 500 km	$725 million to $975 million.	$305 million to $610 million.
Easement width	60 metres.	15 to 25 metres.
Access to new generation along the route	Additional generation can be connected given sufficient transmission line capacity.	Additional GPG can be connected given sufficient pipeline capacity.
Asset life	Electricity transmission lines and gas pipelines have similar asset lifetimes.	Electricity transmission lines and gas pipelines have similar asset lifetimes.

8.6 Electricity and gas case study diagrams

8.6.1 Electricity transmission single line diagrams

Figure 8-3 — 100 km

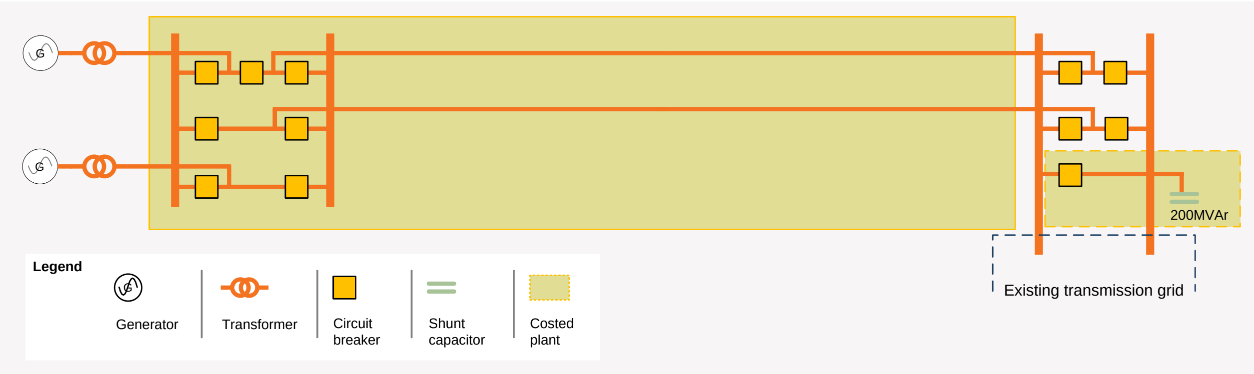


Figure 8-4 — 250 km, Option 1

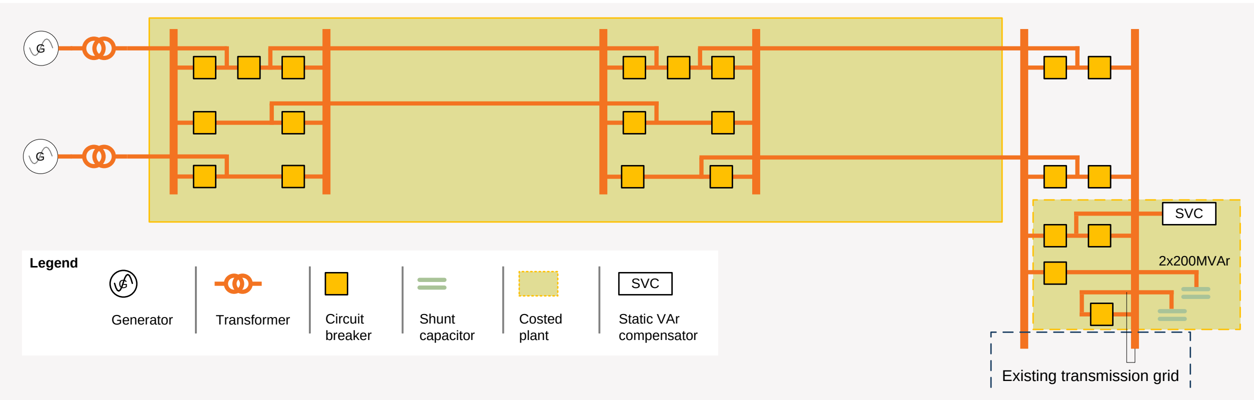


Figure 8-5 — 250 km, Option 2

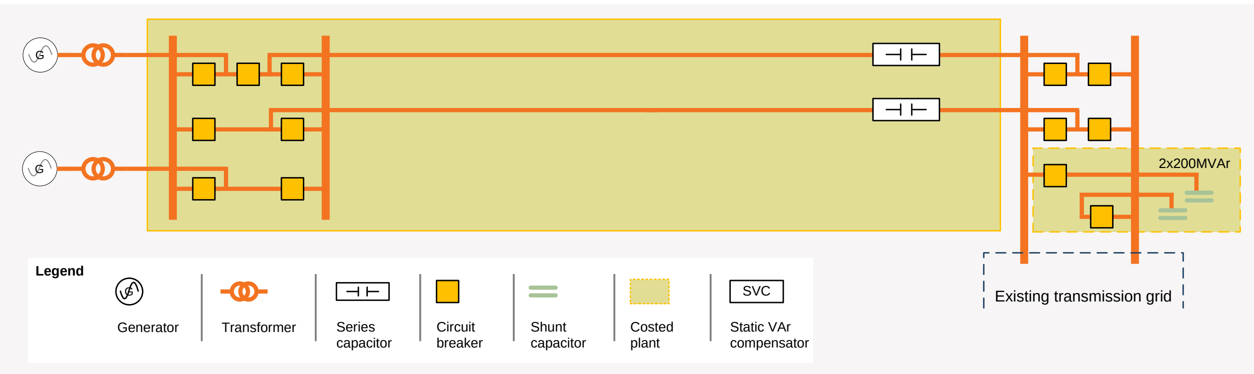
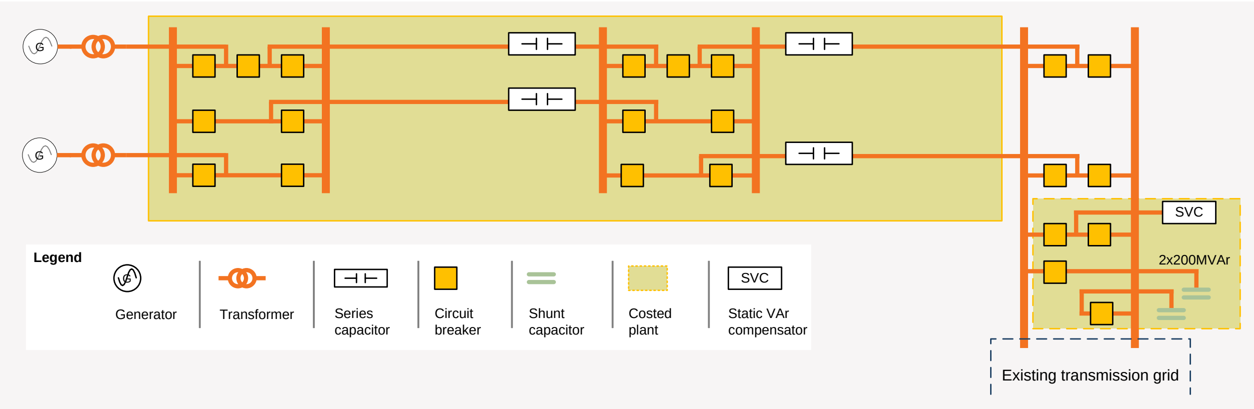


Figure 8-6 — 500 km



8.6.2 Gas transmission diagrams

Figure 8-7 — 100 km, 250 km, 500 km, Option 1

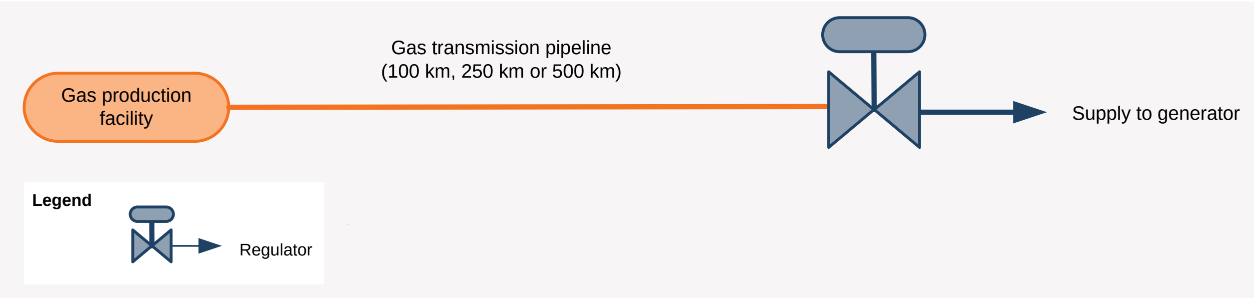


Figure 8-8 — 500 km, Option 2

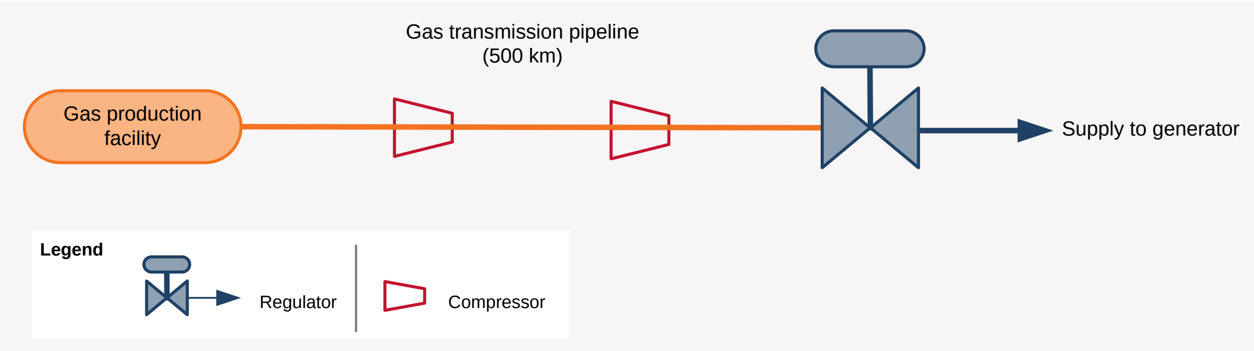
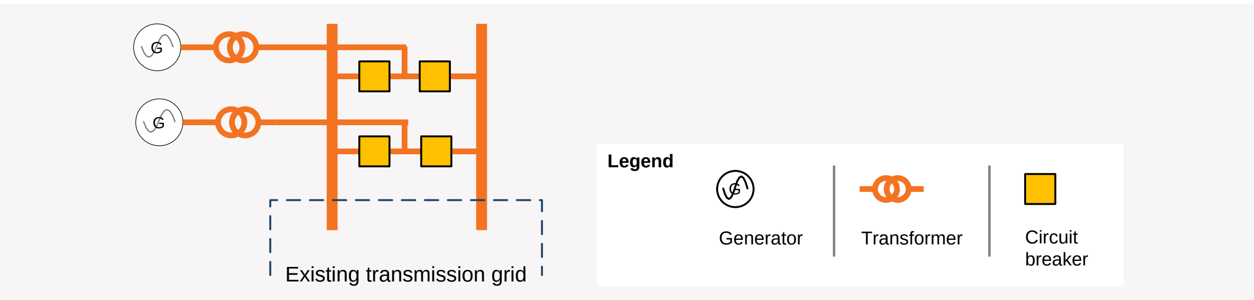


Figure 8-9 — Electrical connection of GPG in gas transmission case study



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CHAPTER 9 - THE CHANGING NATURE OF DEMAND

Summary

This chapter presents an analysis of the potential impact on demand profiles from widespread adoption of plug-in electric vehicles and increasing penetration of rooftop solar photovoltaic (PV) generation[1].

A number of factors are changing the nature of demand in the National Electricity Market (NEM), including energy efficiency technologies, the price elasticity of demand with respect to increasing prices, plug-in electric vehicles, and solar PV generation.

Plug-in electric vehicles and solar PV generation were chosen as the focus for this analysis, as an abrupt “step change” in the application of these technologies is anticipated, rather than an incremental impact on demand and the associated demand profiles. As a result, future studies of a similar nature will address other factors and considerations.

Preliminary results from the analysis suggest that (based on a high level of adoption) plug-in electric vehicle demand profiles show uncontrolled charging has the potential to significantly increase the summer and winter maximum demand (MD).

An alternative charging profile, however, with 50% of vehicles charging late at night, suggests there are potential benefits from implementing controlled charging schemes and providing incentives for using smart charging techniques.

Assuming a high level of adoption, summer and winter solar PV generation output profiles were compared with the energy and MD projections for 2030, the analysis of which showed the following:

- Solar PV generation has the potential to moderately reduce summer MD and significantly contribute to daily energy on clear days.
- Encouraging solar PV generation owners to match their electricity consumption patterns and their output may:
  - Result in an increased contribution from these sources towards meeting the MD
  - Potentially delay transmission network investment, especially in parts of the distribution network with high solar PV generation uptake.

The examples used in this analysis were chosen to illustrate potential impacts on demand (and associated demand profiles). As a result, the study assumed sufficient plug-in electric vehicle and solar PV generation adoption to noticeably impact the demand profiles studied.

These study conclusions will be used with projections of plug-in electric vehicle and solar PV generation adoption to inform planning responses to changes in both these potential areas of development.

[1] References to solar PV generation involve domestic applications of rooftop solar PV unless specified otherwise.

9.1 The impacts on demand

Electricity demand is the main driver for investment in the NEM. To predict long-term trends in demand, AEMO produces annual energy and MD projections for each region, which are used as demand profile[2] inputs to model the hourly shape of demand for the 20-year outlook period.

The nature of electricity demand will change with the increasing adoption of plug-in electric vehicles, rooftop solar PV generation, and other emerging generation technologies, all of which are being driven by climate change policies, rising electricity prices, and the changing costs of different energy technologies.

In response, AEMO is developing new processes and assumptions to incorporate these changes into the energy and MD projections, and demand profile development.

Demand projection and demand profile development

The existing demand projection development process uses historical demand data and reference demand profiles as key inputs. The nature of demand, however, is changing due to government policies, technology trends, and consumer behaviour.

Although each small change in consumer appliance ownership or behaviour has some impact on demand, daily demand profiles have remained relatively stable, with changes generally being incremental over time.

Some technological and policy changes over the last 10 years, however, have significantly impacted the shape of demand. These impacts have emerged in the aggregate demand data and have been incorporated into the models as trends in residential demand.

Examples of the types of changes include the following:

- Residential air conditioners have become increasingly affordable and popular, considerably increasing peak demands during summer.
- The uptake of off-peak electric hot water systems was encouraged by various state governments and state electricity commissions during the 1990s and 2000s. These systems shifted some water heating load from peak demand times to an off-peak time, increasing the utilisation of existing generation and network capacity.
- The Australian Government’s phase-out of inefficient incandescent lighting began in 2009, which has reduced residential and commercial electricity demand, particularly in the evenings.

The impacts of plug-in electric vehicles and solar PV generation

Plug-in electric vehicle and solar PV generation technologies have the potential to significantly impact demand, and the rapid adoption of solar PV generation demonstrates that this will not necessarily be incremental.

AEMO estimates that at the end of September 2011, total solar PV generation capacity was approaching 1,000 megawatts peak (MWp).[3] Solar PV generation is the first widespread technology used by householders and small businesses to generate electricity independently of retailers, and the resulting reduction in electricity demand currently being attributed to solar PV generation is unprecedented in the NEM.

[2] A key input into the time-sequential studies used in the NTNDP.

[3] The output capacity of PV systems is typically quoted in kilowatts peak (kWp) or megawatts peak (MWp). This is the output of the PV modules under standard test conditions of 1,000 watts per metre squared (W/m^2) of solar irradiance and ambient temperature of 25 °C. In practice, the power exported from a PV system to the grid, in kW or MW, will be lower due to the losses from factors due to the inverter and wiring of the system.

Although future adoption is uncertain, several persistent driving factors include the following:

- Climate change policies that include government subsidies for certain technologies, especially renewable energy.
- Rising electricity prices resulting from increasing expenditure on transmission network infrastructure and the cost pass-through of some climate change policies.
- Rising petrol prices due to increasing global demand for oil. These increases are likely to continue for the foreseeable future, as well as including a carbon price (depending on climate change policy outcomes).
- An increasing consumer desire to minimise the environmental footprint at a personal level.
- Declining technology costs for solar PV generation due to the high Australian dollar and the development of the international solar PV generation market. This has been partly attributed to scale efficiency gains in manufacturing and silicon supply. In the future, technology costs for plug-in electric vehicles are also likely to decline, depending on the extent of their global uptake as an alternative to conventional cars.

Currently, there are few plug-in electric vehicles on the road in Australia, but several major car companies are planning to release models in Australia over the next few years.[4]

Incorporating plug-in electric vehicles and solar PV generation into projections of demand

Initial studies exploring the impacts these technologies may have on demand indicate that significant adoption of either will considerably change demand and the demand profiles. As a result, the energy and MD projection processes will account for the adoption of these technologies from 2012 onwards.

Enabling technologies and policies for demand management

Other technologies and policy options (both existing and proposed) enabling consumers to adjust electricity use to reduce their bills or otherwise be rewarded for certain behaviours include the following:

- Retail pricing structures, such as increasing customer exposure to extreme price events.
- Communications networks, allowing energy businesses to control load under agreements with customers.
- Domestic energy storage systems, such as fuel cells or batteries, allowing householders to store solar PV generation for use at peak times.
- Changes to energy ratings programs, encouraging the use of highly efficient appliances or appliances that have minimal impact on peak demand.
- Changes to building standards, significantly reducing the electrical load requirements for lighting, heating, cooling, and water heating.

Although these demand management initiatives have not been modelled, opportunities to contribute to improving electricity market outcomes for plug-in electric vehicles and solar PV generation uptake are highlighted.

[4] For example, the Mitsubishi i-MiEV, Renault Fluence Z.E., and the Nissan LEAF.

9.2 Current forecasting approaches

This section relates the possible implications from changing electricity demand patterns due to plug-in electric vehicles and solar PV generation to the current methodologies used to produce the energy and MD projections.

Energy and maximum demand projections and demand profile development

AEMO publishes 10-year summer and winter energy and MD projections each year via the Electricity Statement of Opportunities (ESOO).

The projections are based on econometric modelling, which relates historical demand growth to macroeconomic and temperature trends using multi-variable regression. For MD modelling, the relationship between temperature and demand is the central parameter for predicting the distribution of demand that may result from various different scenarios.[5]

For information about the current modelling approaches, see the 2011 ESOO[6], which contains the latest energy and MD projections for the NEM, and a detailed description of the modelling process used for each region.

Demand profiles and the impact of plug-in electric vehicles and solar PV generation

The 2010 NTNDP accounted for some measure of plug-in electric vehicle loads, given assumptions about plug-in electric vehicles and solar PV generation result in certain changes to demand profiles during the day. For an assumed level of daily plug-in electric vehicle demand, the 2010 NTNDP distributed this load across overnight demand to reduce the trough in demand that otherwise occurs.

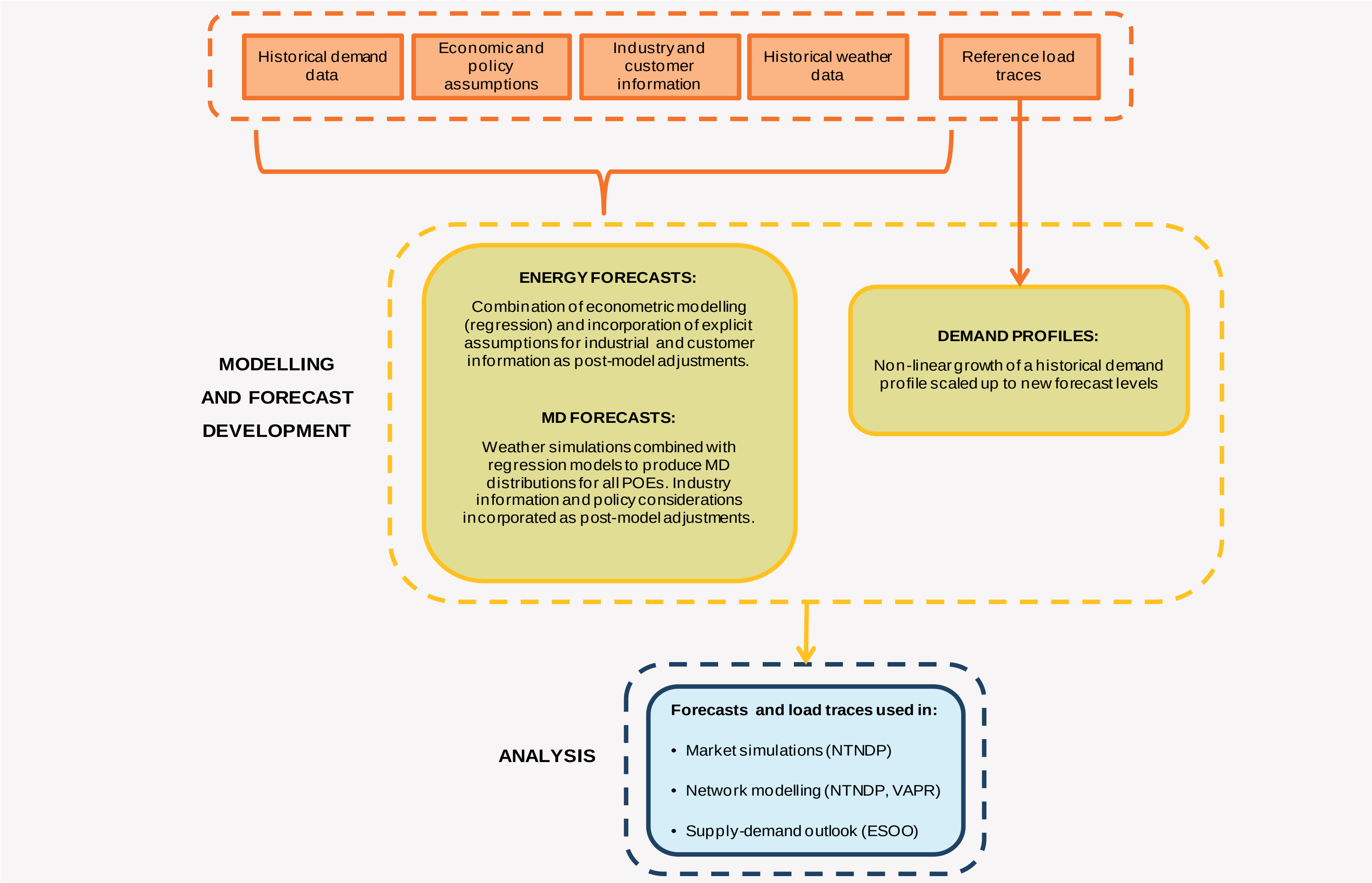
The 2011 NTNDP studies that are reported in this chapter consider two alternative charging profiles that better reflect potential charging patterns, given the specifications of vehicles planned for Australian deployment from 2012 onwards.

Figure 9-1 shows a flow chart summarising the current energy and MD projection development process. Incorporating plug-in electric vehicles and solar PV generation will require extra input data that includes the number of plug-in electric vehicles owned, the existing capacity of solar PV generation, and assumptions about the future growth of both.

5 This is the same methodology used in developing AEMO's MD projections for South Australia and Victoria. In other regions the methodologies vary slightly. See note 6 in this chapter.

6 Available at http://www.aemo.com.au/planning/0410-0079.pdf. Accessed 23 September 2011.

Figure 9-1 — AEMO energy and MD projection process



9.3 Plug-in electric vehicle and solar PV generation modelling

This section presents modelling results for plug-in electric vehicle loads and solar PV generation output, and represents an initial examination of the impacts both technologies have on regional demand.

The New South Wales region was the example used to develop the modelling, and assumptions involving plug-in electric vehicle numbers and solar PV generation capacities have been developed to represent realistic penetration in that region.[7]

In the future, AEMO will adjust model assumptions to develop projections for the other regions.

9.3.1 Plug-in electric vehicle projection development

The disaggregated charging of a large number of plug-in electric vehicles potentially results in two different load profiles, based on the following basic scenario assumptions:

- Scenario EV1, involving 1 million vehicles and uncontrolled charging.[8]
- Scenario EV2, involving 1 million vehicles, half of which use smart charging.[9]

The scenarios reflect reasonable levels of plug-in electric vehicle penetration in New South Wales, and all involve weekdays, when the summer and winter MDs typically occur. The key assumptions involve the number of plug-in electric vehicles and the charging patterns.

Plug-in electric vehicle numbers

There are conflicting estimates about the number of plug-in electric vehicles entering the Australian vehicle market over the next 10 years. In a report prepared for the New South Wales Government, it was estimated that under optimistic pricing assumptions for plug-in hybrid and all-electric vehicles, the two vehicle types may start to increase their market share from 2020 onwards, representing over 50% of vehicle sales by 2028.[10]

A report for the Victorian Government, however, characterised 850,000 vehicles by 2030, approximately 15% – 20% of private vehicles, as being a high uptake in Victoria.[11]

Some plug-in electric vehicle manufacturers and service providers have presented much lower cost projections and higher sales estimates. For example, in a 2011 submission to the Australian Energy Market Commission's (AEMC) Review of Demand-Side Participation in the National Electricity Market, it was estimated that plug-in electric vehicles will represent the cheapest new vehicle option for 85% of consumers by 2020, leading to a much larger uptake before 2030.[12]

It is likely that the bulk of plug-in electric vehicle uptake will be in urban centres, where trip distances are generally short. The number of private vehicles in the greater Sydney area in 2009–10 was approximately 2.5 million. This figure has been growing at an average annual rate of 2.3% since 2001–02, and at this rate of growth the number of private vehicles in Sydney in 2030 will be approximately 4 million.

7 The scenarios modelled are indicative only and based on the possible penetration of plug-in electric vehicles and PV over the next two decades. New South Wales was chosen as an illustrative example but any region would have been valid.

8 See 'Charging patterns' in this section.

9 See 'Charging patterns' in this section.

10 AECOM. "Economic viability of plug-in electric vehicles". Available http://www.environment.nsw.gov.au/resources/climatechange/ElectricVehiclesReport.pdf. Accessed 23 September 2011.

11 MMA. "Electricity Markets and the Uptake of Plug-in electric vehicles". Available http://new.dpi.vic.gov.au/__data/assets/pdf_file/0018/23661/MMA-final-report.pdf Accessed 23 September 2011.

12 Better Place. "Submission to the 'Power of Choice – Stage 3 DSP Review' 26 August 2011". Available http://www.aemc.gov.au/Media/docs/Better%20Place-e6532c70-7ae7-457a-827a-7c74a832be74-0.pdf. Accessed 23 September 2011.

Charging patterns

The current generation of plug-in electric vehicles has a range of over 100 km per full charge[13], and the average distance of a private vehicle commute in Sydney is 14 km.[14] Other average trip lengths, for recreation, shopping, education, and childcare are all less than 15 km, making it unlikely that vehicles will need a full charge nightly.

The study assumes, on average, a partial charge once a day. For the purposes of the modelling, a partial charge is 2.86 kW for 3.5 hours[15], delivering 10 kWh of energy, which equates to a driving distance of 45 km – 55 km, depending on the vehicle and driving conditions.[16]

The resulting impact on demand will vary, depending on whether individual charging patterns are random or controlled via smart charging.

Smart charging involves the bulk of the charging occurring late at night and early in the morning. This type of charging is unlikely to emerge without regulating charging points or economic incentives, and given this uncertainty, the modelling considers both uncontrolled charging and some smart charging.

Figure 9-2 shows the assumed weekday commencement times and charging patterns for Scenario EV1 and EV2:

- Scenario EV1 (uncontrolled charging) assumes the majority of vehicles are charged in the afternoon or evening.
- Scenario EV2 (50% smart charging) assumes that 50% of vehicles commence charging at either 11:00 PM or 2:30 AM, with the remaining 50% commencing charging at non-smart-charge times.

The pattern for uncontrolled charging has been adjusted from a 2009 McLennan Magasanik Associates report to the Victorian Government on electricity markets and the uptake of plug-in electric vehicles.[17]

[13] See, for example, The Renault Fluence Z.E. (http://www.betterplace.com.au/electric-cars/renault-fluence-ze.html), the Nissan LEAF (http://www.nissan-zeroemission.com/EN/LEAF/specs.html) and Mitsubishi i-MiEV (http://www.mitsubishi-motors.com.au/vehicles/cars/i-miev). Accessed 23 September 2011.

[14] The 2010/11 Household Transport Survey from the New South Wales Bureau of Transport Statistics summarises the driving habits of vehicle owners in the greater Sydney area. Available http://www.bts.nsw.gov.au/ArticleDocuments/79/R2011-09-HTS-Report.pdf.aspx?Embed=Y. Accessed 23 September 2011.

[15] 2.86 kW is the power drawn by the Mitsubishi i-MiEV at an in-home charging point.

[16] The 2011 Nissan LEAF and Mitsubishi i-MiEV have average fuel economies of 4.73 km/kWh and 5.36 km/kWh, respectively. The U.S. Department of Energy fuel economy website compares different models. Available http://www.fueleconomy.gov/feg/evsbs.shtml. Accessed 26 September 2011.

[17] McClennan Maganasik Associates. "(2009) 'Electricity markets and the uptake of plug-in electric vehicles', Report for the Victorian Department of Primary Industries". Available http://new.dpi.vic.gov.au/__data/assets/pdf_file/0018/23661/MMA-final-report.pdf. Accessed 23 September 2011. The profiles in this report were adjusted to assume that during the day there is always some level of plug-in electric vehicle charging.

Figure 9-2 — Commencement times and charging patterns for plug-in electric vehicle charging (weekday)

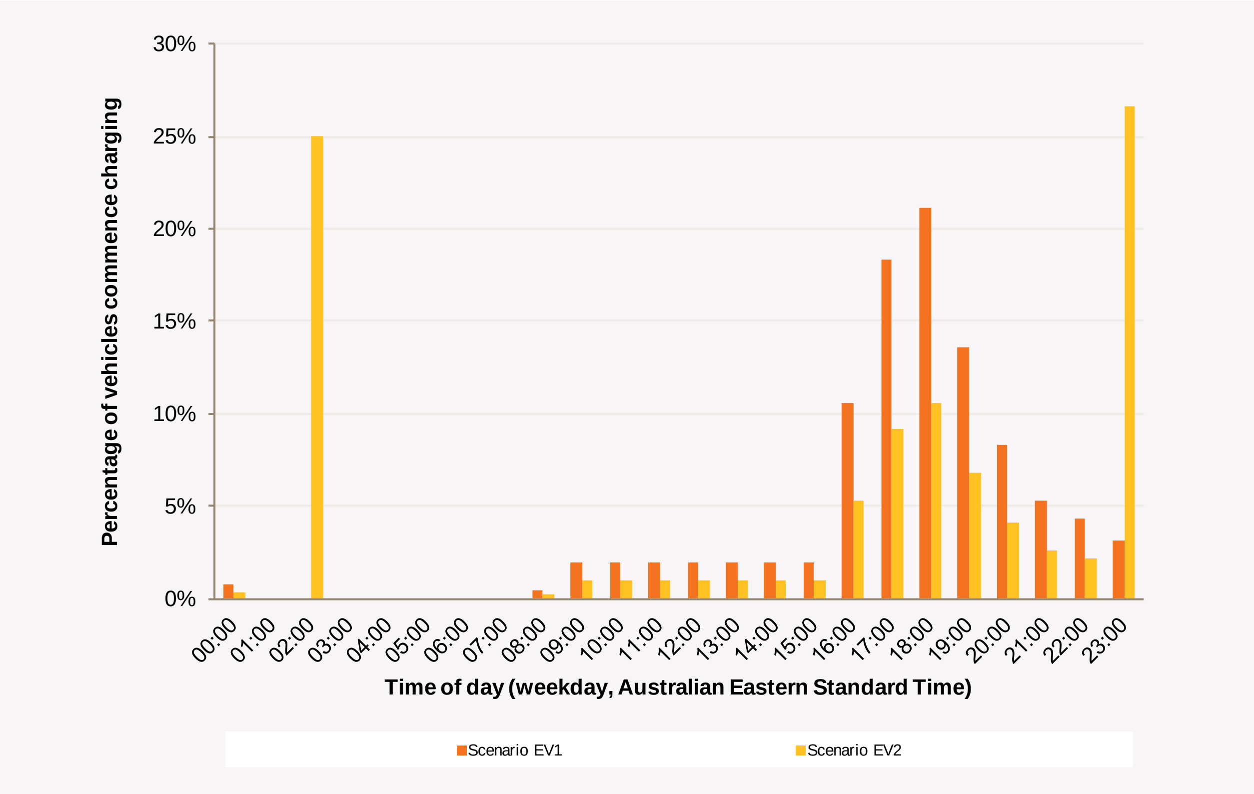


Table 9-1 summarises the main assumptions for each scenario.

Table 9-1 — Plug-in electric vehicle projection assumptions

Assumption	Scenario EV1	Scenario EV2
Number of plug-in electric vehicles	1,000,000	1,000,000
Charge frequency	Daily	Daily
Charge time (hours)	3.5	3.5
Charge power (kW/vehicle)	2.86	2.86
Percentage of vehicles smart charging	0	50

9.3.2 Plug-in electric vehicle demand profiles

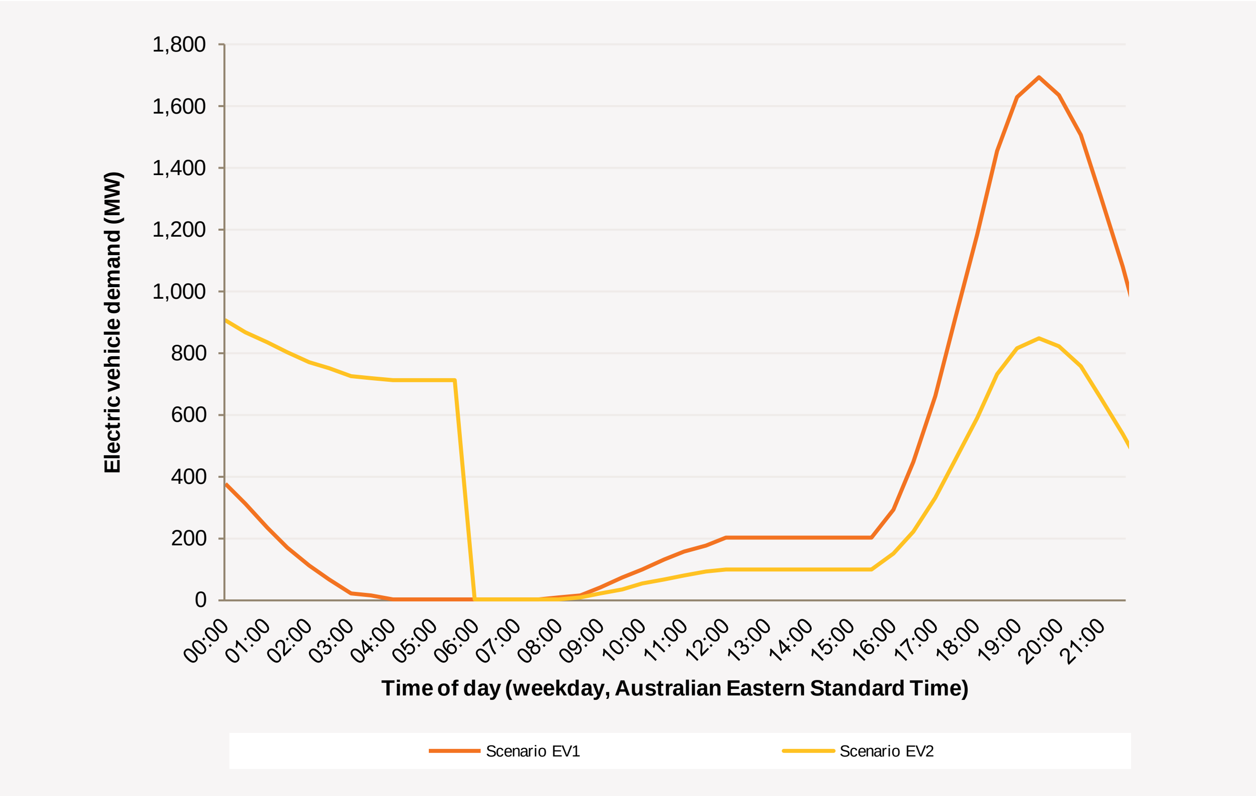
Figure 9-3 shows the weekday demand (charging) profiles for Scenario EV1 and EV2:

- Scenario EV1 experiences the largest load in the evening (when owners arrive home), and peak demand occurs at 6:30 PM, after which fewer vehicles commence charging than finish charging, and the total load declines.
- Scenario EV2 experiences its peak at 11:00 PM, which is when 25% of vehicles begin to smart charge.

The area under the curves represents the total energy consumed through charging:

- Scenario EV1, with uncontrolled charging, consumes the bulk of its energy between 5:00 PM and 10:00 PM.
- Scenario EV2 evenly consumes energy between uncontrolled daytime charging and smart charging (from 11:00 PM to 6:00 AM).

Figure 9-3 — Demand (charging) profiles for plug-in electric vehicles (weekday)



9.3.3 Solar PV generation projection development

This section presents hypothetical daily solar PV generation power production curves. Understanding the nature of these curves and how they change according to different sunlight and temperature conditions is fundamental to developing assumptions about how to incorporate solar PV generation into the demand profiles and energy and MD projections.

Two scenarios have been modelled representing summer and winter days with good and bad sunlight:

- Scenario PV1, with high output.
- Scenario PV2, with low output.

An assumed solar PV generation capacity of 2,000 MWp[18] is modelled against the 2030–31 demand profile for summer and winter at times of the year corresponding to the New South Wales MD. This capacity is based on a solar PV generation estimate that is:

- High enough to have a clear impact on the regional load profile.
- Low enough to be a reasonable projection, given the historical uptake rates in New South Wales.[19]

Key aspects of the simulation include the following:

- The simulated solar PV generation system is located in Sydney.
- The modelling software applied solar PV generation system specifications as inputs, including location, components and design characteristics, and uses a year-long climate simulation for the given location to model the output at hourly intervals throughout the year.
- The climate simulation includes ambient temperature and solar radiation based on a typical meteorological year (TMY) deriving from historical Bureau of Meteorology data involving Sydney sunlight and temperature.[20]
- The simulation accounts for losses from the system components and the variation in solar radiation throughout the day. For this model a 1 kWp, north-facing system was assumed, with no shading, at a 30º tilt angle.

The simulated output data was then scaled up to represent 2,000 MWp of solar PV generation capacity.

Table 9-2 lists the assumptions for the high and low solar PV generation output scenarios, which relate to sunlight on the peak day, not the physical properties or performance of the systems themselves.

Table 9-2 — Solar PV generation projection assumptions

Scenarios	Solar PV Generation Capacity (MWp)	Solar PV Generation Output
PV1	2,000	High.
PV2	2,000	Low.

In New South Wales, the actual efficiency and aggregated output will vary depending on the location, components, tilt, orientation, age, shading, and other design aspects. As a result, to analyse the impacts of currently installed systems and project the impact of future installations, future studies will need to investigate the issue of system efficiency and diversity.

18 No explicit modelling or forecast of future capacity was used to determine the capacity assumption, and the output profiles can be scaled directly up or down to represent higher or lower capacities.

19 The PV capacity in New South Wales has grown rapidly in response to the New South Wales Government's Solar Bonus Scheme, which was implemented in 2010 and closed in April 2011. It is estimated that the state-wide capacity eligible for the scheme will exceed 370 MW. See the New South Wales Department of Trade and Investment "New South Wales Solar Bonus Scheme". Available. http://www.trade.nsw.gov.au/energy/sustainable/renewable/solar/solar-scheme/solar-bonus-scheme. Accessed 23 September 2011.

20 The TMY data is a full year of hourly insolation and temperature values for a particular location, which is a combination of individual months of data selected from a historical record as being typical.

9.3.4 Summer solar PV generation output profiles

Figure 9-4 presents the summer solar PV generation output curves based on the following weather assumptions for each scenario:

- Scenario PV1, with high output during summer, assumes a sunny summer day with little to no cloud. From the year of simulated output data, a day was selected in late January:
  - When the New South Wales summer MD usually occurs.
  - To match the day length and solar radiation characteristics of the simulation with demand.
  - Because the simulated temperatures were high, varying between a minimum of 14.9 °C at 5:00 AM and a maximum of 38.5 °C at 2:00 PM.[21]

  The solar PV generation output from the simulation on this day reaches its assumed maximum output of 1,633 MW[22] at approximately 11:00 AM when solar radiation is at its maximum, and decreases from then onwards. From approximately 2:30 PM onwards, the power drops off quite steeply as the sun is lower in the sky. After 5:30 PM the output falls below 10% of the potential maximum.
- Scenario PV2, with low output during summer, assumes a hot and cloudy day, with the level of cloud cover varying throughout. Depending on the weather conditions, any reduction from the summer high output curve shown is possible on a 'non-ideal' day:
  - The curve is based on sunlight and temperature data from a late January day.
  - The Sydney temperature for the simulated day varies between a maximum of 35.5 °C at 1:00 PM and a minimum of 18.8 °C at 10:00 PM.

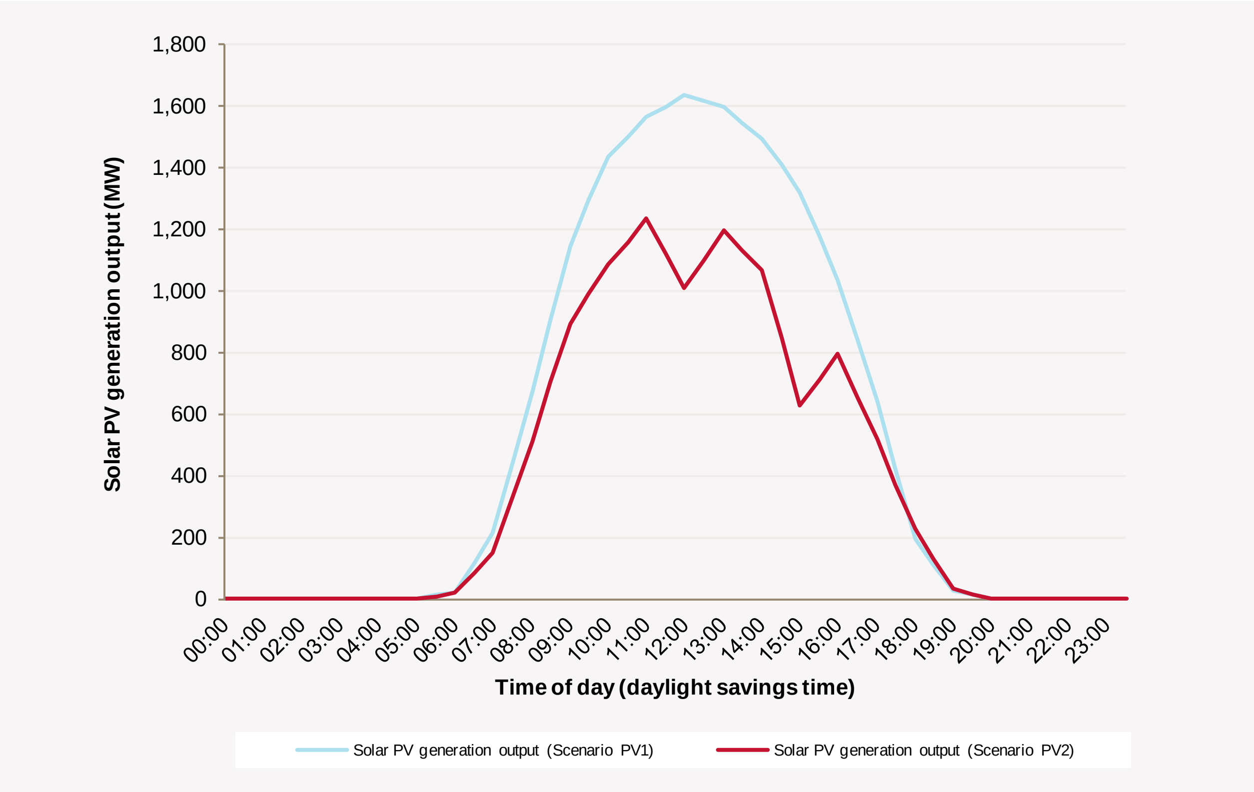
  The solar PV generation output from the simulation on this day reaches 60% of its assumed maximum at approximately 11:00 AM. The variations in output (demonstrated by the line's jaggedness), reflect the impact of changing cloud cover.

Both curves show that in the early morning and evening, when the output is just starting or dropping off, the high and low outputs are roughly equal. This is because there is not much direct sunlight reaching the solar PV generation modules under either scenario, since the sun is low in the sky. At these times the output is due to diffuse light, meaning cloud cover does not necessarily have a large impact on the output.

[21] Temperatures from the simulated day provide an indication of how well matched the simulated PV output may be to a summer MD day.

[22] From the year-long system simulation, the maximum output was 1,790 MW, which occurred in October. The output of PV systems falls as the ambient temperature increases. This is the main reason that the maximum output from a system on a hot day in January will be below the system's best performance.

Figure 9-4 — Summer solar PV generation output curves



9.3.5 Winter solar PV generation output profiles

Figure 9-5 presents the winter solar PV generation output curves based on the following weather assumptions for each scenario:

- Scenario PV1, with high output during winter, assumes a cold but sunny winter day with little or no cloud cover. The sunlight data is from mid-July, which is when the New South Wales winter MD often occurs. The simulated temperature for the day is between 7.2 °C and 14.5 °C.[23]

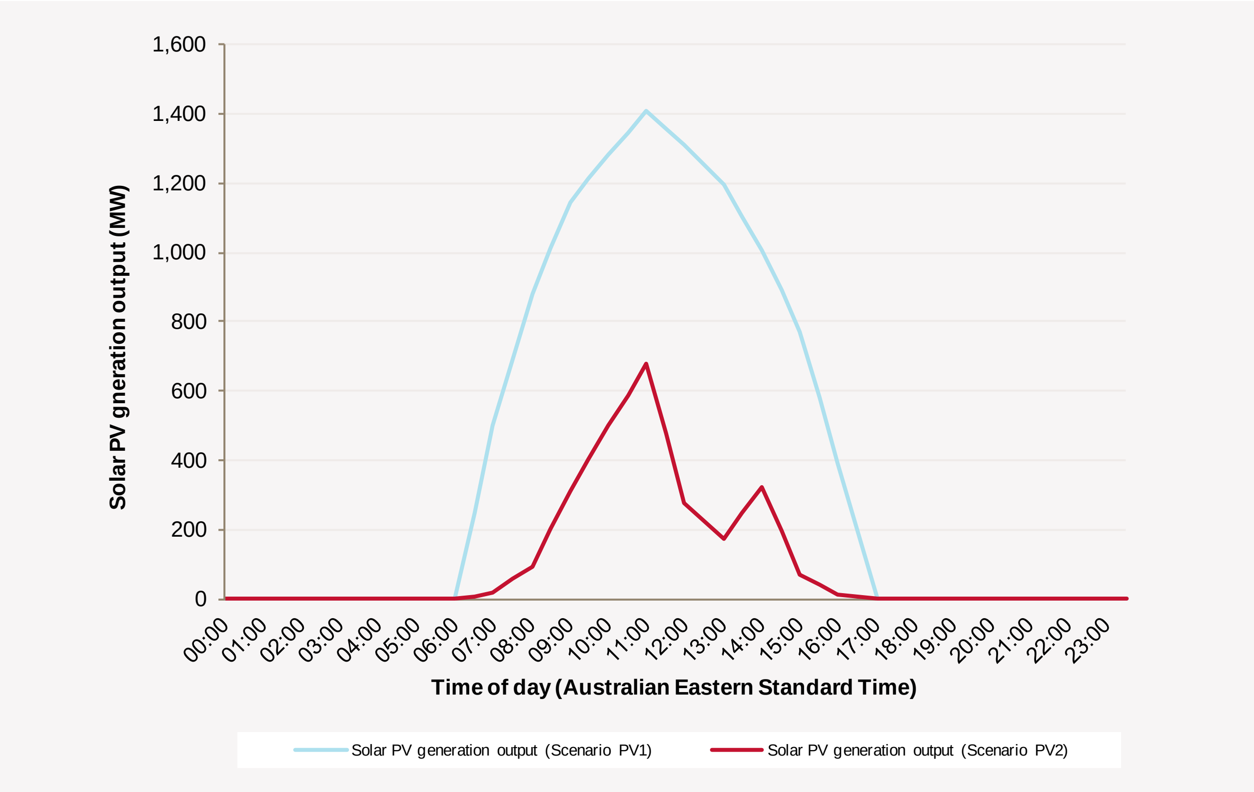
  The output from the simulation on this day reaches 79% of its assumed maximum at approximately 11:00 AM. The general reduction in output compared to the summer projections is due to the reduced intensity of sunlight during the winter months. The shorter day length, due to the sun's lower position in the sky, means the output begins to decrease rapidly at a slightly earlier time. From 2:30 PM onwards the solar PV generation output drops below 50% of the assumed maximum and decreases rapidly. The output falls below 10% of the assumed maximum after 4:00 PM.

- Scenario PV2, with low output during winter, assumes an overcast winter day with varying levels of cloud cover. The simulated temperature for the day is between 6.5 °C and 10.2 °C. The output from the simulation on this day remains below 38% of the assumed maximum (approximately half the winter Scenario PV1 maximum). The sunlight data is also from a cold day in mid-July.

  The output from the simulation on this day changes significantly in the middle of the day. The fluctuations themselves are quite smooth, with two output peaks reflecting the aggregated output from a large number of systems. The output of individual systems can fluctuate rapidly, however, on a minute-to-minute basis, depending on cloud movements in particular locations. The bulk of the energy is produced between 10:00 AM and 2:00 PM. The output falls rapidly from 2:00 PM onwards.

[23] Temperatures from the simulated day are provided to indicate how well matched the simulated PV output may be to a winter MD day.

Figure 9-5 — Winter solar PV generation output curves



9.4 Adjusted demand profiles

This section combines the results from the plug-in electric vehicle loads and solar PV generation output modelling with demand profiles to show the potential impact on demand.

The demand data derives from New South Wales regional data from the 2011 summer and winter MD days[24], scaled up to enable the MD to satisfy the 2030–31 10% probability of exceedence (POE) summer MD and winter MD forecasts for New South Wales (used in the 2010 NTNDP Decentralised World, medium carbon price (DW-M) scenario).

The study results are indicative only, showing the possible changes to demand resulting from these technologies, which can be adjusted for alternative scenarios by proportionally changing the increases or decreases to regional demand.

9.4.1 Adjusted demand profiles for plug-in electric vehicle impacts

Figure 9-6 shows the adjusted summer demand profiles for Scenario EV1 and EV2:

- The demand profile could change as a result of plug-in electric vehicle loads.
- The level of peak demand increased under both scenarios.
- The level of increase of peak demand due to plug-in electric vehicles will directly depend on the amount of smart charging.

[24] The summer MD for New South Wales occurred on 1 February 2011. The winter MD for New South Wales occurred on 19 July 2011.

Scenario EV1 increases the peak by 914 MW and changes the time of its occurrence from 5:30 PM (daylight savings time) to 6:00 PM.

Scenario EV2 has less impact on the peak, which increases by 456 MW, as 50% fewer vehicles are charging during the afternoon and evening, and the time of the peak did not change.

The assumed plug-in electric vehicle load for both projections continues to grow from 5:30 PM to 7:30 PM (as shown in Figure 9-3). This means that the shape of the peak in Figure 9-6 has been flattened slightly, and extended.

Under Scenario EV2, overnight demand from 11:00 PM to 6:00 AM is increased by approximately 750 MW due to smart charging.

Figure 9-7 shows the adjusted winter demand profiles for Scenario EV1 and EV2:

- The demand profile shows a moderate morning peak and a higher evening peak.
- Plug-in electric vehicles are unlikely to affect the morning peak, as most vehicles will have finished charging by the time the morning load increases, but the evening peak is affected.
- The peak increases are greater in winter than in summer, because the winter peak tends to happen later in the day when the assumed plug-in electric vehicle load is higher.

Scenario EV1 increases the peak at 6:30 PM by 1,460 MW.

Scenario EV2 increases the peak at 6:30 PM by 730 MW (approximately half).

Figure 9-6 — Adjusted summer demand profiles for plug-in electric vehicle scenarios

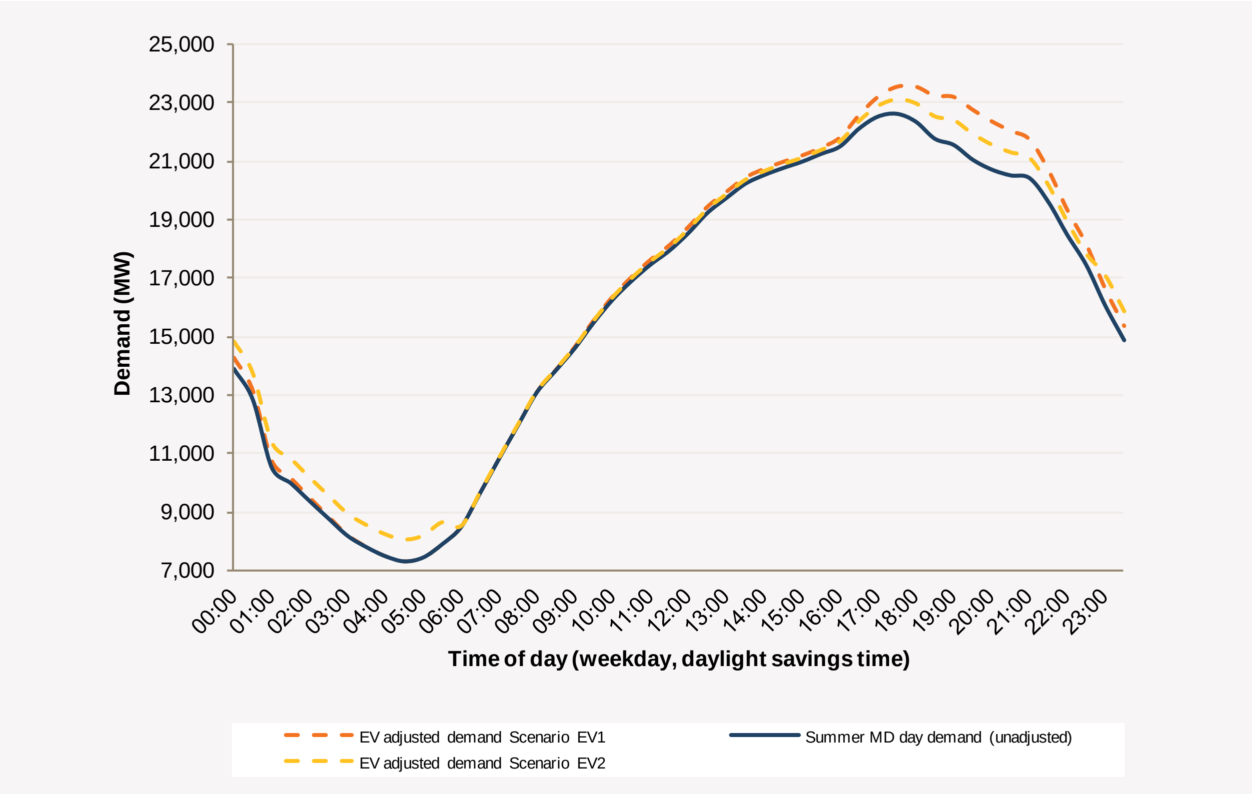
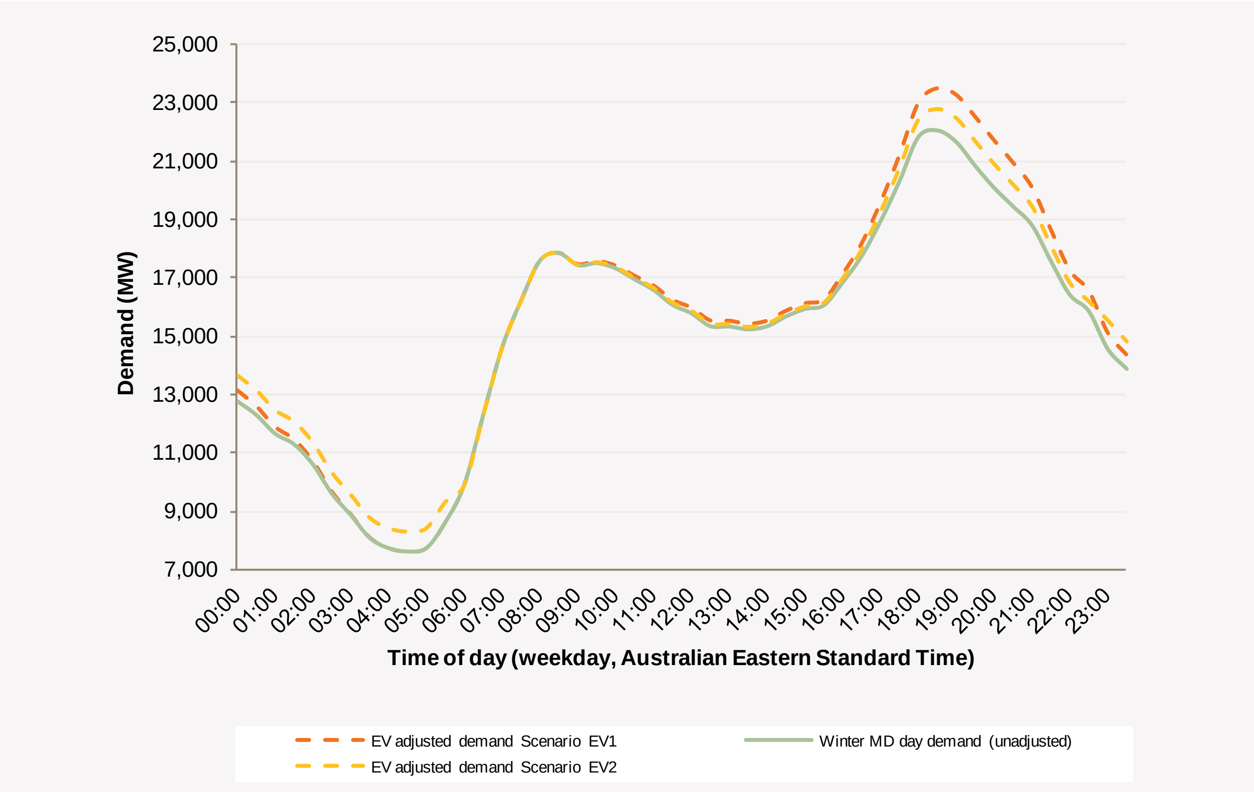


Figure 9-7 — Adjusted winter demand profiles for plug-in electric vehicle scenarios



9.4.2 Adjusted demand profiles for solar PV generation impacts

Figure 9-8 shows the adjusted summer demand profile (resulting from solar PV generation demand offsets) for Scenario PV1 and PV2.

The peak for the unadjusted load was at 5:30 PM (daylight savings time). In Sydney, sunset in late January is at approximately 8:00 PM (daylight savings time).[25]

The figure shows that solar PV generation output under both scenarios has the following effects:

- There is some reduction to the MD, with the figure also showing that the bulk of the energy delivered is in the middle of the day.
- The overall shape of the demand profile is slightly changed.

For Scenario PV1, with steady solar PV generation output in the middle of the day, the increase to the afternoon and evening peak is steeper between 3:30 PM and 5:30 PM, as solar PV generation output begins to fall.

For Scenario PV2, with solar PV generation output fluctuating according to cloud cover, some increases in output can be seen as small decreases in demand.

[25] Geoscience Australia has a sunrise and sunset calculator for various locations at http://www.ga.gov.au/geodesy/astro/sunrise.jsp. Accessed 23 September 2011.

Figure 9-8 — Adjusted summer demand profiles for solar PV generation impacts

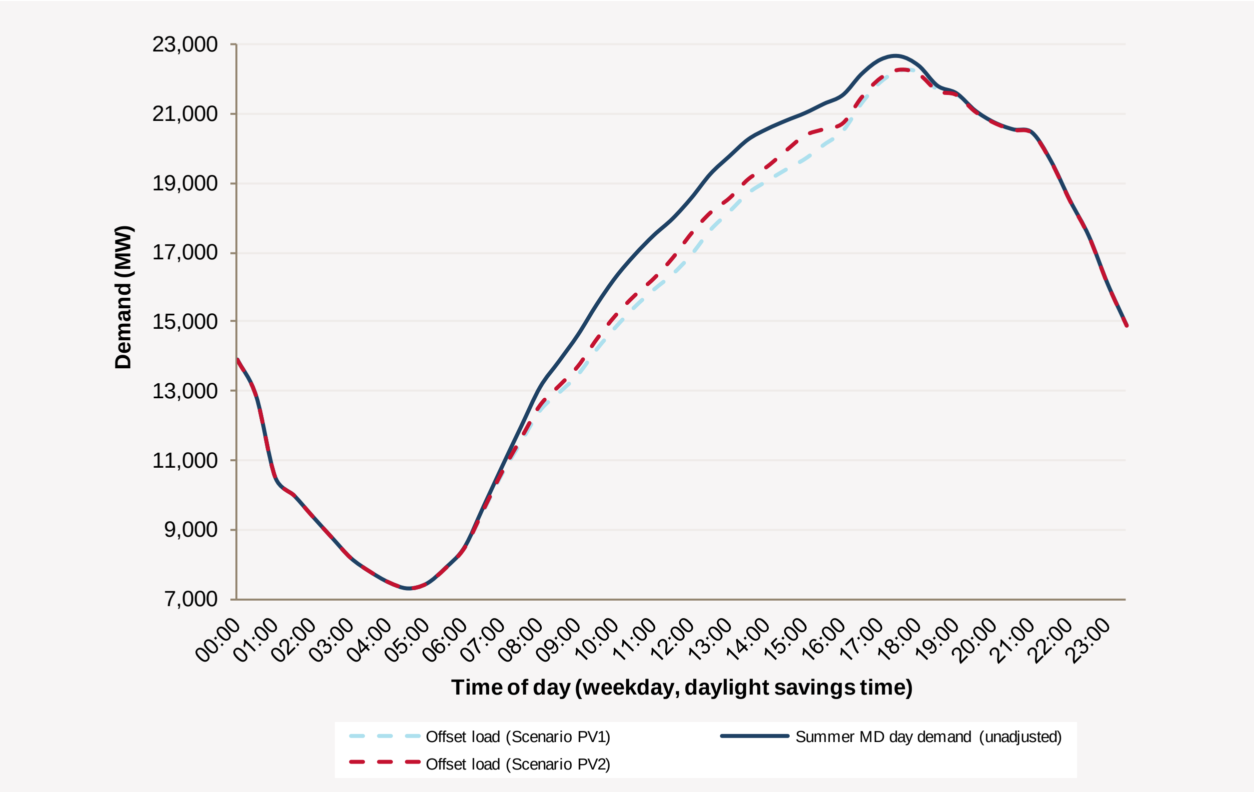


Table 9-3 summarises the impacts from Scenario PV1 and PV2, the results showing that solar PV generation makes a varying contribution to both daily energy and MD.

Table 9–3 — Solar PV generation projection impacts

Scenario[a]	Solar PV Generation Output		Summer MD Impact	Energy Impact
	MW	Percentage of Maximum Potential Solar PV Generation Output		
PV1	418	26%	A 1.8% reduction in peak, shifted from 5:30 PM to 6:00 PM (daylight savings time).	A 13 MWh reduction, 3.4% of total energy.
PV2	373	23%	A 1.6% reduction in peak, no change in time.	A 9.4 MWh reduction, 2.5% of total energy.

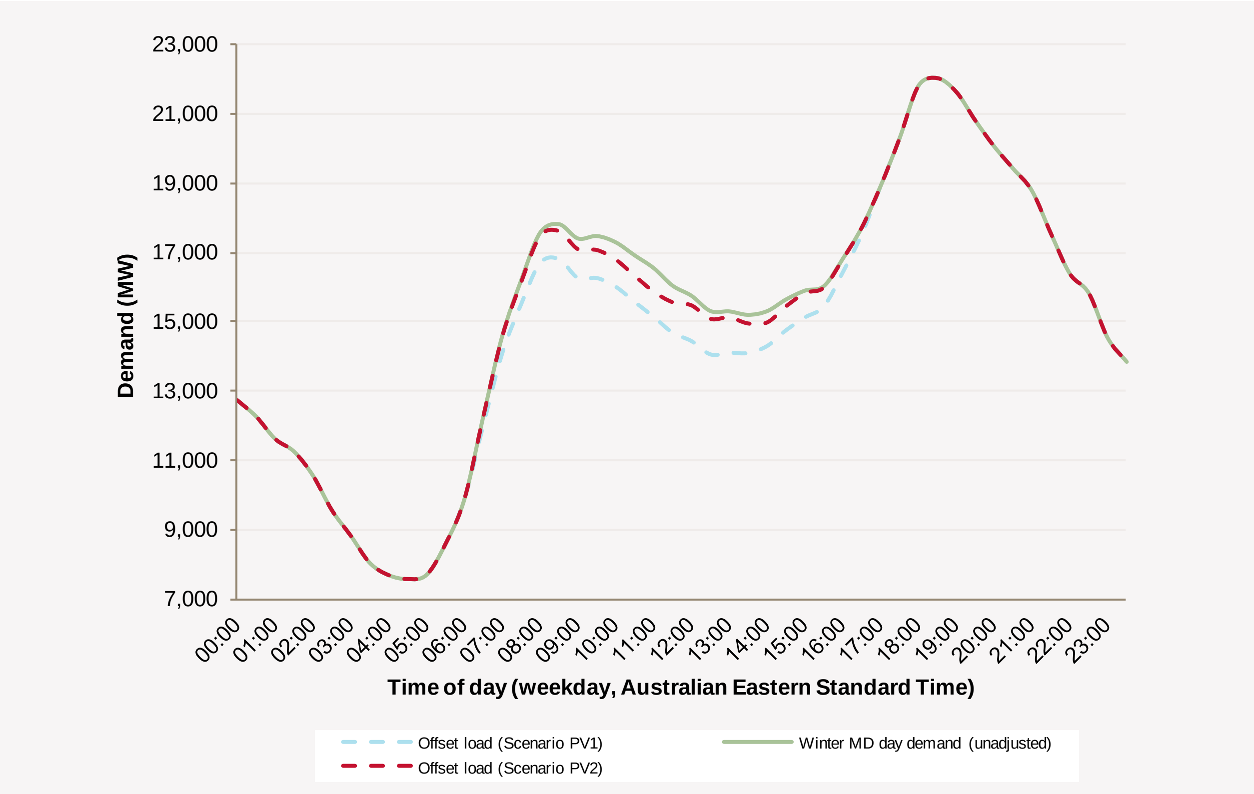
a. For a complete list of the scenario assumptions, see Section 9.3.2.

A comparison of Scenario PV1 and PV2 provides a sense of the possible weather-related variability in terms of the impact on demand on any winter day.

Figure 9-9 shows the adjusted winter demand profile (resulting from solar PV generation demand offsets) for Scenario PV1 and PV2:

- There is no impact on the winter peak due to the later winter MD (approximately 6:30 PM) and shorter days.
- There is an impact on demand in the morning.

Figure 9-9 — Adjusted winter demand profiles for solar PV generation impacts



9.4.3 Adjusted demand profiles for combined plug-in electric vehicle and solar PV generation impacts

Figure 9-10 and Figure 9-11 show the adjusted demand profiles for the combined plug-in electric vehicle and solar PV generation scenario impacts for summer and winter, respectively. These combinations are designed to indicate how demand may change as a result of the increased penetration of both technologies.

Based on the scenario assumptions:

- A best-case scenario comprises a summer combination of:
  - High solar PV generation with good sunlight (Scenario PV1).
  - High penetration of plug-in electric vehicles with some smart charging (Scenario EV2).

  This combination has the potential to reduce the level of the peak, reduce energy demand in the middle of the day, and increase demand overnight.
- A worst-case scenario comprises a summer combination of:
  - High solar PV generation penetration with poor sunlight (Scenario PV2).
  - High penetration of plug-in electric vehicles with no smart charging (Scenario EV1).

  In this case the peak increases and demand remains high well into the evening. The energy provided by solar PV generation is low, and at the time of the peak is not enough to compensate for the extra demand from plug-in electric vehicles.

Figure 9-11 shows that in winter the extra load from plug-in electric vehicles may lead to an increase in peak demand that is not offset by solar PV generation output.

Figure 9-10 — Adjusted summer demand profiles for combined plug-in electric vehicle and solar PV generation projection impacts

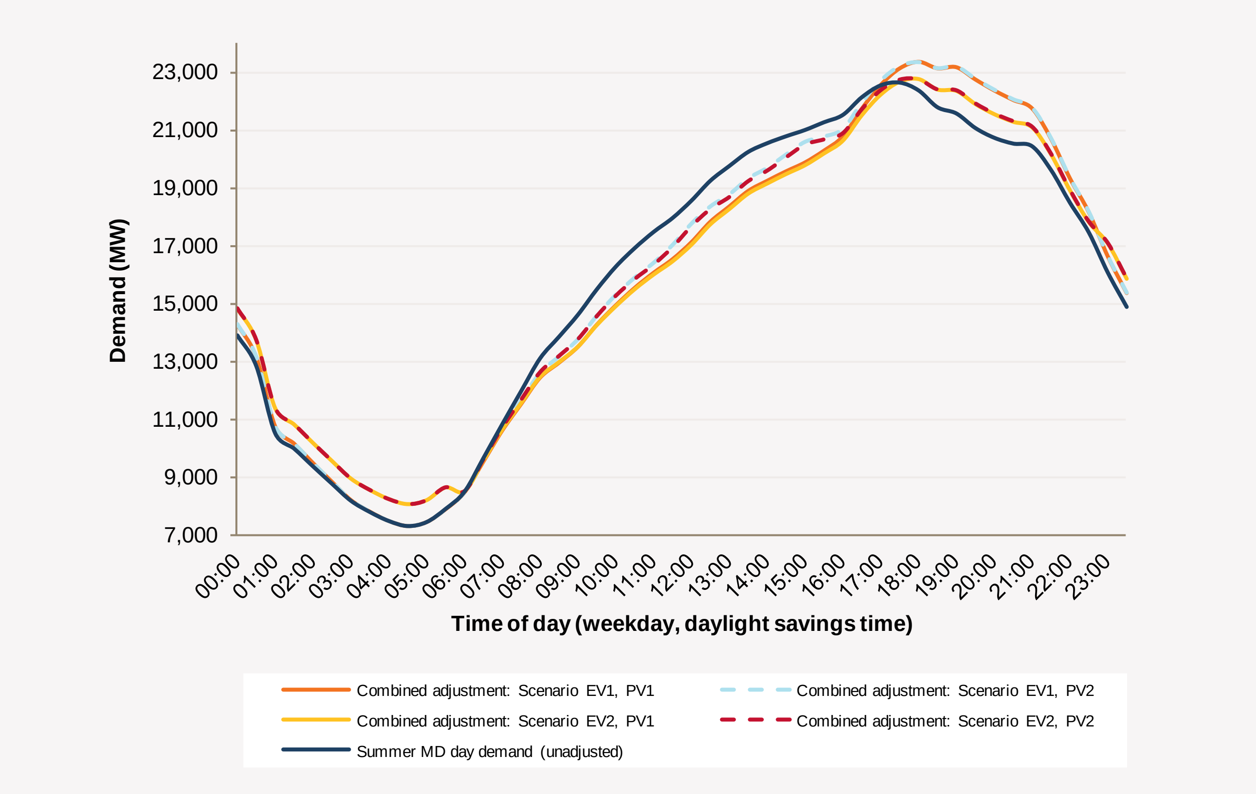


Figure 9-11 — Adjusted winter demand profiles for combined plug-in electric vehicle and solar PV generation projection impacts

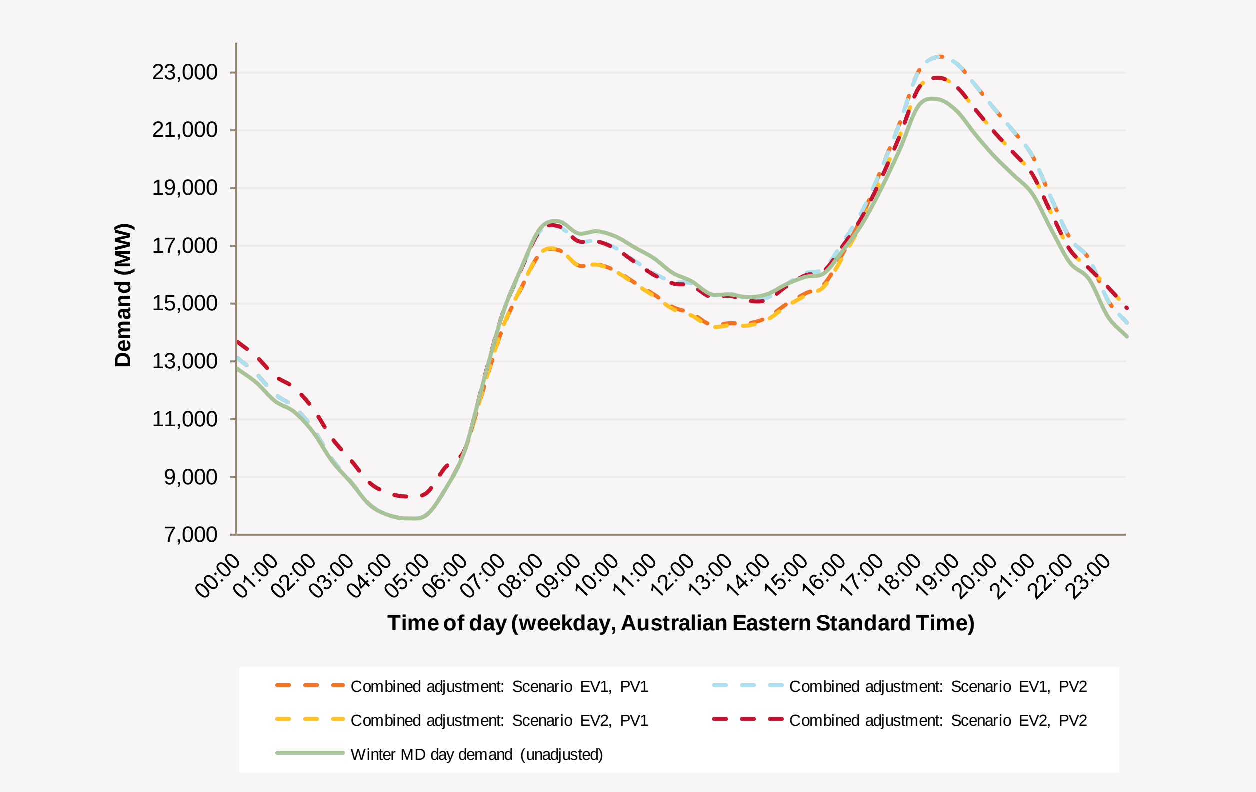


Table 9-4 summarises the main characteristics of the projection combinations from Figure 9-10 and Figure 9-11.

Table 9–4 — Electric vehicle and solar PV generation projection qualitative impacts on summer and winter maximum demand days

Scenario Combination	Electric Vehicle Assumptions	Solar PV Generation Assumptions	Summer MD Day Impact	Winter MD Day Impact
EV1, PV1	Uncontrolled charging.	High output.	Daytime energy decreased. MD increased and extended to 7:30 PM. Output does not entirely compensate for new EV load in the afternoon and evening.	Daytime energy decreased. Large increase to MD and no output at time of peak.
EV1, PV2	Uncontrolled charging.	Low output.	Daytime energy slightly decreased. MD increased and extended to 7:30 PM. Output does not entirely compensate for new EV load in the afternoon and evening.	Insignificant daytime energy decrease. Large increase to MD and no output at time of peak.
EV2, PV1	Some smart charging.	High output.	Daytime energy decreased, late night and early morning energy increased. MD increased slightly and shifted by half an hour.	Daytime energy decreased, late night/early morning energy increased. MD increased, with no output at time of peak.
EV2, PV2	Some smart charging.	Low output.	Daytime energy slightly decreased. Late night and early morning energy increased. MD increased slightly and less pronounced, and shifted by half an hour.	Insignificant daytime energy decrease. Late night/early morning energy increased. MD increased, with no output at time of peak.

9.4.4 Planning and policy implications

Plug-in electric vehicles

Plug-in electric vehicle loads have the potential to significantly increase the energy required on summer and winter evenings, when demand is already at its highest. Under Scenario EV1 in particular, the summer MD period is extended by approximately an hour, because more vehicles are being added to the load when some commercial and residential demand is normally decreasing.

To accommodate this increase in MD will require additional transmission and distribution network investment, with significant cost implications for electricity customers. The increased MD might also lead to additional high-price periods in the NEM, resulting in investment in new peaking generation.

Maximising the use of smart charging has the potential to avoid these costs, and several policy options for implementing smart charging exist, some of which are being reviewed by state governments[26] and through a current AEMC investigation.[27]

[26] See, for example, the Queensland Office of Climate Change issues paper “An Electric Vehicle Roadmap for Queensland”. Available http://www.climatechange.qld.gov.au/whatsbeingdone/queensland/pdf/ev-roadmap.pdf. Accessed 29 September 2011.

[27] AEMC. “Approach Paper: Energy Market Arrangements for Electric and Natural Gas Vehicles”. Available http://www.aemc.gov.au/Media/docs/Approach%20Paper-df092b78-2115-42f9-bb7a-eb31718b9cdb-0.PDF. Accessed 29 September 2011.

Methods to implement smart charging include the following:

- Financial incentives that encourage certain customer behaviour.
- Standards for charging points that program them to charge only at certain times.
- The remote control of charging points by either existing or new operators.

Some businesses planning supporting infrastructure for plug-in electric vehicle charging are also proposing to use plugged-in vehicles as a source of energy during demand peaks. This technology, sometimes referred to as Vehicle-to-Grid (V2G)[28], involves smart charging points that can draw power from vehicle batteries, with the potential to reduce network loading at peak times and reduce the need for network upgrades and peaking generation.

Although the technological and regulatory requirements to implement these initiatives are still in the early stages of development, the technology still provides an important example of a plug-in electric vehicle charging network's potential to provide more dynamic demand and supply characteristics.

Photovoltaics (solar PV generation)

Most planning for new transmission network infrastructure relies on demand forecasts at a sub-regional rather than a regional level, such as the Victorian Terminal Station Demand Forecast.[29] This is particularly relevant, given that a high concentration of solar PV generation in certain residential areas has the potential to lead to more pronounced load impacts than the scenarios examined. In terms of the planning and policy implications:

- Solar PV generation installations in particular parts of the distribution network will be of most benefit for delaying network investment when local demand matches solar PV generation patterns (commercial building loads being a good example of loads that closely match the solar PV generation output profile, particularly in the summer).
- Household solar PV generation installations may benefit from specific incentives to encourage the use of certain appliances during the day instead of the evening, and increasing the correlation between demand and output.

  Most states have implemented programs offering household installations a net tariff for power production.[30] These tariffs generally measure the system's net output (power produced minus power consumed) on a half-hourly basis, and pay the owner a premium for the output.

At low levels of adoption, the net tariff structure is unlikely to have much impact on network planning. However, as solar PV generation in certain areas increases, the opportunities to delay network investment through more strategic system design and demand-side participation from solar PV generation owners will increase. Options for achieving this include the following:

- Encouraging installations close to commercial loads with high daytime energy use.
- Encouraging more western orientation to facilitate higher afternoon output.
- Encouraging uptake in residential areas with mid-afternoon peaking characteristics.
- Targeted retail electricity contracts that reward consumption that matches demand.

Solar PV generation reduces the energy NEM generators must supply. The output during high-demand daytime periods has the potential to impact NEM spot prices and reduce overall sales volumes. These two factors provide important signals for some new generation investment, and solar PV generation may delay this investment if its adoption increases.

[28] V2G has not been modelled.

[29] Available http://www.aemo.com.au/planning/transmission.html. Accessed 23 September 2011.

[30] Feed-in tariffs in New South Wales and the Australian Capital Territory are gross tariffs that pay a premium for all PV generation produced. All other states have implemented net tariffs.

Combined outcomes

The planning and policy implications deriving from the analysis include the following:

- Scenarios with high solar PV generation capacity have the potential to delay the need for new base load generation investment.
- If electric plug-in vehicle demand increases peak loads, new peaking generation will be required to accommodate it. This will still be the case with high solar PV generation adoption, because its output may be variable at the time of the peak, due to the time of day or the amount of sunlight.
- Plug-in electric vehicle charging technologies that allow power to be drawn from vehicle batteries at peak times have the potential to accommodate some variability, potentially delaying the need for new peaking generation investment.
- The combined offset projections emphasise the importance of ensuring plug-in electric vehicle charging mechanisms are effectively managed, and provide strong incentives for vehicle owners not to charge at peak times.

9.4.5 Summary of demand projection impacts

Photovoltaics (solar PV generation)

AEMO's energy projections and planning documents are important inputs into investment decisions in the electricity industry. Solar PV generation output is currently accounted for in NEM market data as a reduction in demand (a demand offset), because the power being produced is not dispatched or sold through the NEM.

The energy output of solar PV generation systems does not represent a reduction in actual energy consumption, however, because that power is still being used at the point of generation or fed to the network.

Greater transparency, enabling stakeholders to better understand demand and solar PV generation projections will result from including an estimate of solar PV generation in AEMO's exempt and non-scheduled energy and MD projections.[31]

To effectively estimate solar PV generation production for the exempt and non-scheduled energy and MD projections, AEMO will undertake further modelling to develop assumptions about its output during times of peak demand and throughout the year.

[31] For the latest non-scheduled and exempt generation forecasts for the NEM, see the 2011 ESOO, Chapter 3, Section 3.8. Available http://www.aemo.com.au/planning/0410-0079.pdf. Accessed 23 September 2011.

Energy and MD projection development

One option for energy projection development includes modelling the annual output under typical climate conditions at locations in each region with the most solar PV generation capacity (using simulations like the one presented in Section 9.3). Developing these projections will require several assumptions:

- The capacity and location of solar PV generation systems in each region.
- The aggregate efficiency of these systems.
- The future (projected) solar PV generation capacity in each region.

There are several uncertainties associated with these assumptions:

- The number of installed systems is increasing rapidly, making it impossible to know the exact capacity of the installed systems at the time of modelling.
- Every system is installed differently, with different components, tilt, orientation, and shading. This means each system will have slightly different conversion efficiencies from sunlight to electricity at different times of the day.
- The sunlight conditions across a region are always changing. The distributed nature of the systems means it is impossible to determine what the sunlight conditions for each system will be at any given time.

Managing these uncertainties requires developing solar PV generation capacity best estimates for each region (based on installation data provided to AEMO by the Office of the Renewable Energy Regulator (ORER) and the distribution businesses).

Statistical analysis of actual output data will also allow the development of assumptions about the aggregate efficiency of installed systems, and their output under different weather conditions.

The variability of sunlight conditions introduces additional complexity in terms of incorporating solar PV generation output into the MD projections. One approach involves a similar methodology to determining wind energy contribution factors[32]:

- Analysing summer solar PV generation output in relevant locations from 5:00 PM onwards.
- Making a statistical approximation of the solar PV generation availability at the time of peak demand for different confidence intervals.

[32] For more information, see the 2011 ESOO, Chapter 8, Section 8.3.3. Available http://www.aemo.com.au/planning/0410-0079.pdf. Accessed 23 September 2011.

GLOSSARY

Definitions

Many of the listed terms are already defined in the National Electricity Rules (NER), version 45[1]. For ease of reference, these terms are highlighted in blue. Some terms, although defined in the NER, have been clarified, and these terms are highlighted in green.

Term	Definition
active power	See electrical power.
advanced proposal	A proposed generation project that meets at least three and shows progress on two of the five criteria specified by AEMO for a committed project – generation. See also 'proposed project' and 'publicly announced proposal'.
allocated installed capacity	The generation capacity allocated to a region when assessing the reliability of supply. Allocated installed capacity is equal to the scheduled generation and semi-scheduled generation capacity within a region plus the allocated net import from neighbouring regions. See also 'capacity for reliability'.
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.
annualised cost	The cost per year of owning and operating an asset over its entire lifespan.
annual planning report	An annual report providing forecasts of gas or electricity (or both) supply, capacity, and demand, and other planning information.
as-generated	A measure of demand or energy (in megawatts (MW) and megawatt hours (MWh), respectively) at the terminals of a generating system. This measure includes consumer load, transmission and distribution losses, and generator auxiliary loads.
augmentation	The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline.
Australian Wind Energy Forecasting System (AWEFS)	A system used by AEMO to produce wind generation forecasts ranging from five minutes ahead to two years ahead.
automatic access standard	In relation to a technical requirement of access, a standard of performance, identified in a schedule of Chapter 5 (of the NER) as an automatic access standard for that technical requirement, such that a plant that meets that standard would not be denied access because of that technical requirement. (See also minimum access standard and negotiated access standard.)
back assessment	The comparison of old maximum demand (MD) projections with actual (historical) MD values.

[1] An electronic copy of the latest version of the NER can be obtained from http://www.aemc.gov.au/rules.php

Term	Definition
backcasting	Backcasting involves 'forecasting' historical maximum demands (MDs), and applies the current forecasting model to project values of seasonal MD that have already occurred (but were not used to derive the model). Backcasting takes actual economic and climatic conditions and temperatures into account to produce a single point MD projection for each season for comparison with the actual (historical) seasonal MDs.
Base load generating system	A generating system designed to run almost constantly at near maximum capacity levels, usually at lower cost than intermediate or peaking generating systems.
capacitive reactance	The component of a circuit element's impedance that is due to the establishment of an electric field. Current through the capacitive component is proportional to the differential of the voltage across that component. See also 'reactive power'.
capacity factor	The output of generating units or systems, averaged over time, expressed as a percentage of rated or maximum output.
capacity for reliability	The allocated installed capacity required to meet a region's minimum reserve level (MRL). When met, sufficient supplies are available to the region to meet the Reliability Standard. Capacity for reliability = 10% Probability of Exceedence (POE) scheduled and semi-scheduled maximum demand + minimum reserve level – committed demand-side participation.
capacity limited	A generating unit whose power output is limited.
capital deferral benefit	A benefit deriving from the reduced capital costs resulting from being able to reduce (or defer) generation or transmission investment.
causer-pays methodology	A methodology used to allocate frequency control ancillary service (FCAS) costs. See also 'frequency control ancillary services (FCAS)'.
central dispatch	The process managed by AEMO for the dispatch of scheduled generating units, semi-scheduled generating units, scheduled loads, scheduled network services and market ancillary services in accordance with Rule 3.8.
cleared supply	An estimate of the expected demand at the end of a dispatch interval. Calculated at the start of the dispatch interval, it is the sum of the following: • Generating unit dispatch targets within a region. • Net interconnector dispatch targets into a region.
coincidence factor	An expression of the degree of historical coincidence of the maximum demands (MDs) within different regions in the National Electricity Market (NEM), or between regional MDs and the NEM-wide MD.
committed project	A committed project is any new generation development or non-regulated transmission development that meets all five criteria specified by the AEMO for a committed project – generation (see Chapter 4 of the Electricity Statement of Opportunities (ESOO) for more information).
compound average growth rate	The year-over-year growth rate over a specified period of time.
conceptual augmentation	A proposed transmission network augmentation option that could provide market benefits (possibly including Reliability Benefits). Conceptual augmentations may or may not be built in the future. The timing and value of these projects depends on the development of the electricity market. Conceptual augmentations do not satisfy the criteria for a committed project. See also 'committed project'.
connection asset	The electricity transmission or distribution network components used to provide connection services (for example, 220/66 kV transformers).

Term	Definition
connection point (electricity)	The agreed point of supply established between network service provider(s) and another registered participant, non-reregistered customer or franchise customer.
constrained	A limitation on the capability of a network, load, or a generating unit such that it is unacceptable to either transfer, consume or generate the level of electrical power that would occur if the limitation was removed.
connection asset constraint	A constraint applying to an asset connecting the electricity transmission network to the distribution network.
constraint equation	The mathematical expression of a physical system limitation or requirement that must be considered by the central dispatch algorithm when determining the optimum economic dispatch outcome. See also ' 'FCAS constraint equation', 'invoked constraint equation', and 'network constraint equation'.
constraint equation violation	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.
consumer	See customer.
contingency event	An event affecting the power system, such as the failure or unplanned removal from operational service of a generating unit or transmission network element.
contingency services	Services provided by registered participants that enable the maintenance or restoration of power system security, or both. This includes, for example, actual active and reactive power capacities, which can be made available and used when a contingency event occurs.
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.
customer (electricity)	A person who engages in the activity of purchasing electricity supplied through a transmission or distribution system to a connection point.
damping torque	A stabilising force applied to the rotor of a generating unit, via the operation of excitation system controls and the electrical network that quickly reduces electrical power oscillations
demand	See electricity demand.
demand diversity	Refers 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. • '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 response aggregator (DRA)	An organisation contracted to facilitate and administer the provision of demand-side responses.
demand-side management	The act of administering electricity demand-side participants (possibly through a demand-side response aggregator).

Term	Definition
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.
demand-side response aggregator	An organisation or agency for the provision and administration of electricity demand-side responses/participation.
discount rate	The rate used to discount future cash flows to the present value.
discovered petroleum initially-in-place	The quantity of petroleum estimated, at a given date, contained in known accumulations prior to production.
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)'.
dispatch instruction	An instruction issued by AEMO: • to implement central dispatch, or • where AEMO has the power to give a direction.
dispatch interval	A period of five minutes.
dispatch targets	A particular dispatch interval's specified generating unit output and interconnector power flow targets.
dispatched load	The load which has been dispatched as part of central dispatch.
distribution losses	Electrical energy losses incurred in distributing electricity over a distribution network.
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.
diversity	The lack of coincidence of peak demand across several sources of demand, such as residential, industrial, and gas powered generation.
diversity factor	Refers to the ratio of the NEM maximum demand to the sum of maximum demands in each NEM region. This is sometimes referred to as the demand factor, and is always less than one. See also 'demand diversity'.
economic demonstrated resources (EDR)	A mineral resource that demonstrates the following: • Tonnage, grade, and mineral content can be estimated with a high level of confidence, based on verified geological evidence. • Profitable extraction or production has been analytically demonstrated, or assumed with reasonable certainty.
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	Definition
electricity demand	The electrical power requirement met by generating units. The Electricity Statement of Opportunities (ESOO) reports demand on a generator-terminal basis, which includes the following: • The electrical power consumed by the consumer load. • Distribution and transmission losses. • Power station transformer losses and auxiliary loads. The ESOO reports demand as half-hourly averages.
embedded generating unit	A generating unit connected within a distribution network and not having direct access to the transmission network.
embedded generator	A generator who owns, operates or controls an embedded generating unit.
energy	See 'electrical energy'.
Energy Adequacy Assessment Projection (EAAP)	A quarterly report, produced by AEMO, of projected energy availability for each region over a 24-month period for three different rainfall scenarios. The EAAP reports the impact of the projected energy availabilities on regional electrical supply reliability in terms of long-term unserved energy (USE).
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.
estimated ultimate recovery (EUR)	A term applied to any discovered or undiscovered petroleum accumulations to define potentially recoverable quantities under defined technical and commercial conditions. This includes quantities already produced (total of recoverable resources).
ex-ante	Before the event.
exempted generator	A generator exempted from the requirement to register in accordance with clause 2.2.1 of the NER, and in accordance with the Australian Energy Market Operator's (AEMO) Generator Registration Guide.
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)'.
fault clearing control scheme	A protection system designed to isolate an electrical fault of a defined type within a particular area (referred to as a protection zone).
first-tier load	Electricity purchased at a connection point directly and in its entirety from the local retailer and which is classified as a first-tier load in accordance with Chapter 2 (of the NER).
flow path	Those elements of the electricity transmission networks used to transport significant amounts of electricity between generation centres and major load centres.
forced outage	An unplanned outage of an electricity transmission network element (transmission line, transformer, generator, reactive plant, etc).
franchise customer	A person who does not meet its local jurisdiction requirements to make it eligible to be registered by AEMO as a customer for a load.
frequency control ancillary services (FCAS)	Those ancillary services concerned with balancing, over short intervals (shorter than the dispatch interval), the power supplied by generating units and the power consumed by loads. This imbalance is managed by monitoring the power system frequency.

Term	Definition
front-end engineering and design (FEED)	An engineering process commonly undertaken to determine the engineering parameters of a construction or development, in terms of engineering design, route selection, regulatory and financial viability assessments, and environmental and native title clearance processes.
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 that includes auxiliary or reactive plant that is located on the generator's side of the connection point.
generating unit	The actual generator of electricity and all the related equipment essential to its functioning as a single entity.
generation	The production of electrical power by converting another form of energy in a generating unit.
generation capacity	The amount (in megawatts (MW)) of electricity that a generating unit can produce under nominated conditions. The capacity of a generating unit may vary due to a range of factors. For example, the capacity of many thermal generating units is higher in winter than in summer.
generation centre	A geographically concentrated area containing a generating unit or generating units with significant combined generating capability.
generation expansion plan	A plan developed using a special algorithm that models the extent of new entry generation development based on certain economic assumptions.
generator	A person who engages in the activity of owning, controlling or operating a generating system that is connected to, or who otherwise supplies electricity to, a transmission or distribution system and who is registered by AEMO as a generator under Chapter 2 (of the NER) and, for the purposes of Chapter 5 (of the NER), the term includes a person who is required to, or intends to register in that capacity.
generator auxiliary load	Load used to run a power station, including supplies to operate a coal mine (otherwise known as 'used in station load').
generator-terminal basis	A measure of demand at the terminals of a generating unit. This measure covers the entire output of the generating unit (in megawatts (MW)): • Consumer load. • Transmission and distribution losses. • Generating unit auxiliary load. • Generator transformer losses.
gen-tailer	A business with both generation and retail portfolios.
greenfield	Land (as a potential industrial site) not previously developed or polluted.
inductive reactance	The component of a circuit element's impedance that is due to the establishment of a magnetic field. Current through the inductive component is proportional to the integral of the voltage across that component. See also 'reactive power'.
inferred resources	A mineral resource for which tonnage, grade, and mineral content can be estimated with a low level of confidence, and that is inferred from geological evidence.
installed capacity	Refers to generating capacity (in megawatts (MW)) in the following context: • A single generating unit. • A number of generating units of a particular type or in a particular area. • All of the generating units in a region.
instantaneous penetration	Refers to the ratio of wind generation to demand plus exports. This provides a measure of wind generation's contribution to meeting total demand.

Term	Definition
interconnector	A transmission line or group of transmission lines that connects the transmission networks in adjacent regions.
interconnector flow	The quantity of electricity in MW being transmitted by an interconnector.
interconnector power transfer capability	The power transfer capability (in megawatts (MW)) of a transmission network connecting two regions to transfer electricity between those regions.
intermediate generating system	A generating system that adjusts its output as demand for electricity fluctuates throughout the day. These systems are typically in-between base load and peaking generation in terms of efficiency, speed of start-up and shutdown, construction cost, cost of electricity, and capacity factor.
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.
initial reserves	Total discovered reserves at a given date, without taking into account the depletion of reserves due to production.
invoked constraint equation	A constraint equation that is active in central dispatch, and can influence the dispatch outcome.
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) as follows: • Queensland – Powerlink Queensland. • New South Wales – TransGrid. • Victoria – AEMO. • South Australia – ElectraNet. • Tasmania – Transend Networks.
Lack of Reserve (LOR) notice/Low Reserve Condition (LRC) notice	A notice to registered participants advising when reserves are projected to be or are below critical levels. See also 'Lack of Reserve 1 (LOR1)', 'Lack of Reserve 2 (LOR2)', 'Lack of Reserve 3 (LOR3)' and 'low reserve condition (LRC)'.
Lack of Reserve 1 (LOR1)	When, for the nominated period, AEMO considers there are insufficient short-term capacity reserves available. This capacity must be sufficient to provide complete replacement of the contingency capacity reserve when a critical single credible contingency event occurs in the nominated period.
Lack of Reserve 2 (LOR2)	When AEMO considers that the occurrence of a critical single credible contingency event is likely to require involuntary load shedding.
Lack of Reserve 3 (LOR3)	When AEMO considers that customer load (other than ancillary services or contracted interruptible loads) would be, or is actually being, interrupted automatically or manually in order to maintain or restore the security of the power system.
Large-scale Renewable Energy Target (LRET)	See 'national Renewable Energy Target scheme'.
limitation (electricity)	Any limitation on the operation of the transmission system that will give rise to unserved energy (USE) or to generation re-dispatch costs.
limitation value estimate	An electricity transmission network limitation's expected cost to the community, weighted by the probability of a contingency event occurring. This cost comprises load shedding and generation rescheduling (for example increased fuel cost).
liquid fuelled generation	Generation that utilises liquid fuel (usually in the form of distillate, kerosene or fuel oil) as its primary fuel source.
Liquefied Natural Gas	Natural gas that has been converted to liquid form for ease of storage or transport. The Melbourne LNG storage facility is located at Dandenong.

Term	Definition
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.
local network service provider	Within a local area, a network service provider to which that geographical area has been allocated by the authority responsible for administering the jurisdictional electricity legislation in the relevant participating jurisdiction.
local retailer	In relation to a local area, the customer who is: • a business unit or related body corporate of the relevant local network service provider, or • responsible under the laws of the relevant participating jurisdiction for the supply of electricity to franchise customers in that local area, or • if neither 1 or 2 is applicable, such other customer as AEMO may determine.
long-run marginal cost (LRMC)	A generator's long-run marginal cost (LRMC) describes the revenue required to exactly cover financing costs, and the fixed and variable operating and maintenance costs of the investment over the generating system's lifetime.
loss factor	A multiplier used to describe the electrical energy loss for electricity used or transmitted.
low reserve condition (LRC)	When the AEMO considers that a region's reserve margin (calculated under 10% probability of exceedence (POE) scheduled and semi-scheduled maximum demand (MD) conditions) for the period being assessed is below the minimum reserve level (MRL).
Mandatory Renewable Energy Target (MRET)	See 'national Renewable Energy Target scheme'.
marginal loss factor (MLF)	A multiplier used to describe the marginal electrical energy loss for electricity used or transmitted.
market	Any of the markets or exchanges described in the NER, for so long as the market or exchange is conducted by AEMO.
market ancillary services	The ancillary services required by AEMO as part of the spot market, which include the services listed in clause 3.11.2(a) of the NER. The prices of market ancillary services are established using the central dispatch process.
market customer (electricity)	A customer who has classified any of its loads as a market load and who is also registered by AEMO as a market customer under Chapter 2 (of the NER).
market generating unit	A generating unit whose sent-out generation is not purchased in its entirety by the local retailer or by a customer located at the same connection point and which has been classified as such in accordance with Chapter 2 (of the NER).
market generator	A generator who has classified at least one generating unit as a market generating unit in accordance with Chapter 2 (of the NER) and who is also registered by AEMO as a market generator under Chapter 2 (of the NER).
market load	A load that is settled through the spot market, and may also be classified as a scheduled load. Customers submit bids in relation to market loads to purchase electricity through the central dispatch process. They must be controllable according to dispatch instructions issued by AEMO.
market network service provider (MNSP)	A network service provider who has classified any of its network services as a market network service in accordance with Chapter 2 (of the NER) and who is also registered by AEMO as a market network service provider under Chapter 2 (of the NER).

Term	Definition
market non-scheduled (MNS) generating unit	A generating unit with the following characteristics: • Sells energy into the energy spot market. • Is not scheduled by AEMO as part of central dispatch. • Has been classified as an MNS generating unit in accordance with Chapter 2 of the NER.
market scheduled (MS) generating unit	A generating unit with the following characteristics: • Sells energy into the energy spot market. • Is scheduled by AEMO as part of central dispatch. • Has been classified as an MS generating unit in accordance with Chapter 2 of the NER.
market participant (electricity)	A person who is registered by AEMO as a market generator, market customer or market network service provider under Chapter 2 (of the NER).
market price cap (MPC)	A price cap on regional reference prices as described in clause 3.9.4 (of the NER).
maximum daily quantity	Maximum daily quantity of gas supply or demand.
maximum demand (MD)	The highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, or year) either at a connection point, or simultaneously at a defined set of connection points.
Medium-term Projected Assessment of System Adequacy (Medium-term PASA or MT PASA)	The Projected Assessment of System Adequacy in respect of the period from the eighth day after the current trading day to 24 months after the current trading day in accordance with clause 3.7.2 (of the NER).
meter	A device that measures and records volumes and/or quantities of electricity or gas.
metering	The act of recording electricity and gas data (such as volume, peak, quality parameters etc) for the purpose of billing or monitoring quality of supply etc.
metering data	The data obtained from a metering installation, including energy data.
minimum access standard	In relation to a technical requirement of access, a standard of performance, identified in a schedule of Chapter 5 (of the NER) as a minimum access standard for that technical requirement, such that a plant that does not meet that standard will be denied access because of that technical requirement. (See also automatic access standard and negotiated access standard.)
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.
National Electricity Law	The National Electricity Law (NEL) is a schedule to the National Electricity (South Australia) Act 1996, which is applied in other participating jurisdictions by application acts. The NEL sets out some of the key high-level elements of the electricity regulatory framework, such as the functions and powers of NEM institutions, including AEMO, the AEMC, and the AER.
National Electricity Market (NEM)	The wholesale exchange of electricity operated by AEMO under the NER.
National Electricity Market Dispatch Engine (NEMDE)	The software that calculates the optimum economic dispatch of the 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.

Term	Definition
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 the following: • Price, quality, safety, reliability and security of supply of electricity. • The reliability, safety and security of the national electricity system. This is defined in Section 7 of the National Electricity Law (NEL).
National Electricity Rules (NER)	The National Electricity Rules (NER) describes the day-to-day operations of the NEM and the framework for network regulations. See also 'National Electricity Law'.
National Gas Law	The National Electricity Law and National Electricity Rules and the National Gas Law and National Gas Rules bring electricity and gas distribution under a national framework administered by the Australian Energy Regulator (AER).
National Gas Objective (NGO)	To promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.
National Gas Rules (NGR)	See National Gas Law.
national Renewable Energy Target scheme	The national Renewable Energy Target (RET) scheme, which commenced in January 2010, aims to meet a renewable energy target of 20% by 2020. Like its predecessor, the Mandatory Renewable Energy Target (MRET), the national RET scheme requires electricity retailers to source a proportion of their electricity from renewable sources developed after 1997. The national RET scheme is currently structured in two parts: • Small-scale Renewable Energy Scheme (SRES), which is a fixed price, unlimited-quantity scheme available only to small-scale technologies (such as solar water heating) and is being implemented via Small-scale Technology Certificates (STC). • Large-scale Renewable Energy Target (LRET), which is being implemented via Large-scale Generation Certificates (LGC), and targets 41,000 GWh of renewable energy by 2020.
National Transmission Network Development Plan (NTNDP)	An annual report to be produced by AEMO that replaces the existing National Transmission Statement (NTS) from December 2010. Having a 20-year outlook, the NTNDP will identify transmission and generation development opportunities for a range of market development scenarios, consistent with addressing reliability needs and maximising net market benefits, while appropriately considering non-network options.
National Transmission Statement (NTS)	An AEMO report replacing the Annual National Transmission Statement (ANTS) for 2009 only. The National Transmission Network Development Plan (NTNDP) replaced the NTS in December 2010.
negotiated access standard	In relation to a technical requirement of access for a particular plant, an agreed standard of performance determined in accordance with clause 5.3.4A (of the NER) and identified as a negotiated access standard for that technical requirement in a connection agreement. See also 'minimum access standard' and 'automatic access standard'.

Term	Definition
net import limit	Net import limits: • Are equal to the assumed net regional imports arising from the minimum reserve level (MRL) calculations. • Are necessary to ensure consistency between the calculation of MRLs and the assessment of reserve margins (as MRLs need to be met without violating the net import limits). • Only used in the Medium-term Projected Assessment of System Adequacy (Medium-term PASA or MT PASA), Short-term Projected Assessment of System Adequacy (Short-term PASA or ST PASA), and the supply-demand outlook. The net import limits are not included in central dispatch and do not limit actual interconnector power flows.
net market benefit	Refers to market benefits of an augmentation option minus the augmentation cost. The market benefit of an augmentation is defined in the regulatory investment test for transmission developed by the Australian Energy Regulator.
net regional import	The total interconnector flow into a region minus the interconnector flow out of a region.
network	The apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity to customers (whether wholesale or retail) excluding any connection assets. In relation to a network service provider, a network owned, operated or controlled by that network service provider.
network capability	The capability of the network or part of the network to transfer electricity from one location to another.
network congestion	When a transmission network cannot accommodate the dispatch of the least-cost combination of available generation to meet demand.
network constraint equation	A constraint equation deriving from a network limit equation. Network constraint equations mathematically describe transmission network technical capabilities in a form suitable for consideration in the central dispatch process. See also ‘constraint equation’.
network control ancillary service	A service identified in clause 3.11.4(a) (of the NER) which provides AEMO with a capability to control the real or reactive power flow into or out of a transmission network in order to: • maintain the transmission network within its current, voltage or stability limits following a credible contingency event, or • enhance the value of spot market trading in conjunction with 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’.
network limitation	Describes network limits that cause frequently binding network constraint equations, and can represent major sources of network congestion. See also ‘network congestion’.

Term	Definition
network limit equation	Describes the capability to transmit power through a particular portion of the network as a function of the following: • Generating unit outputs. • Interconnector flows. • Transmission equipment ratings. • Demand at one or more connection points. • equipment status or operating mode. The set of all network limit equations fully describes a network's capability. AEMO translates network limit equations into network constraint equations for use in the central dispatch process. See also 'constraint equation'.
network service	Transmission service or distribution service associated with the conveyance, and controlling the conveyance, of electricity through the network.
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 (NSA)	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.
non-coincident peak day demand	A given customer's (or group of customers') gas demand peak day. This does not necessarily occur at the same time as the system demand peak day.
non-contestable augmentation	Electricity transmission network augmentations that are not considered to be economically or practically classified as contestable augmentations.
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-market ancillary services	Network control ancillary services (NCAS), reactive power ancillary services (RPAS) and system restart ancillary services (SRAS). These services are delivered under agreements entered into with AEMO following a call for offers made in accordance with clause 3.11 (of the NER).
non-market generating unit	A generating unit whose sent out generation is purchased in its entirety by the local retailer or by a customer located at the same connection point and which has been classified as such in accordance with Chapter 2 (of the NER).
non-market generator	A generator who has classified a generating unit as a non-market generating unit in accordance with Chapter 2 (of the NER).
non-market non-scheduled (NMNS) generating unit	A generating unit with the following characteristics: • Sells its entire output directly to a local retailer or customer at the same connection point under a power purchase agreement (not through the spot market). • Is not scheduled by AEMO as part of central dispatch. • Has been classified as an NMNS generating unit in accordance with Chapter 2 (of the NER).
non-market scheduled (NMS) generating unit	A generating unit with the following characteristics: • Sells its entire output directly to a local retailer or customer at the same connection point under a power purchase agreement (not through the spot market). • Is scheduled by AEMO as part of central dispatch. • Has been classified as an NMS generating unit in accordance with Chapter 2 (of the NER).

Term	Definition
non-network option	An option intended to relieve a limitation without modifying or installing network elements. Typically, non-network options involve demand-side participation (DSP) (including post contingent load relief) and new generation on the load side of the limitation.
non-registered customer	A person who: • purchases electricity through a connection point with the national grid other than from the spot market, and • is eligible to be registered by AEMO as a customer and to classify the load described in (1) as a first-tier load or a second-tier load, but is not so registered.
non-scheduled generating system	A generating system comprising non-scheduled generating units.
non-scheduled generating unit	A generating unit that is not scheduled by AEMO as part of the central dispatch process, and which has been classified as such in accordance with Chapter 2 (of the NER).
non-scheduled generator	A generator in respect of which any generating unit is classified as a non-scheduled generating unit in accordance with Chapter 2 (of the NER).
normalised wind trace	Used in market stimulations to determine the maximum available wind farm generation capacity for each dispatch interval. Normalised wind traces were developed using two imputs: • Wind speed data from the Australian Bureau of Meteorology to produce wind speed traces. • Wind farm turbine characteristics (power curves) to convert wind speed traces into wind generation output availability traces.
operating cost benefit	A benefit deriving from reduced fuel, operating and maintenance costs, indicating reduced operating costs.
operational demand	That part of the electricity demand supplied by scheduled, semi-scheduled, and significant non-scheduled generating units. The significant non-scheduled generating units included in the definition of operational demand are: • Cullerin Range Wind Farm (New South Wales). • Capital Wind Farm (New South Wales). • Yambuk Wind Farm (Victoria). • Portland Wind Farm (Victoria). • Challicum Hills Wind Farm (Victoria). • Waubra Wind Farm (Victoria). • Mount Millar Wind Farm (South Australia). • Cathedral Rocks Wind Farm (South Australia). • Starfish Hill Wind Farm (South Australia). • Wattle Point Wind Farm (South Australia). • Canunda Wind Farm (South Australia). • Lake Bonney Wind Farm (South Australia). • Woolnorth Wind Farm (Tasmania).
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'.
over voltage	A condition when the operating voltage of network components is above their nominated operation limit.
overload capacity	A measure of a generating unit's ability to generate more electricity than its registered capacity for a given period of time.
own price elasticity	The proportional change in electrical energy consumption in response to a proportional change in retail electricity price.
participant	A person registered with AEMO in accordance with the NGR (Victorian gas industry).

Term	Definition
peaking generating system	A generating system that typically runs only when demand (and spot market price) is high. These systems usually have lower efficiency, higher operating costs, and very fast start up and shutdown times compared with base load and intermediate systems.
petajoule	Petajoule (PJ), SI unit, 1 PJ equals $1x10^{15}$ Joules. Also PJ/yr or petajoules per year.
pipeline	A pipe or system of pipes for or incidental to the conveyance of gas and includes a part of such a pipe or system.
pipeline injections	The injection of gas into a pipeline.
pipeline throughput	The amount of gas that is transported through a pipeline.
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.
possible reserves (3P reserves)	Estimated quantities which have a chance of being discovered under favourable circumstances.
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).
post-contingent	The timeframe after a power system contingency occurs.
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.
price elasticity of demand	A measure of the proportional change in demand (for a commodity) in response to a proportional change in price.
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.

Term	Definition
probable reserves (2P reserves)	The estimated quantities of petroleum, which with a reasonable probability of being produced under existing economic and operating conditions.
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.
proposed project	All generation project proposals that have come to the Australian Energy Market Operator's (AEMO) attention and are not committed. Proposed projects are further classified as either advanced proposals or publicly announced proposals.
prospective resources	Quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations through future development projects.
proved reserves (1P reserves)	The estimated quantities of petroleum resources, which with a reasonable level of certainty are recoverable in future years from known reservoirs under existing economic and operating conditions.
publicly announced proposal	A proposed generation project that has come to the Australian Energy Market Operator's (AEMO) attention, but cannot be classified as an advanced proposal.
range of uncertainty	A range of estimated quantities potentially recoverable from an accumulation by a project.
ratings	Describes an aspect of a network element's operating parameters, including categories like current-carrying capability, maximum voltage rating, and maximum fault level interrupting and withstand capability. Network elements must always be operated within their ratings. Network elements may have ratings that depend on time duration (such as short-term current-carrying capacity).
reactive energy	A measure, in varhour-(varh), of the alternating exchange of stored energy in inductors and capacitors, which is the time-integral of the product of voltage and the out-of-phase component of current flow across a connection point.
reactive power	The rate at which reactive energy is transferred. Reactive power, which is different to active power, is a necessary component of alternating current electricity. In large power systems it is measured in MVAr (1,000,000 volt-amperes reactive). It is predominantly consumed in the creation of magnetic fields in motors and transformers and produced by plant such as: • alternating current generators • capacitors, including the capacitive effect of parallel transmission wires, and • synchronous condensers. Management of reactive power is necessary to ensure network voltage levels remain within required limits, which is in turn essential for maintaining power system security and reliability.
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.

Term	Definition
registered capacity	In relation to a generating unit, the nominal megawatt (MW) capacity of the generating unit registered with AEMO.
registered participant	A person who is registered by AEMO in any one or more of the categories listed in clauses 2.2 to 2.7 (of the NER) (in the case of a person who is registered by AEMO as a trader, such a person is only a registered participant for the purposes referred to in clause 2.5A (of the NER)). However, as set out in clause 8.2.1(a1) (of the NER), for the purposes of some provisions of clause 8.2 (of the NER) only, AEMO and connection applicants who are not otherwise registered participants are also deemed to be registered participants.
regulated interconnector	An interconnector which is referred to in clause 11.8.2 (of the NER) and is subject to transmission service regulation and pricing arrangements in Chapter 6A (of the NER).
regulatory investment test for transmission (RIT-T)	The test developed and published by the AER in accordance with clause 5.6.5B, as in force from time to time, and includes amendments made in accordance with clause 5.6.5B.
Regulatory Test	The test promulgated by the 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. After 1 August 2010, projects are assessed under the RIT-T (subject to transitional arrangements).
reliability	The probability that plant, equipment, a system, or a device, will perform adequately for the period of time intended, under the operating conditions encountered. Also, the expression of a recognised degree of confidence in the certainty of an event or action occurring when expected.
Reliability and Emergency Reserve Trader (RERT)	The actions taken by AEMO in accordance with clause 3.20 (of the NER) to ensure reliability of supply by negotiating and entering into contracts to secure the availability of reserves under reserve contracts. These actions may be taken when: • reserve margins are forecast to fall below minimum reserve levels (MRLs), and • a market response appears unlikely.
reliability benefit	A benefit deriving from improved customer reliability as measured by reduced unserved energy (USE). See also 'unserved energy (USE)'.
Reliability Panel	The panel established by the AEMC under section 38 of the National Electricity Law.
reliability of supply	The likelihood of having sufficient capacity (generation or demand-side participation (DSP)) to meet demand. See also 'electricity demand'.
Reliability Standard	The power system reliability benchmark set by the Reliability Panel. The maximum permissible unserved energy (USE), or the maximum allowable level of electricity at risk of not being supplied to consumers, due to insufficient generation, bulk transmission or demand-side participation (DSP) capacity, is 0.002% of the annual energy consumption for the associated region, or regions, per financial year.
remaining reserves	Reserves at a given date, taking into account the depletion of reserves due to production.
Renewable Energy Target (RET)	See 'national Renewable Energy Target scheme'.
reserve	See 'reserve margin'.

Term	Definition
reserve deficit	The amount by which a region's reserve margin falls below its (specified) minimum reserve level (MRL).
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.
reserves	Quantities of resource anticipated to be commercially recoverable from known accumulations from a given date under defined conditions.
retailer	Those selling the bundled product of energy services to the customer.
routine augmentation	Transmission augmentations that do not meet the criterion for committed projects, but that are likely to proceed, being routine in nature.
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.
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).
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).
scheduled energy	The electrical energy requirement supplied by scheduled generating units. Scheduled energy is measured on a sent-out basis. For a region, the measure includes the output of scheduled generating units within the region plus net imports (imports into the region minus exports from the region).
scheduled generating unit	A generating unit that: • has its output controlled through the central dispatch process, and • is classified as a scheduled generating unit in accordance with Chapter 2 of the NER.
scheduled generator	A generator in respect of which any generating unit is classified as a scheduled generating unit in accordance with Chapter 2 (of the NER).
scheduled load	A market load which has been classified by AEMO in accordance with Chapter 2 (of the NER) as a scheduled load at the market customer's request. Under Chapter 3 (of the NER), a market customer may submit dispatch bids in relation to scheduled loads. For the purposes of Chapter 3 (of the NER) and rule 4.9, two or more scheduled loads referred to in paragraph (a) that have been aggregated in accordance with clause 3.8.3 (of the NER).

Term	Definition
scheduled network service	A network service which is classified as a scheduled network service in accordance with Chapter 2 (of the NER). For the purposes of Chapter 3 (of the NER) and rule 4.9, two or more scheduled network services referred to in paragraph (a) that have been aggregated in accordance with clause 3.8.3 (of the NER).
scheduling	The process of scheduling nominations and increment/decrement offers, which AEMO is required to carry out in accordance with the NGR, for the purpose of balancing gas flows in the transmission system and maintaining the security of the transmission system.
second-tier load	Electricity purchased at a connection point in its entirety other than directly from the local retailer or the spot market and which is classified as a second-tier load in accordance with Chapter 2 (of the NER).
secure operating state	Operation of the electricity transmission network such that should a credible contingency occur, the network will remain in a 'satisfactory' state. See also 'satisfactory operating state'.
semi-scheduled demand	That part of the electricity demand supplied by semi-scheduled generating units. Semi-scheduled demand is measured on a generator-terminal basis. For a region, the measure includes the output of semi-scheduled generating units within the region.
semi-scheduled energy	The electrical energy requirement supplied by semi-scheduled generating units. Semi-scheduled energy is measured on a sent-out basis. For a region, the measure includes the output of semi-scheduled generating units within the region.
semi-scheduled generating system	A generating system comprising semi-scheduled generating units.
semi-scheduled generating unit	A generating unit: • with intermittent output • with a total capacity of 30 megawatts (MW) or greater, and • that may have its output limited to prevent the violation of network constraint equations.
semi-scheduled generator	A generator in respect of which any generating unit is classified as a semi-scheduled generating unit in accordance with Chapter 2 (of the NER).
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.
settlements residue	Any surplus or deficit of funds retained by AEMO upon completion of settlements to all market participants in respect of a trading interval.
settlements residue auction (SRA)	Auctions run by AEMO to sell the rights to the settlements residue associated with inter-regional transfers. Only certain classifications of participants may participate in the auctions. Participants may use the settlements residue for hedging and underwriting inter-regional trading in electricity.
short run marginal cost (SRMC)	The increase in costs for an incremental increase in output. This includes the additional cost of fuel required, and non-fuel variable costs like maintenance, water, chemicals, ash disposal, etc.
Short-term Projected Assessment of System Adequacy (Short-term PASA or ST PASA)	The PASA in respect of the period from 2 days after the current trading day to the end of the 7th day after the current trading day inclusive in respect of each trading interval in that period.

Term	Definition
significant non-scheduled generating unit	Refers to the following: • All market non-scheduled (MNS) generating units. • All non-market non-scheduled (NMNS) generating units and generating units exempted from registration (with an aggregate capacity greater than 1 MW), for which AEMO and the jurisdictional planning bodies (JPBs) have sufficient data to enable the development of energy and maximum demand (MD) projections.
Small-scale Renewable Energy Scheme (SRES)	See 'national Renewable Energy Target scheme'.
smart charging	Smart charging involves the bulk of charging occurring during off peak periods, normally late at night and early in the morning.
smart grids	Smart grids potentially create opportunities for consumers to change energy consumption at short notice, in response to a variety of signals including electricity price.
special participant	A system operator or a distribution system operator.
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.
Statement of Opportunities	The (gas or electricity) Statement of Opportunities published annually by AEMO.
sub-economic demonstrated resources	A mineral resource that demonstrates the following: • Tonnage, grade and mineral content can be estimated with a high level of confidence, based on verified geological evidence. • Profitable extraction or production has not been analytically demonstrated, or assumed with reasonable certainty.
summer	Unless otherwise specified, refers to the period 1 November–31 March (for all regions except Tasmania), and 1 December–28 February (for Tasmania only).
supervisory control and data acquisition (SCADA)	Equipment used to collect power system data: • SCADA data may be transmitted to or from electrical substations, power stations, and control centres. • SCADA data is normally collected for a variety of power system quantities at rates of once every two to four seconds (depending on the quantities measured). The equipment can also be used to send or receive control signals for power system equipment and generating units. The data and control signals are used to manage the operation of the power system from control centres.
supply	The delivery of electricity.

Term	Definition
system capacity	The maximum demand that can be met on a sustained basis over several days given a defined set of operating conditions. System capacity is a function of many factors and accordingly a set of conditions and assumptions must be understood in any system capacity assessment. These factors include the following: • Load distribution across the system. • Hourly load profiles throughout the day at each delivery point. • Heating values and the specific gravity of injected gas at each injection point. • Initial linepack and final linepack and its distribution throughout the system. • Ground and ambient air temperatures. • Minimum and maximum operating pressure limits at critical points throughout the system. • Powers and efficiencies of compressor stations.
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 limitation	A limitation that arises even when all electricity plant is available for service.
supply-demand outlook	The future state of supply's ability to meet projected demand.
synchronous condensor mode	Operation of a synchronous machine to generate or absorb reactive power, enabling control of system voltage.
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.
system restart ancillary services (SRAS)	The set of contracted restart services procured by AEMO to facilitate the supply of sufficient energy to enable the orderly restart of other (large) generating units.
Tasmanian Capacity Reserve Standard	The standard by which Tasmanian reserve adequacy was assessed prior to Tasmania's entry into the NEM. The standard was set by the Tasmanian Reliability and Network Planning Panel, and was specified as the greater of the following: • The level required to ensure that there was a reasonable probability that all single credible contingency events could be sustained without involuntary load shedding. • The level calculated to achieve a reliability standard such that unserved energy in Tasmania would not exceed targets appropriate for Tasmania's transition into the NEM.
terajoule	Terajoule (TJ). An SI unit, 1 TJ equals 1×10^{12} Joules. Also TJ/d or terajoules per day.
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.
trader	Anyone who wishes to participate in a settlements residue auction (SRA) and is not already registered with AEMO as a market customer or a generator must register as a trader.
trading interval	A 30 minute period ending on the hour (EST) or on the half hour and, where identified by a time, means the 30 minute period ending at that time.
transmission losses	Electrical energy losses incurred in transporting electrical energy through a transmission system.

Term	Definition
transmission network	A network within any participating jurisdiction operating at nominal voltages of 220 kV and above plus: any part of a network operating at nominal voltages between 66 kV and 220 kV that operates in parallel to and provides support to the higher voltage transmission network, any part of a network operating at nominal voltages between 66 kV and 220 kV that is not referred to in paragraph (a) but is deemed by the Australian Energy Regulator (AER) to be part of the transmission network.
transmission pipeline	A pipeline that is not a distribution pipeline.
transmission pipeline owner	A person who owns or holds under a lease a transmission pipeline which is being or is to be operated by AEMO.
transmission system (electricity)	A transmission network, together with the connection assets associated with the transmission network, which is connected to another transmission or distribution system.
transmission system (gas)	The transmission pipelines or system of transmission pipelines forming part of the 'gas transmission system' as defined under the Gas Industry Act.
tri-generation	A generation system that produces at least three different forms of energy from the primary energy source: hot water, chilled water, and power generation (electrical energy).
Unconstrained Intermittent Generation Forecast (UIGF)	A forecast produced by the Australian Energy Market Operator's (AEMO) Australian Wind Energy Forecasting System (AWEFS) for an intermittent generating unit, considering: • generating unit (turbine) availability • the availability of the energy required for the unit's energy conversion process (for example wind, solar, or tidal), and • assuming no network limitations. The UIGF applies as an upper dispatch limit for an intermittent generating unit.
under excitation limit	A control function performed by the excitation systems of synchronous machines in a power plant, usually to prevent unstable operation of a generating unit.
unrecoverable	The portion of discovered or undiscovered petroleum initially-in-place quantities, which is estimated as of a given date, deemed not recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur.
unserved energy (USE)	The amount of energy that cannot be supplied because there is insufficient generation capacity, demand-side participation (DSP), or network capability to meet demand. Under the provisions of the Reliability Standard, each region's annual USE can be no more than 0.002% of its annual energy consumption. Compliance is assessed by comparing the 10-year moving average annual USE for each region with the Reliability Standard. See also 'Reliability Standard'.
Value of Customer Reliability (VCR)	A measure of the cost of unserved energy used in Regulatory Test assessments for planned augmentations for the Victorian electricity transmission system. The VCR is determined through a customer survey approach that estimates direct end-user customer costs incurred from power interruptions at the sector and State levels.
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.

Term	Definition
voltage unbalance	A quality of supply problem in a 3-phase system, voltage unbalance occurs when the three phases are not equal in magnitude or equidistant (120 degrees) in phase, and can cause plant failures, typically through overheating.
winter	Unless otherwise specified, refers to the period 1 June–31 August (for all regions).

Company Names

The following table lists the full name and Australian Business Number (ABN) of companies that may be referred to in this document.

Company	Full Company Name	ABN/ACN
ABARE	Australian Bureau of Agricultural and Resource Economics	24 113 085 695
ACIL Tasman	ACIL Tasman Pty Ltd	68 102 652 148
AECOM	AECOM Australia Pty Ltd	20 093 846 925
AEMC	Australian Energy Market Commission	49 236 270 144
AEMO	Australian Energy Market Operator	92 072 010 327
AER	Australian Energy Regulator (ABN provided for Australian Competition and Consumer Commission)	94 410 483 623
Better Place	Better Place (Australia) Pty Ltd	22 133 111 565
Bluescope Steel Australia	Bluescope Steel Limited	16 000 011 058
Commonwealth Scientific and Industrial Research Organisation (CSIRO)	Commonwealth Scientific and Industrial Research Organisation	41 687 119 230
ECAR Energy	Ecar Limited (registered in Ireland)	425871 (Ireland)
ElectraNet	Electranet Pty Limited	41 094 482 416
Energy Exemplar	Energy Exemplar Pty Ltd	91 120 461 716
Geoscience Australia	Geoscience Australia	80 091 799 039
Intelligent Energy Systems (IES)	Intelligent Energy Systems Pty Ltd	51 002 572 090
Lucas	AJ Lucas Group Limited	12 060 309 104
McLennan Magasanik Associates (MMA)	McLennan Magasanik Pearce Unit Trust	33 579 847 254
ORER	Office of the Renewable Energy Regulator	68 574 011 917
Portland Aluminium	Alcoa Portland Aluminium Pty Ltd	80 006 306 752
Powerlink Queensland	Queensland Electricity Transmission Corporation Limiited	82 078 849 233
Queensland Hunter Gas Pipeline	Hunter Gas Pipeline Pty Ltd	40 108 119 544
Sinclair Knight Merz (SKM)	Sinclair Knight Merz Pty Ltd	37 001 024 095
Sleeman Consulting	The Trustee for the Sleeman Trust	60 104 780 846
Standards Australia	Standards Australia Limited	85 087 326 690
Transend Networks	Transend Networks Pty Ltd	57 082 586 892
TransGrid	TransGrid	19 622 755 774

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