Energy network infrastructure and the climate change challenge report by Parsons Brinkerhoff to ENA

March, 2009

Background

Parsons Brinckerhoff, one of the world's leading planning, environment and infrastructure firms, was commissioned by the Energy Networks Association (ENA) to investigate the challenges, solutions and opportunities that climate change creates for the energy network businesses in Australia.

Through this report, ENA seeks to inform relevant Australian policy makers, policy advisers and regulators of the challenges facing energy network businesses imposed by climate change, to provide industry options for addressing the issues, both in relation to adaptation and mitigation, and to identify opportunities for network businesses into the future.

Specifically, Parsons Brinckerhoff reported to ENA:

» the impact of climate change on energy network businesses;

» the impact of energy network businesses on climate change and mitigation; and

» the opportunities for energy network businesses.

Key messages

Some of the key messages to be reported by Parsons Brinckerhoff to ENA include:

» There are significant risks to energy network businesses from climate change. The highest of these risks arises from bushfire, tropical cyclones and a change in the mix of generation. Lesser risks arise from floods, droughts and an increase in peak demand.

» The risks of climate change affect all networks in all regions of Australia, to some extent.

» The cost to energy networks from climate change is estimated to be $2.5bn over the next 5 years. The largest proportion of this cost arises from the requirement to augment networks to accommodate the increased use of airconditioning.

» A high level of investment is required to meaningfully reduce electrical losses. It is estimated that capital expenditure of about $1.2bn would be required to reduce electrical losses by 10%.

» Energy network businesses require a regulatory framework that supports and encourages the mitigation of emissions. In particular, a regulatory framework is required to provide assistance and strong incentives for the reduction of electrical losses in order for this method of emissions reduction to be prioritised and implemented.

» Network businesses can play an enabling role in the reduction of greenhouse gases by energy generators and consumers. However, they are not currently structured to undertake this role. There is an opportunity for policy makers to implement regulatory incentives that facilitate the changes network businesses will need to undertake in developing this enabling role.

Electricity and gas network businesses are intrinsically linked to the challenges, opportunities and solutions regarding climate change.

The life expectancy of network-related infrastructure is around 30 or more years. This means there is now an urgent need to consider and implement new policies that will enable electricity and gas distribution infrastructure to maintain the services expected of them in the future.

About ENA

The Energy Networks Association (ENA) is the peak national body for Australia's energy networks which provide the vital link between gas and electricity producers and consumers. ENA represents gas distribution and electricity network businesses on economic, technical and safety regulation and national energy policy issues.

Energy network businesses deliver electricity and gas to over 13 million customer connections across Australia through approximately 800,000 kilometres of electricity distribution lines. There are also 76,000 kilometres of gas distribution pipelines. These distribution networks are valued at more than $40 billion and each year energy network businesses undertake investment of more than $5 billion in distribution network operation, reinforcement, expansions and greenfields extensions. Electricity transmission network owners operate over 42,000 km of high voltage transmission lines, with a value of $10 billion and undertake $1.2 billion in investment each year.

Key

Points to jurisdiction of business

Other jurisdiction of business

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Energy network infrastructure and the climate change challenge

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Executive summary

Energy networks are a crucial element of the Australian economy, delivering electricity and gas to over 13 million customers across the country. In addition to this key role, network businesses also undertake substantial direct investment each year and control assets valued at over $70bn.

Parsons Brinckerhoff (PB) has been commissioned by the Energy Networks Association of Australia (ENA) to investigate the challenges, solutions and opportunities that climate change creates to the energy network businesses in Australia.

The key messages of the report are summarised below.

Climate science

Climate change is emerging as a major economic and social challenge for energy network businesses.

Potential impacts of climate change in Australia include both single-event extreme weather phenomena such as cyclones and flooding, as well as significant changes in the weather regime.

A substantial increase in fire weather risk is likely at most sites in south-eastern Australia, with the greatest risk generally in inland regions.

The intensity of Australian east coast cyclones will increase significantly; while the region of cyclone genesis may shift southward by a distance of 200 km. Hail risk is likely to increase over the south-east coast of Australia.

The frequency and severity of drought will increase, especially in southern Australia, expanding regions of ground shrinkage. Heatwaves will become more intense, more frequent and longer lasting as the climate warms.

Adaptation

There are significant risks to energy network businesses from climate change. The highest of these risks arise from bushfire, tropical cyclones and a change in the mix of generation. Lesser risks arise from floods, droughts and an increase in peak demand. The risks of climate change affect all networks in all regions of Australia, to some extent.

The cost to energy networks from climate change is estimated to be $2.5bn over the next 5 years. The largest proportion of this cost arises from the requirement to augment networks to accommodate the increased use of airconditioning. The costs will be incurred by electricity transmission and distribution networks and, to a lesser extent, by gas distribution networks.

The costs of climate change are expected to be greater in tropical regions and those regions that have not previously been, but might now be, exposed to cyclones.

To ensure that sufficient investment is made in energy networks to meet customer energy demands, regulatory processes will need to be sufficiently flexible to enable energy network businesses to recover costs from the impact of climate change. Current processes may need to be reviewed to ensure that energy network businesses can adequately deal with an increased level of volatility in expenditure that may be uncertain or difficult to predict.

The nature of the impact of climate change on energy networks in 2070 will be determined by the way in which governments and the public respond to the climate change challenge.

In each of the 2070 scenarios developed, there is an ongoing need for energy networks though the relative importance of gas and electricity networks may change with changes in technology and the way energy is used.

Mitigation

The costs of mitigating operational emissions can be substantial. To mitigate operational emissions in the pursuit of becoming 'carbon neutral' can incur a typical network business a cost of between $1.2m and $3.2m over a 5-year regulatory period.

Electrical losses cause Scope 2 emissions that are about 50 times greater than business operational emissions and therefore represent an opportunity for significant emission mitigation.

Electricity network businesses have at their disposal a number of measures to reduce electrical losses and associated emissions; however, the magnitude of the loss reduction is limited by technical and economic constraints. In many cases, only a small reduction in electrical losses is feasible and at a high cost. A high level of investment is required to meaningfully reduce electrical losses. It is estimated that capital expenditure of about $1.2bn would be required to reduce electrical losses by 10%.

Gas leakage losses are a Scope 1 emission under the Carbon Pollution Reduction Scheme (CPRS) and may be of a magnitude to create CPRS emission obligations. As such, gas losses are a significant issue for gas network businesses. Gas leakage is being reduced by current programs of work to replace old pipes.

There is the potential for energy network businesses to enable and support activities that mitigate network-wide emissions. However, this valuable role would represent a material change in the strategic direction for network businesses.

Energy network businesses require a regulatory framework that supports and encourages the mitigation of emissions. In particular, a regulatory framework is required to provide assistance and strong incentives for the reduction of electrical losses in order for this method of emissions reduction to be prioritised and implemented.

Opportunities

There are a number of opportunities for energy network businesses to grow as a result of climate change. The nature of the growth will depend on the future sources and use of energy.

Network businesses can play an enabling role in the reduction of greenhouse gases by energy generators and consumers. However, they are not currently structured to undertake this role. There is an opportunity for policy makers to implement regulatory incentives that facilitate the changes network businesses will need to undertake in developing this enabling role.

The fundamental change in the way that networks will operate in the future will only occur if network businesses are aware of available and emerging technology and have a sufficient understanding of the way that technology can be applied. This understanding can only be gained from research, trials, testing of technologies and a generally closer association with developers and suppliers of equipment and technological solutions.

Introduction

Parsons Brinckerhoff (PB) has been commissioned by the Energy Networks Association of Australia (ENA) to investigate the challenges, solutions and opportunities that climate change creates to the energy network businesses in Australia ('the study').

In this section of the report, we establish the context and background for the study, and set out the scope, objectives and timing of the study. This section also includes details of the structure and contents of the report.

1.1 Background and context

The ENA is developing a strategic approach on behalf of its members in regards to climate change policy. By commissioning this report, the ENA seeks to inform relevant Australian policy makers, policy advisers and regulators of the challenges facing energy network businesses imposed by climate change, to provide industry options for addressing the issues, both in relation to adaptation and mitigation, and to identify opportunities for network businesses going forward.

Electricity and gas network businesses are intrinsically linked to the challenges, opportunities and solutions regarding climate change. While the network businesses facilitate the transport and end use of a vast amount of energy that supports economic growth, the infrastructure itself is impacted both physically by changing weather patterns, and by requirements to changing network development drivers such as to the connection of higher proportions of renewable generation.

The energy industry estimates that between 2008 and 2030, the capital expenditure needed to meet demand will be $30–35bn[1]. This estimate may change, depending on the increase in demand for improved energy efficiency and greenhouse gas reduction, as well as a projected escalation in climate volatility. The life expectancy of network-related infrastructure is around 30 or more years. This means there is now an urgent need to consider and implement new policies that will enable electricity and gas distribution infrastructure to maintain the services expected of them in the future. This will need to take place under rapidly changing regulatory regimes and market forces in response to the anticipated Carbon Pollution Reduction Scheme (CPRS) and other government policies.

It is therefore very important for the energy network businesses to understand the issues surrounding their future activities in the context of climate change and to be represented as stakeholders in the changing policy landscape driven by carbon pollution reduction imperatives.

The achievement of this objective will require the ENA to adopt an integrated and flexible approach which seamlessly draws together all diverse facets of this study, from climate change science and energy regulatory environment issues to engineering design standards changes. It will also necessitate an insightful assessment of the solutions and opportunities presented by the climate change challenge; solutions and opportunities built on industry experience and commercial realities.

Addressing climate change calls for an examination of plausible future scenarios from a long-term perspective, the capacity to deal with uncertain and changing information, and responses that may extend beyond jurisdictional boundaries and energy network business

[1] Request for a Report on Energy Network Infrastructure & the Climate Change Challenge (Challenges, Solutions & Opportunities), ENA 2008.

responsibilities. These are significant challenges for the energy network businesses and this report therefore aims to illuminate the nature of the potential impacts of climate change of greatest relevance for the energy network businesses in Australia, and to suggest appropriate mitigation and adaptation strategies and organisational responses alongside the valuable opportunities that can be identified and seized.

1.2 The climate change challenge

Leading scientists on the Intergovernmental Panel for Climate Change (IPCC) published their fourth assessment of the state of knowledge about climate change and its impacts in 2007 (IPPC 2007). They reached consensus that human activity including economic activity such as the provision of gas and electricity is responsible for many observed climate changes, particularly the warming temperatures of the last several decades. They also concluded that there is a need for far more extensive adaptation than is currently occurring to reduce vulnerability to future climate change. The report noted that understanding of the physical climate system has progressed rapidly, but that the use of this knowledge to support decision making, manage risks, and engage stakeholders is inadequate. Companies can no longer continue to treat climate change solely as an issue of corporate responsibility. Climate change has now become a major economic and social issue with huge implications on corporate competitive advantage and profitability.

Current climate change forecasts predict that the global warming which has occurred over the past 150 years will continue and potentially accelerate into the future. By 2100, average temperatures are likely to increase by a further 2.0–4.5°C, depending on future global greenhouse gas emission levels. However, substantially higher increases as high as 10°C cannot be excluded unless urgent international action is taken.

Potential impacts of climate change in Australia include single-event extreme weather phenomena such as cyclones and flooding, as well as significant changes in weather patterns. These climatic changes are expected to have a range of negative impacts on water supplies, food production, human health, tourism, ecosystems, industry (including physical infrastructure) and the economy. The Final Garnaut Report and the CPRS White Paper provided major inputs into the debate about the potential impacts of climate change.

As part of asset and business risk management, the forecast impact on energy network infrastructure and options for mitigation and adaptation need to be assessed. The upward trend in the probability of extreme weather events over the last few decades is not only expected to continue but has been reflected in insurance losses as further evidence of the need to incorporate climate change into business strategy.

A key impact on industry and the economy is that of policy measures introduced by governments such as carbon emissions trading and mandatory renewable energy targets. The former reduces greenhouse gas emissions by imposing limits on emissions that can be produced and allowing permits to be traded in an open market. The latter promotes investment in renewable energy by setting mandatory targets for the energy sector. Despite the various challenges to be addressed, both the direct impacts of climate change and those of a political and market nature also pose opportunities for businesses to grow into new areas and to take advantage of the changing landscape of prices and policies aimed at climate

change mitigation and adaptation.

In the face of climate change impacts, the key challenges for the energy network businesses in relation to the objectives listed by the ENA are:

- to reduce greenhouse gas emissions
- to ensure asset management decisions and outcomes are effective and efficient
- to encourage efficient and timely investment
- to continue to provide secure and reliable energy to customers.

1.3 Project scope, objectives and timing

The broad scope and requirements of this report are to identify the challenges, potential solutions and policy options for:

- adapting to climate change by modifying construction specifications applied to new network infrastructure and modifying existing infrastructure so that it can better withstand the higher environmental impacts associated with expected weather patterns over the next 30 to 50 years
- informing governments, regulators and other Australian policy makers of practical network solutions and opportunities to abate energy network related greenhouse emissions.

The detailed scope set out for PB includes:

- setting the scene — this consists of reviewing the relevant literature on climate change science, stating the challenges facing the energy network businesses and presenting the network businesses' possible response to climate change challenges and opportunities
- assessing the adaptive capacity of energy network businesses to climate change with a focus on demand risk, supply risk, and changing and extreme weather events
- developing a range of adaptation options for those risks that are identified to be within the sphere of influence of the energy network businesses. In particular, the potential need for changes to infrastructure design standards and the alteration of existing structures. As required by the ENA, this assessment is to be conducted on a regional basis
- proposing policy measures and funding arrangements to be developed in order that energy network businesses can efficiently adapt to the challenges and mitigate the risks posed by climate change
- identifying impacts of network businesses on climate change including the network sector emissions
- developing a full suite of mitigation options both for gas and electricity network businesses
- identifying key risks and areas of opportunity
- providing focus for further work.

The main objective of this report is to influence policy makers, advisers, and economic/technical regulators on energy distribution climate change issues. The findings of this report

should enable the ENA to influence policy outcomes driven by the challenges posed by climate change and likely impacts on the network businesses' operating environment. The report aims to identify physical and market risks that climate change presents to electricity and gas network businesses over the next 50 years, including projected extreme weather events, requirements for greater energy efficiency and greenhouse gas abatement, government regulations, and public engagement. The analysis in the study covers climate change impacts on network businesses for 2030 and 2070 in line with the CSIRO climate change forecasts. A further aim of this study is to identify the potential adaptation and mitigation options and opportunities and their potential to deliver desired outcomes in the face of climate change challenge and growing government involvement and public sentiment.

The study covers electricity and gas transmission and distribution network businesses. It is broad in its coverage and high level in focus. The timeframe included a research and drafting phase, with a period of intense consultation between PB and ENA leading to the presentation of the final report.

1.4 The structure of this report

This report is structured in sections as follows:

Section 2 of the report sets up the scene. Essentially it describes the energy network in broad terms and its key parameters and presents a targeted summary of climate change science to underpin subsequent analysis.

Section 3 presents our approach to the study. Here the report highlights the key issues and challenges of the study and presents the overarching methodology. In addition, this section explains how scenarios for risk analysis were developed and how a risk-based approach to climate change impacts was conducted. Key principles and assumptions are also explained.

Section 4 builds on the previous sections and presents an extensive discussion of the impacts of climate change on network businesses. The focus of the section is on developing adaptation options for both gas and electricity network businesses. Impacts of climatic events are analysed and likely energy network businesses responses to these events are hypothesised over the period to 2030 and 2070.

Section 5 describes the impacts of network businesses on climate change. Essentially, the section focuses on mitigation initiatives that the energy network businesses can develop to further reduce greenhouse gas emissions.

Section 6 identifies opportunities resultant from climate change that the energy network businesses can seize. This includes opportunities for network businesses to enable energy users and generators to reduce greenhouse gas emissions. The focus is on those opportunities that can be implemented in the near future (that is to 2030) rather than those that may be available in 2070. Opportunities beyond 2030 are identified but with less certainty of their existence as they are difficult to predict in such a fluid and fast-moving environment governed by climate change imperatives and policies geared towards limiting and managing greenhouse gas emissions.

2 Setting the scene

In this section, we present the essential elements that underpin the study. This includes an overall discussion of the Australian energy networks and the climate change science supporting the analysis of the impacts of climate change on energy networks.

2.1 Australian energy networks

2.1.1 Electricity

The geographical spread of the Australian population has resulted in the development of four main electricity networks, as shown in Figure 2 1.

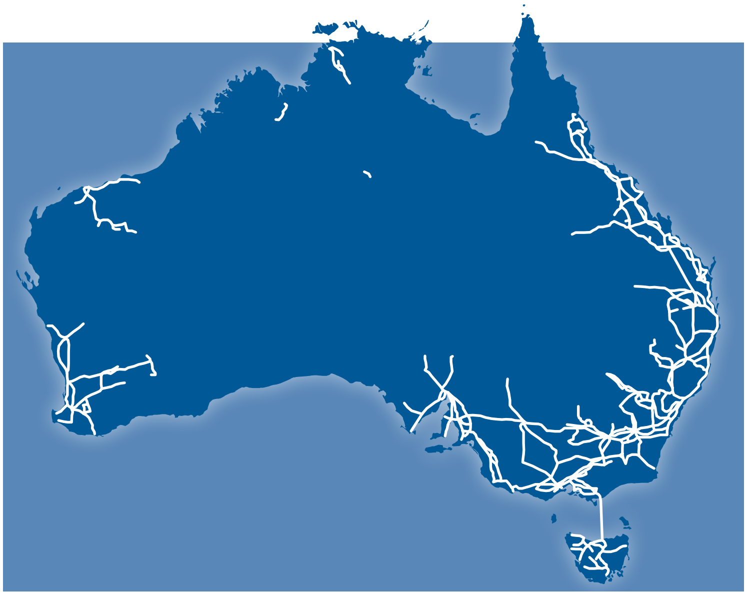


Figure 2 1: Electricity transmission network and generation sites of Australia

Source: Asia–Pacific Partnership (AAP) Energy Regulatory and Market Development Forum (ERMDF) 2008

The length of the transmission network in Australia is shown in Table 2 1 for each voltage level.

Metric	Unit	Voltage					
Voltage	kV	500	330	275	220	132	110
Network length	km	1,803	8,251	9,897	7,016	26,157	4,118

Table 2 1: Transmission network length by voltage in Australia

Source: Energy Supply Association of Australia (ESAA) 2008a

The four networks are owned, operated and regulated independently of each other. Table 2 2 describes the networks, the states or territories where the businesses operate and the associated businesses.

The eastern and south-eastern coastal areas have been interconnected to form the National Electricity Market (NEM). The NEM covers Queensland, New South Wales, Australian Capital Territory, Victoria, South Australia and Tasmania, and comprises approximately 90% of the electricity consumption in the country. The main network in Western Australia is called the South West Interconnected System (SWIS). This network is separated from the NEM by approximately 1,500 km and interconnection of these networks is not expected. Western Australia also hosts some smaller interconnected systems including the North West Inter

Network	States/Territories	Asset owner/operator	
		Transmission	Distribution
NEM	Australian Capital Territory	TransGrid	ActewAGL
	New South Wales	EnergyAustralia TransGrid	Country Energy EnergyAustralia Integral Energy
	Queensland	Powerlink	Energex Ergon Energy
	South Australia	ElectraNet SA	ETSA Utilities
	Tasmania	Transend	Aurora Energy
	Victoria	SP AusNet/VENcorp	Jemena CitiPower Powercor SP AusNet United Energy
NTEN	Northern Territory	Power and Water Corporation	Power and Water Corporation
SWIS	Western Australia	Western Power	Western Power
NWIS		Horizon Power	Horizon Power

Table 2 2: Electricity businesses in Australia

connected System (NWIS). The Northern Territory electricity network (NTEN) is also independent of the other main networks.

The figures for peak electricity demand, generation capacity and production for the aggregate of the Australian networks are given in Table 2 3.

Metric	Unit	Current	Forecast
		2006–07	2012–13
Peak demand	GW	38.4	47.0
Generation capacity	GW	47.4	54.3
Energy production	TWh	209.4	237.6

Table 2 3: Current and forecast electric energy metrics for Australia

Source: ESAA 2008a

Electricity generation has increased steadily at approximately 2.1% per year from 1990 to 2006 (International Energy Association 2007, part 3 p. 102), and the generation capacity in Australia is reflective of the steady growth in peak demand. The total forecast of existing and committed generation capacity across Australia is growing at an average of 4% increase per year over the next 2 years. This is representative of a mature electricity market with 'above average' load growth for a developed nation.

2.1.2 Gas

Australia has multiple gas networks. The networks are owned and operated independently of each other. The geographical spread of the Australian population has resulted in the gas networks, as shown in Figure 2 2.

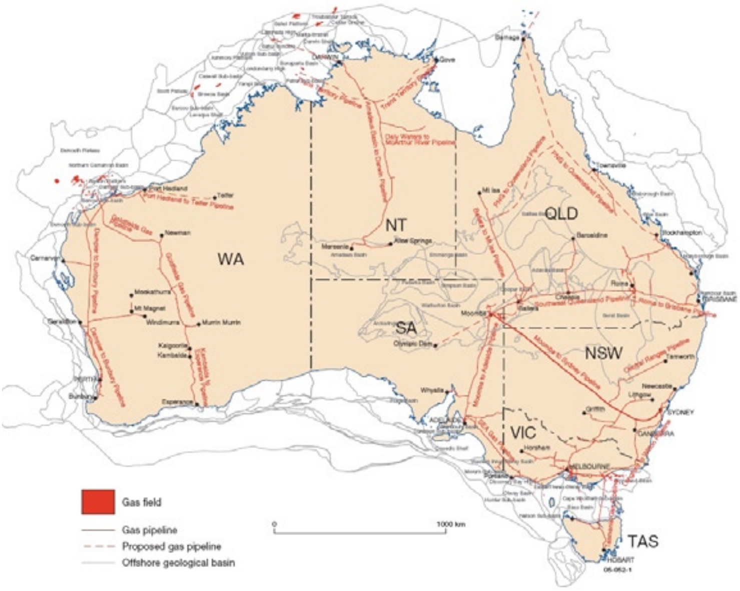


Figure 2 2: Australia's major gas pipelines

Source: ESAA 2008a

The length of the gas transmission network in Australia is shown in Table 2 4 each pressure range.

Metric	Unit	Operating pressure		
		Reticulation		Transmission
Pressure	kPa	< 210	210 - 1,050	> 1,050
Network length	km	22,822	81,181	25,824

Table 2 4: Gas transmission network length by pressure in Australia

Source: ESAA 2008a

The figures for current and forecasted gas production and consumption are given in Table 2 5.

Metric	Unit	Current	Forecast
		2006–07	2012–13
Gas consumption[1]	PJ	1,115	1,201[3]
Gas production[2]	PJ	8,785	9,464[3]

Table 2 5: Current and forecast gas energy metrics for Australia

Sources:

[1] *ESAA 2008a*

[2] *Australian Government; Austrade*

[3] *Estimate based on an average of 1.5% growth per annum.*

Network	States/ Territories	Asset owner/operator			
		Transmission		Distribution	
GMC	Australian Capital Territory	APA Group	ActewAGL	ActewAGL	
GMC	New South Wales	APA Group ActewAGL	Country Energy Jemena	ActewAGL Jemena Envestra/ APA Group	APT Allgas Energy Central Ranges Pipeline Country Energy
GMO	Queensland	Australian Gasfields APA Group Arrow Energy Enertrade	Envestra/ APA Group Epic Energy Jemena NewGen Power Santos	APT Allgas Energy Envestra/ APA Group	
REMCo	South Australia	APA Group Envestra/ APA Group Epic Energy	Origin Energy Santos SEA Gas	Envestra/ APA Group	
REMCo	Western Australia	APA Group DBNGP Transmission Epic Energy Esperance Pipeline Company Goldfields Gas Transmission Southern Cross Pipelines Australia	Envestra/ APA Group WestNet Apache Energy Newmont Mining Origin Energy Woodside Energy	WestNet	
N/A	Tasmania	Babcock & Brown		Powerco Tasmania	
VENCorp	Victoria	APA Group Gas Pipelines of Victoria Envestra/ APA Group	Jemena Origin Energy SEA Gas	Envestra/ APA Group Multinet Gas SP AusNet	
N/A	Northern Territory	APA Group ConocoPhillips	Envestra/ APA Group	Envestra/ APA Group	

Table 2 6: Gas businesses in Australia

Table 2 6 describes the gas networks, the states or territories where the businesses operate and the associated businesses.

There is a fully functioning open market for gas operating in the state of Victoria. This market is managed by the Victorian Energy Networks Corporation (VENcorp[2]). In the other states, the marketplace is not as well developed. However, in April 2007 the Council of Australian Governments (COAG) announced its intention to establish a new national market operator to replace the existing functions of energy market operators. These include the National Electricity Market Management Company (NEMMCO), VENCorp, the Retail Energy Market Company (REMCO[3]) and the Gas Market Company (GMC[4]). Accordingly, COAG tasked the Ministerial Council on Energy (MCE) with developing a detailed implementation plan to establish the energy market operator by July 2009[5]. This new body will be known as the Australian Energy Market Operator (AEMO).

Australia has an abundant supply of natural gas resources[6]. As at January 2006, Australia has demonstrated natural gas resources totalling 57 years of reserves of production and 45 years of reserves of production of liquefied petroleum gas (LPG). Natural gas consumption has increased in Australia in the past 30 years and this trend is projected to continue in the longer term. Growth in Australian gas consumption is projected to continue, with growth averaging 1.6% per annum until 2030, medium-term growth of 2.2% per annum is forecast to 2011–12[7]. This reflects structural changes in the economy as well as the implementation of a range of energy efficiency and conservation measures.

2.1.3 The importance of energy networks

Energy networks are a crucial element of the Australian economy, delivering electricity and gas to over 13 million customers across the country. In addition to this key role, network businesses also undertake substantial direct investment each year and control assets valued at over $44bn.

The electricity and gas sector directly generates approximately 1.5% of Australia's GDP[8]. While this in itself is a sizeable contribution, the importance of electricity and gas in the overall economy cannot be overstated. Practically every economic sector is heavily reliant on the consistent and reliable supply of energy that network businesses deliver. Energy networks in Australia face unique challenges compared with those in other countries. The distances that must be covered are great and the population density is relatively low. As a consequence, Australian energy networks must be built and operated carefully in order to maintain the high level of reliability and operational performance that is expected by business and consumers. In particular, energy networks need to be flexible to meet changing supply and demand, responsive in repairing damage to maintain reliability, and efficient in transporting energy with minimal loss.

[2] http://www.vencorp.com.au/

[3] http://www.remco.net.au/

[4] http://www.gasmarketco.com.au/

[5] http://www.nemmco.com.au/corpinfo/aemo.html

[6] Research paper no. 25 2007-08, 'Australia's natural gas: issues and trends', http://www.aph.gov.au/library/pubs/rp/2007-08/08rp25.htm

[7] ABARE, National and State Projections to 2029-30

[8] ABS Catalogue No. 5206 (chain volume measures)

Energy networks comprise valuable assets and require significant capital and operational expenditure to maintain, grow and develop. Table 2 7 indicates that the total value of regulatory asset bases for Australian energy network businesses is approximately $70bn, annual capital expenditure is over $6bn, and annual operational expenditure is over $4bn.

Sector	Businesses	Regulated asset base ($ billion)	Capital expenditure ($ billion pa)	Operational expenditure ($ billion pa)
Electricity distribution	15	45.0	4.5	3.1
Electricity transmission	7	15.0	1.6	0.7
Gas distribution	10	7.4	0.5	0.4
Gas transmission	10	2.6	0.1	0.2
TOTAL		70.0	6.7	4.4

Table 2 7: Value of energy network assets and annual expenditure

Sources: Regulatory submissions, PB analysis, and AER 2007

Energy networks businesses undertake capital expenditure for a number of reasons. Energy network assets have very long service lives (about 40 years), and their condition must be preserved through replacement or renewals in order to maintain reliability. Consumers and business place a very high value on receiving a reliable supply of energy and it is this high value that drives significant investment in maintaining and improving the security and reliability of energy supply infrastructure. Networks also require augmentation, including extension, at times due to either new generation, new loads or load growth. Finally, network businesses are embarking on a process of technological advancement that will prepare networks for future changes to the structure of the energy industry and will help enable the industry to meet market and environmental challenges. This report includes consideration of the enabling role that energy networks can play in helping mitigate and adapt to climate change. A range of new technologies for networks will be employed in order to best meet the challenges of climate change, and significant increased investment in this area will be required in the near future.

2.2 Climate change science

Climate change is emerging as a major economic and social challenge for energy network businesses. There is now a general consensus among scientists, political and business leaders, and the general community that climate change is caused by human activity including the generation, transmission, distribution and consumption of energy. There is also a growing consensus that there is a link between greenhouse gas emissions and economic activity and that abatement is needed to reduce the impacts of climate change on the environment.

Current climate change forecasts predict that the global warming which has occurred over the past 150 years will continue and potentially accelerate into the future. The fourth assessment report of the IPCC in 2007 confirmed that since 1850, global average temperatures have increased by about 0.76°C and predicts that the rate of warming will continue to increase. By 2100, average temperatures are likely to increase by a further 2.0

to 4.5°C depending on future global greenhouse gas emission levels. At present, the central IPCC estimate is for a 3°C increase by 2100; however, substantially higher increases as high as 10°C cannot be excluded unless urgent action is taken.

Key message

Climate change is emerging as a major economic and social challenge for energy network businesses.

Comparisons with historical temperature data at land and sea measuring stations confirm that temperatures in Australia have also increased since 1900. Bureau of Meteorology data shows that average temperatures in Australia have warmed by 0.9°C since the start of the 20th century, and are in line with global temperature increases over the same period (CSIRO & BoM 2007). Most of this warming has occurred since 1950, with minimum temperatures increasing slightly more than maximum temperatures.

Figure 2 3 shows increases in Australian annual mean temperature between 1900 and 2007 (Garnaut 2008a).

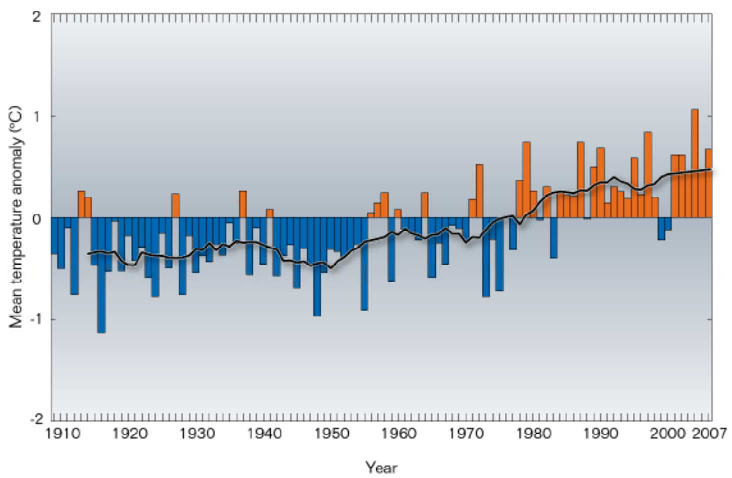


Figure 2 3: Australian annual mean average temperature anomalies and trend, 1990–2007

Note: The data shows temperature difference from the 1961–90 mean. The black line shows the 10-year trailing average.
Source: Bureau of Meteorology.

The Australian climate is one of the most variable of all the continents. Internal and external factors drive climate variability on a range of timescales. Internal factors are natural and arise from complex interactions within the climate system such as the El Nino-Southern Oscillation, the Inter-decadal Pacific Oscillation, and the Indian Ocean Dipole (CSIRO & BoM, 2008). Natural external factors include the earth's rotations, orbital parameters, volcanic eruptions and variations in energy from the sun. Some external factors such as the burning of fossil fuels, land-use change and stratospheric ozone in the atmosphere are human induced.

The Garnaut climate change review (2008b) stated that rapid developments of climate-related research and modelling have allowed increasingly more definitive assessments of the human impacts on climate. The 2007 Intergovernmental Panel for Climate Change (IPCC) fourth assessment report noted an improvement in the scientific understanding of the influence of human activity on climate change. The report concluded that the warming of the system is 'unequivocal' and that there is a greater than 90% chance that the global

average net effect of human activities since 1850 has been one of warming. Hence, most of the global and Australian warming since the mid-20th century is very likely due to human activity (IPCC 2007).

Temperature changes over Australia since 1950 are shown in Figure 2 4. The greatest warming has occurred in central and eastern Australia, with the least warming in the far north-west. Mean maximum temperatures have increased in south-eastern Australia, resulting in droughts becoming hotter (Nicholls 2004, in Garnaut 2008a, p. 145).

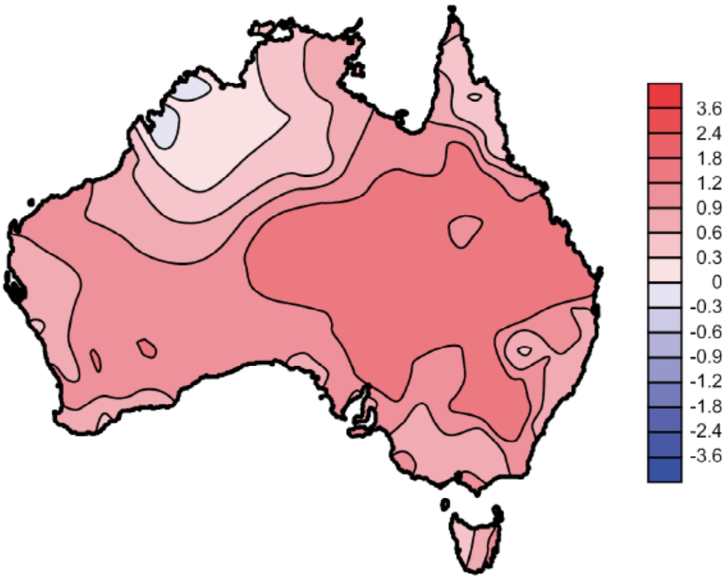


Figure 2 4: Regional trends in annual mean temperature since 1950

Source: CSIRO & BoM 2008,

There has been a major change in Australian rainfall patterns since the 1950s, with large geographic variations as shown in Figure 2 5 (Garnaut 2008a, p. 145). Most of eastern and south-western Australia has become drier, with significant reductions in rainfall along much of the Queensland and New South Wales coast. In contrast, north-western Australia has become substantially wetter over recent decades, mostly during summer and autumn (CSIRO & BoM 2008, p. 8). Trends are highly dependent on the period of analysis due to large variability between decades. In Australia, observed changes in the climate suggest that the frequency of extremes in rainfall events is increasing at a faster rate than the mean (CSIRO & BoM 2007).

Attributing changes in Australian rainfall patterns to climate change is difficult due to naturally high inter-annual precipitation variability. The rainfall decline observed in south-east Australia in the 1990s, for example, is complex, due to the nature of factors affecting this region (CSIRO & BoM 2007). These factors include major climatic systems such as the El Nino-Southern Oscillation. In contrast, the decline in rainfall in the south-west of Western Australia for instance can be attributed to human-induced climate change, as suggested by a number of studies (Cai & Cowen 2006, in Garnaut 2008a, p. 146).

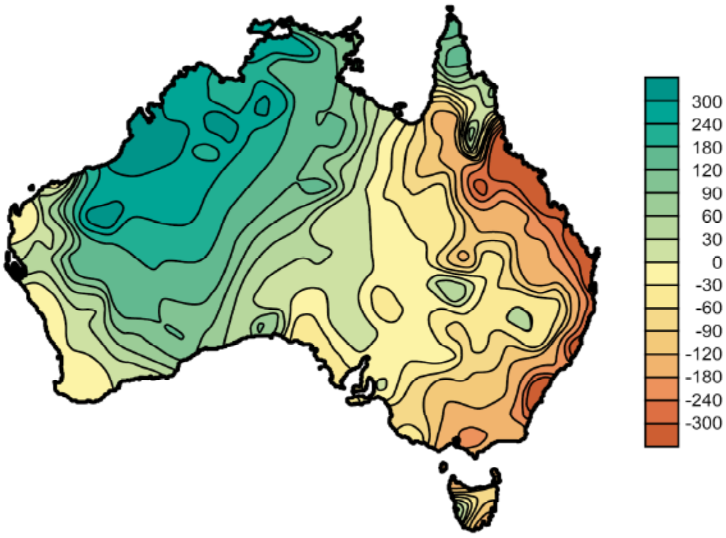
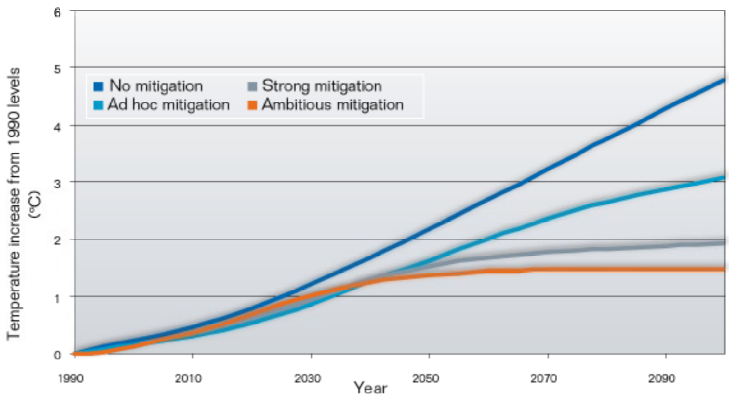


Figure 2 5: Regional trends in annual mean precipitation since 1950

Source: CSIRO & BoM 2008

2.2.1 Current forecasts and potential impacts of climate change

Current forecasts of climate change are based on a range of emission scenarios. The Garnaut final report (2008b) identified four general emission cases for projections of greenhouse gas increases. The models are based on assumptions of no mitigation, ad hoc mitigation, strong mitigation and ambitious mitigation. The models are indicated in Figure 2 6.



Note: Temperature increases from 1990 levels are from the MAGICC climate model (Wigley 2003).

Figure 2 6: Best estimate global average temperature outcomes for four emissions cases

Source: Garnaut 2008b.

The climatic effects of projected changes in emissions can be simulated using climate models, which are mathematical representations of the Earth's climate system (CSIRO & BoM 2008, p. 12). The four main sources of uncertainty in climate change models are: (1) the projected increase in the greenhouse gases; (2) the relationship between greenhouse gas emissions and their atmospheric concentrations; (3) the global warming for a given change in concentrations; and (4) regional climate change. The emissions scenarios depend on assumptions about future demographic changes, economic development and technological improvements. These variables become greater further into the future, but the emissions scenarios are fairly similar up to 2030. Uncertainties in projected regional climate to 2030 are mostly due to differences between the results of the climate models rather than the different emissions scenarios. Beyond 2040 the emissions scenarios become more important.

There are significant uncertainties associated with factors that may enhance or suppress global warming, such as net aerosol effects or changes in cloud properties. Climate change projections take account of these uncertainties by expressing outcomes in terms of a range. For instance, the A1B emission scenario model estimates a 0.54–1.44°C temperature increase over Australia by 2030 (CSIRO & BoM 2008, p. 18). As the Garnaut report (2008b) highlights due to the high level of uncertainty and the range of possible climate responses, there is a tendency in the policy community to focus on the mean, or best estimate, outcomes of climate change. However, an understanding of plausible extremes in the response of the climate system is vital to assessing risk.

Potential impacts of climate change in Australia include both single-event extreme weather phenomena such as cyclones and flooding, as well as significant changes in the weather regime. Such changes include increases in temperature, reduced rainfall in southern regions of Australia and more frequent and intense storms. Accompanying these weather events are predicted higher sea levels. These climatic changes are expected to have a range of negative impacts on water supplies, food production, human health, tourism, ecosystems, industry (including physical infrastructure) and the economy.

The climatic parameters relevant for assessing the likely impact of climate change on energy network businesses are:.

- temperature changes
- rainfall changes
- wind-speed changes (mean and peak)
- rising sea levels
- infectious diseases.

Temperature changes

Annual mean temperatures over Australia are expected to rise by about 1°C above 1990 levels by 2030 (CSIRO & BoM 2007). The range of uncertainty produces a national average increase of between 0.4 and 1.8°C by 2030. Coastal areas will experience slightly less warming in the range 0.7–0.9°C, while inland Australia will experience greater warming in the range 1.0–1.2°C. In general, the north-west is expected to warm more quickly than the rest of the country (Garnaut 2008a, p. 152). Projected temperature increases vary seasonally, with greater warming expected in spring and summer than in winter.

From 2030 to 2070 there are marked differences between projected temperature changes, with significant regional variation predicted between models. Warming is dependent upon the assumed emission model scenario. By 2070, the annual warming ranges from 1.0–2.5°C with a best estimate of 1.8°C for a low emissions case and a range of 2.2–5.0°C with a best estimate 3.4°C for the high emissions case.

Based on the SRES A1B scenario, temperatures are expected to increase by 0.5–1.0°C across all southern and eastern coastal regions and 1.0–1.5°C in central inland and west coast areas by 2030. Temperature changes predicted for 2070 are for an increase of 1.5–4.0°C in southern and eastern coastal areas, and 2.5–5.0°C in central inland and west coast regions. The greatest warming for 2070 is projected for north-western Australia.

Estimated increases in maximum temperatures and the number of hot days will result in heatwaves and increased bushfire risk. These extreme events are discussed under Section 2.2.2 of this report.

Rainfall changes

Regional projections for rainfall are less certain than for temperature due to the complex relationship between local precipitation and atmospheric temperature (Department of the Environment and Heritage 2006). Local rainfall patterns are highly sensitive to the amount of water available for evaporation, the local topography, land cover, and atmospheric and ocean circulations (Garnaut 2008a). The localised nature of such influences on precipitation is likely to result in considerable regional variation in rainfall changes across Australia, such that some areas are expected to experience an increase in rainfall. The complexities also lead to disagreement between climate models regarding the potential extent, and even direction, of the net rainfall change for an area.

Best estimates are for a 3–5% decrease in rainfall over Australia by 2030, with slightly greater decreases in central and south-western areas and less change in the far north. The range of potential change is greater when allowing for differences between climate models, with models ranging from -10% to +5% in northern areas and -10% to little change in southern areas. For a low emissions case, the best 2070 estimate is for an annual rainfall change of -20% to +10% in central, eastern and northern areas, and a -20% to little change in southern areas. Models in general show a tendency for rainfall reduction in southern Australia. Projected annual rainfall changes are detailed in Table 2 8.

Region	2030	2070
Northern Australia	-10% to +5%	-20% to +10%
Southern Australia	-10% to 0%	-20% to 0%

Table 2 8: Projected annual rainfall changes over Australia for 2030 and 2070, relative to 1990

Source: CSIRO & BoM 2007

In addition to changes in annual average rainfall, the character of seasonal and daily rainfall may change. Large decreases in rainfall are expected over Australia in winter and spring, while rainfall may increase in some areas and decrease in others during summer and autumn (CSIRO & BoM 2007, in Garnaut 2008a, p. 155). There is expected to be an increase in the intensity of rainfall events in some areas, and the number of days without rainfall is also expected to increase. This suggests that future rainfall patterns may have longer dry spells broken by heavier rainfall events. Projected changes to state-wide average rainfall for 2030 and 2070 are detailed in Table 2 9.

As detailed in Garnaut, the best-estimate outcomes do not reflect the extent of uncertainty in potential rainfall for Australia from climate change. Rainfall projections are highly sensitive to small changes in model assumptions and inputs, and hence the range of precipitation outcomes predicted by various climate models for Australia is large. Further uncertainty results from the considerable natural inter-annual and decadal variability in Australian rainfall patterns. Such variation may act to further mask, or enhance, precipitation trends due to climate change (CSIRO & BoM 2007).

Region	2030	2070
NSW	-2.5%	-9.3%
Victoria	-3.5%	-12.9%
QLD	-2.4%	-8.6%
SA	-4.2%	-15.5%
WA	-4.1%	-14.9%
Tasmania	-1.4%	-5.1%
NT	-2.5%	-9.0%
ACT	-2.8%	-10.3%

Table 2 9: Best estimate projected changes to state-wide average rainfall

Source: Garnaut 2008a

Wind-speed changes

Wind speeds are likely to increase in most coastal areas due to climate change (CSIRO 2007). Best estimates for 2030 are for a +2 to +5% increase across Australian coastal regions, except for a band around 30 S in winter and 40 S in summer where decreases of about -2% to -5% are projected. The greatest increases in mean wind speeds by 2030 appear to be in coastal and inland Queensland and south-east Tasmania. Changes in wind strength later in the 21st century will be larger in magnitude, depending on the emission scenario. In 2070, the largest increases in wind speed are likely to occur in coastal and inland Queensland, central Australia, Tasmania and the central west coast of Western Australia. Figure 2 7 shows best estimate percentage changes in mean wind speed for 2030, 2050 and 2070 using six SRES model scenarios.

Uncertainty exists in the intensity of average wind-speed changes between models. The wind-speed changes in the models above are annually averaged, and mask significant seasonal variations from historical data. Figure 2-8 is thus provided to illustrate projected changes in mean 10 m wind speed for summer, winter, autumn and spring for 2030.

Little change is projected for annual average wind speed across Australia for 2030. Seasonal changes are anticipated, however, as shown in Figure 2 8. In summer, increases are evident around much of the Australian coastline except Bass Strait and the far north. Wind speeds increase over south Western Australia in autumn, while in spring increases are expected in eastern Queensland, north-east New South Wales, eastern Tasmania and parts of South Australia and Northern Territory. Winter wind speeds increase in Tasmania and in an east-west band across the country.

Directional wind changes, which are important for processes such as coastal erosion and storm surge, were not undertaken in the CSIRO & BoM (2007) analysis. Uncertainty exists over the severity and extent of changes in mean wind speed as illustrated by the significant variation projected between 10th and 90th percentile model scenarios in Figure 2 9.

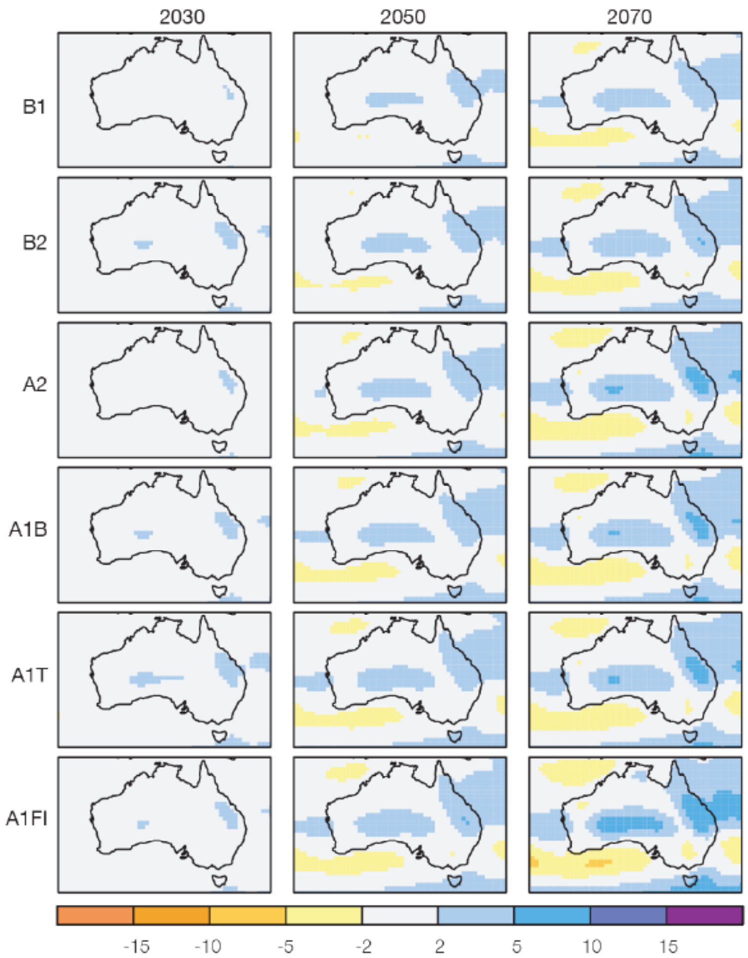


Figure 2 7: Best estimate (50th percentile) of per cent change in mean 10 m wind speed for 2030, 2050 and 2070. Results are for all six SRES scenarios

Source: CSIRO & BoM 2007

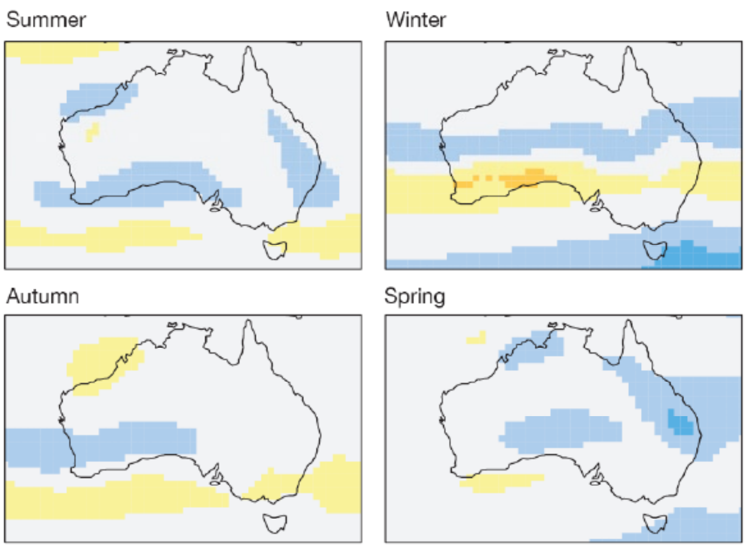


Figure 2 8: Projections (10th and 90 percentiles) of the net per cent change to mean 10 m wind speed by 2030 for scenario A1B for summer, winter and annual

Source: CSIRO & BoM 2007

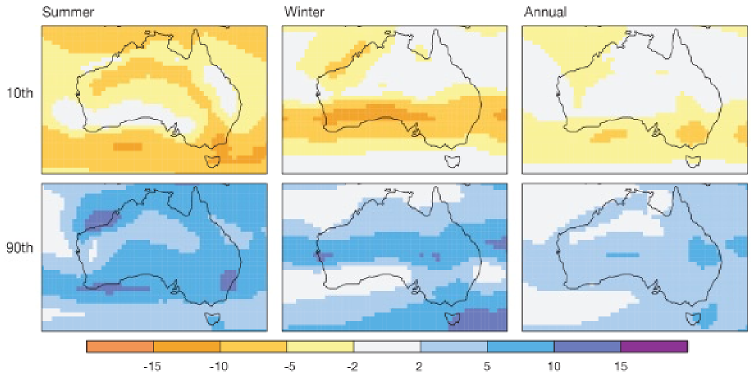


Figure 2 9: Projections (10th and 90 percentiles) of the net percent change to mean 10 m wind speed by 2030 for scenario A1B for summer, winter and annual

Source: CSIRO & BoM 2007

In winter, changes to extreme daily wind speed are similar to the changes in seasonal mean wind speed based on the results of a limited set of models. However, there is little relationship between summer mean and extreme wind speed changes. Extreme winds in summer are likely to be governed more by small-scale systems that are not adequately captured by the resolution of the climate models. Extreme winter events on the other hand are more likely to be governed by larger scale systems such as trade winds and mid-latitude cyclones. In both the tropics and mid-latitudes, extreme wind events are more likely to be related to smaller scale systems such as tropical cyclones and intense convective events which may be associated with tropical storms in the tropics and frontal activity or low pressure systems further south. Projections suggest a 5–10% increase in extreme wind velocity and frequency could be expected by 2030 and a 10–30% increase by 2070 over most regional areas.

Indications would suggest that a 5–10% increase in extreme wind velocity and frequency could be expected by 2030 and a 10–20% increase by 2070 over most regional areas.

Rising sea levels

Throughout the 21st century and beyond, sea levels are expected to continue to rise as a result of climate change. This is due to the thermal expansion of water, melting of land-based glaciers and ice caps and contributions from the ice-sheets of Antarctica and Greenland (CSIRO & BoM 2008). Sea level rises have already been observed with ocean levels around Australia rising by an average of 1.2 mm per year over the 20th century (CSIRO & BoM 2007). Table 2 10 shows low and high global projected sea level rises for 2030 and 2070.

Sea level	2030	2070
Low sea levels rise	3 cm	7 cm
High sea level rise	17 cm	52 cm

Table 2 10: Low and high projected sea levels rise by 2030 and 2070

Source: DSE 2007

The level of understanding on the magnitude and timing of contributions to sea level rise from ice melt is low (Garnaut 2008a, p. 130). It should be noted that there is potential for substantially greater rises in sea level if ice-flow rates from Greenland and Antarctica

continue to grow linearly with their melt pattern between 1993 and 2003. This will particularly impact upon the upper ranges of sea level rise projection (IPCC 2007).

Figure 2 10 shows 17 models of projected sea level rise around Australia. A 'best-estimate' Australian sea level rise model was not available due to significant uncertainty and variation between models. In general, the models indicate that sea level rise on the north-west and east coasts of Australia will be greater than the global mean sea level rise (CSIRO & BoM 2007). As is the case for temperature and rainfall, the El Nino-Southern Oscillation creates significant regional variability in the magnitude and trend of sea level rise in the oceans surrounding Australia.

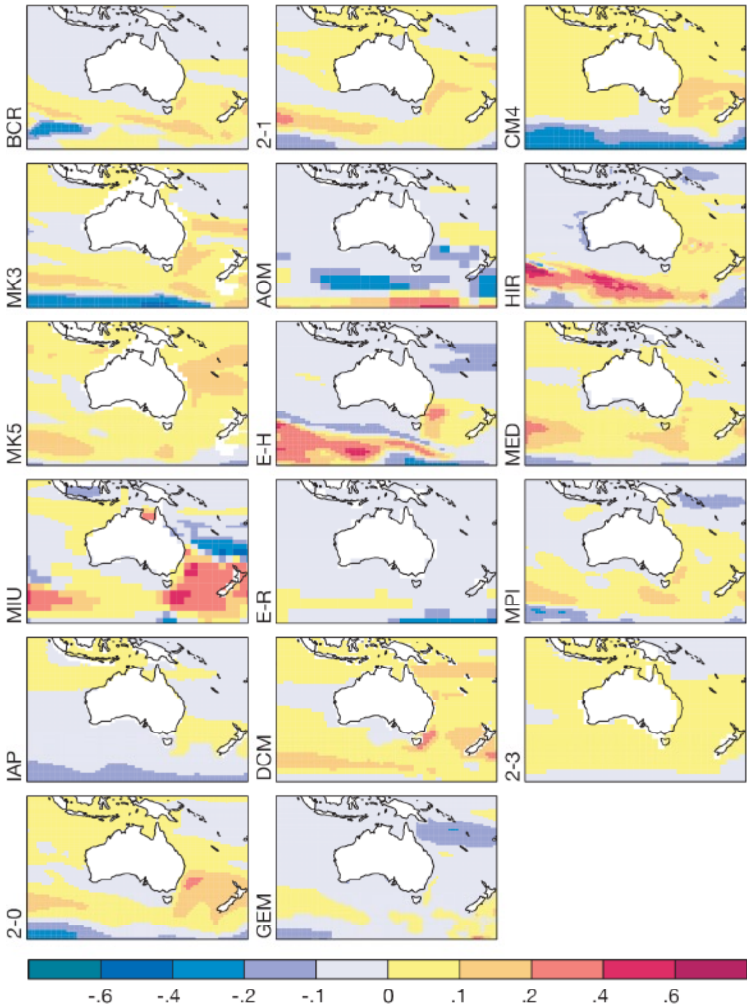


Figure 2 10: Projected sea level rise to 2070 relative to the global averaged value for each model (in metres). Calculations based on 17 models

Source: CSIRO & BoM 2007

Increased mean sea levels are likely to increase flooding of low-lying coastal areas, particularly when combined with storm surge (CSIRO & BoM 2007, p. 92). Storm surges occurring on higher mean sea levels will enable inundation and damaging waves to penetrate further inland. This would increase flooding, erosion and damage to built infrastructure. Changes to wind speed will also affect storm surge height. As with temperature and precipitation, extreme sea level events are likely to have greater impacts than an increase in mean sea level.

Studies indicate that portions of the Victorian and Queensland coasts have the potential for significant increases in inundation due to higher mean sea level and more intense weather systems. Storm surge events are predicted to impact heavily in the areas around Corner inlet and Gippsland lakes in eastern Victoria and a number of locations in Queensland, including Cairns and the Sunshine Coast (CSIRO & BoM 2007, p. 96).

Infectious diseases

Climate change is forecast to increase the spread of infectious diseases such as Ross River fever, malaria and dengue fever. Increasing temperatures in northern Australia will permit mosquitoes to move further south into previously inhospitable areas as well as higher latitudes, while disease transmission seasons may also last longer. Epidemics of dengue fever appear to recently have become more regular in north Queensland; however, this is partly attributable to increasing travel in the region.

The spread of infectious diseases due to climate change will be a function of social, environmental and political factors, including public health, population density, waste management systems and human behaviour. The impact of potentially increasing rates of infectious disease on energy network businesses is considered minor and is therefore not used as an input to the risk assessment process in this report.

Key message

Potential impacts of climate change in Australia include both single-event extreme weather phenomena such as cyclones and flooding, as well as significant changes in the weather regime.

2.2.2 Extreme weather event projections

The Garnaut climate change review (2008a) defines severe weather events as an event of an intensity that is rare at a particular place and time of year. Definitions of ‘rare’ vary, but are usually defined as being rarer than the 10th or 90th percentile of probability. Single events, such as tropical cyclones or long-lived heatwaves cannot be directly attributable to climate change. Climate change may, however, affect the factors that lead to such events and make certain events, such as tropical cyclone Larry that caused significant damage in Queensland during the summer of 2006/07, much more likely (Garnaut 2008a, p. 144). Global warming can thus make events like tropical cyclone Larry or other severe weather phenomena observed in recent years, seem less extraordinary.

The relationship between averages and extremes is often non-linear. For instance, a shift in average temperature is likely to be associated with much more significant changes in very hot days (Department of the Environment and Heritage 2006). Hence, changes in average climate superimposed on daily, seasonal and annual variability, may lead to significant changes in the frequency of extreme weather events (Garnaut 2008a)

Extreme weather events used for the purposes of this report are as follows:

- tropical cyclones
- severe thunderstorms
- bushfires
- drought
- heatwaves.

Tropical cyclones

Studies suggest that the frequency of Australian east coast cyclones will either remain the same or decrease by up to 44%, while the intensity of category 3–5 storms will increase by 60% for 2030 and 140% for 2070 (CSIRO & BoM 2007). Projections also indicate that the region of east coast cyclone genesis may shift southward by 2 degrees or a distance of 200 km, largely associated with warmer sea surface temperatures in response to increasing greenhouse gases (Leslie et al. 2007, in Garnaut 2008a). Models also estimate that the number of strong cyclones reaching the Australian coastline will increase, and 'super cyclones' of intensity unrecorded to date on the Australia east coast, may develop over the next 50 years.

The increased intensity of cyclones is likely to increase near-storm precipitation, wind speeds and extreme wave heights in affected regions (IPCC 2007 in Garnaut 2008a). The increased storm surges associated with tropical cyclones will also lead to coastal flooding and erosion, potentially leading to an increased number of landslides. Tropical cyclones will also increase off-shore impacts, with increasing occurrence of intense wind and wave events, exacerbated by rising sea levels. Such extreme weather events are likely to impact on coastal infrastructure and increase the risk to human health and lives (AGO 2006, p. 17). Coastal areas in south-east Queensland and northern New South Wales are among the areas likely to be subjected to increasing severe cyclonic impacts.

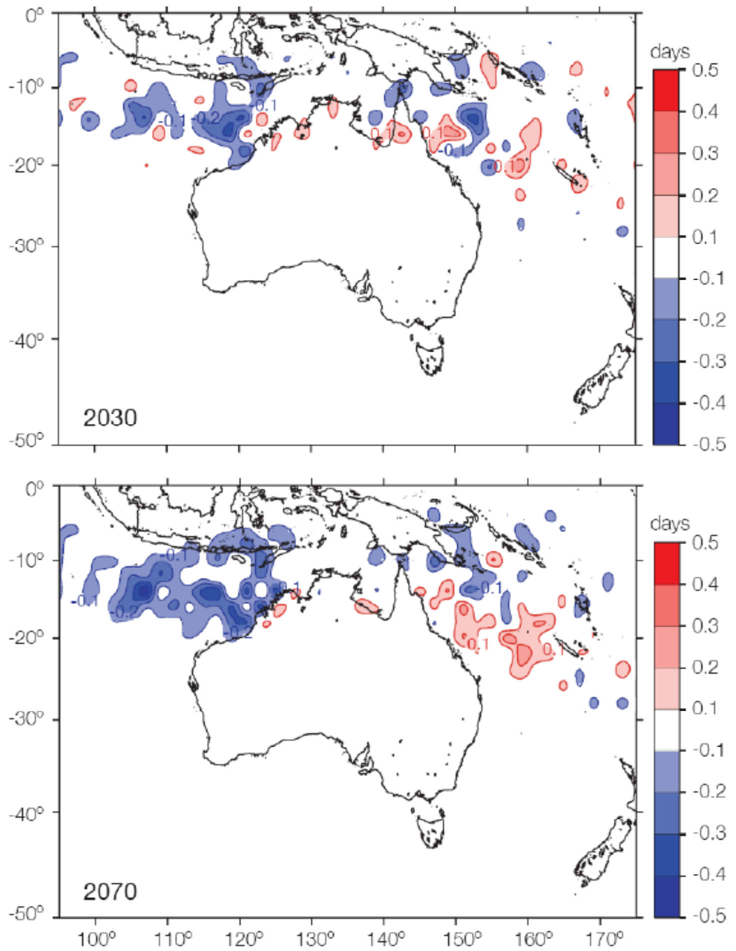


Figure 2 11 shows simulated changes in annual average tropical cyclone occurrence in the Australian region. The simulation indicates a general increase in cyclone occurrence off the north-east coast of Australia in 2030 and 2070, and decreased cyclone occurrence off the north-west coast over the respective periods.

Figure 2 11: Simulated change in annual tropical cyclone occurrence in the Australian region for 2030 and 2070. Results from CCAM Mark3 simulations forced with the SRES A2 scenario

Source: (Abbs et al. 2006, in CSIRO & BoM 2007)

2

Severe thunderstorms and tornadoes

In Australia, a thunderstorm is classified as severe by the Bureau of Meteorology if it produces either hailstones with a diameter larger than 2 cm, wind gusts greater than 90 km/h, flash flooding or a tornado (CSIRO & BoM 2007).

Model results show that conditions will become less suitable for the occurrence of tornadoes in southern Australia in the cool season. Cool season (May to October) tornadoes account for about 50% of all observed tornado events in Australia, observed mostly in Western Australia and South Australia. A scientific determination of the impact of climate change on tornadoes in summer months is not yet possible.

Hail storms on the eastern coastal region are typically associated with storm fronts and severe downdraft and outflow winds. Hail risk is likely to increase over the south-east coast of Australia as illustrated in Figure 2 12 (CSIRO & BoM 2007). Figure 2 12 shows the projected changes in hail days per year from the CSIRO Mark 3.5 Model for the SRES A2 scenario. Blue regions indicate a decrease in hail risk and red regions indicate an increase in hail risk. The large hail risk for the east coast south of the 25th latitude is projected to increase from 4 days per year in 2030 to 6 days per year in 2070. Decreases in hail risk along the southern coastal region are projected in the corresponding periods.

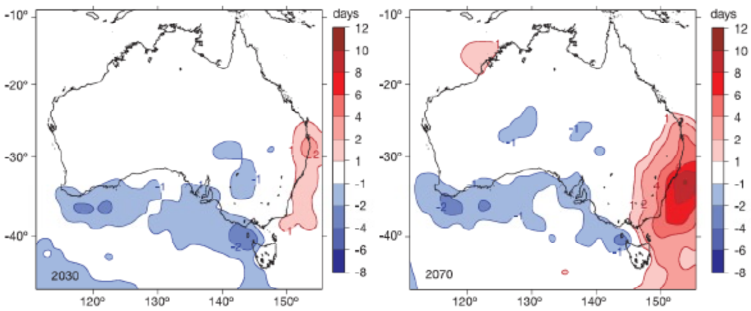


Figure 2 12: Hail risk days per year for 2030 and 2070

Source: CSIRO & BoM 2007

Bush fires

Fire weather risk is expected to increase as a result of increased mean and extreme temperatures, and decreased relative humidity (AGO 2006). A substantial increase in fire weather risk is likely at most sites in southern-eastern Australia, with the exception of Tasmania (CSIRO & BoM 2007). The increase in fire weather risk is generally largest inland. Fire risk may exist elsewhere in Australia, but this has yet to be thoroughly examined (CSIRO & BoM 2007).

The most recent projections (Lucas et al. 2007 in Garnaut 2008a) suggest that fire seasons will start earlier, end slightly later, and generally be more intense in their duration. This effect increases over time, but should be clearly evident by 2020. Table 2 11 shows projections for increases in the number of days with very high and extreme fire weather. The figures in Table 2 11 are based on scenarios producing 1°C and 2.9°C temperature increases for 2034 and 2067 respectively, under a no-mitigation case (Garnaut 2008a, p. 157).

Fire weather	2034	2067
Very high fire weather	+10–30 days	+20–100 days
Extreme fire weather	+15–65 days	+100–300 days

Table 2 11: Projected increases in the number of days with very high and extreme Australian fire weather for selected increases in global mean temperature

Drought

Drought occurrence is projected to increase over most of southern Australia but particularly in south-western Australia. Drought projections are based on simulated changes in rainfall and potential evaporation from the Canadian (CCCma1) and CSIRO (Mark 2) global climate models. The potential rainfall reductions in some regions will result in an escalation in the effects of drought currently being experienced in many parts of the country. The simulations indicate that most of Australia is likely to experience up to 20% more drought-prone months by 2030. Drought periods are likely to extend in duration in eastern Australia by 40% by 2070 and 80% in south-western Australia (Mpelasoka et al. 2007, in CSIRO & BoM 2007).

The increased frequency and severity of drought will reduce soil moisture, especially in southern Australia, increasing ground movement and causing changes in groundwater (AGO 2006, p. 17). Regions of ground shrinkage due to deep cracking soils are likely to increase.

Heatwaves

Heatwaves have become increasingly common across Australia. The number of hot days and warm nights has increased per year since 1955. Extended hot periods have also increased. In the summer of 2007/08 for instance, Adelaide experienced 17 consecutive days over 30°C, breaking the previous record of 14 days. Hobart matched its previous record high temperature of 37.3°C and Melbourne recorded a record high overnight minimum of 26.9°C (National Climate Centre 2008, in Garnaut 2008a, p. 151).

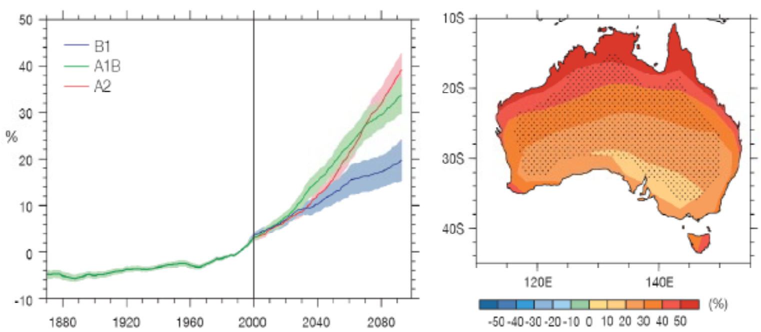


Figure 2 13: Area-average time series of warm nights (left) from the CMIP3 multi-model dataset, using SRES B1, A1B and A2 scenarios. Mean projected changes in warm nights over Australia for 2100 (right) using CMIP3 multi-model dataset for A1B

Source: Tabaldi et al., 2006 in CSIRO & BoM 2007)

Heatwaves are expected to become more intense, more frequent and longer lasting as the climate warms (IPCC 2007 in Garnaut 2008a). There is projected to be a strong increase in the frequency of hot days and warm nights. Figure 2 13 indicates that the number of warm nights is projected to increase throughout the 21st century, and that the frequency of warm nights will increase over all parts of Australia, with the greatest increases in the far north coastal areas.

The projected increase in days over 35°C for all Australian capital cities is included in Table 2 12. Most notable is the marked increase in the number of hot days in Darwin, increasing from the current average of 9 days a year, to 36 days a year in 2030, and 221 in 2070 (Garnaut 2008a, p. 156).

State/Territory	Current	2030	2070
Adelaide	17	22	34
Brisbane	0.9	1.7	8
Canberra	5	8	21
Darwin	9	36	221
Hobart	1.4	1.7	2.5
Melbourne	9	12	21
Perth	27	35	56
Sydney	3.3	4.4	9

Table 2 12: Projected increases in days over 35°C for all Australian capital cities under a no-mitigation case

Source: CSIRO & BoM 2007 in Garnaut 2008a

Key message

A substantial increase in fire weather risk is likely at most sites in southern-eastern Australia, with the greatest risk generally in inland regions.

The intensity of Australian east coast cyclones will increase significantly, while the region of cyclone genesis may shift southward by a distance of 200 km. Hail risk is likely to increase over the south-east coast of Australia.

The frequency and severity of drought will increase, especially in southern Australia, expanding regions of ground shrinkage. Heatwaves will become more intense, more frequent and longer lasting as the climate warms.

3 Our approach to the study

Given the complexities, uncertainties and broad scope of this study, the establishment of an effective and robust methodology has been a critical part of the work. In this section, we describe some of the issues and challenges associated with developing a credible approach, and set out the broad, over-arching methodology, including principles and key assumptions. We also outline our approach to the development of the scenarios used in our analysis and the application of a risk-based approach to assessment.

3.1 Issues and challenges

Energy network businesses are comparatively large and complex organisations delivering energy transportation and distribution services through the ownership and operation of a large number of high value physical assets, usually across a large and diverse geographic region. Efficient discharge of business operational responsibilities requires the effective coordination of a large, dispersed workforce, and the planned organisation of a variety of specialist plant and equipment, and a large vehicle fleet.

The potential outcomes are numerous, complex and uncertain

Climate change comprises a highly complex set of concepts, issues and problems.The number of scientific considerations alone makes for the prospect of a huge number of potential scenario permutations. Assessing the potential physical impacts of climate change over a long time horizon (2030 and 2070) for a country the size of Australia, and translating these individual scientific parameters into meaningful climate change events through the consideration of credible combinations and probable outcomes, represents a significant challenge.

Overlaying these numerous, and varied, climate change scenarios on the highly complex and diverse energy network businesses in an attempt to identify the possible business impacts and outcomes, represents a potentially highly complex, multi-dimensional problem.

The uncertainty surrounding climatic and physical science outcomes and also the uncertainty associated with changes to external business frameworks and the level of government (policy) responses to climate change, adds significantly to the assessment challenge. Potential uncertainties include, but are not limited to the following:

- multiple variables in the predicted climatic changes (such as temperature changes, wind speed changes)
- numerous potential outcome 'events' such as increases or decreases of temperatures over time and over different regions of Australia
- the potential effects of these events and outcomes on the energy networks businesses (such as increased demand for electricity due to temperature increases)
- the likely price of carbon permits over time
- the future likely mitigation measures (such as regulation and responses by the community at large)
- the future likely uptake of renewable energy and any switching of energy forms (for example from electricity to natural gas)
- the feedback of those measures on the potential effects on the energy network businesses.

Because of the breadth of scope of this study, PB (Parsons Brinckerhoff) has adopted a flexible approach which has enabled us to focus on those outcomes of climate change which are significant and relevant to network businesses. Adopting a number of key principles and assumptions has meant that many of the potentially complex issues are restated in a 'manageable' form — which can be appropriately considered within the time and scope of the engagement.

Adaptation and mitigation (abatement) are related

Some complex interdependencies are subtle and not immediately obvious. For example, there is a link between actions which may be taken by the businesses to reduce the impacts of their energy networks on climate change (mitigation) and the physical impacts of climate change on their energy networks (adaptation). This association between mitigation and adaptation can be complex — particularly as there is almost certain to be a time lag between mitigating actions and any adaptation impact. An example of this might be the investment in stronger, larger, cross-sectional area conductors for the purposes of reducing the impact of storm conditions on network performance — and the consequential impact which this may have on the reduction of energy losses, and hence carbon emissions. Figure 3 1 shows how energy business activities can impact on climate change and how policy measures can be used to reduce business impacts (adaptation) and also reduce emissions (mitigation).

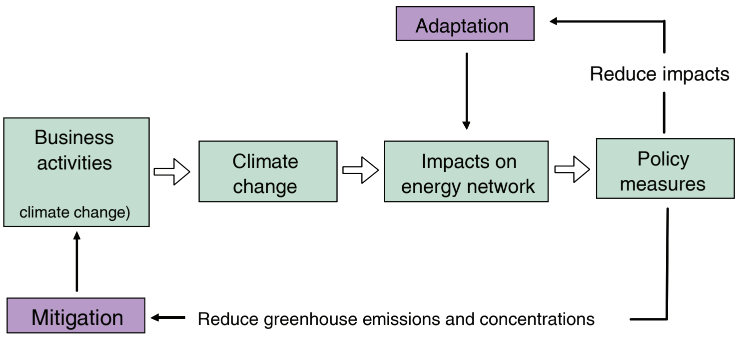


Figure 3 1: Relationship between mitigation action and adaptation impact

At a prima-facie level, external policy measures, public engagement and response and external markets are decoupled from climate change science. However, further examination leads to the prospect of meaningful links between these inputs.

The problem is multidimensional

The work undertaken in this review has both temporal (time) and spatial (geographic) dimensions. The climate science scenarios, government policies and other external business factors all vary geographically. In addition, the scope of the study requires views, thoughts and perspectives of impacts of climate change on network businesses in the long term. For the purposes of this study, we have taken two time 'snapshots' — 2030 ('around the corner') and 2070 ('the future'). These additional dimensions of time and geography add to the potential complexity of the problem.

Given all this, it was recognised early in this work that the development of a robust and credible approach to the work, i.e. an effective methodology, would be critical if the aims and objectives of the study were to be achieved.

3.2 The overarching methodology

In this section we provide a brief overview of the approach we have adopted for the assessment of the impact of climate change on the energy networks in Australia.

An important aspect of our approach in undertaking this study has been to try to ensure full coverage of the issues. That is, to try to ensure that as much as possible, all potential impacts, issues or opportunities are identified and captured.

Our work adopts a whole-of-business approach and is, therefore, not just concerned with the issues that come most readily to mind when considering the implications of climate change — particularly those related to asset-based adaptation. Inclusion of broader issues associated with the (energy network) business environment was an important part of the study.

In our deliberations, we have favoured coverage rather than analytical depth, for two reasons. Firstly, the value of analytical rigour and depth is likely to be questionable given the level of future uncertainties associated with climate change and the further uncertainties in the regulatory and public responses. Secondly, we believe that ensuring that the full range of issues has been identified and captured is likely to prove more fruitful — in terms of policy opportunities — in the long run than an over-analytic approach which focuses on a limited number of specific areas and therefore runs the risk of getting 'lost in the detail'. We believe that this approach is most likely to (i) capture any 'big-ticket' items or issues; and (ii) minimise the prospect of over-analysis based on a large number of climate science scenarios.

In essence, we have attempted to avoid putting effort into analysing sensitivities around uncertainties where the outcome is unlikely to have a material impact on the businesses.

We have adopted a risk-assessment approach to the study

PB's view is that the best way to identify and capture the impacts on, and opportunities for, energy network businesses resulting from climate change — whilst effectively dealing with the inherent uncertainties associated with the alternative outcomes — is to adopt a classic risk assessment approach based on a limited number of credible scenarios. The scenarios aim to capture a reasonable range of potential climate and business environment outcomes. In developing the likely scenarios for risk assessment, we considered only those likely events and scenarios that are expected to have an impact on energy networks.

To manage the complexities and the huge number of permutations, we have developed a system of simplifying the risk assessment processes by reducing the number of permutations to a more meaningful set of outcomes without diminishing the rigour or the credibility of the methodology.

While the link between adaptation and mitigation is recognised, in the presentation of our thoughts and findings in this study, the issues, risks and opportunities associated with adaptation (the impact of climate change on the energy networks businesses) are addressed separately from those associated with mitigation (the effect of the businesses on climate change). This is one of our simplifying assumptions which has enabled us to provide the coverage required in this study to capture all of the potential issues and outcomes.

In essence, the PB approach to the work comprises the following key elements:

- the development of credible scenarios based on fundamental inputs
- the application of PB's environmental and energy industry knowledge to ascertain:
- the potential implications for energy networks businesses resulting from credible combinations of these fundamental input (i.e. the 'events' that might arise)
- an assessment of the likelihood of these events occurring
- an assessment of the impact that these would have on the energy businesses, should they occur
- analysis to determine the potential 'hot spots[9]' through a risk assessment process
- identification of areas of opportunity for policy development and further industry consideration.

An overview of this process is provided in Figure 3 2.

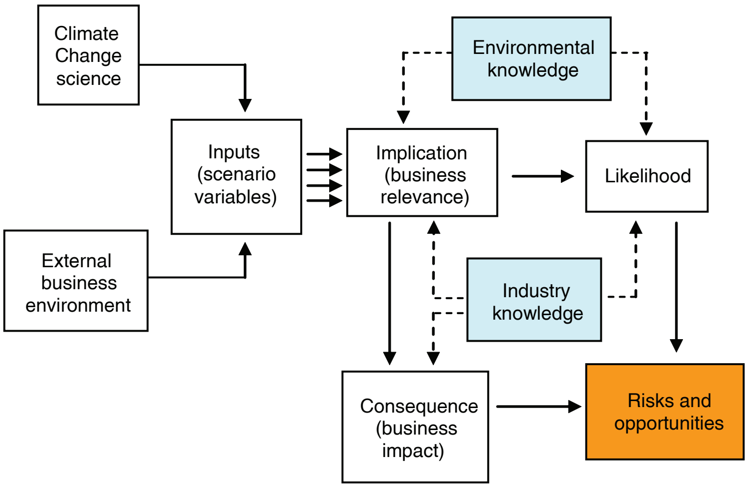


Figure 3 2: Overview of assessment process

The approach is to focus on risks, challenges and opportunities which are specific to the energy industry. Furthermore, in determining the approach and process, it was assumed that most, but not all, network-specific issues will be adaptation related. The process set out in Figure 3 2 is designed to capture these industry-specific adaptation events.

Mitigation issues

It is recognised (and assumed in this study) that the majority of mitigation issues will be common to many different industries and business operations. These will include climate change impacts associated with travel and transport, heating and lighting, IT etc. However, it is further recognised that there are a number of mitigation issues which are specific to the gas and electricity network businesses — such as electrical and gas losses, and the use of industry-specific greenhouse gases such as sulfur hexafluoride (SF_6).

[9] 'Hot spots' are the implications with significant consequence to network businesses identified through the risk assessment process i.e. the high risks.

Gas and electricity network businesses

We have elected to deal separately with the gas and electricity sectors, while recognising and identifying common risks and issues. This is particularly the case for mitigation and for business operating externalities such as government policy and regulatory treatment of network costs, investment, service and performance.

3.3 Scenario development

The development of a manageable number of credible scenarios forms an important aspect of PB's approach to this study. The scenarios are the key inputs to the assessment process. It is important to note that the fundamental concept of a scenario is to represent a single possible future outcome. This is distinctly and importantly different from a forecast or projection which attempts to model the most probable forward outcome.

The scenarios developed and used by PB for this study aim to capture the important aspects of owning and operating an energy network within an environment of a materially changing climate. During our initial work on the development of the study methodology, and through discussion with Energy Networks Association (ENA) representatives, it became clear that the key challenges, solutions and opportunities associated with climate change impacts were likely to be as much about government responses, regulatory framework and public engagement as about climate science, and potentially more so.

As a result, PB has developed a set of hybrid risk assessment scenarios which incorporate the following key elements:

- physical climate change
- business environment
- government and regulatory response
- public engagement.

Our view is that it will be the combinations of varying degrees of each of these elements which will determine the future impact on the Australian energy network businesses.

3.3.1 Physical climate change

Anticipated changes in climatic conditions as a result of human activity is a key consideration of this study. Climate science therefore forms an essential ingredient to the development of credible scenarios.

The most influential projections used in climate change analysis are those set out in the Special Report on Emissions Scenarios (SRES) of the IPCC (2007). These projections form the basis for the work undertaken by the CSIRO & BoM (2007) and more recently by Garnaut (2008b).

In our scenario development and assessment we have used 2030 and 2070 as the two time horizons for the assessment of potential impacts, solutions and opportunities. Climate science projections are available for both of these future dates through SRES and IPCC.

According to the Garnaut final report (2008b, p. 64) and CSIRO, the SRES A1B scenario is the best estimate of annual warming over Australia relative to the climate of 1990. CSIRO & BoM (2007) recognises SRES A1FI as the high emissions scenario; however, recent scenario projections by Garnaut indicate potential emission paths greater than the A1FI high emissions scenario. The 'Platinum Age' and 'Garnaut-Treasury reference case' models, developed as part of the Garnaut Climate Change Review project higher emissions paths to 2030 than the A1FI high emissions scenario; comparable emissions scenarios with A1FI are projected to 2070. Australian regional climate change impact projections that are relevant for energy network businesses are not available to accompany the new Garnaut scenario models. As these regional climate change impact projects are not available, we have utilised the A1FI scenario. A1B and A1FI are therefore the two climate science scenarios used in our hybrid composite scenarios for risk assessment.

The climate science parameters associated with these projections, which PB has determined to be most relevant to the energy networks businesses (in terms of risks, solutions and opportunities) are as follows:

- temperature
- wind speed
- storm activity and rainfall
- sea level.

The projected changes for each of these core elements is presented in Table 3 1.

Scenario	Year	Temp	Wind	Storm	Sea level
A1B (best estimate)	2030	+0.6–1.5°C[1]	+2–5%[2]	TBC[3]	+3 cm[4]
	2070	+1–2.5°C[5]	+5–10%[6]	TBC[3]	+21–48 cm[4]
A1FI (high emissions)	2030	+0.6–1.8°C	+2–5%[2]	+60%[7]	+17 cm
	2070	+2.2–5.0°C	+10–15%	+140%[7]	+26–59 cm

Table 3 1: Climate science parameters for each scenario

Table notes:

[1] *+16–65 days extreme fire danger, 2-3 (20%) additional drought-prone months*

[2] *Inland southern Queensland only*

[3] *No specific A1B or A1FI data but implication for tropical cyclones and hail risk*

[4] *Implication for storm surge*

[5] *30% increase in warm nights, +100–300 days extreme fire danger, +40–80% drought-prone months*

[6] *Across most of Queensland and south-central Australia (SA & WA)*

[7] *Increased severity of category 3–5 storms*

These projected changes in fundamental climatic conditions are used to establish consequential events relevant to the energy network businesses.

3.3.2 Business environment

Government (and regulatory response), while essentially a secondary effect, is recognised as being the source of, potentially, the most significant business impacts. It is the mitigation policies and abatement policy framework within which the businesses are required to operate that has the potential to represent the most significant potential impact and source of opportunity for energy networks.

The extent to which the public engages and participates in climate change measures, also has the potential to significantly affect the level and nature of risks and opportunities in the energy networks businesses. This aspect is also factored into the scenario design.

It should be noted that the CSIRO climate science scenarios used in this study also make assumptions about government policy response, emissions trading and other regulatory instruments associated, particularly, with mitigation measures. However, these are global considerations and do not, therefore, adequately reflect the Australian business environment specific to the energy network businesses. The effect of these is, therefore, considerably diluted when it comes to being relevant to Australian businesses. The business environment element of the composite scenarios developed by PB as part of this study aims to capture local issues.

The policy and other external factors which PB has considered in developing its input scenarios includes, but is not limited to, the following key policies and initiatives:

- implementation of the Australian Carbon Pollution Reduction Scheme (CPRS)[10]
- the form of regulatory framework for monopoly electricity and gas network businesses
- the Australian Renewable Energy Target (RET)
- the Minimum Energy Performance Scheme (MEPS)
- Climate Challenge Plus
- Feed-in tariffs (FIT)
- photovoltaic (PV) rebate program
- Clean Coal Fund
- Green Loans
- Renewable Energy Fund
- Interval meter roll-out
- Low Emission Plan for Renters
- Green Car Fund.

The extent to which these policies, programs and other forms of regulation continue to develop, the way in which they may be implemented in future, and the community's

[10] The proposed Australian Emissions Trading Scheme.

responses to them, will have a profound effect upon the development of the Australian energy industry in general, and the energy network businesses in particular.

It is recognised that a number of these policies and support programs are relevant to today and may, or may not, exist or be relevant in future. Clearly, it is extremely difficult to predict the policy instruments and regulatory sentiment which may exist in 20, 50 or 60 years time.

Hence, in order to manage this uncertainty, but to still enable this important aspect of ‘business environment’ to be captured into the scenarios, we have attempted to quantify the extent of changes to the business environment in terms relative to our present knowledge and opinion. This is based on our understanding of what can reasonably be expected from the Australian Government and from other policy makers to influence behaviour related to climate change.

This results in an assessment of the level of Australian Government response as being either low or high.

Similarly, as part of our scenario construction, we have incorporated the potential impact of the extent of public engagement though a relative assessment, leading to a high or low grading.

3.3.3 Creating the composite scenarios

Two alternative climate science scenarios, two levels of government policy advice and a high and low rating for the level of public interest and engagement, results in the potential for nine different scenarios.

As climate projection A1B represents the best estimate of projected changes in climate science, and with due regard to the extent to which variations in climate science parameters are likely to impact on the energy network businesses, we selected A1B as our base science scenario. We then considered the relationship between government policy response and the likely extent of public engagement.

Our view is that there is a comparatively strong correlation between these two aspects of business environment (government policy and public engagement). Moreover, a high level of public interest is unlikely to exist in the face of high levels of government apathy or inaction. Similarly, a highly motivated and engaged Australian public are likely to drive high levels of government action and involvement or are likely to be the result of government actions. Correlation between the policies of a democratically elected government and the voting public is perhaps not too surprising.

As a consequence, and for purposes of reducing the number of scenarios without compromising robustness, we have combined the level of government response and the level of public engagement — on the assumption that they will be reasonably well aligned.

Furthermore, as the climate science scenario A1FI represents a high (global) emissions case, we have assumed that it is most likely that this would lead to high levels of government response and a high level of public awareness and engagement. In short, this climate science outcome would result in all governments being eventually driven to take action.

The result is that the number of fundamental composite scenarios is reduced to three. These are set out in Table 3 2.

Scenario no.	Climate science scenario (CSIRO)	Government policy response	Public engagement
1	A1B	Low	Low
2	A1B	High	High
3	A1FI	High	High

Table 3 2: Summary of scenarios

Geographic location will affect outcomes

The potential impact, risks and opportunities associated with climate change will be geography specific — this is true for both the climate science and also for the business environment. The impact on energy networks of changes in climate science parameters will differ significantly across Australia. For example, some areas will experience lower average rainfall while other areas may be newly exposed to storms and cyclonic activity. The infrastructure in some regions will be better prepared for variation and uncertainty in temperatures and wind speed than others.

In an attempt to capture these spatial differences, we set out by dividing the country into seven regions — six coastal regions and a single inland region. Our methodology provided for the number of independent regions to be rationalised if insufficient differences in impact and opportunity outcomes made this more efficient. The seven geographic regions used by PB are presented in Figure 3 3.

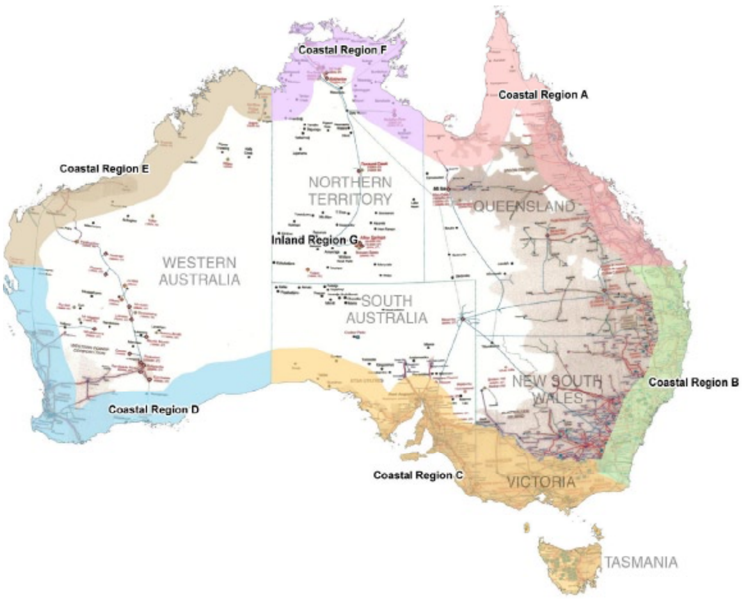


Figure 3 3: Geographic assessment regions

Australian Coastal Regions ~ 200km

3.4 Risk assessment

Our methodology for providing the required level of business coverage while effectively (and efficiently) dealing with the significant level of uncertainly, led to the application of a classic

risk assessment approach. For a defined event, an assessment of both likelihood (of the event occurring) and consequence (of the event occurring) is used to arrive at a risk rating associated with the given event. The process involved a semi-qualitative analysis of risk in accordance with the Australian risk management standard[11].

Knowledge of the energy industry and environmental issues have been used to determine the events which are likely to result from the input scenario variables and which are relevant to gas and electricity network businesses in the context of an impact and opportunity arising from climate change. This implication or business relevance, and the likelihood of its occurrence under the given scenario, formed a key input to the risk assessment.

Business consequence was assessed according to six impact groups. These groups have been defined such as to attempt to capture the full range of business impacts; not just those associated with impact on the physical network assets, for example. These business groupings are health and safety, network performance, network investment (commercial), business operations, business reputation and the environment. The scenario inputs, business relevance (defined events) and consequence categories, are given in Table 3 3.

Inputs (scenario variables)	Implications (business relevance)	Consequences (business impact)
Temperature	Bushfire	Health and safety
Sea level	Drought	Network performance
Wind speed	Tropical cyclone	Network investment (commercial impact)
Rainfall	Severe thunderstorm	Business operations
Storms	Floods	Reputation
Renewable energy target	Change in peak demand	Environment
CPRS (ETS)	Change in energy volume	
Energy efficiency standards	Change in generation mix (includes distribution —connected and renewable)	
Public sentiment	Change in network capacity	

Table 3 3: Risk assessment elements

Both likelihood and consequence assessments have been undertaken in accordance with a 1–5 rating. The likelihood ratings are given in Table 3 4.

An assessment and rating of the consequences requires a quantification of the impact for each consequence level in each of the six business impact categories — a total of 30 quantifications. PB has modelled the quantification of business impacts on a moderate-sized energy networks business — defined as one having annual revenues in the range $300m to $500m. The consequence definitions are carefully determined to ensure that, for any given consequence level, the impact on the business is of the same magnitude (e.g. the network

[11] AS/NZS 4360:2004.

Level	Descriptor	Description
5	Almost certain	The event will occur on an annual basis or more frequently
4	Likely	The event will probably occur each year
3	Possible	The event might occur during a year
2	Unlikely	The event is unlikely to occur during the year
1	Rare	The event is most unlikely to occur during the year

Table 3 4: Likelihood table

business should be indifferent to whether or not a ‘moderate’ consequence occurs as a business operation issue or a public relations-type issue).

A table that provides detail of the quantification of business impacts used in the risk assessment process in included in Appendix C.

The risk score is determined as the product of the likelihood score (for the given event) and the highest consequence score. We have further grouped the risks into three levels: high, medium and low, based on their scores. Negative risks are allowed and will emerge as opportunities or potential benefits. A table illustrating the risk assessment is included in Appendix C.

The tables have been constructed based on AS/NZS 4360:2004.

3.5 Cost estimation

We have estimated the cost to network businesses of the impact from climate change and the cost of a network business mitigating emissions. These estimates are presented for a typical network business in Sections 4.5 and 5.2.

3.5.1 Cost estimate of the impact of climate change on network businesses

The risks identified in the risk assessment have been used to establish the actions that we consider a typical network business is likely to undertake in response to climate change. This involves the following:

- identifying the specific risks that are rated as ‘high’ or ‘medium’
- identifying the potential impact for each of the risks
- determining a number of potential responses that a network business might take to reduce the impact and mitigate the risk
- identifying a likely set of responses from the set of potential responses
- estimating the cost to a typical network business of the recommended response.

The cost estimate prepared presents a total cost estimate for all energy network businesses and also the costs for a typical network business. A typical network business has been defined by the size of its regulated asset base (RAB).

3.6 Survey of network businesses

In order to collect information regarding the level of network business activity in response to climate change, PB conducted a survey of ENA member companies.

The survey focused on current and planned activities to both adapt to the impacts of climate change and to mitigate greenhouse gas emissions. The mitigation activities included those taken to address the businesses' operational emissions as well as emissions such as network losses and the indirect emissions associated with the end use of energy transported across the network. The survey also asked for greenhouse gas emissions figures, emissions reporting activities and the key risks that the businesses perceived that they face due to climate change.

The survey was used as an input to the overall assessment in a number of ways:

- to familiarise with the current level of network business activity
- to identify the areas in which activity is focused and in which activity is lacking
- to understand the key risks as perceived by the businesses
- to provide a collated list of network business activities as an item in the report
- to direct the focus of mitigation strategies based on the magnitude and breakdown of emission profiles.

The survey also acted as a conduit for companies to ensure that their particular concerns were considered in the risk assessment process undertaken by PB. The results of the survey have been used to inform our identification of opportunities (Section 6) and our conclusions and recommendations.

4 Impact of climate change on network businesses

In this section we identify the climate change impacts on network businesses and estimate the cost to network businesses as a result of climate change. These impacts are the result of the physical impact of climate change, government policy and incentives, and public responses to climate change.

The impacts are described for three scenarios and two timeframes. Regional variations are also identified. The construction of the scenarios is described in Section 3.3. Impacts have been categorised into three groups: physical, commercial and corporate. Physical impacts are those that result in a physical change to the network through damage or involve widespread interruptions to supply. Commercial impacts are those that affect network investment or revenues. Corporate impacts are adverse publicity and health, safety and environmental impacts.

4.1 Key risks

This section presents the output from the risk assessment process used to identify the key climate change impacts on network businesses. Appendix C contains the output tables from the risk assessment. The risk analysis considers a group of impacts on network businesses. Each of these impacts has been assessed on the basis of (three) different climate change scenarios, electricity and gas network types, and also for defined geographic regions of Australia.

We have condensed the risks identified in the risk assessment process to summarise the important risks that will have some impact on network businesses. The high and medium risks along with the region of Australia and the network type are presented for Scenario 1[12] in Table 4 1.

Risks	Regions impacted	Network type
HIGH RISK		
Bushfire	All regions	Electricity transmission & distribution
Tropical cyclones	Tropical regions	Electricity transmission & distribution
Change in generation mix	NSW & Vic Qld & Vic	Electricity transmission & distribution Gas pipelines
MODERATE RISK		
Floods	Tropical regions	Gas distribution Electricity transmission & distribution
Severe thunderstorms	All regions	Electricity transmission & distribution
Change in peak demand	All regions	Electricity transmission & distribution
Tropical cyclones	Coastal southern Queensland and northern NSW	Electricity transmission & distribution
Drought	All regions	Gas pipelines & distribution networks

Table 4 1: High and medium risks (Scenario 1)

[12] Scenario 1 is described in more detail in Section 3.3. This scenario involves a moderate change in climate and low government and public responses to climate change.

The high and medium risks along with the region of Australia and the network type are presented for Scenarios 2 and 3[13] in Table 4 2. The impact is presented for Scenarios 2 and 3 combined — as our analysis identified no significant differences in the impact on network businesses between these two scenarios.

Risks	Regions impacted	Network type
HIGH RISK		
Bushfire	All regions	Electricity transmission & distribution
Tropical cyclones	Tropical regions	Electricity transmission & distribution
Change in generation mix	All regions Qld, Vic & NSW	Electricity transmission & distribution Gas pipelines
MODERATE RISK		
Floods	Tropical regions	Gas distribution Electricity transmission & distribution
Severe thunderstorms	All regions	Electricity transmission & distribution
Change in peak demand	All regions	Electricity transmission & distribution
Tropical cyclones	Coastal southern Queensland and northern NSW	Electricity transmission & distribution
Drought	All regions	Gas pipelines & distribution networks

Table 4 2: High and medium risks (Scenarios 2 and 3)

Each of the risks, including the key risks identified in Table 4 1and Table 4 2 is discussed in following sections.

Key message

There are significant risks to energy network businesses from climate change. The highest of these risks arises from bushfire, tropical cyclones and a change in the mix of generation. Lesser risks arise from floods, droughts and an increase in peak demand.

The risks of climate change affect all networks in all regions of Australia, to some extent.

4.2 Key risks as seen by energy network businesses

Figure 4 1 presents a summary of Energy Networks Association (ENA) member perceptions of the key risks resulting from climate change. Physical impacts on the network infrastructure and regulatory risk were identified as the principal risks to the overall network business performance.

The risk assessment in this section is aligned with the key risks assessed by the energy network businesses. However, the results are an outcome of our own assessment of risks which is based on analysis of different sources and opinions.

[13] Scenario 2 comprises a moderate change in climate and high government and public responses to climate change. Scenario 3 comprises a high change in climate and high government and public responses to climate change.

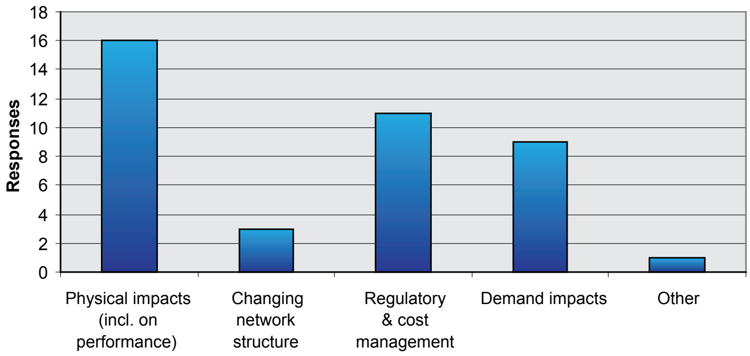


Figure 4 1: ENA network business assessment of risks posed by climate change

4.3 Climatic events

There are many changes affecting climate that could potentially impact on energy networks. Some of these changes, such as warmer winters, will have very little impact on energy networks while others, such as increases in the intensity of tropical storms, may have a significant effect.

We have included in this section, the impact from bushfires. While bushfires are not a climatic event, their intensity and frequency is directly related to a combination of drought, warmer temperatures and high winds.

The main climatic events that will have an impact on energy networks are:

- tropical cyclones
- bushfire
- thunderstorms
- increasing temperature
- drought
- floods.

Other impacts that have been considered as part of this study are the change in vegetation growth that results from periods of drought followed by heavy rain, the reduction in network capacity that results from increased temperature, and the spread of infectious diseases.

4.3.1 Physical impact on the network and on business operations

Climate change and associated extreme events can have a direct physical impact on energy networks. In this section we consider the direct physical impact, such as network damage, the associated impact on the service provided to customers, and the impact on operational groups such as repair crews and call centres.

Tropical cyclones

In 2030, tropical cyclones are predicted to both increase in intensity and to affect areas where they have not previously been experienced (CSIRO & BoM 2007). In each of the climate scenarios used in our assessment, the severity of tropical cyclones is expected to increase by 60% or greater. Severe tropical cyclones have the potential to have the most devastating impact on electricity infrastructure. For example, Cyclone Tracy in Darwin in

1974 destroyed most building structures, vegetation and distribution lines in the path of the storm eye. However, the transmission lines were slightly removed from the airborne debris path and remained intact.

In March 2006 tropical Cyclone Larry had devastating impacts on the North Queensland towns of Mission Beach, Innisfail and Babinda and surrounding areas. This storm's damage path extended some 150 km inland with significant impacts to all overhead line networks in the area. At the same time as Larry impacted on the coastline, 500 km off the coast another larger tropical cyclone, Wati, of greater intensity was heading for the Queensland coast. Fortunately, this storm veered away from the coast and degenerated but serves to illustrate the potential for compounding major events with disastrous consequences.

An increase in intensity of tropical cyclones will affect the northern parts of Australia that are subject to tropical cyclones. The movement of cyclones into regions that have not previously experienced cyclones will affect southern Queensland and parts of Western Australia. The climatic changes will result in an increased risk to electricity distribution and transmission businesses but are likely to have little effect on gas pipelines or gas distribution networks as these pipelines and networks are generally buried.

Damage from tropical cyclones primarily affects overhead networks where flying debris causes physical damage to the lines and structures or high velocity winds directly damage the network. Damage to electricity networks can be extensive resulting in widespread electricity supply interruptions and extended interruptions due to lengthy repair times.

A large proportion of distribution lines were constructed during the period 1945 and 1970 using hardwood poles. PB understands that most of these lines were constructed for the wind loadings expected at the time. These structure design loadings provide for synoptic wind loads of that time, with a 30% increased loading in cyclonic areas. These loadings do not correlate with the current wind loading standards.

Actions that can be taken by electricity network operators to mitigate the impact of cyclones on networks include redesigning the network and improving emergency response. The most effective way of minimising the impact of cyclones on networks is to construct the networks underground. Placing the distribution networks underground is feasible; however, the cost of an underground circuit compared to an equivalent overhead circuit is significantly higher, with this cost ratio increasing sharply as the operating voltage increases. It is even more expensive to convert an existing overhead network to underground. Transmission networks can be designed to withstand some cyclone damage, however, constructing underground transmission and subtransmission networks is very expensive and unlikely to be practical where transmission of energy over large distances is required[14] .

Bushfire

Climate forecasts predict a significant increase in the number of additional extreme fire weather days each year. In the southern regions of Australia (south of 25th latitude) and inland areas an additional 15 to 65 extreme fire weather days are forecast under the CSIRO 'best estimate' scenario and more than 15 to 65 extreme fire weather days are forecast in

[14] At transmission voltages underground circuit costs can be many times overhead circuit costs, depending on environment and terrain associated with the route.

the CSIRO scenario we have used to represent the 'high emissions' [15]. The CSIRO & BoM (2007) reports that the impact of climate change on bushfire in tropical regions is yet to be thoroughly scientifically examined.

Overhead electricity networks are exposed to the effects of bushfires and are also a potential source of bushfire ignition. Bushfires can affect electricity networks by burning wooden poles, by smoke and ash causing insulation to break down or by the disconnection of parts of a network to prevent operational instability during bushfires. Furthermore, as electricity networks are a potential source of ignition for bushfires, fire authorities may order a part of a network to be de-energised at times of high risk or during fire fighting activities. Bushfires may be caused by an electricity network in a number of situations such as where a live conductor falls to the ground, where a switch operates and sparks are emitted, or where vegetation makes contact with high voltage conductors.

Bushfires can have extreme effects on networks. For example, in 2003 extensive interruptions to electricity and gas supply occurred as a result of bushfires in and around Canberra. These fires caused extensive damage to the electricity network, particularly wooden poles, and widespread interruptions to electricity supply which lasted for several weeks in some areas. Similar impact is likely from the recent Victorian bushfires. Our analysis rates the risk to electricity networks from the increasing number of extreme fire weather days as 'high'.

Fires can also cause damage to the above-ground gas pipes where they enter residential premises, thereby fuelling fires. However, in these cases the damage to the network is seldom significant. Our analysis rates the risk to gas networks, of bushfire, as 'low'.

Severe thunderstorms

Severe thunderstorms can produce hailstones, wind gusts greater than 90 km/h, flash flooding and tornados. Associated with severe thunderstorms is an increase in lightning.

In 2030, some areas such as the northern New South Wales coast and southern coastal Queensland are expected to experience an increase in thunderstorm activity while other areas such as southern Western Australia, parts of South Australia, western Victoria and the north-west tip of Tasmania are expected to experience a decrease. In addition to changes in severe thunderstorms, much of Australia is predicted to experience increases in peak wind speed of between 5 and 10%.

Storms and lightning are the cause of many electricity network outages but have little impact on gas networks. Overhead electricity systems are exposed to windblown debris during storms and can be severely impacted by lightning strikes. In assessing the risk to energy networks we have considered the combined impact of severe thunderstorms, lightning and increase in peak wind speed. The risk to electricity networks from these events is rated as 'moderate'.

Storms can result in widespread damage to overhead networks, particularly distribution networks, which result in extended outages for customers and lengthy repair times. Damage can be caused by a number of means including the physical impact of debris, from debris and tree branches creating a short circuit between conductors and from lightning causing damage to structures or injecting highly damaging electricity voltage spikes onto the network.

[15] The A1B and A1FI climate science scenarios are the two climate science scenarios used by PB in the scenario design. Section 3.3 of this report describes this in more detail.

Increasing temperature and network capacity

Average temperatures are predicted to increase between 0.6 and 1.5°C by 2030 in each of the scenarios modelled. Additionally, the number of days with temperatures in excess of 35°C is expected in increase across the continent with significant increases in the number of these hot days in central and north-western Australia.

While increasing temperatures affect gas and electricity networks, the small increase in average temperatures in the range of 0.6 to 1.5 degrees is unlikely to have a significant impact on carrying capacity of network businesses. However, the increasing temperature will result in an increase in airconditioning load. This increase in airconditioning load is discussed further in Section 4.4. The increased number of hot days has an impact on electricity networks as high airconditioning demand increases the stress on network elements and may lead to increased failures, particularly on older networks. Further, the cyclic ratings of transformers are reduced under such conditions. In some southern areas the increasing temperature will reduce demand for winter heating and this will affect both gas and electricity networks. Our analysis rates the risk to electricity and gas network capacity, from increasing temperature, as being ‘low’.

Drought

In each region of Australia, droughts are expected to become more common. The prediction for Scenarios 1 and 2 is an increase of 20% drought-prone months per year and for Scenario 3 an increase of more than 20%.

Drought has a significant impact on generation facilities as water shortages affect hydro generation and also the cooling systems of coal-fired generators. The impact of these changes in generation is discussed in Section 4.4.

Droughts can have some effect on the gas networks. Significant ground movement in clay soils can cause pipes to crack resulting in gas escapes. This can cause an accelerated replacement of the gas pipes. Our analysis rates the risk to gas networks capacity from drought as ‘moderate’.

Drought has little direct effect on electricity networks and the direct risk to these networks is rated as ‘low’. Overhead power poles erected in cracking clay soils that have eccentric vertical loading configurations may have the potential to experience accelerated leaning due to deeper cracking potential at poles as deeper soil moisture levels are reduced. Buildings and substation support structures may have the potential to crack or move horizontally due to differential movement of the subsoil or shrinkage effects. Droughts can also lead to subsidence and shrinkage that can place stress on gas pipelines and electricity cable joints.

During periods of low rainfall, instances of flashover or electrical tracking due to insulation pollution from industrial, seaborne salts and dust sources are likely to be more prevalent. This will lead to an increase in maintenance activity and management. Flashover and electrical tracking can result in network outages and, potentially, fires that burn wooden cross-arms and poles. This may lead to an increasing need for seasonal washing of insulators on critical load feeders (although rain falls are likely to be more intense and so some natural washing of pollutants will occur).

Floods

In the two climate scenarios modelled by PB, extreme rainfall is predicted to increase. In 2030 for the coastal regions of Australia this increase is predicted to be between 0 and 10% in Scenarios 1 and 2 and greater than 0 to 10% in Scenario 3. Extreme rainfall in inland areas in predicted to increase between 0 and 5% in all scenarios.

Flooding as a result of extreme rainfall is rated as a 'moderate' risk to both electricity and gas networks.

Some facilities such as electricity basement substations are susceptible to flooding and flash floods can lead to soil erosion that exposes buried pipelines or cables. Flooding can also affect ground-based equipment such as substations. In the case of gas distribution systems, severe flooding in the metropolitan areas can cause underground regulator pits to fill with water causing gas outage.

The restoration of gas and electricity supply can be extensive due to restricted access to the networks resulting from the flooding. This can result in lengthy outages to supply.

Vegetation growth

It has been predicted that periods of seasonal rainfall, when they occur, are likely to be more intense. Recent experience in Queensland and northern New South Wales suggests that when this occurs in summer periods, and is immediately followed by extended periods of heatwave conditions, vegetation growth rates can increase substantially. This is particularly the case with some tree species in fertile soils. Tree growth rates of up to 7.5 m per annum have been recorded for established seedlings.

It is normal business practice for overhead electricity transmission and distribution networks to be regularly cleared to keep vegetation clear of exposed conductors. Vegetation that is too close to overhead lines can cause electricity supply interruptions by touching exposed conductors or by branches dislodging in high winds and creating short circuits when blown onto lines.

PB believes that vegetation management over the future periods is likely to become a more significant issue in areas where rapid growth occurs. At other times, such as during extended drought, a reduction in vegetation management activities will be required. The variability in vegetation management costs will require additional management attention and significant increases in vegetation management expenditure may be required in some years.

4.3.2 Commercial impact on network business operations

The commercial implications arising from the direct impact of climatic events are primarily associated with changes in the levels of operating costs and/or network capital investment. Capital expenditure can be incurred in an effort to reduce the impact of these extreme events or as a result of rebuilding physical business assets following the occurrence of an extreme event. Similarly, changes in operational expenditure can result from the additional repair costs following an extreme event, or can be incurred where maintenance programs are increased in an attempt to reduce the potential impact of an extreme event.

Regulatory treatment of exceptional costs

Cyclones and bushfires could result in unplanned capital and operating expenditures for a network business that substantially affects its profitability in the period. Many of the existing regulatory arrangements provide a mechanism to pass-through some categories of exceptional unplanned costs. Regulatory mechanisms that provide a pass-through of exceptional costs will need to be effective as these types of extreme climatic events become more common.

Capital expenditure

Network business can take preventative measures to reduce the impact of extreme events. These preventative measures may involve redesigning structures, strengthening parts of a network or rebuilding electricity networks underground. Along with prudent expenditure such as changing the design of new structures to withstand extreme events or accelerating the replacement of assets with assets that are better able to withstand the impact of climate effects, there may be a case in some areas to undertake significant rebuilding of the network (including placing assets underground) to prevent widespread outages. For example, a rebuild may be justified in areas where the networks are not currently designed to withstand a cyclone but may in 2030 be subject to cyclones as a result of climate change.

Operational expenditure

Operational expenditure patterns may also change as a result of climate change. Extreme events can have a large impact on operational expenditure patterns as increases in operational expenditure are experienced throughout the businesses in areas such as call centres, control rooms, asset data capture and field repairs. Maintenance expenditures will also increase as a result of measures such as the requirement to respond to outages and damage due to extreme weather events, and undertake additional vegetation control.

The increase in the number of high bushfire risk days is likely to lead to increases in both in the response to bushfires and to the cost of bushfire insurance.

4.3.3 Corporate impact

The corporate impacts we have considered that result from climate change include health safety and environmental impacts and public image (or reputation).

Health and safety

Network businesses have a legal and moral obligation to take full account of any, and all, health and safety issues that affect both their workforce and the public. The health and safety systems that protect workers and the public are not expected to change as a result of climate change. There may be some additional exposure to risk as a result of increased numbers of storm, cyclone and bushfire events but this should not result in any significant increase in personal injury.

Environment

Environmental incidents that affect network businesses include oil spills, escape of gases, and land degradation through vegetation clearing or asset construction. Our analysis rates the risk of environmental damage as a result of climate change as ‘low’.

Public image

Widespread and extended interruptions to normal supply of gas or electricity can result in significant adverse media and damage to a company's public image. The public is generally tolerant of short outages that occur during extreme events such as thunderstorms but are less tolerant of extended outages that affect business and lifestyle. An increase in outages resulting from cyclones, storms, and bushfires is predicted and as a result our analysis rates the risk to public image as 'moderate'.

Network businesses can reduce the adverse public reaction resulting from extreme events by reducing the impact of the event through network reinforcement and operational response. They can also reduce the adverse public reaction by improving communication with customers. Improvements to communications with customers may involve increasing capacity of call centres, improvements to automated information systems, real-time web-based outage information, or increased use of radio and print media to inform customers.

4.4 Energy usage and demand

The various scenarios used to assess the impact of climate change on network businesses incorporate government and public response to climate change. Government and public response to climate change may lead to changes in generation sources and in patterns and extent of energy usage. These changes in generation and usage will have a significant impact on network businesses.

The potential impact of the following three events have been analysed in the PB risk assessment:

- change in generation mix
- change in peak demand
- change in energy volume.

A change from the current generation mix is considered highly likely as a direct result of the Australian Government's intention to place a value on carbon emissions through the introduction of the Carbon Pollution Reduction Scheme (CPRS). The proportional contribution (to total demand) from non-fossil fuel technologies will increase. In addition, the value placed on carbon will also change the order in which generation is economically dispatched to meet demand, the 'merit' order. This will change the pattern of power flows on the interconnected transmission network. The application of renewable energy targets and an increased public awareness will also contribute to this change.

Public awareness is likely to lead to an increased proportion of renewable energy capacity and an increased take up of photovoltaic (PV) or other forms of comparatively small, local, generation. In addition to these changes that are largely driven by public policy and public sentiment, drought is predicted to affect the operation of hydro generation and may affect the operation of coal-fired generators where cooling water becomes scarce.

An increase in peak demand is predicted to occur as a result of the increased use of domestic airconditioning units. This impact is likely to be particularly apparent in the short-term (5 to 10 years) as public perception of increasing temperatures leads to increased

penetration and use of airconditioning. Conversely, decreases in peak demand may occur as a result of an increased public awareness of the impact of energy use on climate change and through the availability of higher quality energy use information through the installation of ‘smart’ meters[16]. Peak demands on energy networks — both gas and electricity — may also be affected by the operation of embedded, or distributed, generators[17].

An increase in energy volume transported through gas networks will result from an increase in gas-fired generation[18]. Energy transported through gas networks may also increase with the take-up of gas-fired airconditioning systems. The increased use of airconditioners will lead to increases in energy volume transported through electricity networks. An increased reliance on desalinated water[19] and the uptake of electric vehicles will also contribute to an increase in the volume of energy transported and distributed.

Conversely, warmer weather in winter will result in a reduction in the requirement for space heating in some southerly regions. Solar-heated water may also replace gas- and electric-heated water. Both of these affects will have a downward effect on energy transported through gas and electricity networks. Net energy transported through electricity networks may also decrease due to embedded generation[20], through improved energy efficiency resulting from measures such as insulation, and through new low-energy appliances such as LED lighting.

4.4.1 Physical impact on the network and on business operations

This section discusses the physical impact on the network and on business operations resulting from changes in energy use and demand.

Change in generation mix

In Scenarios 1 and 2 we have assumed that over 4,000 MW of brown coal generation and 500 MW of gas-fired generation is retired in Victoria along with 770 MW of black coal generation in South Australia and 890 MW in Queensland. We have further assumed that this retired generation is replaced by a mix of generation primarily consisting of wind, gas, solar and geothermal. For the South West Interconnected System in Western Australia (SWIS) no retirements are forecast and new generation to meet growing demand is sourced from wind and biomass generators. Our assumptions[21] are based on the 10% case presented in the ACIL Tasman report prepared for the Energy Supply Association of Australia (ESAA) entitled The impact of an ETS on the energy supply industry (2008b).

[16] Smart meters measure energy consumed in 30 minute intervals. These meters enable information to be provided to customers on their energy consumption at different times of the day and can be combined with local displays to provide customers with real-time energy price and consumption information.

[17] Generators connected to the electricity distribution networks, as opposed to the higher voltage transmission networks, are termed ‘embedded’ or ‘distributed’ generators.

[18] This will involve an increase in the number of centralised generators connected to gas transmission pipelines, increases in embedded generation through the conversion of standby generators from oil to gas, and from micro-generation at domestic and/or business and commercial sites.

[19] Water desalination is energy intensive. A plant producing 150 GL of water will consume approximately 750 GWh per year.

[20] It is recognised that while embedded generation will generally reduce flows on higher voltage networks, it is possible for net flows (and losses) to increase — especially at places where, and at times when, the level of local demand is low.

[21] One of the assumptions made by ACIL Tasman in the 10% case is that carbon capture and storage technologies are still in the demonstration phase.

In Scenario 3 we have assumed that the same generation retirements occur in Victoria as in Scenarios 1 and 2 but additional black coal retirements occur in Queensland and New South Wales. This retired generation is replaced by a mix of generation primarily consisting of wind, gas, solar and geothermal. For the SWIS the assumptions are the same as Scenarios 1 and 2. These assumptions are based on the 20% case presented in the ESAA report (2008b).

Both of these changes in generation mix will have a significant impact on network businesses. Our analysis rates the risk to both gas and electricity networks from the change in generation mix as ‘high’. The location of new generation facilities is uncertain and it is the location that will determine the impact on network businesses. Generators are generally sited either near the source of fuel or, where the fuel is readily transportable, near the load. Wind generators are generally sited in areas of steady wind and geothermal generators are located near the heat source. Where coal generators are retired and are replaced with gas or renewable generators then the new generators will either be located at a different site from the existing generator or, in the case of a gas-fired generator, a gas pipeline will be required to supply fuel to the generator.

New gas pipelines or additional network capacity from existing pipelines are likely to be required to meet the demands of large-scale gas generation.

For electricity transmission networks the connection of large generators in new locations will require additional connection assets and potentially new transmission lines. The connection of these generators will also impact power flows and system stability in the transmission network that may result in the requirement to perform additional network augmentation in areas not proximate to the new generators.

For distribution networks, the connection of smaller generation units such as wind generation may require the augmentation of networks and can lead to technical problems such as increases in fault levels and difficulties in the management of system voltage. These can often require additional expenditure to resolve. Further, the introduction of increased volumes of embedded generation introduces new risk to network operation. For example, distribution networks are traditionally radial networks where energy is distributed from a substation to a load.

Large volumes of embedded generation may require distribution networks to reconfigure, augment or defer augmentation of the network. Additionally, distributors will need to change their information collecting, monitoring and planning processes to ensure that they take account of the available embedded generation. This may involve the implementation of new IT systems as well as new operational processes.

The existing network concept involving large-scale generators transmitting energy over distances to be distributed to energy users is likely to be challenged by the changing mix of generation. This will not only introduce the requirement for new network to be constructed but will also involve significant technical challenges to network businesses to redesign the way that networks operate and interact with generators and loads.

All network businesses are likely to experience an increase in the number of connection applications resulting from a change in generation mix. This will involve additional effort to manage the application processes, to provide information to applicants, to undertake network capacity analysis, and to provide necessary network configuration information to applicants.

Change in peak demand

The number of days with temperatures in excess of 35°C is expected to increase across the continent with significant increases in the number of these hot days in central and north-western Australia. This will lead to additional airconditioning load on electricity networks and consequently an increase in peak demand.

The increase in hot days will increase the airconditioning load on electricity networks. In many regions at present, the peak demand on electricity networks is driven by airconditioning load. By 2030, most regions are likely to experience peak loads on hot days when customers use airconditioning units. In areas where airconditioning load leads to peak electricity demand, a series of hot days can lead to extremes of peak demand that can place stress on electricity networks[22], making them more susceptible to failure. Networks will need to be reinforced to meet these extremes.

Energy networks, particularly electricity networks, are designed and constructed to meet the peak demand. Where peak demand increases, the network will typically require augmentation to meet the increased demand even though the peak may only last a few hours on the hottest or coldest day of the year. All network businesses undertake a process of forecasting the peak demand on their network and then planning to augment the network to meet the increasing demand. The forecasts prepared for the networks take account of the factors that impact peak demand such as population growth, residential construction, business activity and airconditioning growth. The forecasts are converted into augmentation plans that may result in the construction of new lines and substations for electricity networks or additional compressor facilities on gas pipelines.

As the processes used to forecast increasing network peak demand are well established and the augmentation of networks is 'business as usual' for network businesses, PB has rated the risk to energy networks from a change in peak demand as 'low'. Despite this low risk, significant additional expenditure will be required on electricity networks to meet increasing airconditioning load.

In Scenario 1, where we have modelled only a low public response to climate change, we consider that airconditioning load will continue to increase with temperature. In Scenarios 2 and 3, where there is a high public response to climate change, we consider that airconditioning load may moderate as customers take action to reduce energy consumption such as controlling their demand, improving the insulation of buildings and dwellings, and zoning airconditioning.

In relation to gas networks, the number of additional hot days does not affect the overall gas demand except for gas-fired generation. However, the higher temperature in winter will decrease the overall demand for gas.

Change in energy volume

In the same way that climate change is impacting generation mix, we anticipate a number of factors will affect energy consumption. Some of these factors such as increased use of airconditioning and additional gas-fired generation will lead to an increase in energy volume, and others such as increase energy efficiency and solar hot water heaters will lead to a decrease in energy consumption.

[22] Smart meters measure energy consumed in 30 minute intervals. These meters enable information to be provided

The factors leading to an increase in energy volumes include, but are not limited to, the following:

- increased use of airconditioners
- change in migration patterns[23]
- electric and gas-powered vehicles
- increased use of desalination plants
- residential combined heat and power units using natural gas.

The factors leading to decrease in energy volumes include the following:

- tightening of the Minimum Energy Performance Standards (MEPS) limits and expansion of the scheme to include more appliance types
- establishment of government energy efficiency schemes
- reduced energy consumption as result of public awareness
- carbon price increases cost of energy leading to reduced consumption
- increased temperature leads to less heating load (regional impact)
- solar water heating reduces need for electricity and gas hot-water
- continuous flow hot water units instead of bulk hot water units
- more thermally efficient homes
- embedded generation reduces electricity transported
- new technologies and energy efficient appliances such as LED lighting.

In the absence of measures to address climate change, electricity consumption in Australia could be expected to continue growing in the roughly linear fashion that has typified previous decades. When trying to incorporate the impacts of climate change however, there is a high level of uncertainty surrounding the magnitude of the many forces that will either decrease or increase consumption.

With the pending introduction of an emissions trading scheme in Australia that will work to increase energy prices, and the development of a number of government schemes and programs targeting energy efficiency, the general expectation is for consumption growth to slow from approximately 2010 onwards. However, the anticipated uptake of mass-market electric vehicles in the next few decades has the potential to drive electricity volumes to levels higher than would have otherwise be expected. This is reflected in the Garnaut final report (2008b) which presents the forecast for Australia's electricity consumption reproduced in Figure 4 2 below.

[23] Smart meters measure energy consumed in 30 minute intervals. These meters enable information to be provided

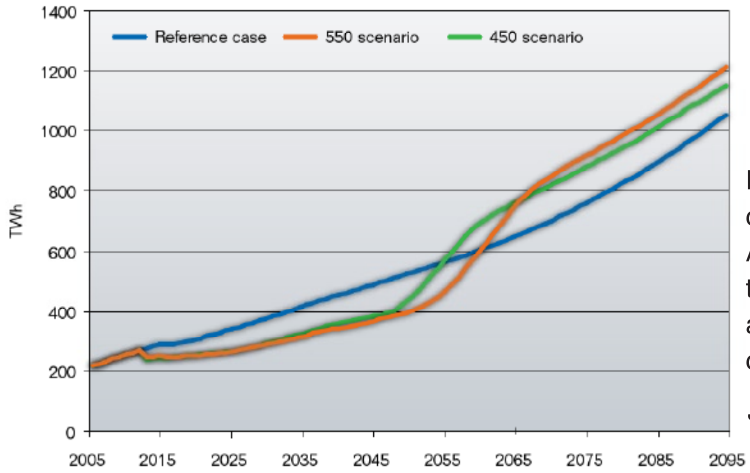


Figure 4 2: Electricity consumption forecasts for Australia under emissions trading with different atmospheric greenhouse gas concentration caps

Source: Garnaut 2008b

The commercial impacts of changing energy consumption volumes are discussed in Section 4.4.2. The opportunities arsing from potentially increasing energy consumption are discussed in Section 6.3.

4.4.2 Commercial impact on network business operations

The commercial impact from changed energy usage and demand as a result of climate change includes increased capital expenditure, increased operational expenditure, reduced energy volumes and the prospect of stranded assets.

Capital expenditure

The change in generation mix may lead to significant additional expenditure on gas pipelines. In the scenarios considered as part of this review, at least 10,000 MW of new gas generation capacity is required by 2030. Part of this new generation capacity is required to meet forecast economic growth; however, a large proportion replaces retired brown and black coal generation.

The location of new gas generation is uncertain; however, the report recently commissioned by ESAA (2008b) predicts a significant amount of new gas-fired generation in New South Wales, Victoria, Queensland and Western Australia. Where gas-fired generation is located close to the centres of electricity load, investment in gas pipeline capacity will be required and where gas-fired generation is located close to the gas source, investment in electricity transmission networks will be required. In some cases, we expect the expenditure to be relatively modest and may involve the installation of additional compressors on gas pipelines, additional looping[24] of pipelines or connection to generators to existing transmission networks. In other cases, it is likely that significant expenditure will be required to build new gas pipelines or new transmission lines.

The connection of a significant volume of renewable generation will impact both transmission and distribution networks. The remote location of wind generation sites will add to the cost of connecting new wind generators. Suitable locations for geothermal and large-scale solar generators are also remote from existing loads and networks and are therefore likely to require significant transmission or subtransmission network augmentation.

[24] Looping a gas pipeline involves the construction of a parallel section of pipeline to provide additional capacity.

The connection of embedded generation at the distribution level will require additional expenditure for network reconfiguration (including fault level reduction) and potentially new IT systems to monitor and control the effects of embedded generation on the network.

Existing connection processes are not efficient for the large volumes of generator connection applications expected (or already being experienced in some areas). A standardised approach to connection applications using industry standard technical and commercial agreements would be beneficial to both network businesses and connection applicants.

Tariffs

The introduction of widespread embedded generation in the electricity distribution network may also involve the development and restructuring of energy tariffs as most current tariffs assume that energy is distributed from a central location to a remote load. Distributed generation may alter the costs attributable to particular types of customers and therefore may result in tariff restructuring.

Stranded assets

An additional impact from the change in generation mix is the potential for stranded assets. Electricity networks in Australia have not experienced significant retirements of generation on the scale that is predicted. These retirements are likely to lead to transmission assets that are no longer required. This may lead to costs to dismantle lines and/or maintain lines that are not used. The risk of stranded assets is appropriately borne by customers given the changing nature of network usage that is driven by customer and generator behaviour.

Network business revenues

Scenarios 2 and 3 assume a high public response to climate change. If a high public response occurs, and some of the factors that may lead to an increase in electricity consumption, such as electric vehicles, do not materialise, it is possible that electricity networks will experience a decrease in electricity consumption per capita. Depending on the regulatory framework in place, this may lead to a reduction in expected revenues for network businesses within a regulatory period.

Gas network operators may also experience reducing revenues due to the drive for greater efficiency in appliances, better thermal performance of houses and a shift to solar heating for hot water. This situation is further exacerbated by global warming which will increase the winter temperature decreasing the gas demand and as a result the gas revenue.

Economic network development

In residential areas where gas distribution networks are growing, the economic development of the networks relies on customer load from space heating or water heating or potentially embedded micro generators. If embedded micro gas generators are not commercialised and water is mainly heated by solar energy then it may no longer be economic to develop gas distribution networks. This is likely to affect the northern regions of Australia where space heating is not required.

4.4.3 Corporate impact

There is predicted to be few significant corporate impacts from changed energy usage and peak demand as a result of climate change. One area that is affected is the safe operation and maintenance of distribution networks with substantial embedded generation. Employee and public safety can be impacted unless the many sources of energy within the network are carefully managed and coordinated. Without appropriate information, systems and processes there is the potential for embedded generation to increase the potential for electric shock to a line workers, tradespeople or energy users. The management of these sources of energy will require additional attention to prevent an increased risk of electric shock.

4.5 Costs

In this section we provide an estimate of the cost to network businesses from climate change. The costs have been estimated using the key risks identified in Section 4.1. For each of the key risks we have estimated the cost to a typical energy network business in each applicable region.

The cost estimate provides an indication of the total cost to network businesses from the impact of climate change and also the cost faced by the typical individual business.

4.5.1 Assumptions, limitations and timeframe

There is a large degree of uncertainty around the impact of climate change on individual network businesses. The uncertainty in impact arises from:

- the uncertainty associated with the future occurrence of specific climatic events occurring
- the uncertainty of government and public response to climate change
- the uncertainty of precisely how a given event will affect specific networks and network elements.

Despite these uncertainties PB would expect that a well-managed network business will have considered, or will currently be considering, the impact of climate change on the network and will, over the next 5 years, proceed to implement physical and operational changes in response to climate change.

In our analysis, it is assumed that a variety of different responses is available to a network business in order to mitigate the risk associated with climate change. From this range of available responses, PB has used its experience to select a typical set of responses that might be implemented by a network business. From this, we have estimated the cost of implementing the set of responses for a typical network business[25].

The typical network business has been sized by regulated asset base (RAB). The typical businesses are assumed to have the following RAB:

[24] It is important to note that the resulting cost estimate is not specific to a particular network as PB has not specifically analysed the current state of any network. Our estimate, therefore, is not sufficiently detailed or robust to support a regulatory submission. Further work will be required to support regulatory submissions. In PB's view, this would need to consider the current condition of the network, existing expansion and replacement programs, and applicable options to reduce the impact from climate change events.

- electricity transmission — $2,500m
- electricity distribution — $3,000m
- gas distribution — $820m.

Costs have been estimated for each of the high and medium risk items identified in the risk assessment with the exception of the impact from a change in generation mix and the cost of network augmentation resulting from increasing use of airconditioning.

The costs associated with a change in generation mix have been excluded for two reasons. Firstly, our cost estimate has been prepared for the next 5 years and the impact of a change in generation mix is likely to have less impact over the next 5 years and more impact in the longer term. Secondly, the uncertainties arising from a change in generation mix are considerable and less predictable than many of the other risks. We have therefore excluded this cost impact from our estimate and acknowledge that this will result in a total cost estimate which is certainly different, and probably lower, than actual cost expected for a network business as a result of climate change.

The cost resulting from increasing use of airconditioning has not been assessed as a key risk[26]. However, despite the low risk to network businesses, the cost of augmenting the network is material and has therefore been included in the total costs.

The cost has been estimated for a typical network business over a period of 5 years. We have selected a 5-year period as this is the length of the regulatory period for most regulated network businesses and 5-year expenditure forecasts are prepared by network business during their price reset processes. The cost estimate can therefore be compared with the typical expenditure for a network business over its 5-year regulatory period.

Included in the costs are a number of responses that result in one-off expenditure. For example, the cost of adding additional spare plant items for use when responding to cyclone damage. It is assumed that each of these one-off expenditures occurs during the 5-year period considered.

4.5.2 Total costs

The total cost to Australian energy network businesses over the next 5 years as a result of the impact of climate change is estimated to be $2.5bn (This excludes the cost of changes to networks as a result of the anticipated change in generation mix).

The major component of this cost (57%) is the cost of augmenting electricity transmission and distribution businesses to accommodate additional airconditioning demand. Other cost components include items such as additional spares to better respond to storms, increases in asset replacement programs to minimise the impact from bushfires, increases in vegetation management programs, and increases in the cost of new assets to reduce their susceptibility to tropical cyclones. Appendix D includes a description of the responses that are available to network businesses and a cost analysis table which exhibits the range of options considered, the cost of typical options and the outcome that can be expected from that expenditure.

[26] The impact on network businesses from increasing use of airconditioners appears as a change in the growth in energy demand on electricity networks and will be managed by network businesses using existing planning and network augmentation processes.

4.5.3 Regional costs

Costs for the next five year period for a typical network business are presented by region in Table 4 3 below.

Region	Electricity transmission	Electricity distribution	Gas distribution
	$m	$m	$m
Tropical regions	130	170	3
Coastal southern Queensland and northern NSW	130	190	1
All other regions	80	110	1

Table 4 3: Network business costs by region

Notes:

Costs include the cost of augmenting electricity networks as a result of the forecast increase in airconditioning demand.

Costs do not include the cost of connecting or augmenting networks as a result of a change in the mix of generation.

Gas transmission pipelines have not been included in the table as the primary cost to these businesses from climate change is likely to result from a change in generation mix.

Key message

The cost to energy networks from climate change is estimated to be $2.5bn over the next 5 years. The largest proportion of this cost arises from the requirement to augment networks to accommodate the increased use of airconditioning.

Climate change will result in a material increase in cost to electricity transmission and distribution networks and a lesser increase for gas distribution networks.

The costs of climate change are expected to be greater in tropical regions and those regions that have not previously been, but might now be, exposed to cyclones.

4.6 Regulatory response

Climate change will have a real and extensive impact on network businesses. Climate change will affect many network areas including network planning, design and equipment standards, capital programs, maintenance programs, network operations and other non-network aspects of businesses such as tariff design and commercial arrangements.

The cost of climate change is already apparent in some aspects of network operations such as in the volume of connection enquiries being received by network businesses from embedded generation proponents. We consider that network businesses will experience higher costs in the short term as they begin to respond to a number of increasing risks such as the increase in bushfire risk as a result of drought.

Regulators will need to respond to the changing needs of network businesses resulting from climate change. Unless network businesses can recover the predicted additional cost of climate change impacts, it is likely that insufficient investment will be made in the networks to maintain the levels of service and reliability that customers expect from energy networks. In some cases additional costs, such as an increase in spares holdings to improve response to storm damage, will be relatively easy to forecast. In other cases, such as the impact on networks of large numbers of photovoltaic embedded generators, the costs will be uncertain and therefore more difficult to predict. Additionally, there are likely to be some events that such as cyclones or extensive bushfires that are outside the normal expectations of network operators. Regulatory processes will need to be sufficiently flexible to accommodate the changing and sometimes unpredictable nature of the costs facing network businesses.

Key message

To ensure that sufficient investment is made in energy networks to meet customer energy demands, regulatory processes will need to be sufficiently flexible to enable energy network businesses to recover costs from the impact of climate change. Current processes may need to be reviewed to ensure they can adequately deal with an increased volatility in expenditure that may be uncertain or difficult to predict.

4.7 The future — 2070

In this section we discuss some of the potential challenges and possible solutions and opportunities for the energy network businesses in the long-term future. In the context of this report we define the long-term future as being beyond 2030 and out to 2070. We attempt to paint a picture of 'what could be' under alternative future scenarios. We have deliberately aimed to be broad and non-conventional in our thinking in an attempt to encourage the development of unconstrained ideas and to increase the probability of identifying issues and opportunities outside of what is presently considered to be the norm.

Our risk assessment approach has attempted to identify the key issues for network businesses at 2030. Understandably, these tend to be based on an extension of today's knowledge and practices. We have taken the view that an extension of this formulaic risk assessment approach out further to 2070 is likely to be of limited value — mainly because it will be based on an extension, or extrapolation, of current thoughts and practices and is therefore unlikely to capture innovation and 'alternative' thinking.

In this section we ponder the long-term future, and the potential implications for the Australian network businesses. Our thoughts are framed in terms of prospects and ideas which are at the extremities of both established thinking and current planning horizons. We accept that predicting the future of the energy networks industry with any level of certainty is notoriously difficult, but recognise that innovation and policy action today can influence and shape the future of the industry. While this is the broad objective of this report, this sentiment would seem to be particularly important when deliberating the distant future.

In order to facilitate consideration of how the future energy network businesses may look in the time period beyond 2030, we have established a number of important assumptions. These are set out below.

Assumptions

We make the following assumptions upon which our assessment of future challenges and opportunities is based:

- natural gas is still available in 2070
- there is still demand for electricity but gas enjoys greater popularity due to its lower carbon intensity
- physical pipes and conductors are still required for the delivery of gas and electricity (i.e. wireless electricity channels not commercially available for the bulk transmission and distribution of electricity)
- there is minimum effect on gas networks due to climate change from 2030 to 2070
- the majority of gas network development continues to occur in populated areas
- gas continues to be a technically viable fuel source for the generation of electricity
- numerous alternative energy sources exist and are commercially viable, including nuclear, hydrogen fuel cells, broad spectrum of renewable technologies
- public awareness of, and concerns for, the environment means that the construction of new overhead lines, while not impossible, will become increasingly difficult.
- increase use of high efficiency appliances for both domestic/industrial applications
- energy is considered a scare resource and a highly valuable commodity and is costed and priced accordingly
- free markets are still available for the delivery of Australia's energy requirements
- networks largely continue to operate as natural monopolies in geographic areas
- the majority of Australian residents generally continue to live in stationary proximate clusters (i.e. towns and cities) although homes may be more geographically disbursed
- changing lifestyles mean less cooking.

In this section, we consider how the three scenarios examined in the 2030 risk assessment may present themselves when projected out beyond 2030 towards 2070. As we have aimed to be broad and non-conventional in our thinking, we have developed three scenarios that 'might be' rather than try to scientifically extrapolate the present or 2030. The three future scenarios are:

- cautious response
- leading response
- rapid change.

In the context of what might be in 2070, each of these scenarios is described below. We then go on to discuss what this could mean for the energy network businesses in terms of physical impact on the network and on business operations, commercial implications and key opportunities. Our discussion addresses both gas and electricity energy network businesses.

4.7.1 Cautious response

The cautious response future scenario is charactered by predicable levels of climate change coupled with low levels of Australian Government response and comparatively passive customer participation and engagement. Of all three future scenarios, this is closest to 'business as usual' for the energy network businesses as follows:

- Environmental concerns are 'moderate' and free markets for energy, and energy intensive resources, continue as the principal mechanism for the delivery of the country's energy requirements. Many of the impacts and opportunities are not too dissimilar from those which may occur much earlier (e.g. 2030) under a more leading, pro-active customer and government response.
- A significant proportion of the generation capacity continues to be large, centralised, facilities — although the mix has changed such that smaller gas generators and larger renewable schemes contribute significantly to overall demand. The majority of electricity generation capacity is gas fuelled.
- Gas and electricity networks — at both transmission and distribution level — continue to play an important role in the delivery of energy to users.
- Networks continue to expand, partly to meet the requirements of demand and population growth but mainly due to the migration to gas-fired generation and also changes in the location of large generation plant resulting from the change in fuel mix and the shift to renewable generation.
- The relatively benign level of customer engagement results in only moderate levels of demand-side participation — with some response to energy price signals and to broad government policy measures such as building insulation improvements and increased use of public transport.
- Energy network businesses continue to be responsible for continuity and reliability of supplies and for service quality. Under this scenario, the emphasis is on the development of larger scale renewable generation facilities with limited contribution from embedded generation.

Physical impacts on the networks

Predictable levels of change in climatic parameters such as wind, storm and temperature will mean that network adaption will be effectively delivered through well-established and evolved asset management processes and systems. Asset design and construction standards will have developed to address the levels of variation and uncertainly in environmental conditions to which energy networks will be exposed.

Overhead electricity networks will be designed to operate safely and effectively at higher temperatures, in higher wind speeds, and in more frequent storms of greater intensity. Flood mitigation and the potential impact on underground cables and overhead line supports from ground subsidence will continue to play an important part in the design of electricity systems.

Electricity distribution networks form an integrated part of the local energy clusters and move from being 'passive' systems with uni-directional power flows to 'active' systems having

multi-directional power flows — more akin to transmission networks. Embedded generation will provide a genuine cost-effective alternative to large transmission-connected thermal generation facilities. In some cases the network has become a back-up system that supports embedded generation.

With increased ambient temperature, it is expected that the gas producers will supply the gas at a higher temperature to reduce their operating costs. From an infrastructure perspective, the transmission pipelines will have to be designed to cope with the higher temperature gas passing through the pipelines.

Compressors used in the transmission system will be redesigned for higher efficiency reducing gas consumption. Similarly all gas-operated equipment such as valve actuators will be redesigned so that no gas is vented into atmosphere.

There will be a greater emphasis to ensure that the metering at both the injection and withdrawal points are sufficiently accurate to minimise any losses in the gas pipelines due to metering accuracy.

Commercial implications

While networks continue to general expand and develop due to population growth, a much greater potential influence on energy networks will be the increased use of gas as an energy source — both for industrial, commercial and domestic heating and also for electricity generation. Migration from the general use of electricity to that of gas, together with an increase in the connection of embedded generation, will increase the risk of commercial stranding for some electricity network assets.

That is, the utilisation of assets will diminish to a level which does not support an ongoing return on, or return of, the investment. Under the present regulatory arrangements this cost risk of stranding assets, ultimately falls to the end user (customer). Any shift of this risk back to the investor will result in the requirement for increased returns — which again flows back to the end customers.

Increased demand-side response may also contribute to this investment risk associated with stranded assets — although with low levels of customer engagement and government response on climate change, this is risk is likely to be foreseeable and, therefore, manageable through the established procedures of the day. As long as the time constant associated with the adjustment of required revenues is significantly (at least 10 times shorter) than the commercial life of the investments, then risks will be manageable.

4.7.2 Leading response

This scenario is characterised by the most probable outcomes in terms of physical climate change, but with high levels of both (Australian) Government response and public engagement in climate change issues as follows:

- Environmental concerns are acute.
- Australia taking a leading, pro-active, role in the global climate change challenge. Integrated international carbon markets provide a strong global incentive for investment in low carbon energy and for high levels of activity and innovation in carbon abatement and mitigation measures.

- While customers continue to desire competitive levels of service and price, the impact of the global climate and the local environment is a high priority and is carefully scrutinised. This extends to activities and outcomes beyond those which can be effectively quantified through a carbon market.
- The attitude and approach to climate change of all businesses, and the actions associated with social responsibility, are central to corporate existence.
- Natural gas is the only significant carbon-based fuel, but represents only a small proportion of the energy mix.
- Hydrogen-based distributed energy cells and community micro nuclear fission facilities — combined with small solar and wind generators predominate.
- Significant advances in intelligent energy storage technology means that the unpredictable and stochastic nature of some renewable energy generation sources is no longer an issue and energy storage (potentially from 'connected' electric vehicles) is available within the network.

This scenario represents significant but managed change in the energy network industries.

Physical impacts on the networks

Huge changes in consumer behaviour, lifestyle and consumption patterns means that per capita energy requirements are one-fifth the 2010 levels and with the vast majority of energy produced in close proximity to point of use, the requirement for energy networks is significantly reduced. Renewable generation, and other low-carbon forms of producing consumer useable energy, predominate.

Local energy 'webs' or 'clusters' have developed which connect diverse sources and sinks of energy through highly sophisticated and integrated systems of conductors and communication link. Clusters are typically 10–30 MW in size and are interconnected with each other through more traditional means to provide redundancy and security. Cluster and micro grid system operators emerge to take responsibility for overseeing the level of monitoring and control required to deal with complex and multi-directional local energy flows. Interaction with climatic conditions is automatic and comprehensive.

The operational management of gas, electricity, hydrogen and other energy sources is completely integrated — optimising energy conversion (between sources) to deliver lowest environmental costs and value to end users.

Transmission lines and high capacity network links essentially provide only a back-up support framework for times when local energy clusters fail and top up of local energy storage facilities is required.

The rapid decarbonisation of the electricity supply means that electric vehicles are encouraged as a way of reducing transport emissions. This drives a rapid roll-out of charging infrastructure and drives an increase in electricity consumption.

Commercial implications

Electricity and gas network owners and operators become true energy network operators and energy solution companies. There will still be a degree of natural monopoly ownership but the development of complex local energy clusters has significantly increased competition. A number of energy solution businesses will emerge and compete on price, service, climate and environmental credentials and on innovative solutions. A form of economic regulation continues but only for large capacity interconnection services where competition is not viable.

As part of developing innovative energy transportation solutions, network business need to become more involved in end use and competition focuses on customer outcomes rather than simply on delivery of energy to customer gate.

Monopoly energy network businesses must diversify into the ownership and management of other monopoly services and infrastructure to remain competitive and in business. This may include certain aspect of communications, water, rail and road.

4.7.3 Rapid change

The rapid change scenario reflects a slow global social and government policy response to the growing climate change science imperative. The result is a high carbon outcome and the unquestionable need for international government to act quickly. This scenario aims to reflect the ‘11th hour’ response characterised by the urgent need for rapid change:

- Global uncertainty on the best approach for tackling climate change is fuelled by a lack of consensus on the international stage.
- The majority of generating capacity via large, centrally connected facilities having a mix of fuels — dominated by gas, hydro and nuclear energy.
- Energy consumption and peak demand is significantly curtailed through tough government policy measures on energy use and transport.
- The nation’s energy requirements (price, security and climate change policy) are met largely through a government-led approach to governance of the energy industry. Environment concerns are acute.
- The shift to hydrogen and other new energy technologies earlier than expected leads to high energy prices; this helps to reduce demand.
- There is a move towards the connection of generation to the distribution networks but the lack of a planned and coordinated approach means that this is ad hoc and sub-optimal — both technically and commercially.
- Network development is also ad hoc, sporadic and sub-optimal — with excess capacity in some areas and significant constraints in other areas. This leads to market access challenges for renewable generators and customers alike.
- Stranding of energy network assets (both technical and economic) is a significant risk which deters investment and has an upward impact on the costs of third-party network access.

Physical impact on the network and on business operations

In addition to the items raised in Section 4.7.2, it is also expected that gas will be used as a transportation fuel for vehicles. This means that there could be a number of gas refilling

stations embedded in the gas network which will lead to investment in, and changes to, the physical network.

It is expected that the distribution network will be replaced with pipes that will be able to operate at high pressure; eliminating the various pressure tiers that currently exist. This means that the distribution network will have sufficient capacity to supply any types of appliances that exist in the future.

Commercial implications

The future of both the gas transmission and distribution business is heavily dependent on the availability of gas as an energy source. Assuming that gas is available and the gas fields are located in remote areas, the transmission pipelines in Australia which transports the natural gas to the major centres will be interconnected to form a transmission network. This will then allow for trading of natural gas purchased at various locations to be traded and transported within Australia. This interstate trading will result in the formation of trading hubs at critical points in the network.

From a distribution perspective, it is expected that there will be a shift from the traditional use of natural gas for residential customers. While currently gas is used for heating, hot water and cooking, it is expected that there will be additional gas-fired micro generation which may also be used for heating hot water.

Metering will also have changed. There will be higher performance meters which are compensated for temperature and pressure to reduce any errors will be introduced into the system. These meters will have the information tele-metered to a central source and also to customers. This facility can also provide pricing signals to the customer so that the customer can decide when to use gas and will also address the issue of theft of gas.

One of the issues for using natural gas as a fuel source for electricity generation has created an inter-dependence of gas and electricity. If a transmission pipeline ruptures for whatever reason, both the supply of gas and electricity are threatened. Similarly with the proliferation of micro generators, any localised disruption to the gas supply could affect the electricity in the area which then puts a major load to the electricity distribution networks.

Similarly, any localised gas outage could also mean that road vehicle refuelling facilities in the area are unable to supply gas to the vehicles.

Key message

The nature of the impact of climate change on energy networks in 2070 will be determined by the way in which governments and the public respond to the climate change challenge. In each of the 2070 scenarios there is an ongoing need for energy networks though the relative importance of gas and electricity networks may change with changes in technology and the way energy is used.

Impact of network businesses on climate change and mitigation

In this section we look at the way in which network businesses can have an impact on climate change.

5.1 Network business emissions profile

Like most businesses, energy network businesses create direct and indirect greenhouse gas emissions in the course of their normal operations. Part of the challenge for network businesses posed by climate change is to reduce their emission of greenhouse gasses in order to mitigate their effect on climate change. Mitigation is an important response to climate change for all organisations and will be driven by evolving government policies, regulatory structures, consumer preference, and corporate social responsibility initiatives.

The greenhouse gas emissions for network businesses can be considered to fall into three main groups as follows:

- emissions from business operations
- emissions from network losses
- emissions from energy network users.

Emissions from business operations such as the use of energy in offices and facilities, the running of vehicle fleets, and the disposal of co-mingled waste are common to many businesses and are generally well understood. Energy network businesses are also responsible for some unique operational emissions such as leakage of sulfur hexafluoride (SF_6) used in electrical equipment. Network businesses have a reasonable level of control over these types of emissions.

An important consideration for network businesses is also indirect emissions from electrical line losses and fugitive emissions of gas through pipeline leakage. These emissions are less able to be controlled by a network business and, in the case of electricity, do not count towards a liability under the proposed design of the Carbon Pollution Reduction Scheme (CPRS). However, the comparatively large magnitude of such emissions renders them an important consideration. Emissions from network losses tend to be far greater than those from business operations.

The role that network businesses play in the generation and end use of energy that their networks deliver to the Australian economy should also be considered. Most electricity and gas consumed in Australia is transported by energy network businesses and the use of that electricity and gas forms one of the largest contributors to Australia's greenhouse gas footprint. Although network businesses have very little, if any, control over these types of indirect emissions, the large magnitude of the emissions and the direct link that network businesses maintain with the user or generator means that it warrants relevant consideration. This may create opportunities for the network businesses to facilitate upstream and downstream mitigation and reduction programs — provided the regulatory framework incentivises, or at least recognises, this potential role.

Although the volume of emissions varies considerably between specific network businesses based on their size, location and operational requirements, it is instructive to consider the emissions magnitude of the typical network business. The example used below is of a

medium sized distribution business. The order of magnitude of these emissions is broadly similar for both electricity and gas businesses, except that the ratio of emissions from transported energy to emissions from network losses will be lower. This is because of the higher global warming potential of unburnt gas compared to the carbon dioxide formed during combustion.

Operational emissions	Emissions (t CO2-e)	% of operational emissions
Total operational emissions	10,000	
Electricity use	5,500	55%
Vehicle fleet fuel	3,500	35%
SF6 leakage (electricity networks only)	300	3%
Waste	700	7%
General emission magnitudes (electricity business)		
Operational emissions (t CO2-e)		10,000
Emissions from network losses (t CO2-e)		500,000
Final emissions from transported energy (t CO2-e)		15,000,000

Table 5 1: Typical magnitude of emissions for an energy network business

Table 5 1 indicates that for a typical network business the emissions from business operations are a small percentage of the emissions from network losses — 2% in this example. It also shows that network losses are a small percentage of the emissions from production and use of the energy that the network business transports — 3% in this example.

The National Greenhouse and Energy Reporting System (NGERS) will form the basis of measurement and reporting for the CPRS. According to NGERS, emissions produced by a facility[27] of a business are classified as Scope 1, Scope 2 or Scope 3.

- Scope 1 emissions are directly produced at the business' facility. These include emissions from fuel that is used in vehicles, to generate electricity or in industrial processes as well as fugitive emissions.
- Scope 2 emissions are considered to be 'indirect' in that they are associated with the consumption of electricity, heating, cooling, or steam within the facility, but the production occurs outside the facility.
- Scope 3 emissions are the other indirect emissions that occur as a result of an activity at the facility and that are not included in Scope 2 emissions. Scope 3 emissions are produced outside the facility and include emissions from such activities as flights and waste disposal.

Scope 1 emissions are subject to obligations under the proposed CPRS if they exceed 25,000 tCO2e per year for a facility. Both Scope 1 and Scope 2 emissions must be reported under NGERS if relevant thresholds are exceeded. Therefore it is imperative for network businesses

[27] The term 'facility' is defined in the National Greenhouse and Energy Reporting Guidelines, Department of Climate Change, 2008.

to distinguish Scope 1 emissions from other emission types. It is noted that the attribution of emissions to Scopes 1, 2 or 3 differs for gas businesses and for electricity businesses. This is mainly due to the energy transport losses for gas being classified as Scope 1 whereas electricity losses are classified as Scope 2. The following table categorises a range of typical emissions into Scope 1 or Scope 2 for electricity and gas network businesses.

	Electricity	Gas
Scope 1	Vehicles SF6 leakage Generation assets Gas consumption	Vehicles Gas leakages losses Operational gas losses Gas consumption
Scope 2	Electricity line losses Electricity consumption	Electricity consumption
Scope 3	Flights Waste	Flights Waste
No scope	Electricity generated for use by consumers	Gas used by consumers

Table 5 2: Classification of common emissions for energy network businesses

5.2 Emissions from network business operations

As set out in Table 5 1, the emissions created by network businesses as part of their normal operations consist primarily of electricity use in buildings, depots and other facilities (Scope 2), and fuel used in vehicle fleets (Scope 1). These sources can account for around 90% of operational emissions and are therefore a natural target for corporate emission reduction strategies. Lesser contributors include waste disposal (Scope 3) and loss of SF_6, which as a fugitive emission is classified as Scope 1 under CPRS. It should be noted that in general, SF_6 comprises a larger proportion of emissions for transmission businesses than distribution businesses due to the type of equipment used. In some businesses, SF_6 can be a major source of emissions and can be of a similar magnitude to those created by vehicle fleets.

Other sources of direct emissions that typically account for a minor proportion can be natural gas use in facilities, fugitive emissions of hydro-fluorocarbons, and fuel use in generation facilities (all Scope 1 emissions).

With the exception of SF_6 leakage, the main constituents of network business operational emissions (electricity, vehicles and waste) are common to many other businesses and relevant mitigation measures are generally well understood. This is reflected in the results of the survey of network businesses which indicated that more than 90% of businesses are currently undertaking activities aimed at mitigating operational emissions and that 100% of businesses plan to either continue or undertake further mitigation activities in the future.

The key opportunities for energy network businesses to reduce direct emissions are discussed in the following sections.

5.2.1 Electricity use emissions

The emissions associated with electricity use can be mitigated in a number of ways as follows.

Energy efficiency

There are several energy efficiency initiatives that can be introduced to office buildings and depots. Some of these initiatives will already have a payback period short enough to create an attractive rate of return on investment. Lighting, airconditioning and information technology are areas that consume a large proportion of business electricity needs and offer the potential for efficiency gains.

Lighting efficiency measures include the:

- increased use of natural light
- use of motion sensors to switch of unnecessary lights
- replacement of incandescent globes (including halogen) with either fluorescent or LEDs
- design of lighting surrounds and placement of lights to maximise useable light.

With the exception of the increased use of natural light, which is generally incorporated into building design, the above measures are suitable for retrofit to existing buildings, particularly when renovating or re-fitting areas.

Airconditioning loads can be reduced through incorporating passive or active solar elements into building design such as insulation, fixed shading, double glazing, thermal mass, chilled beams, active shading and air venting. However, many of these techniques are not suitable to building retrofits and efficiency measures may be limited to the airconditioning system itself. Refurbishing older airconditioning units with newer high efficiency models and correct balancing of the system can produce savings in energy use and running costs.

New buildings with a high Green Star rating will address lighting and airconditioning power loads through design of the building envelope and the building services.

Information technology contributes significantly to power consumption in a typical office environment. Not only do desktops, laptops, monitors and servers all use power, but server rooms often have significant airconditioning requirements to remove the waste heat that the equipment generates. Power-saving measures typically include the roll-out of default settings on computers to enable power-saving modes and the upgrade of equipment to more efficient models.

Renewable electricity

Renewable sources of electricity generation such as wind, solar and biomass are essentially considered to be free of greenhouse gas emissions and can be used to reduce the emissions profile of a business. The most common way to source a proportion of electricity from renewable generation is via the Australian Government's accredited GreenPower program. Alternatively, some generators offer renewable electricity products directly to the consumer. Given that there presently is a cost premium associated with renewable electricity, a businesses strategy to reduce emissions typically starts with a low percentage of renewable electricity (in the order of 5%) with a view to increasing this percentage over

time. The cost premium can be offset through energy efficiency measures that are discussed in the following subsection. It is expected that in a carbon economy, the CPRS will serve to reduce the cost differential between grid electricity and new renewable electricity.

A further method of sourcing renewable electricity is to produce it on site using small-scale generation facilities such as solar photovoltaic cells. Some buildings with a high (5 star or above) Green Star rating include on site renewable generation in their design. Dedicated renewable generation such as this is significantly more costly than purchasing renewable electricity from retailers or large-scale generators so it remains relatively uncommon at this stage as a method of mitigation.

5.2.2 Vehicle emissions

The mitigation in vehicle emissions could be considered more challenging than for electricity emissions in that there is not currently a direct vehicular equivalent for purchasing renewable electricity. Renewable fuels such as biodiesel or ethanol are typically mixed in low percentages with fossil fuels and availability of 100% renewable fuels is very limited. The main ways to reduce vehicle fleet emissions are to:

- reduce the distances travelled by optimising travel and delivery schedules
- use smaller vehicles with higher fuel efficiency
- use hybrid or pure electric vehicles
- use the most appropriate fuel for the application, e.g. diesel, LPG, CNG
- use renewable fuels, e.g. biodiesel or ethanol where feasible and cost-effective.

Given that a range of vehicle types are needed for a range of purposes in the fleet of a network business, it is typical to have a variety of the above measures adopted. Reducing the distances travelled is typically the result of normal business process optimisation and there are often few gains remaining to be made in this area.

The replacement of large passenger cars with smaller and more fuel-efficient models can offer significant fuel and emission savings and also lower fleet purchase costs. Smaller cars also tend to have a superior resale rating than base model large cars, further improving the economic benefit of this strategy. Hybrid models can also be used to reduce fuel consumption and emissions but currently attract a significant cost premium over equivalent standard vehicles and need to be scheduled for frequent use in order to be an economically attractive proposition. Nevertheless, this situation is likely to improve over the next decade.

Pure electric vehicles currently have a very limited availability in Australia but are expected to become more widely available after 2010 when a number of car firms plan to release electric models internationally. These models are likely to attract a price premium above comparable fossil fuelled cars, but will offer significantly reduced running costs. Electric vehicles need to be charged with renewable electricity in order to reduce emissions compared with equivalent fossil fuelled vehicles.

Diesel, LPG and CNG can offer reduced emissions compared with petrol equivalent models for certain applications, but the gains are typically moderate and in the order of 10%. The choice of fuel tends to be driven more by vehicle type and running costs than for reduction

in emissions. If changing to a more efficient fuel type is not viable or applicable, emissions can be reduced by incorporating a proportion of renewable sourced fuel. Petrol is commonly available in a blend of 5% or 10% ethanol. It should be noted that the actual emission savings quoted often do not account for the energy used in the manufacture of the ethanol. Biodiesel has limited availability as a blend with fossil diesel and there is very limited availability of 100% biodiesel.

5.2.3 Sulfur hexafluoride emissions

Sulfur hexafluoride (SF_6) is an inert gas used in the electricity industry as a gaseous dielectric (insulator). It has attractive insulation and arc quenching properties that are currently not matched by alternative substances. It can be commonly found in circuit breakers and gas-insulated switchgear (GIS) installations. The use of SF_6 allows for smaller physical sizes of switchgear and has largely replaced bulky oil filled switchgear. Currently, there is a trend towards vacuum circuit breakers instead of SF_6 breakers, particularly at distribution level voltages as vacuum breakers are safer and require less maintenance. However, SF_6 will remain the preferred option for many applications, particularly in electricity transmission applications.

SF_6 can leak as equipment ages and can be lost to the atmosphere during overhauls and maintenance. SF_6 has been identified as one of the most potent greenhouse gases. Its global warming potential (GWP) is estimated at 22,800 times that of carbon dioxide (CO2) when measured over 100 years (IPCC 2007) SF_6 has an atmospheric life time of 650 to 3,200 years. The yearly SF_6 emission rate from the overall electricity industry has been estimated as 0.1% of the yearly emission rate of man-made global warming gases. The impact on global warming due to the SF_6 concentration in the atmosphere (atmospheric burden) is calculated approximately between 0.01 and 0.02% of the overall greenhouse effect.

Common situations that may cause the escape of SF_6 to the environment include:

- failure of seals
- escapes during commissioning of switchgear and equipment
- during operational checking of gas pressure on site
- sampling and transporting for off-site gas analysis
- recovery, reclaiming and refilling
- recovery and reclaiming at the end of the life of the equipment.

Use of specialised tools and established procedures will minimise the risk of releasing SF_6 into the atmosphere. CIGRE has identified the importance of this aspect and published a document named 'Practical SF_6 Handling Instructions' detailing appropriate process for proper handling of SF_6.

In Australia, the Energy Networks Association (ENA) has produced the 'ENA Industry Guideline for SF_6 Management' that aims to minimise SF_6 emissions in the energy network industry through best practice processes.

5.2.4 Offsets

In addition to the mitigation activities discussed in the above sections, the application of 'offsets' offers a further method by which to mitigate emissions. The principle behind an offset is that funding an activity outside of the business that results in a decrease in emissions, or a sequestration of emissions from a business as usual scenario, can be balanced against the emissions that are created by the business itself. In this way, the offset works to reduce the business' carbon footprint.

Offsets offer the advantage of being disconnected from the exact source of emissions which provides flexibility in how the offset is used. Depending on the type of offset, they can also be highly cost-effective on a per tCO2-e basis. However, offsets are generally not suitable for use as the primary means by which to mitigate a business' emissions. The lower cost offsets tend to involve forestry where carbon is sequestered into trees as they grow and where the amount of carbon sequestered over the trees' lifetime is brought forward and counted as an immediate deduction. In this way, although the carbon emissions may balance over the long term, the short term net result is an increase in atmospheric carbon. Given that climate change is related to atmospheric levels of carbon, this situation is not as environmentally effective as an offset that removes or reduces carbon emissions at the same rate, and at the same time, as the emissions being produced.

Offsets are typically used as a final stage of an emissions reduction strategy once operational emissions are reduced as much as is economically and technically possible at the source. A common application of offsets is for vehicle fleets and other travel where cost effective technical mitigation solutions are limited.

5.2.5 Cost of mitigation

For most companies, including energy network businesses, mitigating operational emissions relies heavily on the purchase of offsets. This is particularly the case if the goal is to achieve carbon neutrality. Reducing the actual production of emissions should be undertaken first through initiatives such as energy efficiency, reduced consumption and utilising renewable energy. However, there is usually a limit, either technical or financial, to the magnitude of such mitigation. The remaining emissions can be mitigated through offsets.

In a typical case, the cost of mitigation for feasible measures may range from $-80 per tCO2e for efficient lighting to $45 per tCO2e for 100% GreenPower purchase. In this example, the average abatement cost is likely to be approximately the cost of commercially available offsets, in the range of $20 per tCO2e. Therefore, the average cost of abatement including offsets is also approximately equal to the nominal offset cost of $20 per tCO2e.

On this basis, a network business may incur an annual cost of mitigating operational emissions in the range of $250,000 to $600,000. Over a typical 5-year regulatory period this equates to a range of $1.25m to $3m.

Key message

The cost of mitigating operational emissions (which do not include emissions from network losses) is likely to exceed $1m for a typical energy network business over a 5-year regulatory period.

5.3 Emissions from electrical losses

When transmitting or distributing electric power in a network, a certain amount of electricity will be inherently lost through the infrastructure. This loss effectively creates additional greenhouse gas emissions, as more generation is required to compensate for the loss. The rate of greenhouse gas emissions is related to emission intensity of the generation sources and is therefore highly dependent on location of the network element that is causing the loss. For example, electrical losses in Tasmania will cause relatively little greenhouse gas emissions if the load is being served predominantly by hydro power[28]. Conversely, losses in states that are being served by coal-fired generation will cause a high level of emissions.

Regardless of the generation source and resultant carbon emissions, electrical losses represent an economic inefficiency within the electricity supply chain. Under current regulatory and market arrangements, electricity businesses are not liable for the cost of lost electricity. Therefore, electricity network businesses do not have an inherent incentive to reduce electrical losses. Electricity network businesses will only have an incentive to reduce electrical losses where a specific incentive has been implemented, such as where an incentive is built into the price-control mechanism.

From the viewpoint of an electricity network business, the emissions associated with electrical losses are classified as Scope 2. The emissions would be classified as Scope 1 for the power generators. Therefore, electricity network businesses are not liable for the emissions associated with electrical losses and the CPRS will not provide a direct price signal to electricity network businesses to focus on reduction of emissions from losses.

However, the economic advantage of reducing losses can be used in helping justify regulated capital expenditure projects as efficient, and many businesses assess the impact on electrical losses in their project business case process. In order for network businesses to invest in electrical loss reduction and therefore reduction of emissions, the regulatory environment needs to support and encourage such investment. Any support mechanism needs to capture the carbon value of loss reduction as well as the electricity value.

Key message

Electricity network businesses require a regulatory environment that supports and provides incentives for the reduction of electrical losses in order for this method of emissions reduction to be prioritised and implemented.

Electrical losses can be categorised into three groups.

Conductor losses: These are typically known as I2R losses. Due to the inherent resistance (R) of conductors, heat is generated when current (I) passes through them. The amount of electric energy converted to heat energy along the conductor is wasted to the surrounds as a loss. Conductor losses cannot be avoided entirely in electrical networks as they are coupled with inherent properties of conductors, but can be reduced using larger sized conductors or more conductive metals. Conductor losses (per unit of energy transported) are reduced when power is transmitted and distributed at higher voltages.

Transformer losses: There are two types of transformer losses: no-load losses and load losses. When a transformer is connected to an electricity network, there will be a certain

[28] This is apparent under NGERS where Tasmania has the lowest NGA Factor of all states.

amount of magnetisation loss due to the construction properties of the transformer which results in heating of the transformer core, as well as vibration and noise. This is called the no-load loss. When a transformer is loaded, I2R losses (similar to conductor losses) will arise due to the inherent resistance of the transformer windings. Such losses are called load losses.

Corona losses: This is the phenomenon of ionising air around electrodes due to a high potential gradient and results in the crackling of conductors at very high voltages. Typically, corona is not a concern below 200 kV voltage levels.

The first and second types of losses are common to both transmission and distribution networks. The corona loss is associated with extra-high voltage transmission networks. Due to the relatively minor contribution of corona losses to overall electrical losses, this type of loss is not considered in detail.

Typically distribution losses in Australia are in the range 3 to 8% and transmission losses are 1 to 4% of input energy[29]. The ESAA reports an Australian weighted average distribution loss of 5.6% for 2006–07[30]. Some remote locations exhibit losses much greater than the average range. For example loads in rural Queensland experience distribution losses greater than 25% and transmission losses to Broken Hill in New South Wales exceed 10%. Other loads located close to generation facilities and distribution supply points experience losses lower than the typical range.

Network losses also increase with load. When load grows in the network, suitable network reinforcement strategies are implemented and there is an opportunity for the incorporation of loss reduction considerations at this stage.

Key message

Electricity network businesses have at their disposal a number of measures to reduce electrical losses and associated emissions; however, the magnitude of the loss reduction is limited by technical and economic constraints. In many cases, only a small reduction in electrical losses is feasible and at a high cost.

It is important to realise that network losses, while causing a significant level of emissions, are secondary to the emission intensity of the electricity generation. Connecting significant remote renewable generation may increase overall losses but allow a large reduction in overall emissions. There is an opportunity for treatment of losses in the regulatory framework to provide meaningful improvement in loss performance and loss related emissions.

It should be noted that network losses are not the only losses in the electricity supply chain from generator to consumer. Wiring on the consumer's side of the meter, either in a house or business can create a significant level of loss. As these losses are dictated by consumer designs and standards such as building codes, the associated emissions are considered part of total network user emissions.

The key technical and operational methods by which energy network businesses can reduce emissions associated with electrical losses are discussed in the following sections.

29 NEMMCO, List of Regional Boundaries and Marginal Loss Factors for the 2008/09 Financial Year and Distribution Loss Factors for the 2008/09 Financial Year

30 Energy Supply Association of Australia (ESAA) 2008a, Electricity Gas Australia, p28

5.3.1 Line augmentation

Losses in distribution networks tend to be higher than those in transmission networks. Heavily loaded long distribution feeders that cause substantial power losses are common in most of the distribution networks. Upgrading to larger capacity conductors is a method of reducing line losses.

Above 220 kV voltage levels, the conductor selection will be partly determined by the corona phenomenon and multiple conductors will be used to obtain larger equivalent cross-sections irrespective of the actual current carrying requirements. Furthermore, the network is generally operated with at least an N-1 level of redundancy, reducing loading levels on individual conductors and thereby effectively increasing the cross-sectional area of the conducting path. Therefore, many of the transmission lines including and above 220 kV will not experience excessive loading issues that can cause higher losses. Such transmission lines will not require any upgrades to reduce losses.

However, there can be transmission lines of 220 kV and above that are heavily loaded and continuously transmitting large amount of power. Typically these are the lines connected to major generator stations and large load centres. These lines will require case by case assessment to determine whether options such as increasing the operating voltage or upgrading to larger conductors are viable.

Most augmentation options will not be economically viable considering loss reductions alone. Generally the justification needs to be coupled with reliability improvement or asset replacement in order to pass regulatory tests. However, such augmentations may become theoretically viable if the cost of lost electricity and carbon emissions is appropriately factored into the assessment. This would need to be supported by an appropriate regulatory framework. Currently, consideration of loss reduction may justify the timing of an augmentation project to be brought forward.

In rural areas, line augmentation to reduce losses is likely to involve reconductoring, whereas in metropolitan areas connection of a new feeder may be the more viable option. As an indicative analysis of line augmentation, a hypothetical case is considered of a 40 km 132 kV Grape (30/2.5 ACSR) transmission line supplying a peak load of 70 MW at 0.95 power factor. Based on a typical daily load curve shown in Figure 5 1, the line losses were estimated at 42 MWh per day. If the line is upgraded to the larger Lime (30/3.5 ACSR) conductor, the line losses would be reduced to around 20 MWh per day. This loss saving of 22 MWh per day is equivalent to a reduction of 52%, which is at the higher end of savings that would typically be available on individual lines in the network.

Depending on the condition of the existing tower structures, the cost of the line upgrade can vary significantly. If the existing towers are suitable for the larger conductor, the upgrade will simply involve replacing the existing conductor and restringing the line. The indicative cost for such work in this case study is around $1.4m. If the line including towers were to be reconstructed, it would cost significantly more at around $16m. For this case, the costs are equivalent to $35,000 and $400,000 per km respectively. It should be noted that the construction costs depend on several factors such as terrain, easement, locality, length and costs can vary substantially from case to case.

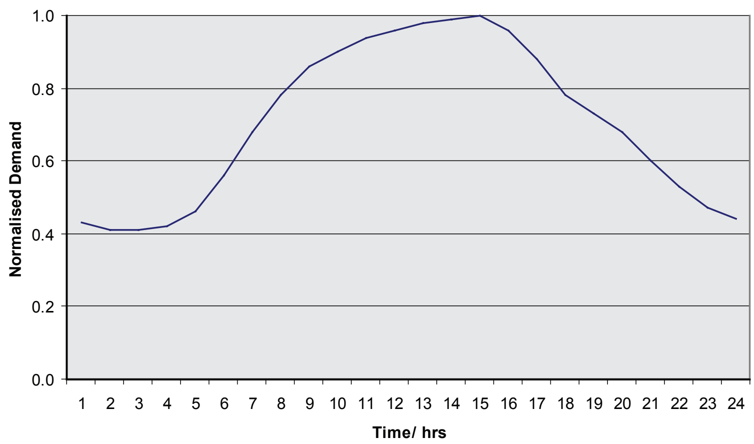


Figure 5 1: A typical normalised load profile

5.3.2 Reactive power compensation

Transmitting reactive power along transmission and distribution lines in addition to real power increases the net apparent power (and hence the current) flowing through the lines and results in higher losses. Therefore minimising reactive power transfer along the network by installing an appropriate amount of reactive power sources close to the load centres reduces the net flow in the network and results in reduced losses. When the load reactive power requirement is compensated at the distribution level, the burden on the transmission network due to reactive power transfer may also be eased and will offer lower overall network losses.

Considering the same case study example discussed above, if the load power factor is improved to 0.98 through the installation of 9 MVAr capacitors to provide reactive power support, the losses would reduce by around 2 MWh per day to 40 MWh/day. The indicative cost for the installation of 9 MVAr medium-voltage capacitors will be around $0.3m.

5.3.3 Low loss transformers

Thousands of transformers are installed in transmission and distribution networks from the source end (generators) to the customer end. Due to the large number of transformers, small improvements in transformer performance can potentially result in a significant reduction in overall losses.

Recent technological advances have succeeded in reducing core losses and resistive or winding losses, thereby increasing efficiency. The use of high efficiency conventional transformers is an option to be considered in relation to loss minimisation.

Considering the same example discussed in previous sections and assuming an 80 MVA transformer having 40 kW no load loss and 400 kW full load loss, the estimated transformer loss will be around 5.4 MWh per day. Low loss transformers will typically reduce the transformer losses by 20–25%. Therefore, the estimated loss reduction for replacing the traditional transformer with a similar capacity low loss transformer is around 493 MWh per annum assuming 25% loss reduction. Low loss transformers cost around 20% more than conventional transformers. The indicative cost for an 80 MVA 132/33 kV transformer will be around $1.5m and therefore, the cost for a low loss transformer of the same capacity is estimated to be around $1.8m.

5.3.4 Other technical measures

The following technical measures are seen as having less potential impact on emissions reduction due to higher anticipated costs or limited applicability. Accordingly, these measures are discussed but not analysed in detail.

Higher voltages

Higher distribution voltages can reduce line losses especially where substantial amounts of power are to be delivered over long distances. Typically, this happens in rural networks where substations are located far apart. Increasing voltage of an existing line may require replacement of transformers at terminal stations, zone substations and distribution substations. Furthermore, it may involve replacement of insulator sets, or even reconstruction of the line if higher safety clearances are required. Therefore, this will be an option that can be considered in long-term developments.

Likewise, converting heavily loaded long transmission lines to a higher voltage level will help in reducing overall transmission losses. However, this is likely to require reconstruction of lines and the upgrade of terminal stations at both ends of the transmission line. Furthermore, higher transmission voltages give rise to other concerns like corona, radio frequency interference and noise. Therefore, this approach will not be widely applicable and will require detailed technical analysis.

Construction of new substations

Construction of new distribution substations can assist in reducing the power losses along distribution lines as this can facilitate relatively short runs of lines with moderate loading. However, an increased number of substations may lead to increased transformer losses. Therefore, this approach is a compromise between line losses and transformer losses.

Load balancing

As a large proportion of single-phase loads are connected to the distribution network, a certain amount of load imbalance among the three phases is expected, especially at low voltages. Given that power loss is a function of the square of the current, if the loading of a low voltage distribution feeder is highly imbalanced, there will be higher losses than for a balanced feeder carrying the same total power.

Therefore identifying heavily unbalanced distribution feeders and conducting periodic load balancing will help in reducing losses in distribution networks. Unbalance also generates negative phase sequence voltages which can contribute to excessive heating in equipment, further increasing losses. This approach is more practical in overhead distribution networks than underground networks.

Augmentation of heavily loaded transformers

Augmentation of transformer capacity will reduce either the effective impedance of the installation or loading of the transformer. This will result in reduced power losses through the transformers. Therefore, the capacity reinforcement of heavily loaded transformers can assist in reducing overall power losses but may be offset marginally by higher no-load losses.. This approach is considered to be relatively high cost, partly because transformer

augmentation has implications for fault levels and commonly requires additional works to be undertaken to address the fault levels. However, there is scope to include the impact on losses when such augmentations are being considered based on other drivers such as capacity expansion or reliability improvement.

5.3.5 Operational and planning measures

In addition to the technical measures already discussed, there are a range of operational measures that can be undertaken to reduce losses. It is generally assumed that these measures are currently employed to a large extent or are typically outside the control of the network businesses and therefore pose a relatively minor contribution to emission reduction.

Distribution feeder rearrangements

Most distribution networks are operated as radial lines with some flexibility in load transfer using switching arrangements. Therefore, by analysing the power flows in the network, it may be possible to rearrange the feeding arrangements to a certain extent in order to reduce the overall losses in a selected geographic area. Given that most distribution networks are not designed with a great deal of flexibility, this approach will have several practical constraints.

Review of short-term planning approach

When distribution networks reach their loading capacity, load will be transferred to alternative connection points to manage the network as a short-term planning option. Under a framework that does not incentivise loss reduction, supply continuity will be paramount in such situations. However, there is scope to bring the treatment of losses into the short-term planning approach in order to reduce overall losses.

Even though load transfer or forced switching cannot be fully avoided as a short-term planning option, considered medium and long-term planning will enable the network operators to identify the issues well in advance and allow sufficient timeframe to put satisfactory remedial measures in place. This will help in managing the network power losses as well.

Remove existing operational constraints in the network

Due to various operational challenges in the network such as fault level issues, protection issues, equipment rating issues etc, transmission networks may be segmented and operated with open points as a short/medium-term option to mitigate constraints. Such an approach may cause increased system losses as the power flow is 'artificially' directed. Therefore implementing appropriate network augmentation plans to mitigate existing network constraints and restoring the standard network power flows will help reduce the transmission losses. The scope of this measure is, however, constrained by the need to operate the network to protect the reliability of the network. As a key performance indicator under electricity regulations and as one that is often incentivised, reliability naturally drives the operation of the network ahead of considerations such as losses.

Strategic positioning of future generation

Presently, the majority of generation is concentrated into generation centres and the transmission network is used to deliver the generated power to load centres. The location of

these large power stations is determined by the availability of primary energy sources (coal fields, hydro dams, gas pipelines etc).

If it is possible to position future generators close to load centres, the reduction in transmission distance will result in lower transmission losses.

5.3.6 Mitigation costs

The key technical methods by which electrical losses can be reduced include line augmentation, reactive power compensation and low-loss transformers. Based on a combination of these methods, reducing the electrical losses for a typical networks business by 10% is expected to cost in the order of $60m. Applied industry-wide, the cost would total some $1.2bn.

Key message

A high level of investment is required to meaningfully reduce electrical losses. Network businesses would require a regulatory framework that provides assistance and strong incentives to undertake such investment.

5.4 Emissions from gas losses

5.4.1 Causes of gas losses

Loss of gas during transport through a network can occur due to leakage of the pipelines and equipment. As a fugitive emission, this is a Scope 1 emission under the CPRS and may be of a magnitude to create CPRS emission obligations. As such, gas losses are a significant issue for gas network businesses.

Natural gas is primarily composed of methane (CH4), which has a global warming potential (GWP) of 21 over a 100-year time frame. Compared to carbon dioxide, methane has a very high global warming impact, but a short net lifetime in the atmosphere of 8.4 years. The GWP of methane over a 20-year period is 72 times that of carbon dioxide. Accordingly, unburnt methane has a significantly higher global warming impact than the carbon dioxide created when it is burnt.

The leakage of gas is one component of a factor called unaccounted-for gas (UAG), defined as the difference between the total measured amount of gas injected into the system and the total measured amount of gas withdrawn from the system over a time period. UAG is measured in units of energy per time i.e. GJ/a.

In theory, if all the gas that is injected into the system is delivered to the withdrawal points, there should not be any UAG. However, it is unlikely that the UAG will be zero due to a number of factors including leakages, meter accuracy, timing of meter reading, and measurement errors associated with pressure and temperature. In addition, the factors that affect UAG in the transmission system are different to the factors that affect the UAG in the distribution system.

Transmission pipelines are considered not to leak, and as such, any UAG in the transmission system is generally due to metering errors, and no fugitive emissions are expected. However, transmission businesses often use the gas as a compressor fuel in the compressor stations which will create carbon dioxide emissions. This operational gas is sometimes included as a component of UAG.

Unlike transmission UAG, the factors that contribute to the distribution UAG include those that involve fugitive emissions and those that create no emissions:

- leaks in the distribution pipes (fugitive emissions)
- purging of new gas mains and services (fugitive emissions)
- metering accuracy (no emissions)
- timing of the meter reading cycle (no emissions)
- theft of gas (assumed no fugitive emissions)
- changes in the gas temperature and pressure (no emissions).

Leaks from the distribution system are currently a significant component of UAG and are generally related to the old cast iron and unprotected steel system. One method of estimating gas leakage is to apply a factor (typically in the range from 0% to 55%) to the unaccounted for gas. The exact factor depends on local conditions and can vary significantly between states. This method is allowed under NGERS; however, NGERS applies a single factor of 55%, which may overestimate the actual amount of leakage depending on which state the relevant infrastructure resides. Other methods are also available to gas network businesses under NGERS including the use of per kilometre emission factors.

Purging of gas pipes and services is carried out when new pipes are installed and have to be filled with gas. This is done by venting some of the gas to atmosphere so that the pipes do not contain an explosive mixture. The venting of gas is not metered and as such contributes to the UAG.

Metering accuracy from both the business' custody transfer meter and the customer meters is another factor of UAG. It is worth noting that VENCorp has estimated that the uncertainty in measurement in a distribution system could be as high as ±2.4%. Another component of UAG is the timing of the meter reading. Gas meters are read on a 2-month cycle (60-day cycle). As all the meters cannot be read at the same time, the total calculation of UAG is affected by the staggered meter reading.

Other factors such as the temperature and pressure of the gas being measured at the customer premises versus the gas temperature and pressure when injected into the system will also contribute to the UAG.

One other component of UAG which is very difficult to estimate is theft of gas by customers. It is assumed that stolen gas is burnt and therefore does not contribute to fugitive emissions, but will create carbon dioxide emissions.

Gas losses total approximately 1% of total system throughput and UAG totals approximately 2.5%. For 2006/07 the lost gas is estimated at around 4 PJ. Based on a nominal price of $5 per GJ, the value of UAG is around $50m per annum and of that, the cost attributed to leaks is approximately $20m per annum.

5.4.2 Mitigation of gas losses

To mitigate fugitive emissions from leaks from the distribution system, gas distribution businesses are currently undergoing some from of rehabilitation of the old system. It is expected that by 2030, all of the old cast iron and unprotected steel systems would have been replaced and losses would be reduced substantially. As this work is currently being planned for and undertaken, it is not considered to be an additional cost to mitigate gas network businesses impact on climate change. However, governments and regulators should recognise the value of this work from the viewpoint not only of economic efficiency but also in relation to carbon emissions reduction.

In addition to changes to the gas network that the businesses would normally undertake, the initiatives to reduce gas losses and associated carbon emissions that gas network businesses might be encouraged to undertake in future include:

- redesign of gas actuator equipment — generally this equipment vents the gas to atmosphere
- quicker response time for any third-party damage to gas mains to reduce the potential amount of gas released to the atmosphere
- redesign the current practice of venting gas as part of a gas pipe purging operation
- more accurate metering to increase the certainty in measurement of any gas losses and better quantifying of emissions and the effect of mitigation measures.
- SCADA control of networks to operate fringe point pressure at the minimum allowed level.

5.5 Indirect emissions from energy network users

Energy network users are responsible for greenhouse gas emissions created in the production and use of energy that is transported across energy networks. Some electricity generators produce emissions at the power plant, the level of emissions depending on the technology employed and the volume of energy that the power station produces. Electricity consumers can in many cases choose the means by which their power is generated and collectively dictate the volume of energy that is demanded of the power plants in the network. Gas consumers create emissions when gas is burnt.

Energy network businesses have very little, if any, direct influence on the emissions that are generated by the production and use of the energy that they transport. The aim of a network business is to efficiently and reliably transport energy from its point of generation to its point of consumption, regardless of whether generation or use of the energy has a high carbon emissions profile. However, network businesses do have an important role to play in the reduction of overall network emissions. Distribution businesses in particular have a relationship to end users in that they maintain a direct physical connection with each consumer and have an obligation for service to that consumer. Changing the focus of a network business to include a role in reducing network wide emissions would require that the value of this role is reflected in a flexible regulatory framework.

The importance of the potential for mitigating industry-wide greenhouse gas emissions through enabling network users to reduce their own emissions is emphasised when

considering that network user emissions are in the order of 1,000 times greater than network business operational emissions.

Key message

There is the potential for energy network businesses to enable and support activities that mitigate network-wide emissions. However, this valuable role would represent a material change in the strategic direction for network businesses and would need to be reflected in regulations and incentives.

The key opportunities for energy network businesses to enable network users to reduce their emissions are discussed in Section 6.1.

6 Opportunities for energy network businesses

Climate change and the response to climate change create a number of opportunities for network businesses. Network businesses transport much of the energy consumed in Australia and provide a physical connection to nearly every customer in Australia. These network businesses are therefore in a position to enable connection of low emission generation and to influence the way in which energy is delivered and consumed.

Network businesses also have opportunities for growth under the impact of climate change. There are obvious growth prospects for natural gas pipelines as natural gas is enjoying strong growth as an electricity generation source and this is likely to continue as a carbon-pricing mechanism is introduced in Australia and continues to develop internationally. Funding for research and trialling of plant for carbon capture and storage (CCS) are gathering pace. The commercial application of CCS to fossil fuel electricity generation could necessitate significant pipeline infrastructure to transport carbon dioxide to suitable storage reservoirs. Similarly, the pending introduction of electric vehicles may provide opportunities for additional investment in electricity networks.

As a further example, as the carbon intensity of the electricity supply base reduces, electricity may increasingly offer a distinct environmental advantage over other forms of energy such as oil. Given the right technological innovation, this growing advantage could offer significant growth prospects for electricity networks.

The Garnaut review alluded to the opportunities for electricity transmission businesses in relation to climate change when it recently noted that:

There are public good arguments for reducing (network) constraints in light of the expected changes required for Australia’s transition to a carbon-constrained future. (Garnaut 2008a)

Furthermore there are opportunities for network businesses to contribute positively to the way that energy is used and to enable consumers to reduce their greenhouse gas emissions. These opportunities arise through the role that network businesses have in connecting customers to networks, through the tariffs charged for network use, and through the provision of services and information to network users.

In this section, we broadly discuss the opportunities for network businesses to enable a reduction in greenhouse gas emissions, and to prosper in an era of carbon constraints and a changing climate.

6.1 Network business enabling role

Electricity and gas network businesses are in a unique position to assist network users to reduce greenhouse gas emissions. Virtually every customer in Australia is connected to an electricity network, gas network or both. The way in which these customers are connected to the network, the services and information they are offered, the energy metering and the charges for connection can have a significant impact on customers and the customers’ efforts to reduce greenhouse gases. However, the behaviour of network businesses is currently constrained by the regulatory framework and the incentives provided to the businesses.

We have identified a number of ways in which network businesses might contribute to a reduction in greenhouse gas emissions by providing an enabling role. These include:

- assisting with connection of alternative (low emission) forms of generation
- assisting with reduction in consumption
- managing peak demand
- providing smart metering
- providing load control systems
- constructing networks to connect distributed generators
- designing and operating of network to reduce losses
- providing data and technical expertise.

6.1.1 Supply side opportunities

Connection of alternative forms of generation

Network businesses are generally required through regulation to provide access to generators. However, unless the connection involves the construction of new network assets, they have little incentive to encourage connections. Network businesses can assist in the connection of alternative forms of generation through providing information that makes connection simpler and through providing the physical network.

Electricity networks can encourage the connection of low emission generation by providing easy access to information for potential generators. This is particularly important for smaller scale generators that do not have the capacity or knowledge to follow processes designed for the connection of large generators. Many low emissions generators are small scale and would benefit from this approach. This might involve simplifying and standardising connection processes, making capacity or fault level[31] information readily available, or generally providing positive assistance to low emission generation proponents.

The current regulatory regime covering connection of generators to transmission systems requires a connecting generator to cover the cost of connection up to the point of connection. This could result in a single generator paying the full cost of a network extension (or not being able to make an economic connection) to the network. Subsequently connecting generators may be able to access the network connection without sharing the full cost of the network extension. This 'second-comer' connectee issue is recognised in Garnaut (2008a) for transmission networks. However, it is also an issue for generators embedded in distribution networks and might also apply in certain situations to gas networks. Policy makers need to consider the development of incentives that support the connection of low emissions generators by network businesses.

Construction of networks to connect distributed generators

The traditional role of transmission networks is to connect generators to loads and the traditional role of electricity distribution networks is to distribute energy from a bulk supply point to end users. Many low greenhouse gas emission generators are much smaller than traditional large-scale thermal generators and these smaller generators are increasingly

[31] Electricity networks are required to interrupt supply when an electrical fault occurs in order to ensure the safety of people and equipment. The equipment used to interrupt supply and the network is rated for a certain fault level. The addition of generators to a network can often result in an increase in fault level requiring some change to the network or network equipment before the generator can be connected.

connected to distribution networks. Electricity businesses clearly have a role in providing the network to connect distributed generators.

Gas networks can also facilitate the connection of gas-fired generators through the provision of new pipelines to large-scale gas-fired generators and through the provision of a gas distribution network to smaller embedded gas generators such as micro-turbines.

6.1.2 Demand side opportunities

Reduction in consumption

Network businesses often have a good understanding of the way in which energy is used and the way in which energy consumption could be reduced. Network businesses undertake a range of peak demand and energy consumption forecasts and therefore have a direct interest in the ways that energy is used and the factors that contribute to high peak demand and consumption. There are no current incentives for network businesses to make this knowledge and experience available to users and as a consequence, network businesses are not structured to provide corresponding services. Networks are, however, in a position to develop targeted programs to advise customers on energy consumption if appropriate incentives are put in place. For example, distribution network businesses might provide users with information on power factor improvement techniques or the ways to use high power appliances more efficiently.

A specific opportunity relates to the emissions created by street-lighting, where electricity network businesses own the street-light assets but local government controls the assets and pays for the power. Electricity network businesses have significant knowledge of street-lighting technology and would be in a position to inform and facilitate energy efficiency measures of local government

Peak demand management

Peak demand management which involves customers reducing demand during peak network loads is generally considered to be desirable as it reduces the need to construct additional network or generation facilities that may be poorly utilised. As a secondary effect, it can also lead to a reduction in overall consumption, as described above. Further, peak demand management may result in the use of embedded generators[32] to reduce demand. As the embedded generator is usually close to the end user, this may result in lower network losses, and if the embedded generators are of a low emission technology this will reduce generation emissions. If peak network demand is reduced and consequently the network is not augmented, the overall network utilisation will increase which will likely increase overall losses as a percentage of energy delivered compared to the case where the network is augmented to address the peak demand. This increase in losses could counter any emission reduction benefits of the peak demand management.

Smart metering

Providing information to customers about their energy usage enables the customers to make informed choices about their usage. Customer metering provides the raw data that forms the basis to understanding energy consumption. Smart meters capable of measuring and recording energy flows combined with a communications system that provides access to the

[32] Embedded generators are connected at the distribution level and are typically close to a load centre.

data are now widely recognised as a key to enabling customers to control their energy usage.

The role that network businesses can play in providing such meters as well as the communications and data collection infrastructure is also being recognised. This is evidenced by the recent decision by the Ministerial Council on Energy (MCE) for electricity distributors to take the lead in the multi-billion dollar project to roll out interval meters and associated data-gathering systems.

Interval meters are a basic form of smart meters that allow for the energy price to be varied and communicated to the customer in order to better reflect real market conditions. More advanced forms of smart meters can interface with, or encapsulate, load control systems such that customer demand can be controlled automatically as discussed in the following section.

Provision of load control systems

Load control systems allow energy users to modify their consumption to respond to external factors such as energy price or temperature. Electricity network businesses have traditionally provided load control systems to hot water customers through the provision of time switches or ripple control systems.

Network businesses will soon be developing their capacity to facilitate customer load control as electronic smart meters and associated communications networks are rolled out. Although the current specification of smart meters do not allow for specific load control, this is envisaged as the next future step of the technology. The installation of these advanced systems would enable network businesses to offer facilities that control devices to optimise the use of energy. This technique could therefore be used help reduce greenhouse emissions.

6.1.3 Network opportunities

Design and operation of network to reduce losses

Gas network businesses generally have an incentive to reduce fugitive emissions from gas networks and are in a position to reduce emissions through activities such as the replacement of old degraded pipes.

Electricity networks have a limited incentive to reduce losses but are in a position to reduce losses through activities such as the optimal sizing of conductors and components.

Methods by which electrical and gas losses may be reduced are covered more fully in Section 5.

Providing data and technical expertise

The interaction between the use of energy by energy consumers and the provision of the energy through networks can be complex. Energy network operators have a well-developed understanding of the interaction between consumption and supply and are in a position to provide data that might be useful to customers that are seeking to reduce energy consumption. For example, many customers would not be aware of the impact of power factor on losses. Network businesses can provide data and expertise in power factor improvement that will result in a reduction in greenhouse gases. There is scope for regulators to incentivise network businesses to invest in the provision of such information given the likely resultant market benefits.

Key message

There are a number of opportunities for network businesses to grow as a result of climate change. The nature of the growth will depend on the future sources and use of energy.

Network businesses can play an enabling role in the reduction of greenhouse gases by energy generators and consumers. However, they are not currently structured to undertake this role. There is an opportunity for policy makers to implement regulatory incentives that facilitate the changes network businesses will need to undertake in developing this enabling role.

6.2 Features of future energy networks

Energy networks are changing as a result of changes in generation mix, changes in technology, and changes in customer requirements. These factors along with the considerable cost of continually adding network capacity to meet growing peak demand are leading to innovations in network operation and management that are likely to fundamentally change the way networks will operate in the future.

Climate change will affect the network through customer demands for better information and systems to measure and control their energy usage and through a change in generation mix. This creates an opportunity for network businesses to build and adapt their networks to make use of new and emerging technologies and to enable customers to reduce their greenhouse gas emissions. Some of the features of future energy networks that make use of technology and provide enabling information and systems to customers are described in this section.

6.2.1 Smart grids and intelligent networks

The 'smart grid' or 'intelligent network' are concepts that are attracting significant interest and are the subject of international research. The concepts utilise technology to provide more efficient and reliable networks that meet the needs of customers and embedded generators.

The smart grid vision involves the use of metering, control and communications technologies along with computer applications. These smart grids are applicable to both gas and electricity networks. The technologies enable network providers to build and operate a network that meets the needs of customers by providing customers with a means of understanding their energy usage and offering control over energy usage along with accommodating a variety of generation options, managing two-way electricity flows from embedded generation and enabling energy markets.

The development of smart grids will involve the use of widespread measuring and control elements across a network such as meters and remotely operated switches. Information is collected from the measuring devices across the network and fed via a communications network to computers that collect and analyse data. This provides the capability to respond to changes in the network (such as faults) and to automatically respond to these changes thereby providing a more reliable and efficient energy supply.

Internationally there are a large number of research projects and pilot programs exploring opportunities and development of smart grids. In the US and Europe, government and industry are sponsoring research into many elements of smart grids. In Europe the role of research into smart grids is recognised as an enabler to the reduction of greenhouse gas emissions.

Research is needed to help identify the most cost-effective technologies and measures. This would enable Europe to meet its targets under the Kyoto protocol and beyond. (European Technology Platform SmartGrids — Vision and Strategy for Europe's Electricity Networks of the Future, 2006)

The implementation of smart grids within Australia will similarly require research and trials as Australian energy networks and market structures differ from both European and US networks and markets.

6.2.2 Future network design and technologies

Network topography

Traditionally electricity transmission networks connected large-scale generators to load points and gas pipelines connected a single point of supply to a large customers or city gates. In the future these transmission systems are likely to change as the number of connection points increases due to changing generation and supply patterns. For example, the gas transmission network is becoming interconnected and additional sources of supply such as coal seam gas will result in a network that is increasingly interconnected.

Distribution networks will develop to accommodate embedded sources of generation and this may result in networks that are islands rather than interconnected.

Embedded generation

Large volumes of embedded generation have a number of implications for networks. Where the embedded generators rely on gas as a source of fuel, the gas network becomes increasingly important and the gas network will need to develop to supply additional demand.

Embedded generation affects the operation and technical aspects of electricity networks. This may lead to improvements in security of supply if the generation is diverse and well dispersed throughout the network. Conversely, embedded generators can contribute to technical issues such as fault levels and may have implications for the safe operation of networks. Further, the quality of energy supply can be affected by embedded generators requiring more complex methods of network operation.

Energy storage

Developments in energy storage might result in significant changes to networks. For example, the use of batteries in electric vehicles to feed back energy at times of peak demand could reduce the need for additional network capacity to meet peak demand but will increase the complexity of operating and managing an electricity distribution network. This proposed technology, known as 'vehicle-to-grid' is currently being researched in the US and Europe.

Bi-directional power flows

Increasing diversity in generation and increasing embedded generation will alter power flows in electricity networks. Other technologies such as electric vehicles acting as energy sources (from battery storage or stationary generation) will add to the diversity of supply and demand. Much of the embedded generation capacity is expected to be from renewable sources such as solar photovoltaic that has a variable power output. These factors will lead to more complex power flows within electricity networks. Multi-directional power flows on distribution networks will mean that these lower voltage systems will become more akin to transmission networks — requiring active, rather than passive, management and control.

Transmission networks will need to develop to accommodate these changing power flows and to ensure that low emissions generation can connect to the networks. Distribution networks will need to react to large volumes of distributed generation which will involve new skills in network planning and operations.

Metering and measurement

Smart meters connected to communications networks will provide huge increases in the data available to network businesses and customers. Further, measurement devices measuring network operational status, plant status and environmental factors will become increasingly common. These devices provide much of the raw data that is needed by customers to control their energy consumption.

The large increase in data that occurs as a result of wide-scale installation of interval meters will require large investments in data processing and storage along with additional analytical systems to make use of the data.

Control

New communications systems and electronic devices embedded in equipment and appliances will enable widespread control of loads and generators. Further, the network will be fitted with an increasing number of devices that can be controlled leading to remote configuration of networks and allowing advanced features such as 'self-healing' to be implemented.

Communications devices

Networks communications are already evolving away from traditional copper-wired systems to newer technologies. Further changes in communications technologies are anticipated with systems evolving to handle much greater volumes of data and wireless components becoming commonplace. These technologies will enable network businesses to better understand the status of their networks and will provide cost-effective communications to many devices. Similarly the technologies will enable customers to access information regarding energy usage and will allow customers to control their usage.

Data acquisition systems

The combination of additional electronic devices and the availability of communications systems will allow additional data to be collected. Data will need to be collected in a logical way so that the data can be validated, stored and made available to users. These users might include network operators, market operators, retailers and customers.

Data analysis systems

Many of the technology changes discussed above such as communications systems and metering and measurement will result in additional data that is available to network operators and customers. This raw data will have real value when it is sorted and interpreted to provide information on which operating decisions will be made. IT systems that can analyse data and provide information will be required. In some cases automation of responses will be possible, further improving reliability and flexibility of networks. For example, a fault may occur in a section of network. This fault could be detected automatically and the IT system could analyse the situation and take immediate corrective action such as simultaneously reducing customer load by switching off controllable customer load and reconfiguring the network by remotely operating switches to isolate the faulty network elements.

6.2.3 Research, development and innovation

Energy network technologies are continuing to evolve and the impact of climate change is likely to increase the opportunities for deployment. However, the current regulatory framework does not encourage network businesses to undertake the research that is necessary to efficiently adopt these new technologies.

Innovation is essential to ensure that network businesses can configure the networks to adapt to changing technologies. Internationally significant expenditure has been committed to research involving new technologies such as synchronising wind generation output and the storage of electricity at home and elsewhere in the grid. While Australian network businesses can benefit from international research there are differences between US or European energy operations and Australian network design, network structure and market structure. It is therefore necessary for Australian network businesses to undertake some research and development of new technologies to ensure they are suited to local conditions.

Research and development is by nature speculative. Research and development may not result in tangible assets that would be assessed as prudent and efficient expenditure under existing regulatory processes. There is scope for current regulatory review processes to be adapted to incorporate the opportunity for network businesses to undertake research, development and trials of new technology.

Key message

The fundamental change in the way that networks will operate in the future will only occur if network businesses are aware of available and emerging technology and have a sufficient understanding of the way that technology can be applied. This understanding can only be gained from research, trials, testing of technologies and a generally closer association with developers and suppliers of equipment and technological solutions.

6.3 Growth opportunities

6.3.1 Electricity network development

Growth in consumption from electric vehicles

The total volume of electricity in future years will be driven by competing forces, some of which will work to reduce consumption and others that will increase consumption. Given the high level of uncertainty surrounding individual influences, and the way in which they might interact, there is significant uncertainly associated the effect on overall electricity demand.

Figure 6 1 forecasts that the anticipated uptake of mass-market electric vehicles in the next few decades has the potential to drive electricity volumes to levels higher than would otherwise be expected. To frame the potential volume opportunity of electric vehicles, current and proposed electric car designs utilise battery packs in the order of 16–20 kWh capacity. Assuming a typical daily usage of 10 kWh, this represents an effective doubling of household electricity consumption based on a single electric car.

Under Garnaut's 'standard technology scenario', electric vehicles are introduced to the mass market around 2030, by which time they are expected to be cost competitive with internal combustion engine and hybrid vehicles (Garnaut 2008b). However, factoring in a gradual uptake of the technology as well as the typical vehicle replacement age, the real impact of electric vehicles on electricity consumption will be felt between 2050 and 2075. During this period their market share is projected to grow from 13% to over 90% under the 550 ppm scenario. This development is shown in the changing share of fuel type in Figure 6 1 and is reflected by the rapid increase in electricity consumption displayed in Figure 4 2.

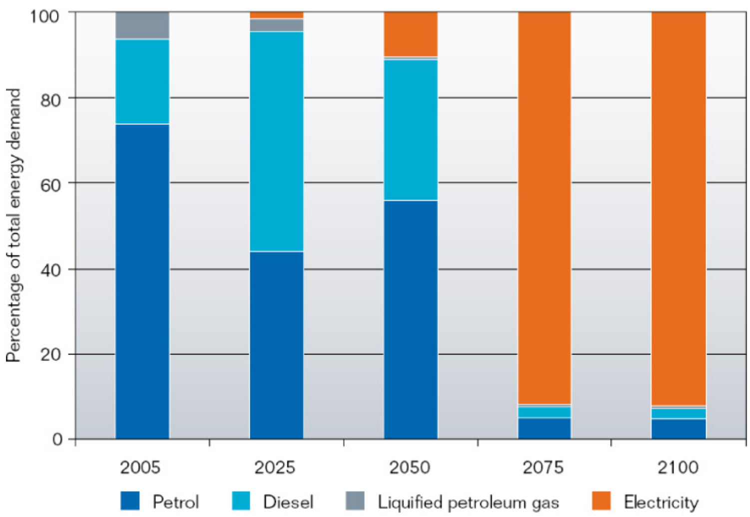


Figure 6 1: Share of road transport fuel type (Garnaut's 550 ppm scenario)

Source: Garnaut 2008b

It should be noted that these forecasts by Garnaut are based on a 'standard technology scenario' and in the absence of escalated fossil fuel prices. The standard technology scenario takes a 'cautious view of future trends', and there is significant evidence in industry to suggest that technology will develop faster than this scenario suggests. Garnaut considers this point and analyses an 'enhanced technology scenario' which brings the uptake of electric vehicles forward by one decade.

Most major car companies have announced that they are developing electric car models, and General Motors, Toyota and Mitsubishi have each announced that they will have electric cars (either plug-in hybrid or pure electric) available for sale in 2010. Holden has confirmed a target date during 2012 for the General Motors plug-in hybrid to be available in Australia. On this basis it is likely that a range of electric vehicles will be available in Australian showrooms by 2015, albeit at a cost premium to hybrid or internal combustion engine models. Considering the cost reductions that have been reported for Toyota's Prius components during the past decade and the continual development of battery technology, cost competitiveness of electric vehicles by 2020 is feasible.

Elevated fossil fuel prices will also act to drive a more rapid uptake of electric vehicles. Garnaut considers a scenario of elevated fossil fuel prices; however, this scenario is still relatively conservative in that the oil price in 2050 is forecast to not reach its recent peak of around US$150 per barrel. This scenario is forecast to bring the uptake of electric vehicles forward by 5 years. Higher fossil fuel prices are not expected to further accelerate the short term development of electric vehicle technology, but will impact the running cost comparison with fossil fuel vehicles and drive a more rapid transition to an electrified vehicle fleet.

The CSIRO report Fuel for thought (2008) predicts that up to two-thirds of kilometres travelled in Australia could come from electric vehicles (either plug-in hybrid or pure electric) by 2050 under a scenario incorporating the IEA high oil price (US$100 per barrel) and an emissions target of 60% below 2000 levels.

The feasible prospect of both a rapid commercialisation in electric vehicles and high fossil fuel prices bring considerable upside to the opportunities for electricity volumes.

A further impact of electric vehicles is a potential increase in both electrical loads and the utilisation of electricity assets. These impacts will be determined by the charging patterns adopted by electric vehicle users. Electric vehicle chargers can be designed for various power levels but are commonly in the range of 2–4 kW. Once there is widespread uptake of electric vehicles, this charging load has the potential to drive peak demand levels instead of airconditioning or heating loads. A key focus of current battery research and development is to allow faster charging to improve the convenience and flexibility of electric vehicles. Charging times of 2 hours have been achieved in commercial battery technology which would require charging loads in the order of 8 kW. An increase in peak demand represents both a challenge and an opportunity for electricity network businesses to manage the demand and to invest in the required network augmentation.

It is anticipated that most charging of electric vehicles will be conducted at night. This is not only likely to be driven by convenience but also by the introduction of time-of-use electricity tariffs. The result could potentially flatten the electricity demand profile and allow a higher economic utilisation of electricity assets that would be reflected in the inherent value of the assets. In Figure 6 2 research conducted by the Oak Ridge National Laboratory for the US Department of Energy illustrates that the potential impact of charging on the demand profile depends entirely on the time of charging. This figure is based on a market share of 25% for plug-in hybrid electric vehicles with an average daily consumption of around 8 kWh per vehicle. It is considered that time-of-use tariffs and automated charging timers can be effective in driving night time charging rather than evening charging.

This could align recharge times with demand troughs in the early hours of the morning to a greater degree than illustrated in Figure 6 2.

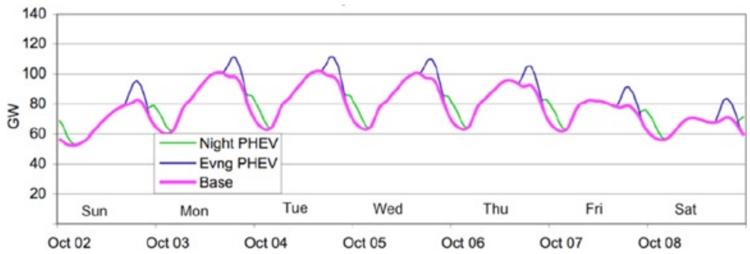


Figure 6 2: Impact of evening and night charging scenarios on electrical load profile in the USA for 25% market share of plug-in hybrids in 2030

However, it should be noted that not all electric vehicles will be charged overnight. Both private vehicles and fleet vehicles may require charging during the day if they are covering longer distances. Therefore there remains the potential for electric vehicles to increase peak demand levels. A further consideration is the potential future use of batteries in electric vehicles to store energy and provide capacity at times of peak demand.

The uptake of electric vehicles also presents the opportunity for distribution businesses to invest in the installation of charging infrastructure in public areas, such as shopping centres, work places and car parks. Cities including London, Paris and several in California have begun installing public charging facilities for electric vehicles.

Connection of generation

The connection of a diverse range of low-emission generation types will require additional electricity network and therefore will result in network growth. Some generation types, such as wind or geothermal may require significant transmission network expansion.

Metering

As discussed in Section 6.1.2, smart meters have been recognised as an enabling technology that will provide energy users increased ability to manage their consumption. The installation of large numbers of new meters and the two-way communications systems that are currently favoured to communicate with the meters offer an avenue for growth in distribution network assets.

Network capacity and strengthening

Additional network capacity, particularly in regional electricity transmission interconnection, has been identified as a requirement arising from climate change initiatives. These new and augmented interconnectors will result in growth in the electricity transmission networks.

In Section 4 we identified a number of areas where network businesses could improve their networks to minimise the impact of climate change on network reliability. Undertaking the network strengthening required to make network more resistant to extreme weather events will result in growth in electricity transmission and distribution networks. These opportunities are discussed in detail and quantified in Section 4.

6.3.2 Gas network expansion

Geo-sequestration of carbon dioxide

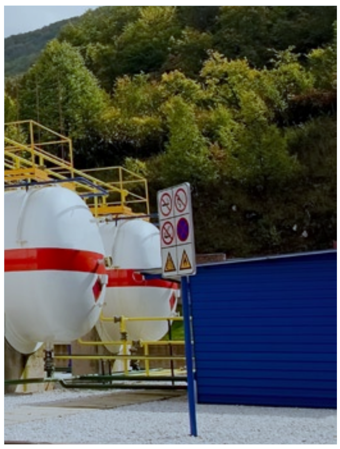
Geo-sequestration has been identified as a means of reducing carbon dioxide emissions to atmosphere. While the technology is still being developed, the gas network businesses have an opportunity to plan for their introduction and become involved in the dialogue leading to the likely development of new networks to transfer carbon dioxide captured from electricity generation plants and transferred to identified sequestration locations.

In particular, due to the characteristics of carbon dioxide gas, its transport requires special treatment and particular pipeline design features will be required. For example, compressing carbon dioxide enables the injection and storage of greater volumes. This method is already a mature technology and in the USA, about 40 Mt/a travel through 2,500 km network of high pressure pipelines (Garnaut 2008a).

Growth in natural gas consumption

Gas is forecast to be the preferred fuel for new large-scale generation over the next decade. The use of gas to power electricity generators will require additional gas transmission capacity that will involve the construction of new pipelines or augmentation of existing pipelines.

The opportunities for growth in gas distribution as a result of climate change rely on the adoption of new technologies. These technologies could include gas-powered airconditioning, micro combined heat and power turbines, fuel cells and gas-powered vehicles. Each of these technologies continues to evolve and, if widely adopted, could result in significant growth in gas distribution networks.



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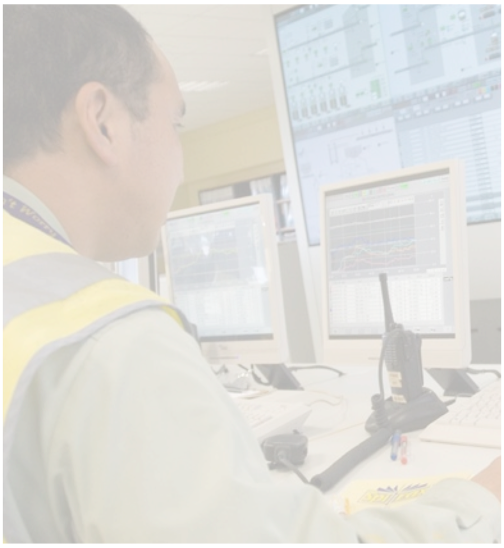
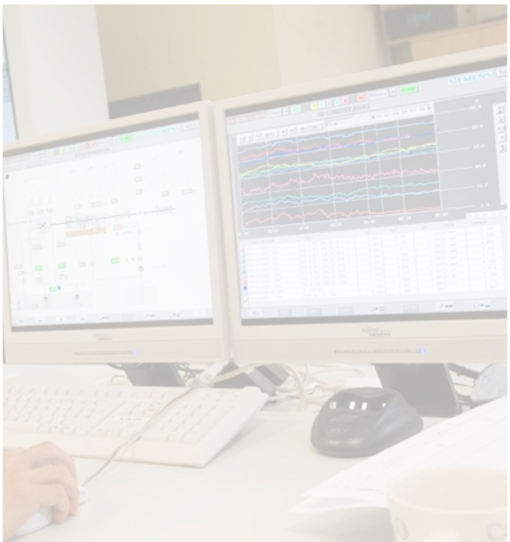
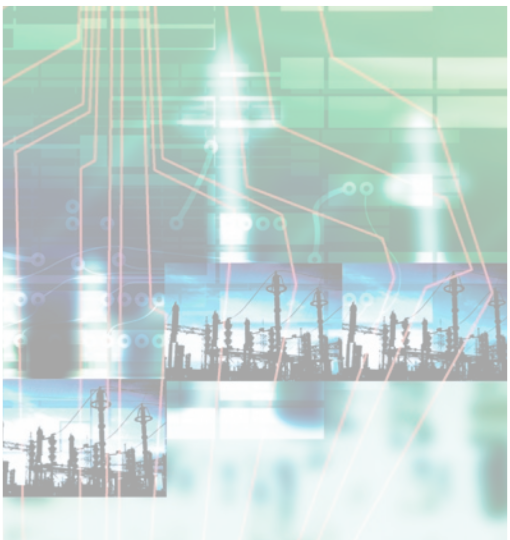




APPENDICES



Survey of network businesses

This appendix collates the responses of Energy Networks Association (ENA) member companies to the survey conducted by PB (Parsons Brinckerhoff). The primary aim of the survey was to collect information regarding the current and planned activities being undertaken in response to climate change in the areas of mitigation and adaptation

Mitigation of operational emissions	
General	Carry out company-wide energy efficiency and emissions abatement study
	Develop corporate strategies for climate change and other sustainability and issues
	Incorporate climate change impacts into Environmental Management System
	Plan to achieve carbon neutrality
	Plant trees to offset direct emissions
Electricity use	Conduct energy auditing and assessment activities
	Purchase increased percentage of renewable energy for facilities (ranging from 10% to 100%)
	Review building designs for energy efficiency
	Build energy-efficient retrofits
	Use efficient lighting upgrades
	Adjust airconditioning system
	Strategically target ICT energy use
	Educate staff in energy efficiency
Vehicle fleets	Conduct fleet vehicle emissions studies
	Review vehicle policies and fleet strategies
	Replace vehicles with smaller models
	Replace petrol fleet vehicles with LPG models
	Use hybrid vehicles to lower emissions
	Use blended biodiesel (B20)
	Offset fleet carbon emissions
	Participate in Victorian Government Travel Smart Program
SF_6	Develop SF_6 management strategy
	Give preference to non-SF_6 equipment in procurement of switchgear
	Establish SF6-free zone substations
Waste	Recycle to reduce co-mingled waste
Supply chain	Encourage suppliers to reduce their climate change impact

Table 1 1: Mitigation activities

Mitigation of network losses	
Electricity	Measure network losses
	Investigate options to reduce losses
	Develop strategy to address line losses
	Ensure network planning process take into account financial (NPV) impact of line losses
	Alter network design to reduce losses
	Use low voltage regulators
Gas	Feed gas network leakage survey into planned maintenance program
	Establish control mechanisms for managing unaccounted for gas levels
	Reduce leakage by carrying out mains renewal

Mitigation of indirect emissions — Network energy	
Electricity	Develop position document and strategies on AER demand-side management and non-network solutions
	Prepare a document for developers to encourage implementation of AER demand-side management and non-network solution initiatives
	Promote efficient road-lighting to councils
	Promote embedded generation and facilitate connection
	Support connection of renewable generation
	Develop simplified approach for connection of renewables and embedded generation
	Conduct public educational programs regarding energy efficiency
	Promote staff education initiatives
	Offer renewable energy through retail arm
	Carry out trials of renewable or alternative technology for remote generation projects
	Participate in Federal Government Solar Cities Program
	Perform airconditioning load control trials
	Carry out demand management initiatives (commercial and industrial)
	Conduct free energy audits
Gas	(None reported)

	Adaptation activities
Corporate	Incorporate climate change into corporate strategy
	Incorporate climate change into environmental policy
	Incorporate climate change into risk management framework
	Commission a study on adaptation
	Develop climate change financial impact modelling study
	Carry out emissions reporting
Policy	Become familiar with legislation and reporting
	Become involved in policy setting and in providing advice
	Participate in public submission processes
System planning	Incorporate climate change impacts into planning process
	Use low, medium and high future carbon scenarios in planning of reinforcements
Demand-Side Management	Participate in the Ministerial Council of energy smart metering initiative
	Develop smart meter implementation plans
	Install smart meters
	Develop projects for the Australian Energy Regulator demand-side management learning by doing fund
	Comply with relevant renewable energy feed-in-tariff laws
	Provide data to support community initiatives
Event response	Investigate emergency response required for extreme weather events of increasing magnitude
Operations	Review vegetation management strategy
Physical impacts	Carry out risk assessments on critical infrastructure including climate change impacts
	Review design standards in regards to exposure damage
	Revise overhead design standards including asset lives to account for increased wind speeds and bushfire risks
	Increase coverage of surge diverters for pole-mounted transformers in response to increased lightning activity
	Identify and relocate ground-mounted assets in flood-prone areas
Bushfire risk	Undertake capital replacement program to reduce the risk of bushfires initiated by electrical infrastructure
Water	Reduce water use
	Use non-potable water use for some applications

Table 1 2: Adaptation activities

2. Scenario development

2.1 Selection of SRES A1B for ‘average’ scenario

The most influential projections used in climate change analysis are those set out in the Special Report on Emissions Scenarios (SRES) of the IPCC (2007). SRES provide a wide range of future emissions paths out to 2100 based on different assumptions of growth and technology. Scenarios are A1, A2, B1 and B2. The framework employed in this project uses two SRES A1-based scenarios (A1B & A1FI).

The SRES A1 scenarios are based on a future of very rapid economic growth, a global population that peaks in mid-century and declines thereafter, and the rapid introduction of new and more efficient technologies (CSIRO 2007). The SRES A1 storyline develops into three scenario groups that describe alternative directions of technological change in the energy system. The two A1 scenarios used in this project are listed below:

- SRES A1B — A balance across all energy sources: Technological change involving a balance of fossil-intensive and non-fossil-intensive energy sources and technologies. Balance is defined as not relying too heavily on one particular energy source, on the assumption that similar improvement rates apply to all energy supply and end-use technologies (CSIRO 2007).
- SRES A1FI — Fossil intensive: detailed below.

According to the Garnaut Climate Change Review and the CSIRO, the SRES A1B scenario is the ‘best estimate’ of annual warming over Australia by 2030 relative to the climate of 1990. The A1B scenario projects average Australian warming by 2030 in the range of 0.6–1.5°C in each season for most of Australia (CSIRO 2007). Allowing for uncertainty between all SRES emission scenario models expands this range only slightly to 0.4–1.8°C. A1B hence provides the best ‘average’ scenario option relative to other emissions scenario models.

2.2 Selection of SRES A1FI for ‘high’ scenario

The SRES A1FI scenario is based on the SRES A1 storyline outlined above with a technological focus on fossil-intensive energy sources. CSIRO recognises SRES A1FI as the highest emissions scenario of the SRES series. A1FI projected changes are greater than all other SRES scenarios; A1FI changes are larger than those projected in all other A1, A2, B1 and B2 scenarios.

Later in the 21st century the warming is more dependent on the assumed emission scenario; divergence between the SRES A1B and A1FI scenarios increases beyond 2030 (CSIRO 2007).

2.3 Scenario assumptions (2030)

Scenario no.	Climate science scenario (CSIRO)	Government policy response	Public engagement
1	A1B	Low	Low
2	A1B	High	High
3	A1FI	High	High

Table 2 1: Scenario assumptions for 2030

2.3.1 A1B scenario and low government response

Temperature

- Projected temperature changes vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Rainfall

- Projected rainfall changes vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Wind speed

- Projected mean and peak wind speed changes vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Sea levels

- Projected sea level rises vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Storm activity

- Projected changes in storm activity vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Carbon Pollution Reduction Scheme

- Low government target of 10% reduction in emissions by 2030.
- Emission permit price assumed to be less than $50t/CO2-e.

Mandatory renewable energy targets (MRET)

- In 2007 the Australian Government committed to 20% of Australia's electricity supply from renewable energy sources by 2020.
- Low government MRET target — remain at 20% renewables for 2030.

Energy efficiency standards

- Low government response — 10% increase in energy efficiency standards across all sectors for 2030.

2.3.2 A1B scenario and high government response

Temperature

- Projected temperature changes vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Rainfall

- Projected rainfall changes vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Wind speed

- Projected mean and peak wind speed changes vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Sea levels

- Projected sea level rises vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Storm activity

- Projected changes in storm activity vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Carbon Pollution Reduction Scheme

- High government target of 20% reduction in emissions by 2030.
- Emission permit price assumed to be greater than $50t/CO2-e.

Mandatory renewable energy targets (MRET)

- In 2007 the Australian Government committed to 20% of Australia's electricity supply from renewable energy sources by 2020.
- High government MRET target — increase to 30% renewables for 2030.

Energy efficiency standards

- High government response — 20% increase in energy efficiency standards across all sectors for 2030.

2.3.3 A1FI scenario and high government response

Temperature

- Projected temperature changes vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Rainfall

- Projected rainfall changes vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Wind speed

- Projected mean and peak wind speed changes vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Sea levels

- Projected sea level rises vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Storm activity

- Projected changes storm activity varies between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Carbon Pollution Reduction Scheme

- High government target of 20% reduction in emissions by 2030.
- Emission permit price assumed to be greater than $50t/CO2-e.

Mandatory renewable energy targets (MRET)

- In 2007 the Australian Government committed to 20% of Australia's electricity supply from renewable energy sources by 2020.
- High government MRET target — increase to 30% renewables for 2030.

Energy efficiency standards

- High government response — 20% increase in energy efficiency standards across all sectors for 2030.

2.4 Scenario assumptions (2070)

Scenario no.	Climate science scenario (CSIRO)	Government policy response	Public engagement
4	A1B	Low	Low
5	A1B	High	High
6	A1FI	High	High

Table 2 2: Scenario assumptions for 2070

2.4.1 A1B scenario and low government response

Temperature

- Projected temperature changes vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Rainfall

- Projected rainfall changes vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Wind speed

- Projected mean and peak wind speed changes vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Sea levels

- Projected sea level rises vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Storm activity

- Projected changes in storm activity vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Carbon Pollution Reduction Scheme

- Federal Government binding 60% reduction in greenhouse gas (GHG) emissions by 2050. Low government response — emissions reduction target to remain at 60% for 2070.
- Assumption of relatively low emission permit price for 2070.

Mandatory renewable energy targets (MRET)

- Low government MRET target — 30% renewables for 2070.

Energy efficiency standards

- Low government response — 25% increase in energy efficiency standards across all sectors for 2070.

2.4.2 A1B scenario and high government response

Temperature

- Projected temperature changes vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Rainfall

- Projected rainfall changes vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Wind speed

- Projected mean and peak wind speed changes vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Sea levels

- Projected sea level rises vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Storm activity

- Projected changes in storm activity vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Carbon Pollution Reduction Scheme

- Federal Government binding 60% reduction in GHG emissions by 2050. High government response — increase in emissions reduction target to 80% for 2070.
- Assumption of relatively high emission permit price for 2070.

Mandatory renewable energy targets (MRET)

- High government MRET target — 60% renewables for 2070.

Energy efficiency standards

- High government response — 30% increase in energy efficiency standards across all sectors for 2070.

2.4.3 A1FI scenario and high government response

Temperature

- Projected temperature changes vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Rainfall

- Projected rainfall changes vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Wind speed

- Projected mean and peak wind speed changes vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Sea levels

- Projected sea level rises vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Storm activity

- Projected changes in storm activity vary between regions. Specified regional changes are detailed in the Risk Assessment, included in Appendix C.

Carbon Pollution Reduction Scheme

- Federal Government binding 60% reduction in GHG emissions by 2050. High government response — increase in emissions reduction target to 80% for 2070.
- Assumption of relatively high emission permit price for 2070.

Mandatory renewable energy targets (MRET)

- High government MRET target — 60% renewables for 2070.

Energy efficiency standards

- High government response — 30% increase in energy efficiency standards across all sectors for 2070.

3. Risk assessment tables

Level	Descriptor	Health and safety	Network performance	Network commercial	Business operations	Reputation	Environment
5	Catastrophic	Multiple fatalities or serious irreversible effects to >50 persons	No supply to customers for multiple days where >10,000 customers affected (Also consider interruption to generator that affects>10,000 customers)	Capital expenditure on network >$400m (over 4 years) OR >25% revenue erosion.	Unplanned operational expenditure >$5m pa ORSenior management team >1 month to manage incident.	Widespread adverse media including International, national TV, national newspapers and radio — story runs for more than 4 days	Very serious long-term environmental damage. Likely prosecution by Environmental agencies.
4	Major	Single fatality or severe irreversible disability (>30%) to one or more persons	Distribution — widespread interruptions affecting >10,000 customers for >6 hours Transmission — total loss of supply to customers for >6 hours	Capital expenditure on network >$100m <$400m (over 4 years) OR 15–25% revenue erosion.	Operational expenditure >$5m pa ORSenior management team >1 week to manage incident.	Widespread adverse media including statewide TV, statewide newspapers and radio — story runs for multiple days	Serious long-term environmental damage. Possible prosecution by Environmental agencies.
3	Moderate	Injury requiring hospitalisation	Distribution — interruption affecting >10,000 customers for <2 hours or <10,000 customers for >2 hours Transmission — total loss of supply to customers for <6 hours	Capital expenditure on network >$20m <$100m (over 4 years) OR >15% revenue erosion.	Operational expenditure >$1m pa ORMajor disruption to normal activities in operational group such as Control Room or IT.	Localised adverse media including regional TV, statewide newspapers and radio — story runs for multiple days	Serious medium-term environmental damage. Possible prosecution by Environmental agencies.
2	Minor	Injury requiring doctor's treatment	Interruptions to supply or other performance issues that typically occur more than once per year	Capital expenditure on network >$20m <$50m (over 4 years).	Some disruption to normal operational activities affecting more than one operational group.	Localised adverse media either TV or newspapers or radio	Short-term environmental damage requiring corrective action e.g. contained oil spill.
1	Insignificant	No medical treatment required	Minor interruptions affecting few customers	Impact on capital expenditure within normal variation.	Minor operational impact	Negligible media attention	Minor environmental incident easily corrected.

Table 3-1: Risk assessment consequence table

Input (scenario variables)			Implication: Event	Implication: Likelihood	Business impact: H&S	Business impact: Network performance	Business impact: network investment	Business impact: Business operations	Business impact: reputation	Business impact: environment	Risk
Climate science (2030 A1FI)	Temp	0.6 -1.5 Deg C	Bush fire	2	4	1	2	3	5	4	10
	Wind speed	> 2-5%	Generation Mix A	4	1	1	2	1	1	2	8
	Storms	> 60%	Floods	2	2	3	1	4	1	1	8
	Sea level	17 cm	Increased peak demand	4	1	2	3	2	1	1	12
Business environment (high Gov. response & public engagement)	Carbon cap/price	$55/t CO2-e	reduced distribution volume	3	1	1	4	2	1	1	12
	RET legislation	20% elec. supply	Event 6	4							
	Public sentiment	Enviro. conscious	Event 7	4							
	Regulatory framework	high incentives for demand-side response	Event 8	2							

Table 3-2: Example risk assessment table

3.1 Electricity

3.1.1 Scenario A1B high intervention and scenario A1FI high intervention (2030) electricity

Input (scenario¬ variables)			Event (scenario variables)	
Climate science (2030 A1B)	Temperature	0.6–1.5°C increase	Bushfire	Yet to be thoroughly scientifically examined
	Rainfall	0–5% decrease	Drought	20% additional drought-prone months/year
	Mean wind speed	0–10% increase	Heatwaves	3.2 additional days/year above 35°C in Cairns, 32 in Broome & 27 in Darwin
	Peak wind speed	5–10% peak increase	Tropical cyclones	60% increase in severity
	Storms	60% thunderstorm severity increase	Severe thunderstorms	No change
	Sea level	3 cm rise	Flooding	0–10% increase in extreme rainfall amount
Business environment (high government response and public engagement)	Carbon cap/price	High (>$50t/CO2)	Generation	Shut down existing generators — Vic, NSW, Qld
	MRET	>20% elec. supply	Generation	Connection of wind in Vic and NSW plus geothermal in Qld and SA
	Energy efficiency standards	20% increase across all sectors	Generation	Moderate increase in PV
	Public sentiment	High environment consciousness	Demand	Rate same as population growth
	Regulatory framework	High incentives for demand-side response	Consumption	Rate same as population growth

Level	Risk
Event	
Bush fire	H
Change in generation mix	H
Floods	M
Tropical cyclones	H
Severe thunderstorms	M
Drought	L
Change in peak demand	L
Change in energy volume	L
Change in network capacity	L

Table 3-3: Coastal region A (and coastal regions E and F)

	Event (scenario variables)		Event	Risk
Coastal region B Differences from coastal region A only	Bushfire	15–65 additional extreme fire weather days/year	Floods	L
	Heatwaves	1.1 additional days/year above 35°C in Sydney	Tropical cyclones	M
	Severe thunderstorms	4 additional hail risk days/year		
Coastal region C Differences from coastal region A only	Bushfire	15–65 additional extreme fire weather days/year	Floods	L
	Heatwaves	3 additional days/year above 35°C in Melbourne	Tropical cyclones	L
	Tropical cyclones	No effect		
Coastal region D Differences from coastal region A only	Bushfire	15–65 additional extreme fire weather days/year	Floods	L
	Heatwaves	8 additional days/year above 35°C in Perth	Tropical cyclones	L
	Tropical cyclones	No effect		
	Severe thunderstorms	Reduction of 2–4 hail risks days/year		
Coastal region G Differences from coastal region A only	Bushfire	15–65 additional extreme fire weather days/year	Floods	L
	Heatwaves	8 additional days/year above 35°C in Perth	Tropical cyclones	L
	Tropical cyclones	No effect		
	Severe thunderstorms	Reduction of 2–4 hail risks days/year		
	Flooding	0–5% increase in extreme rainfall amount		

Table 3 4: Coastal region B, C, D and G

Assumptions

- Carbon sequestration has not been applied to existing coal-fired power stations
- There is no widespread uptake of electric vehicles
- Bushfire risk in Region A (northern Queensland is similar to the rest of the country)

Notes

- The risk associated with vegetation growth has been identified but is not included in the table. This should be recorded as a secondary risk in the report.

Risk associated with infectious diseases is noted. This should be recorded as a secondary risk in the report in the northern regions only.

3.1.2 Scenario A1B low intervention (2030) electricity

Input (scenario¬ variables)			Event (scenario variables)	
Climate science (2030 A1B)	Temperature	0.6–1.5°C increase	Bushfire	Yet to be thoroughly scientifically examined
	Rainfall	0–5% decrease	Drought	20% additional drought-prone months/year
	Mean wind speed	0–10% increase	Heatwaves	3.2 additional days/year above 35°C in Cairns, 32 in Broome and 27 in Darwin
	Peak wind speed	5–10% peak increase	Tropical cyclones	60% increase in severity
	Storms	60% thunderstorm severity increase	Severe thunderstorms	No change
	Sea level	3 cm rise	Flooding	0–10% increase in extreme rainfall amount
Business environment (high government response and public engagement)	Carbon cap/price	Low (<$50t/CO2	Generation	Shut down existing generators — particularly brown coal in Vic
	MRET	20% elec. supply	Generation	Connection of wind in Vic and NSW plus geothermal in Qld and SA
	Energy efficiency standards	10% increase across all sectors	Generation	Modest increase in PV
	Public sentiment	Low environment consciousness	Demand	Modest decrease in growth rate of demand
	Regulatory framework	Low incentives for demand-side response	Consumption	Modest decrease in growth rate

Level	Risk
Event	
Bush fire	H
Change in generation mix	L
Floods	M
Tropical cyclones	H
Severe thunderstorms	M
Drought	L
Change in peak demand	M
Change in energy volume	L
Change in network capacity	L

Table 3 5: Coastal region A (and coastal regions E and F)

	Event (scenario variables)	
Coastal region B Differences from coastal region A only	Bushfire	15–65 additional extreme fire weather days/year
	Heatwaves	1.1 additional days/year above 35°C in Sydney
	Severe thunderstorms	4 additional hail risk days/year lightning
Coastal region C Differences from coastal region A only	Bushfire	15–65 additional extreme fire weather days/year
	Heatwaves	3 additional days/year above 35°C in Melbourne
	Tropical cyclones	No effect
	Severe thunderstorms	Reduction of 2–4 hail risks days/year
Coastal region D Differences from coastal region A only	Bushfire	15–65 additional extreme fire weather days/year
	Heatwaves	8 additional days/year above 35°C in Perth
	Tropical cyclones	No effect
	Severe thunderstorms	Reduction of 2–4 hail risks days/year
	Generation	Connection of some wind and renewables in preference to coal
Coastal region G Differences from coastal region A only	Bushfire	15–65 additional extreme fire weather days/year
	Heatwaves	8 additional days/year above 35°C in Perth
	Tropical cyclones	No effect
	Severe thunderstorms	Reduction of 2–4 hail risks days/year
	Flooding	0–5% increase in extreme rainfall amount

Region	Event	Risk
Coastal region B	Change in generation mix	H
	Floods	L
	Tropical cyclones	M
Coastal region C	Change in generation mix	H
	Floods	L
	Tropical cyclones	L
Coastal region D	Floods	L
	Tropical cyclones	L
Coastal region G	Floods	L
	Tropical cyclones	L

Table 3 6: Coastal region B, C, D and G

Assumptions

- Carbon sequestration has not been applied to existing coal-fired power stations
- There is no widespread uptake of electric vehicles
- Bushfire risk in Region A (northern Queensland is similar to the rest of the country)

Notes

- The risk associated with vegetation growth has been identified but is not included in the table. This should be recorded as a secondary risk in the report.
- Risk associated with infectious diseases is noted. This should be recorded as a secondary risk in the report in the northern regions only
- Risk rating: above 10 = H (high); 9 and 10 = M (medium); below 9 = L (low)

3.2 Gas

3.2.1 All scenarios (2030) — All regions (gas)

Input (scenario¬ variables)			Event (scenario variables)	
Climate science (2030 A1B)	Temperature	0.6–1.5°C increase	Bushfire	
	Rainfall	0–5% decrease	Drought	20% additional drought-prone months/year
	Mean wind speed	No change	Heatwaves	
	Peak wind speed	5–10% peak increase	Tropical cyclones	
	Storms	Decreased hail risk	Severe thunderstorms	
	Sea level	3 cm rise	Flooding	0–10% increase in extreme rainfall amount (0–5% Inland Region)
Business environment (high government response and public engagement)	Carbon cap/price	Low (<$50t/CO2	Generation	Shut down existing generators — particularly brown coal in Vic
	MRET	20% elec. supply	Generation	Connection of wind in Vic and NSW plus geothermal in Qld and SA
	Energy efficiency Standards	10% increase across all sectors	Generation	Modest increase in PV
	Public sentiment	Low environment consciousness	Demand	Modest decrease in growth rate of demand
	Regulatory framework	Low incentives for demand-side response	Consumption	Modest decrease in growth rate

Level	Risk
Event	
Bush fire	L
Change in generation mix	H (T) M (D)
Floods	M
Tropical cyclones	L
Severe thunderstorms	L
Drought	M
Change in peak demand	L
Change in energy volume	L
Change in network capacity	L

Table 3 7: All scenarios (2030) — All regions (gas)

4. Cost analysis detail

This appendix identifies a number of measures that may be taken to prepare energy networks for the impact of climate change and provides the cost estimate for typical network businesses. The parties involved in these measures include network businesses, governments and regulators.

We have categorised the measures that might be taken under the headings of network construction, network operations and network planning. Network construction measures relate to the construction of the network and include items such as construction standards and asset management. Network operations primarily relate to the response to incidents. Network planning measures are those that involve investigation or a change in approach to current network planning processes.

While we have identified a range of measures that might be taken, there are practical and economic limitations to most of these measures. These limitations are likely to prevent implementation of some of the measures on some networks. In all cases we assume that network businesses will undertake appropriate analysis and assessment prior to implanting any of the measures described.

4.1 Network construction

The measures identified in this section relate to the physical construction of network assets.

Tropical cyclones

Electricity network businesses in cyclone areas already construct their networks knowing that cyclones are possible. However, the severity of cyclones is predicted to increase. Network businesses in existing cyclone-prone areas could review their construction standards so that the impact of more intense and more frequent cyclones is allowed for. In some populous areas, the businesses may consider a program of placing the assets underground in order to minimise the impact of cyclones on commercial centres and large numbers of customers.

Network businesses in areas that have not been subject to cyclones but may become subject to cyclones as a result of climate change (such as southern Queensland) could consider whether the networks construction standards are changed to ensure that new network elements are constructed to minimise the impact of cyclones.

Bushfires

Increased periods and frequency of drought are predicted as a result of climate change. These drought periods combined with higher temperatures and higher wind speeds are expected to lead to more frequent bushfires. Actions that can be taken by network businesses to minimise the impact of bushfires or to minimise the potential for a network to ignite a bushfire include:

- replacing wooden poles with concrete or steel poles
- replacing exposed overhead conductors with covered conductors
- replacing equipment such as fuses that might generate sparks
- relocating lines away from bushfire-prone areas

- increasing vegetation clearance from overhead lines
- suppressing auto reclose functionality on high bushfire risk days
- placing the network underground.

Australian electricity businesses are familiar with bushfire and many of the measures outlined above are already taken to reduce the possibility of the network igniting a bushfire. However, as the bushfire risk increases electricity network businesses south of the 25th latitude could consider undertaking a risk assessment to determine the impact of a significant increase in bushfire risk days and then implement plans to reduce any unacceptable risk.

Severe thunderstorms

Increases in peak wind speed are expected across much of Australia. Standards may need to be reviewed to ensure that new structures are designed to withstand these increased wind speeds.

The northern New South Wales coast and southern coastal Queensland are expected to experience an increase in thunderstorm activity. Electricity network businesses can minimise the impact of thunderstorms and lightning by a variety of means including:

- reinforcing or redesigning structures
- increasing vegetation clearance distances or frequency of clearing
- installing additional surge diverters or rebuilding the network underground.

Electricity network businesses in these affected areas may benefit from a review of network construction and standards to factor in an increase in thunderstorms.

Flooding

Severe flooding in the metropolitan areas can cause underground gas regulator pits and underground electricity substations to fill with water. This will cause electricity and gas outages. The restoration of supply could be extensive due to restricted access to the facilities resulting from the flooding.

Gas network businesses may need to consider reconfiguring their networks so that the large underground pits are replaced with smaller sealed regulator units. Electricity network businesses may need to consider measures to prevent below ground or ground-mounted substations from flooding.

4.2 Network operations

Measures in this section relate to the operations of network businesses including operational business units and operational costs.

Extreme events

Every electricity business in Australia is predicted to be affected by extreme events which include cyclones, bushfires and severe thunderstorms. Electricity network businesses should periodically undertake a review of their capacity to respond to an emergency. These reviews should be based on a forward-looking view of the increased frequency and impact of extreme events rather than the historical frequency and impact. Factors that could be considered in the review include:

- size of the workforce (including contractors)
- location of the workforce
- volume of spares held in stock
- location of spares held in stock
- control room and call centre rosters and systems
- communications to customers including:
- automated information systems
- real-time web-based outage systems
- use of radio and print media.

Vegetation management

Periods of rapid vegetation growth following periods of drought will impact on electricity network businesses, particularly in warmer areas of the country. The increase in the number of extreme bushfire days will affect all electricity network businesses. As a result of these two factors, it may be necessary for electricity network businesses to review their vegetation management processes to account for factors such as the increasing risk of bushfire, vegetation type and changes in vegetation growth patterns during drought.

Drought

Increased drought has the potential to cause damage to underground networks and also to lead to increased flashover or pole fires on electricity networks.

Gas and electricity network businesses could consider the impact of extended periods of drought on their underground networks with a focus on critical pipe and cable joints and terminations.

Electricity network businesses with overhead networks may benefit from an assessment of the increase in risk from flashover or pole fires. The risk assessment should include the risk of a network igniting a bushfire when a flashover or pole fire occurs. Following the risk assessment, additional programs of insulator washing or pole and cross-arm replacement may be justified.

Heat

Maintenance work and field operation activities in periods of heatwave pose increases health issues for workers. Standards and processes that manage fatigue, heat stress and work at remote sites may require review.

4.3 Network planning

In this section, measures relating to planning the networks, including network connections and research and development are outlined.

Embedded generation

A significant increase in embedded generation will have an impact on electricity distribution businesses. Where the generation is gas-fired, embedded generation will also have an impact on gas distribution businesses.

Electricity distribution businesses will be affected in many areas such as:

- the location of embedded generators will need to be known
- network design standards may need review as average loads decrease
- network quality may be affected by a large number of inverter devices
- network control and protection systems are likely to require review
- network switching processes and practices may require review to ensure that work can be safely performed.

PB considers that the impact on electricity distribution networks from embedded generation is potentially significant and should be further considered by the industry. One approach could involve a study that developed a set of scenarios involving differing types and volumes of embedded generation and then determining the impact on typical electricity distribution networks from these different mixes of embedded generation.

Gas distribution businesses may also need to undertake modelling to improve their understanding of a large increase in embedded gas generation. This modelling could consider an increase in other potential increase of gas consumption such as the widespread introduction of gas-powered vehicles.

Generation mix

The change in large-scale generation involving the retirement of some coal generation plants and replacement of this generation with new gas-fired and large-scale renewable sources (such as wind farms) will change electricity transmission networks. Electricity transmission networks already use scenario planning involving a range of alternative generation sources in their network planning. Electricity transmission businesses might review their scenario planning to ensure that the scenarios reflect possible and likely changes in generation mix. The output of this process may result in additional contingent projects and which will then need to be reflected in capital expenditure programs submitted to regulators.

Electricity businesses may also need to review their planning timeframes. Large-scale generation such as coal-fired generators require a relatively long planning timeframe which provides network businesses with the opportunity to build the generation plans into their own development plans and associated regulatory submissions. Proponents of wind farms and gas-fired power stations have shorter development times, particularly where generators are modular. Smaller generators that are likely to be connected to networks are likely to be increasingly modular and the proponents will be seeking to connect these generators relatively quickly. This reduced connection timeframe may require network businesses to review their connection processes and may also require regulatory processes to adapt to these reduced timeframes.

Electricity network businesses enable new large and small-scale generators to connect to

the network. Generator connection is regulated through the National Electricity Rules (NER) and electricity businesses have connection policies and procedures. The cost of connection to networks is largely paid by the generator and this cost can be an impediment to some generators. The removal of impediments in the regulation to the adoption of demand-side response (DSR) provides scope for addressing this issue.

New technologies

The availability of new technologies combined with a high public response might result in the rapid uptake of new technologies that impact electricity networks. For example, the rapid uptake of LED lighting might affect power quality. The industry could consider undertaking an R&D project that identifies potential new technologies and determines the impact that these technologies would have on electricity networks.

Table 4 1: Cost estimation table

Risk description	Potential impact	Potential responses	Typical response, cost impact and outcome	Cost calculation ($m)	Units
Increase in severity of tropical cyclones — greater than 60% increase in severity	Damage to electricity transmission towers	Replace or strengthen towers. Revise standards to increase strength of new towers. Rebuild lines in areas less prone to damage and more easily accessible for repairs. Prepare rapid response to tower damage. Public education exercise.	Undertake a program that targets the weak links in existing lines and strengthen or rebuild towers. Program to be integrated with existing asset replacement and maintenance programs. Expenditure will result in an improvement in cyclone resistance (but will not eliminate the impact from the full force of a sizeable cyclone).	1.1	pa per TNSP affected
			Plan new lines to avoid damage or to improve access for cyclone repair. Increases the cost of new lines by 10%. Expenditure is modest and will result in improved restoration time and some reduction in damage following cyclone.	7.7	pa per TNSP affected
			Review existing plans for rapid response to tower damage to ensure appropriate response to increased cyclone severity. Cost to review and implement plans plus additional spares holdings. Outcome will be a reduction in restoration time following cyclone damage.	10.2	one-off per TNSP affected

Table 4 1: Cost estimation table (continued)

Risk description	Potential impact	Potential responses	Typical response, cost impact and outcome	Cost calculation ($m)	Units
Increase in severity of tropical cyclones — greater than 60% increase in severity	Damage to electricity distribution networks	Replace or strengthen poles. Rebuild existing assets underground. Build new assets underground. Design overhead lines to 'fall-over' in high winds (and lift back following cyclone). Prepare for response to widespread damage. Public education exercise. Promote increase in emergency/ standby generation sets and distributed generation.	Evaluate impact of cyclones on subtransmission lines, zone subs and key HV feeders. Cost to analyse network for impact (for those businesses not already exposed to cyclones). Outcome will be better information which will enable better targeting of future replacement and augmentation expenditure.	0.4	one-off per elec DNSP affected
			Change asset replacement program to target poles that are susceptible and nearing end of life (accelerate replacement of key assets). Increases pole replacement program costs. Will result in a small reduction in damage to network in the event of a cyclone.	3.8	pa per elec DNSP affected
			Ensure routes for lines are accessible and can readily be repaired following cyclone — underground where practicable. Increase cost of new lines. Will result in a reduction in vulnerability of new lines to cyclone damage. Will not affect existing overhead network (no change in vulnerability of existing network).	6.0	pa per elec DNSP affected
			Increase spares holdings in areas where cyclones may occur. Additional cost for spares. Outcome will be a reduction in restoration time following cyclone damage.	27.0	one-off per elec DNSP affected
Tropical cyclones in areas that have not previously experienced cyclones — cyclones moving 200 km further south to impact northern NSW	Same as above	Same as above.	Construct new networks to take account of impact of cyclones. Additional cost to construct new lines. New network will be less susceptible to cyclone damage than existing network.	6.0	pa per elec DNSP affected
		Prepare cyclone response plans (based on plans from cyclone areas). Prepare to shut-down portions of network at times of high cyclone risk.	Prepare cyclone response plans for areas not previously impacted by cyclones. Cost to review and update existing emergency response plans. Response to cyclone damage in these areas that have not previously experienced cyclone damage will be improved.	0.3	one-off per elec DNSP affected

Table 4 1: Cost estimation table (continued)

Risk description	Potential impact	Potential responses	Typical response, cost impact and outcome	Cost calculation ($m)	Units
Bushfire — more than 15–65 additional extreme fire weather days/ year	Electricity transmission and distribution networks — smoke and ash particles causing flashover and outage	Prepare to shut-down portions of network at times of high bushfire risk. Increase insulator washing. Replace pole/tower top structures that are susceptible to flashover (new insulators etc). Rebuild line routes away from high bushfire areas.	Review and revise bushfire response plans to take account of additional risk. Cost of review. Will result in better information on which to base future bushfire mitigation plans.	0.1	one-off per elec TNSP/DNSP affected
			Increase spares holdings to improve response to bushfires. Additional cost for spares. Outcome will be a reduction in restoration time following bushfire.	0.3	one-off per elec TNSP/DNSP affected
			Increase program of insulator washing (aerial for transmission). Additional cost of washing insulators. Small reduction in outages will result and reduced risk of network initiating bushfire.	0.1	pa per elec DNSP
				0.2	pa per TNSP
	Electricity transmission and distribution networks — fault on network igniting bushfire	Prepare response to bushfires. Increase frequency or scale of vegetation clearance. Increase insulator washing. Replace pole-top structures that might initiate fire such as insulators, switches and cross-arms. Rebuild or redesign sections of network to prevent conductor clashing (including installation of covered cable or fitting spreaders). Rebuild assets underground. Rebuild line routes away from high bushfire areas. Increase insurance cover.	Review and revise bushfire response plans to take account of additional risk (same as above)		Above
			Increase program of insulator washing (aerial for transmission) (same as above)		Above
			Accelerate programs to replace pole-top structures on distribution networks. Increase in cost of pole-top structure replacement program. Reduction in probability of network initiating a bushfire. Small improvement in network reliability.	2.3	pa per elec DNSP
			Targeted program on distribution network to fit spreaders or install covered cable. Cost of additional program. Reduction in probability of network initiating a bushfire. Small improvement in network reliability.	1.5	pa per elec DNSP
			Increased cost of insurance. Outcome is that risk to network business is maintained at current level.	0.1	pa per elec TNSP/DNSP

Table 4 1: Cost estimation table (continued)

Risk description	Potential impact	Potential responses	Typical response, cost impact and outcome	Cost calculation ($m)	Units
Change in generation mix	Electricity transmission network — extension and connection required to connect large wind farms or gas-fired generation	Augment network and connect new generators.	Impact will be highly location dependent. Estimating the location and therefore likely impact is beyond the scope of this report. Affected regions likely to be those where large-scale renewable generation such as wind or geothermal is available, or less efficient high-emission generators (brown coal) are located. Network businesses in these areas should incorporate planning scenarios in their network plans to take account of the impact.		
	Electricity distribution network — extension and connection required to connect medium scale wind farms and gas-fired generators	Augment network and connect new generators.	As above.		
	Electricity distribution network — increase in volume of small PV generation connections	Respond to volume of connections. Assess fault level and planning issues. Assess safety and operating procedures. Assess impact of harmonics on quality of supply.	Impact will be highly location and volume dependent. Estimating the location and volume is beyond the scope of this report. Each network business will need to assess the potential impact on its network and operations. Short-term actions could consist of actions such as reviewing connection procedures. Longer term attention will be required to issues such as harmonics and to evaluate 'smart grids'.		
Increase in peak demand	Electricity transmission and distribution networks — network overloaded	Augment network to meet increased demand. Implement demand side response measures.	Build additional new network over the next 20 years to cope with increased demand from increased airconditioning load associated with a temperature increase of 1 degree. Cost of additional network capacity. Outcome is to make new network capacity available with no impact on security or reliability.	283.0	pa for whole of Aust
			Per electricity Transmission Network Service Provider (TNSP)	14.6	pa per elec TNSP
			per electricity Distribution Network Service Provider (DNSP)	13.1	pa per elec DNSP

Table 4 1: Cost estimation table (continued)

Risk description	Potential impact	Potential responses	Typical response, cost impact and outcome	Cost calculation ($m)	Units
Floods — more than 0–10% increase in extreme rainfall amount	Gas and electricity distribution — flooding of sites affecting equipment such as metering or substations	Modify installations (bunding, pumps etc) to minimise impact of flooding. Relocate equipment to other sites (or up poles). Electricity distribution — use raised LV pillars in flood-prone areas. Prepare to shut-down exposed portions of network at times of high flood risk.	Assess flood-prone areas and modify high-risk installations. Increase expenditure in conjunction with asset replacement programs. Minor reduction in assets affected by flooding.	0.4	pa per gas DNSP
				1.5	pa per elec DNSP
	Electricity transmission and distribution networks — fault on network igniting bushfire	Increase remote monitoring and control functionality.	Expand existing programs of remote control and monitoring to cover potentially flooded areas. Increase in expenditure on remote control and monitoring. (Cost increase for gas businesses is insignificant.) Minor expenditure will result in improved reliability for some customers following floods.	0.2	pa per business

Table 4 1: Cost estimation table (continued)

Risk description	Potential impact	Potential responses	Typical response, cost impact and outcome	Cost calculation ($m)	Units
Severe thunderstorms — more than 4 additional hail risk days/year. Also, increase of 5–10% in extreme wind velocity and frequency	Electricity transmission and distribution — wind-blown debris damaging assets and causing electrical faults	Increase frequency or scale of vegetation clearance. Prepare for response to widespread damage. Replace or strengthen poles. Rebuild existing assets underground. Build new assets underground. Improve sectionalising and remote control of network.	Increase vegetation management program by more aggressive trimming or smarter techniques. (DB) Increase in cost of vegetation management. Outcome will aim to be maintenance of current network reliability.	1.6	pa per elec DNSP
			Increase vegetation management program by more aggressive trimming or smarter techniques. (TNSP) Increase in cost of vegetation management. Outcome will aim to be maintenance of current network reliability.	0.5	pa per TNSP
			Review existing plans for rapid response to network damage and increase spares holdings to ensure appropriate response to storms (only businesses that are not subject to cyclones). Additional cost to review plans and increase spares holdings. Outcome is improved response to outages resulting from storms.	9.2	one-off per elec DNSP
			Increase remote control and sectionalising of distribution networks. Increase cost of programs to remotely control and automate network. Improvement in reliability for some customers affected by storms.	0.4	pa per elec DNSP
Drought – more than 20% additional drought-prone months/year	Gas pipelines and electricity distribution networks — ground shrinkage and subsidence causing pipeline and joint failures	Increase pigging of gas transmission pipelines to check for stress fractures. Repair failed joints, cables and pipes. Relocate sections of pipelines/cables. Change design of installations such as compressor or substation footings to withstand shrinkage. Change design of new pipes and cables to accommodate increase in ground movement.	Change to joint design. Increased cost of replacing/repairing joint at time of asset replacement or fault repairs (gas distribution networks). Small reduction in leaks resulting from ground movement.	0.2	pa per gas DNSP
			Change to joint design. Increased cost of replacing/repairing joint at time of asset replacement or fault repairs (electricity distribution networks). Small reduction in faults resulting from ground movement.	0.3	pa per elec DNSP

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