Facilitating distributed generation in Australia - the opportunities and challenges of cogeneration

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Facilitating Distributed Generation in Australia – the Opportunities and Challenges of Cogeneration

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Stationary energy, predominately electricity and thermal energy production, is one of the largest sectors of primary energy consumption in industrialised countries. Electrification has delivered economic growth and improved standards of living while thermal energy provides comfort and sustains industrial growth. However, a range of economic, market, technological and environmental issues exist. In Australia, these include declining energy productivity and increasing energy prices, changing demand and usage patterns, accommodating emerging forms of electricity production and contribution to long-term climate change.

Solutions to these issues include adoption of a mix of technical, regulatory and investment-related initiatives. In particular, the adoption of decentralised energy technologies, principally gas-fired cogeneration (also known as Combined Heat and Power or CHP) and solar photovoltaic (PV) appear to offer substantial technological and economic benefits over incumbent centralised technologies (especially, coal-fired generation). The adoption of these technologies may be enhanced by improved government incentives and regulatory reforms and a better appreciation of factors that influence the availability of investment capital.

This study aims to identify the potential rate and extent of adoption of distributed generation in general and CHP in particular, by comparison with theoretical diffusion rates of other energy technologies. It seeks to expose and explore other factors which impact adoption, including supporting government policy and the need for demonstration to overcome technical risk. Finally, it examines the potential economic and environmental benefits associated with the large scale adoption of distributed energy technology.

Through a mixture of literature review, analysis of a range of technical feasibility studies and a detailed case study, the extent to which distributed technologies may be adopted, and their financial, efficiency and environmental benefits are assessed.

The analysis suggests that cogeneration is technically and economically feasible and is therefore a critical transition technology for the Australian stationary energy sector while distributed generation technologies in general, which are relatively mature and low risk, have the potential to substantially reduce emissions while also reducing costs and network and centralised generation investments.

ABSTRACT

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Abbreviations and Symbols

AC	Alternating Current
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BCM	Billion Cubic Metres
CCGT	Combined Cycle Gas Turbine
COP	Coefficient of Performance
CSG	Coal Seam Gas (also known as unconventional gas)
DC	Direct Current
EEG	*Erneuerbare Energien Gesetz* (Germany's Renewable Energy Sources Act)
ETS	Emissions Trading Scheme
FiT	Feed in Tariff
GDP	Gross Domestic Product
GHG	Green House Gas (gas in t atmosphere that absorbs/emits radiation within the thermal infrared range)
HVAC	Heating Ventilation and Air Conditioning
HZ	Hertz
IPART	Independent Pricing And Regulatory Tribunal
LETDF	Low Emissions Technology Demonstration Fund
LNG	Liquefied Natural Gas
NABERS	National Australian Built Environment Rating System
NEM	National Electricity Market
NOx	Nitrous Oxide
OECD	Organisation for Economic Co-operation and Development
PV	PhotoVoltaic
REC	Renewable Energy Certificates
RET	Renewable Energy Target

KV	KiloVolt
KW, MW, GW	KiloWatt, MegaWatt, GigaWatt
MJ, GJ, TJ, PJ,	MegaJoule, GigaJoule, TerraJoule, PetaJoule

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Chapter 1 Introduction

1.1 Overview

The world today faces enormous challenges. The growing populations of emerging economy countries, their challenges in providing basic services yet also in supporting economic growth, changing industry structures around the world and the impending global consequences of climate change are all impacted by one resource that most[1] of humanity today almost takes for granted – electricity. Stationary energy[2], in particular electricity, has underpinned industrial, commercial and residential endeavour in developed nations. For many countries, including Australia, this electricity provision has depended on centralised thermal power plants reliably burning abundant, low cost coal. Other countries have taken advantage of significant hydro resources or natural gas. Still, the general model has been large, centralised generating plant supplying energy users through an extensive transmission and distribution grid. For more than a century, generating plants have grown larger while the interconnected power grids have become more extensive, demanding increasing investment to maintain reliability, robustness, efficiency and accessibility. Rapidly developing nations, such as China and India, demand rapid growth in electrification to satisfy their burgeoning economies and their citizens' demands for amenities such as lighting, cooking, heating as well as air conditioning, entertainment and communication. Forecast growth (Sieminski, 2013) in global electrification is dramatic from around 20PWh in 2010, to 39 PWh in 2040. The rate of growth of electricity generation at around 2.2% per annum outstrips consumption from all energy sources which is only forecast to grow at 1.4% per annum. This expected future growth is driven by developing economies, the increasing use of electricity-based products and services and the likelihood that a range of new energy demands will require transition from other fuels to electricity; for example, growing deployment of electric vehicles.

Presently, many developing countries seem likely to continue to follow the centralised electricity industry model established in the first industrialised economies. One consequence of these countries following the path of centralised, primarily coal and fossil fuel derived, electricity is an alarming increase in greenhouse, primarily CO_2, emissions and the resultant enhanced greenhouse effect and global climate change this is driving. While our ability to

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[1] In 2008, 18% of the world's population consumed 54% of the world's electricity while 1.2 billion people (around 1 in 5) do not have access to commercial electricity according to the World Bank (WORLD BANK. 2013).

[2] Stationary Energy is energy used for non-transportation purposes and predominately includes electricity generation and fuel used in manufacturing, construction, commercial and domestic sectors

continue to use fossil fuels will, ultimately, be limited by their economic availability, this is projected to come too late to prevent potentially catastrophic climate change impacts[3].

Despite these potentially destructive outcomes, electrification also produces the benefits that increases in national wealth bring and that emerging economies demand and surely deserve, whilst ever the developed world continues to enjoy them.

Reconciling these conflicting requirements - a need for continued economic growth driven by affordable and secure access to electricity and the requirement to quickly migrate from high emitting energy conversion technologies to more sustainable models for generating and distributing electricity - is the real challenge for the future of the global electricity industry.

Australia's economic development has benefited from abundant mineral and fossil fuel energy resources, particularly coal that we both utilise domestically and sell overseas. Black and brown coal is accessible, affordable and reliably converted into electricity. Consequently, our energy system has been dominated by coal. According to the Bureau of Resources and Energy Economics (Ball et al., 2014a) in 2012/13 Australia's 29.9 GW of thermal coal power generation capacity (which sits alongside 14.4GW of gas generation capacity and smaller amounts of hydro and renewable capacity) produced 64% of the total of 249 TWh of electricity generated. This energy is transmitted across more than 44,000 km of high voltage transmission and more than 760,000 km of distribution infrastructure, with around 5% lost in the process, for delivery to thousands of large industrial; tens of thousands of smaller commercial and industrial; and millions residential users. Two-hundred-and twelve TWh or electricity was consumed in the eastern states and South Australia (NEM) with the balance in Western Australia (33 TWh) and the Northern Territory

The complexity of the transmission and distribution network has been compounded over the past decade with the addition of increasing renewable and distributed generation resources in the form of wind and solar photovoltaic ("PV") generation and also by the addition of new loads such as widespread penetration of air conditioning and electronic entertainment equipment. Electrical demand is highly correlated with weather conditions (particularly temperature) as a consequence of commercial and residential air conditioning loads. Together with the highly variable and somewhat unpredictable nature of solar and wind generation,

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[3] According to the IPCC it is likely that, in order to limit warming to 2°C, the share of low-carbon electricity supply must increase from approximately 30% to more than 80% by 2050 while fossil fuel power generation (without CCS) must be phased out almost entirely by 2100

these developments emphasise the need for more responsive generation than traditional thermal facilities provide.

So, while the promise of renewables, and particularly wind and PV, is immense, its integration into the grid to date has highlighted the relatively limited impact it may be able to make in an aged and inflexible power infrastructure model dominated by massive network investments, and entrenched and well-depreciated centralised base load power. These factors exemplify a range of issues confronting the Australian energy sector, from regulatory issues, to demand changes and energy productivity and supply factors. High electricity prices, low energy conversion efficiency, high relative emissions per capita and the debatable inability to accommodate innovative generation resources represent enormous challenges. Fortunately, they would seem to be challenges that can be addressed by the adoption of better systems design, a low risk portfolio of innovative technology and incentives to introduce these into the existing network. These solutions will, of course, require supportive government and regulatory policies and access to capital to drive this penetration.

The uptake of alternative energy technologies exemplified by wind and roof-top PV, in Australia and elsewhere, has demonstrated that more distributed and sustainable generation is technically feasible and accessible. However, factors that must be considered when projecting the future penetration of these technologies include the rational responses of incumbent electricity industry players to retain their current advantages, return rents to their (often publicly owned) shareholders and restrain innovation that threatens their existing assets.

Many of the future technology solutions exist today. Distributed (rather than centralised) generation offers substantial benefits. Stand-alone renewable and sustainable technologies, for example, include high efficiency, low-emitting natural and biogas fired cogeneration, biofuel production, solar PV, solar thermal and (battery) storage alongside enhancements or adaptions to existing generation (such as carbon capture and sequestration, wind, geothermal and hybrid bio-solar-thermal power plants). System innovations include application of design rules and control systems to better integrate sources and uses of energy in, particularly, industrial settings; the application of techniques and products to improve energy efficiency (both in the home and in industry/commerce); the ability to manage demand or provide price, or other, signals that enable consumers to adjust their demand (through smart-metering); and the emergence of localised micro-grids which have many of the above features and technologies at their core (smart-grids).

These technologies require supportive public policy, including policies that assist us in re-thinking our energy supply system. For example, policies concerning research and development ("R&D"), particularly technology demonstration and selective grants, must be better designed in order to deliver real innovation in deploying substantial new, more efficient and lower emitting stationary energy systems. In concert, understanding the drivers of investment for corporations and financial investors is critical to designing the proper incentives.

1.2 Thesis Context

The motivation for this thesis is the need and opportunity to facilitate such a transition towards a more distributed and sustainable stationary energy sector. A particular focus is on how an improved understanding of the actual and potential penetration of emerging technologies in the energy sector, as well as new insights into the technical and financial characteristics of these technologies and their benefits, reveals the substantial potential for gas-fired cogeneration to facilitate a more general industry transition from centralised to decentralised generation.

This thesis will demonstrate that there are technically and economically viable, low emitting distributed technologies that are capable of making a beneficial impact upon the structure and operation of Australia's electricity network, and that policy initiatives should apply greater focus on the benefits of relatively low risk distributed resources rather than established centralised technologies promoted by incumbent providers. In particular, relatively mature distributed cogeneration technologies appear to offer a potential bridge between centralised fossil fuels and renewable distributed energy options.

Australia is a large and growing industrialised economy and energy has played a significant role in its development, contributing around 7% of Australia's gross domestic product ("GDP") (Ball et al., 2014a). As well as being a major driver of domestic industry, energy exports, particularly fossil fuel accounted for around 31% of commodity exports in 2013/14.

The stationary energy sector is dominated by electricity production which is, in turn dominated by coal-fired thermal power plants. Incentives and relative commodity prices have seen a growing role for gas-fired combined cycle plants (a trend that now may have reversed) and utility scale renewable power (in particular wind). Along with these changes in generation, the electricity industry itself has evolved. It has consolidated from its early formation to become dominated by a small number of large, often foreign or state-owned, enterprises.

Today's generation, transmission and distribution infrastructure is widely spread and complex and demands substantial ongoing capital replacement. Recent growing investments in centralised network infrastructure, with the stated objective of meeting growing demand and improving reliability, have caused consumer prices to increase rapidly. However, in the face of declining electricity demand, and the commonly held view that established technologies are going to be unable to cope with the changing demands of a warming planet, the drivers of this investment have been questioned.

In order to optimise available investment, new paradigms for technology and investment risk and return must be considered. A fundamental shift from established centralised infrastructure to distributed resources appears to offer the opportunity for smaller more diverse investments that imply a greater ability to match supply and demand and lower the risk of investment. Technical viability of these resources is demonstrable and private investment is available. However, the direction of public policy does not appear to support the deployment of these relatively low risk alternatives, instead focussing regulatory attention on incumbent operators or financial incentives on technologies that appear to propagate the centralised paradigms such as solar flagships or carbon capture and sequestration ("CCS").

In particular, relatively mature distributed cogeneration technologies appear to offer a potential bridge between centralised fossil fuels and renewable distributed energy options.

1.3 Thesis Objectives and Approach

The objective of this thesis is to understand the potential for distributed generation technologies (in particular, cogeneration) in commercial, industrial and urban micro-grid applications to provide a viable transition from centralised generation, transmission and distribution systems that presently dominate the stationary energy sector in Australia. This thesis seeks to determine whether these technologies can be deployed and, if deployed at scale, whether they can deliver improvements in energy efficiency, economic returns and carbon abatement.

The research methodologies applied in the development of this thesis included desk research and literature review; interviews with industry participants, particularly investors and corporate actors; case study analysis; and a review of a large body of technical and financial feasibility analyses into the deployment of alternative distributed energy technologies in a range of commercial and industrial applications.

This thesis will explore the above issues and specifically address the following research questions:

1. What are underlying theories and frameworks that can explain the adoption of innovative sustainable energy technologies? This is examined through detailed literature review focussed upon accepted theories of technology innovation and the particular characteristics of new energy technologies

2. Can such theories and frameworks contribute to our understanding of the adoption of energy generation technologies in generation in Australia? This is examined through an analysis of a range of market data comparing the deployment of some key generation technologies in Australia over the past decade.

3. What are the particular challenges to the commercial adoption of new energy related technologies? This is examined through a review of literature.

4. How effective are government programs, and, in particular demonstration programs in overcoming these challenges? This is examined with reference to the range of regulatory and programmatic tools designed to encourage transition from inefficient and high emissions technologies to more efficient and lower emissions technologies through a mix of literature review, interviews with industry participants and detailed case study review of the Low Emissions Technology Demonstration Fund.

5. What other frameworks may be useful for understanding the drivers of private investment decision-making on which widespread deployment depends? An original conceptual framework for investment decision making in relation to energy technologies is developed following examination of relevant literature.

6. What is the investment and environmental potential of cogeneration and trigeneration as one particularly promising distributed generation technology? A tool for analysing the financial and emissions potential of cogeneration and trigeneration projects is developed and applied to 86 potential NEM-connected industrial and commercial cogeneration and trigeneration projects. Novel deployment opportunities for cogeneration and trigeneration are also explored by considering opportunities for precincts to disconnect from the grid or substantially change their relationship with it. A case study analysing the economic and environmental characteristics of a precinct-based micro-grid incorporating cogeneration, solar PV and storage is developed.

7. What is the potential impact of wide-scale deployment of distributed generation in Australia and is such deployment economically justified? The potential for, and impact of, deploying distributed generation on a broad scale in commercial, industrial and precinct applications is examined.

1.4 Outline of this Thesis

This introductory chapter provides an overview of the thesis and its relevance and defines the research questions (and mythology adopted) at its heart.

Chapter 2 will provide an overview of the Australian energy system, focussing on stationary energy and natural (and non-conventional) gas. It will identify some key parameters which dimension the industry, key industry participants, and fundamental issues that confront it. With this background, it will discuss the opportunities and challenges to improving the industry and the way in which electricity is delivered to consumers. In particular, it will focus on the opportunities presented by distributed generation technologies.

Having identified the potential for emerging alternative distributed technologies, Chapter 3 will examine the theoretical frameworks which characterise the deployment of new technologies in general, and energy technologies, in particular. By comparing the rate of adoption of new technologies across industries we can determine the pace with which societal and economic benefits are created and shared. Further, we can compare the rate of adoption of energy related technologies by reference to other relevant industries. We can thereby provide a measure of the historical ability to overcome the structural impediments to adoption. Chapter 4 will then consider the adoption patterns of several sustainable energy technologies in Australia (PV, CCGT and Wind) over the past few decades and draw conclusions about the likely future pace of adoption.

Chapter 5 will consider the impediments to the adoption of new energy technologies resulting from a range of factors including technological risk, incentives conflicting incumbent interests, market related factors, and government policy support.

Overcoming the impediments to the adoption of technology demands appropriate public policy and private capital interventions. Particular focus must be placed upon public policy mechanisms which drive research and focus corporate priorities. Chapter 6 identifies and compares key public policy approaches to technology diffusion and commercialisation, particularly in the energy sector. It will compare established theoretical frameworks with practical implementation mechanisms and different procurement incentives. In particular, the effectiveness of grant-based versus procurement-based policy initiatives to encourage commercial scale deployment of technologies will be examined. An original framework for evaluating the effectiveness of public policy initiatives and common causes of failure (in achieving proposed commercialisation objectives) will be presented along with a detailed case study review of Australian demonstration funding programs which were implemented to encourage the commitment of private capital to drive implementation of new low emissions technologies.

In relation to private capital, alternative approaches to investment analysis will be explored in Chapter 7. Established corporate and investment analysis methodologies must be considered by policy makers to assess the cost, efficiency and effectiveness of their policy initiatives that are focussed on encouraging additional investment. An original framework for considering investment merit across a portfolio of potential project investments will be presented along with set of criteria for investment review.

Chapter 8 will evaluate the potential for cogeneration and trigeneration, as applied in industrial and commercial settings. An original analysis of the application of cogeneration and trigeneration in these settings will evaluate the energy, emissions and financial potential of cogeneration and trigeneration while, in Chapter 9, a detailed case study for the deployment of cogeneration and trigeneration in wide-scale micro-grid applications will be presented. Chapters 8 and 9 will highlight the potential for the expansion of low-emissions distributed technologies in key economic sectors and demonstrate that their deployment is technically, economically and environmentally justifiable.

Chapter 10 will discuss the implications of wide-spread deployment of cogeneration and trigeneration and distributed generation in general and the specific impediments to its adoption in Australia. The potential role, benefits and impact of low emissions, distributed energy technology as a transition path between legacy centralised generation and emerging "over-the-horizon" technologies is discussed, as is the need for a supportive public policy environment.

Chapter 2 Australia's Stationary Energy Sector

2.1 The Australian Energy Industry

Australia is the 12th largest economy in the world according to nominal Gross Domestic Product ("GDP"), generating around US$1.56 trillion (United Nations Statistics Division, 2013). In the past twenty-two years, Australia has enjoyed uninterrupted economic growth averaging 3.3% annually. Australia possesses a reasonably well-diversified economy (ABS, 2013b) with no single industry sector of the 20 categorised accounting for more than 8.9% of the economy's Gross Value Add. The economy is boosted by the strength of its services and resources industries but adjusting to the decline of its manufacturing sector. Eastern Australia is home to the majority of Australia's service and financial industries and Western Australia controls the majority of Australia's natural resources. Australia's GDP is dominated by its service and financial industries. The Australian energy industry "is a significant contributor to the Australian economy, worth 6 per cent in terms of gross value add" (Willcock et al., 2013)

The Australian energy sector relies on a diverse range of production sources. The country is rich in primary energy sources including fossil based fuels such as coal and gas, nuclear resources such as uranium and thorium, and renewable resources such as wind, solar, biomass, geothermal, tidal and wave. As a result, Australia is a major exporter of energy, particularly to the Asian region.

Australia's primary energy production in 2012–13 was around 19,000 Petajoules (Ball et al., 2014b), an increase of more than 9% on 2011-12 production. In 2013-14 it had fallen to 18,715 Petajoules {Ball, 2015 #332}. Domestic consumption is around one third of this total with the balance exported. Domestic consumption was dominated by coal followed by crude oil and liquefied natural gas and, of late, renewable energy such as solar and wind is making a growing, if still small, contribution. In 2012-13 petroleum products accounted for 38% of total domestic energy consumption with coal accounting for 32%. Gas consumption has grown rapidly over the past decades and stands at around 24% of total consumption. Renewable energy makes up the balance of around 6% of total energy consumption {Ball, 2015 #332}. Oil and gas consumption in Australia is comparable with the global averages of around 39% and 23% respectively of total energy consumption. The use of nuclear energy, 6% of global consumption, is absent in Australia while global renewable penetration at around 14% of global consumption is higher than in Australia. However, global coal consumption, at 25% of total energy, is far less than Australian coal consumption. With the vast majority of Australia's energy consumption being based on fossil fuels, Australia's energy supply carbon emissions intensity is amongst the highest in the world.

Consumption of energy in Australia is highly concentrated. The largest 300 energy users consume more than 56% of primary energy. Meanwhile, over a hundred thousand smaller enterprises consume just 26% across a range of industries and uses, dominated by transportation (43%), manufacturing (33%), agriculture and mining (14%) and commerce and services (9%){Willcock, 2013 #121}. Residential users consume around 17% of total energy consumption in the country.

According to Bureau of Resources and Energy Economics (Ball et al., 2014b), the "electricity supply sector accounted for the largest share, 28 per cent, of Australia's total net energy consumption in 2012-2013". In 2013-2014, 894 PJ of electricity was generated with around 61% from centralised coal-fired plants (down from 64% in 2012-2013) and a further 22% from natural gas (up from 20.5% in 2012-2013). Renewable generation rose by 12% in 2013-14 to comprise 15% of total generation.

According to the 2015 Australian Energy Update {Ball, 2015 #332}, NSW and ACT energy consumption in 2013-14 was the highest of all states in Australia and totalled 1,511 Petajoules or 25.9% of the total Australian net energy consumption of around 5,830 petajoules. Most was consumed for transport (33.8% up from 30.5% three years earlier), followed by electricity generation (25.7% down from 27% three years earlier), and manufacturing (18.8% down from 24.0% three years earlier). Energy consumption for Victoria in 2013-14 was the second highest among the states, totalling 1,415 petajoules or 24.3% of Australian consumption, with manufacturing consuming 16.5% of this.

The Australian Government's projections (Syed, 2012) of electricity production sees growth at around 1.1% per annum during the period to 2049-50 with renewables accounting for around half of production and gas-fired generation doubling to around 36%. Coal's share of generation is projected to decline from 60% today to just 13% in 2049-50. Over this timeframe, despite the continued growth in international demand for coal, Australia's use of coal is expected to decline from the present 34% to just 6% of total energy consumption by 2049-50 while gas will become an even more important component of the Australian energy mix, increasing in share to 34%.

Australia has been able to significantly increase its production of energy over the past three decades and is now the world's ninth largest energy producer, producing about 2.4% of total world energy. The primary energy sector in the country has also been a major source of employment and infrastructure development. For example, natural gas production and export is set to triple by 2049-50.

Together, the electricity and gas supply markets contribute about $22 billion to the economy's gross value added revenue or around 1.5% of total GDP in 2009-2010. By comparison, coal and crude oil contributed $47 billion to the economy (about 3.5% of total GDP) in 2009-2010.

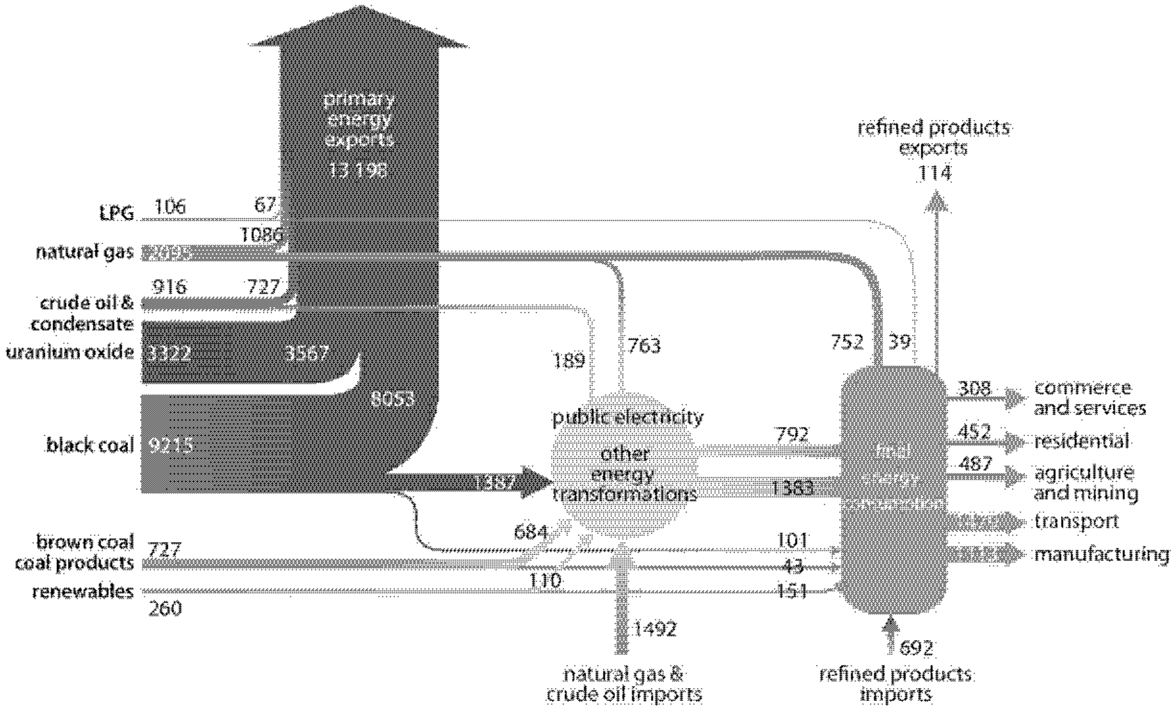


Figure 1 Australian Energy Production and Consumption

Source: (Willcock et al., 2013)

It is apparent that the Australian energy sector is heavily export focussed with black coal, uranium and natural gas being the primary exports, while coal is the dominant source of transformed energy.

2.2 Australia's Stationary Energy Industry

Stationary Energy is energy used for non-transportation purposes and predominately includes electricity generation and fuel used in manufacturing, construction, commercial and domestic sectors. In 2013/14, around 248 TWh of electricity was generated in Australia {Ball, 2015 #332}. By comparison, the previous year, 254 TWh was generated in 2010-11 and 261 TWh generated in 2008/9. Of the gross energy generated in centralised power stations, about 15

TWh is used by the power stations themselves, a further 12.6 TWh is lost or used in transmission leaving around 221 TWh available for final consumption. (International Energy Agency, 2014). In 2011-12, there were 308 coal and gas-fired generators in Australia with an installed capacity of more than 48 GW and a further 12.8GW of hydro and renewables capacity supplying electricity to 9.7 million customers. There were five transmission networks and 13 major distribution networks (AER, 2012).

Domestic black and brown coal dominates electricity production. In 2014, 61 percent of total electricity production came from coal-fired plants which made up half of total generating capacity. The previous year, coal accounted for more than 64% of electricity production and the latest figures are the lowest for coal since 1997-97. Natural gas accounted for around 22 percent of electricity production (up from 20.5 percent the previous year) but around 30% of generating capacity. Output from natural gas is expected increase in share to 34% by 2049-50. Renewable generation increased significantly, with hydro power delivering around 13 per cent of total generation from around 14% of generating capacity while the balance (around 3%) was delivered from other renewables which had around 7% of the country's generating capacity. (International Energy Agency, 2014)

With costs declining rapidly, and despite the removal or reduction in incentives, continued penetration of PV in both residential and commercial/industrial settings seems likely. Presently, over 1.3 million rooftop solar PV installations are installed, with a capacity of around 3.2GW (Australian PV Institute (APVI) Solar Map, 2014). At a capacity factor of around 14%, this would have the ability to generate over 3.9 TWh of energy in a year or around 1.6% of total consumption.

The Eastern Australian National Electricity Market ("NEM") is one of the most geographically dispersed electricity networks in the world, with the world's longest AC current transmission network comprising more than 40,000 km of high voltage transmission lines, 770,000 km of lower voltage distribution networks and 1,500 km of interconnectors that transmit power from one jurisdiction to another. By contrast, with a population three times that of Australia (and serving 29 million customers), the UK has just 835,740 km of cabling, with just 25,000 km in transmission (ENA, 2013), indicating just one of the unique challenges faced by the electricity distribution sector in Australia.

Electricity is the dominant component of stationary energy in Australia and centralised electricity plants, fuelled by coal and natural gas dominate with substantial transmission and distribution infrastructure also accounting for significant energy losses from production through to consumption. However, recent progress in both centralised renewables (particularly wind) and distributed solar PV suggests the potential transformation to a more distributed low-carbon energy system is possible.

2.3 Australia's electricity industry

Electricity supply was introduced to Australia in 1880 with Australia's first hydro-electric resource in Tasmania in 1883. Natural gas was found in South Australia in 1891 and in 1897 South Australian Electric Light and Motive Power was authorized to supply electricity services for the next forty years. By 1944, there were 188 electricity distribution businesses in NSW alone. However, the industry has progressively concentrated and in 1980, there were 25 distribution businesses in NSW while by 2013 there were just three state-owned networks.

Historically, state-based transmission networks were designed and constructed independently to meet the supply needs of each state. As a result, the primary transmission voltage for each state is varied and inconsistent from state to state. The Queensland network (in 2009) had a 275kV primary backbone with limited 330kV and long 132kV transmission lines. Victoria, having the smallest land mass and the most meshed network within the NEM, has a 500kV primary backbone with some 330kV and long 220kV networks. NSW (and ACT) has 330kV as the primary backbone with limited 500kV systems and long 132kV networks.

a) Industry Structure

The current structure of Australia's electricity market was shaped by industry reforms that began in the early 1990s. The National Electricity Market began operation in 1998 and allowed market-determined power flows across the ACT, New South Wales, Queensland, South Australia, Victoria and Tasmania. Western Australia and the Northern Territory are not connected to the NEM. The NEM operates as a wholesale spot market managed by the Australian Energy Market Operator ("AEMO"). In addition to the physical wholesale market, retailers contract with generators through financial markets to better manage price risk.

The Australian electricity industry is dominated by a limited number of generators, network operators and retailers. Key participants in the NEM include generators, transmission networks, distribution networks and retailers, with the key participants identified in the following chart.

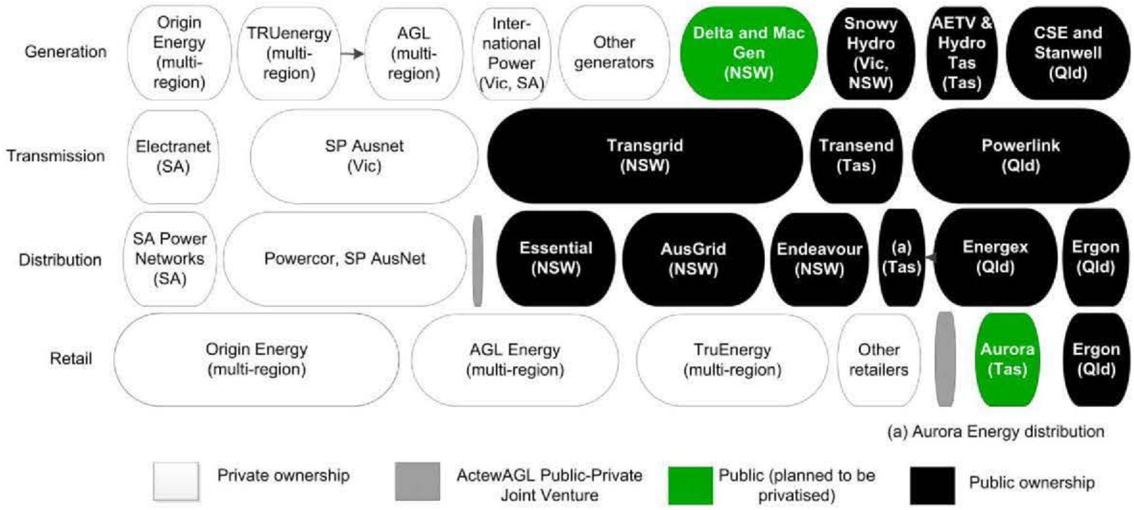


Figure 2 Key Participants in the NEM

Source: {Productivity Commission, 2013 #165}

In 2011 there were 35 major generation companies operating in the NEM. Of these, just eleven companies accounted for 80% of total generation capacity in 2011 (AER, 2012). By 2013 there were around 29 such companies as a result of consolidation in the industry with just seven companies accounting for 80% of total generation capacity (AER, 2014)

Table 1 Top Australian Power Generating Companies

Company	Capacity	% of capacity	Cummulative %
AGL Energy	10,201.00	22%	22%
Origin Energy	6,166.00	13%	35%
Snowy Hydro	5,544.00	12%	46%
EnergyAustralia	4,683.00	10%	56%
CS Energy	4,560.00	10%	66%
GDF Suez	3,355.00	7%	73%
Stanwell Corporation	3,151.00	7%	80%
Hydro Tasmania	2,761.00	6%	86%
Delta Electricity;	1,320.00	3%	88%
Alinta Energy	1,011.00	2%	91%
InterGen	760.00	2%	92%
Arrow Energy	495.00	1%	93%
Infigen Energy	370.00	1%	94%
Pacific Hydro	304.00	1%	95%
Others	2,558.00	5%	100%
TOTAL	**47,239.00**	**100%**	

In the transmission sector, the five major NEM networks are owned by the Queensland, NSW and Tasmanian Governments, alongside foreign owned Singapore Power and YTL Power investments, with the three interconnectors owned predominately by foreign interests from Japan and Singapore. (AER, 2014)

The distribution networks in NSW, Queensland and Tasmania are owned by their respective state governments, ACT is half-owned by the ACT Government, while the six major distributors in Victoria and SA are majority owned by Hong Kong and Singapore based entities (Cheung Kong Infrastructure and Singapore Power International). (IBID)

The centralised power system in Australia has driven a high level of concentration (Green, 2014) and it may be argued that the high proportion of government ownership, cross ownership of participants along with this concentration has had significant adverse impacts on competitiveness, innovation, investment, profitability and pricing. For example, in an analysis undertaken by Ernst and Young (Ernst&Young, 2014a), privately owned network operators in Victoria and South Australia delivered average network price reductions of 18% and 17% respectively for the comparative periods considered, while government owned operators in NSW and Queensland delivered average price increases of 122% and 140% respectively,

b) Revenue and profitability

The average annual revenue for network businesses in the NEM is over $12billion (AER, 2012) with approximately 25% applicable to transmission and the balance to distribution. While the industry has changed significantly over the past several years, in 2007-8 distribution businesses generated just $251,000 per employee in industry value-add while generating a profit margin of 22.2% on revenue of $13.5 billion (ABS, 2008c). Transmission networks, on the other hand, generated over $620,000 of value-add per employee with $2.18 billion in revenue and a profit margin of 20.7%. In contrast, generators, on average, produced a value-add per employee of $534,000 and a profit margin of just 13.6% on revenue of $10.7 billion. In 2014/15, the electricity distribution industry is forecast to generate $5.5bn in profit from $17.8bn in revenue (a margin of 30.8%) and expand value-add per employee by nearly 50% to $371,000 (Kerin, 2014). The profitability of network businesses has been substantially greater than that for generators.

Under the regulated Australian energy system, generators compete to supply electricity to the wholesale market and are incentivised to produce electricity at the lowest sustainable rates, subject to absorbing the relevant regulatory, emissions and environmental charges. However, network businesses are not similarly incentivised. The regulator determines their revenue over a five-year period based on the value of assets employed, required additional investments and operating costs. When power demand falls, generators must either reduce their margins or reduce the utilisation of their assets to meet market demand. However, network businesses are not incentivised to reduce their prices but instead seek to collect their regulated revenue while delivering fewer services which may result in an *increase* in average prices. Thus, the pricing signals for network businesses appear to be illogical and not conducive to signalling benefits of reduced consumption with the Productivity Commission (Productivity Commission, 2013) noting that in relation to distributed generation, " the current policy environment sends opposing signals to distribution networks and consumers". Clearly, network businesses are profiting under a non-competitive regulatory regime while the potential for distributed generation remains constrained under the same regime.

c) Assets and Investment

Between 1955 and 1979 annual investment in the electricity system averaged about $5 billion per annum (Simshauser and Nelson, 2012) while electricity consumption was growing at 7.9% per annum. Investment increased to $9 billion per annum during the 1980s while consumption growth declined to 5.4% per annum (which was a lower rate than forecast at that time) due to a number of discrete industrial loads, primarily aluminium smelters, not materialising. By the mid-1980s the energy system was "chronically oversupplied" and electricity price increases were significantly higher than the industry, government and policymakers had anticipated. Consequently, substantially reduced investment of around $2 billion per annum followed during the 1990s and the oversupply eventually cleared. From 2000 – 2006 investment returned to trend at around $5 billion per annum. However, from 2007 onwards substantially greater investment occurred to provide for asset replacement, environmental policies and the then expanding peak demand requirements.

In 2010, the AER (AER, 2012) noted that operators expected to invest $40 billion through to 2015 with distribution networks attracting investment at a rate of more than five times the investment rate for generating assets. Distribution network operators invested more than $7.2bn in 2010 alone which accounted for 75% of total investment in the NEM and contributed the largest single component of electricity tariffs. In 2010, the total value of generating, transmission and distribution assets in the NEM was around $102 billion with distribution network assets accounting for over 45% of this. Centralised generating assets accounted for 39% and the balance was in transmission network assets. In the ensuing years, investment priorities have changed markedly as the industry has adjusted to falling demand and resistance to rising consumer prices. The Australian Energy Regulator continued to highlight these concerns as the industry slowly adjusts to over-riding trends and demands (AER, 2014).

It may be argued that under the regulated revenue regime where asset investment is a key driver of revenue, network businesses are not incentivised to make optimum economic allocation decisions for capital expenditure. As noted by the Productivity Commission (Productivity Commission, 2013), a "lack of coherence" by government results in "decisions to reduce dividends when price increases are politically sensitive, limit capital spending when governments are concerned about debt levels, or encourage capital expenditure if there are pressures for greater reliability".

2.3.1 Issues Affecting the Australian Electricity Industry

In addition to the above issues directly related to industry structure and regulation (government and cross ownership and a high level of concentration that may adversely impact competition, innovation, investment, profitability and pricing; ineffective regulatory oversight resulting in perverse pricing signals (for network businesses); and inappropriate asset allocation decisions), a range of other issues impact upon the Australian electricity sector.

In December 2013, the Australian Government released an Energy White Paper – Issues Paper (Department of Industry, 2013a) followed by a Green Paper in 2014 (Department of Industry, 2014) that set the direction for its White Paper (released in April 2015) (Department of Industry and Science, 2015) that is intended to be "an integrated and coherent Australian Government position on energy policy." The issues identified in the White Paper are similar to those impacting electricity generation and distribution in other developed countries that have established centralised energy generating plants and a mix of transmission and distribution infrastructure. Emissions, fossil fuel sustainability and security, increasing penetration of distributed and renewable generation, reliability and productivity of centralised generation, fragile transmission infrastructure, regulatory reform and economics impact economies around the world.

Key energy issues include:

a) Energy security and customer reliability

The reliability of electricity supply and the long-term availability of, and access to, electricity is imperative for Australian industry, households and national independence. Severe weather events, natural disasters and maintenance errors can cause substantial disruption and cost national economies billions of dollars.[4]

As depicted in the charts below, despite significant investments in distribution and transmission networks in Australia, AER[5] has observed that the number of outages caused by the distribution system has remained fairly stable over time, while the average minutes of outage has actually increased in Queensland, Victoria and Tasmania.

[4] A widespread blackout in the USA in 2003 was blamed on inadequate adherence to reliability standards possibly as a result of reduced investment in the networks (IEA 2007). Hurricane Sandy which struck north-east USA in late October 2012 left 6.2 million people without power in seven states, including New York City and New Jersey where nuclear power plants were disrupted. More than 600,000 customers remained without power up to 5 days later and two months later, over 8,000 were still reported (NESSEN, S. 2013) to be without power. The Fukishima disaster in Japan, triggered by a tsunami of unpredicted scale resulted in a dramatic shift of Japan's energy mix with the progressive shut-down of its nuclear power plants which had delivered nearly one-quarter of its electricity production. This had the consequent effect of increasing natural gas demand and price while triggering Germany's accelerated closure of eight of its 17 remaining nuclear facilities which previously contributed around 18% of total German electricity production. In February 1998 a five-week-long power outage affected 20 city blocks in central Auckland after maintenance failures saw the four main 110 kV transmission cables into the city fail progressively over a matter of days. Disruption to business and residents imposed massive costs to the New Zealand economy.

[5] AER System Average Interruption Duration & Frequency Indices

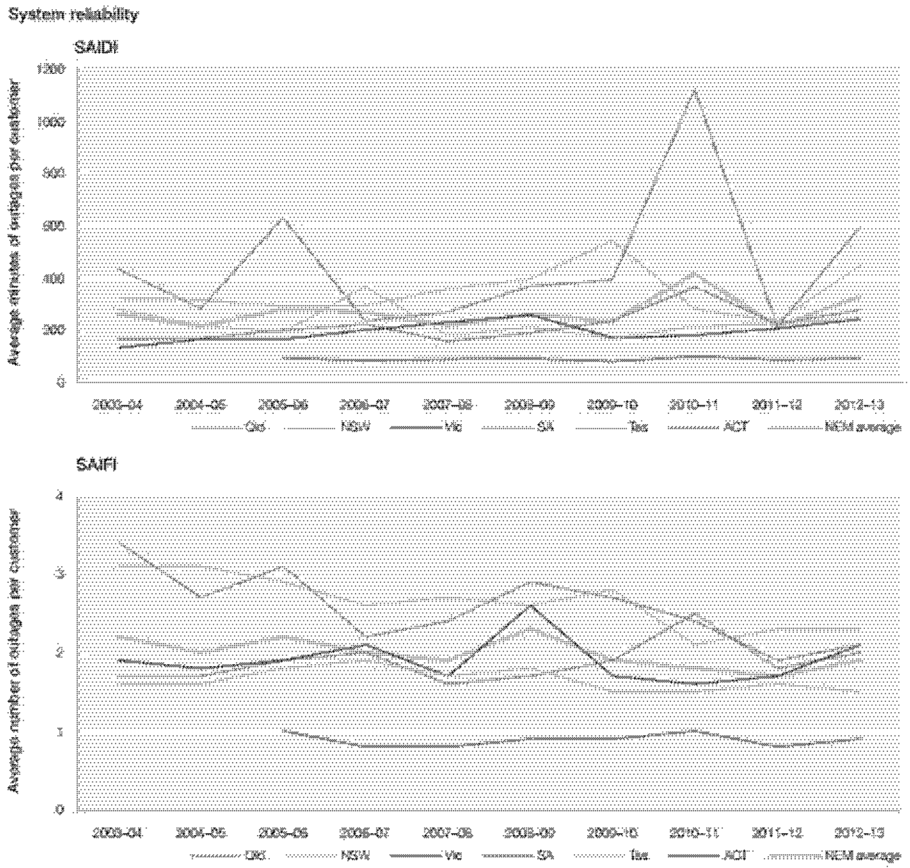


Figure 3 NEM Reliability

Source: {AER, 2014 #327}

As the Productivity Commission (Productivity Commission, 2013) declared "It is certainly not evident that the large increases in capital expenditure across the NEM have yet achieved greater reliability." This would seem to suggest inefficient investment in infrastructure to support centralised generation.

b) Changing demand profile

Behaviour of residential consumers, climatic conditions and the presence of capital intensive and energy intensive industries determine the demand profile for the electricity network. Historically, a substantial proportion of electricity generation capacity (and consequently cost for the consumer) was dedicated to ensuring energy is available during a limited number (estimated to be around 40 hours) of peak demand events each year. Peak demand has risen in most states over the past few decades (Topp, 2012). However, growth in peak loads has slowed in most states since 2008-09 and has been lower than forecast in New South Wales and Queensland. The recent narrowing of the gap between peak and base load demand is a consequence of subdued overall demand, the contribution of distributed generation in the network (particularly roof top solar), weather conditions (La Nina), and industry evolution (growth of services businesses over manufacturing). Having demonstrated an inability to project future trend in consumption, network operators continue to commit a substantial proportion of investment towards ensuring peak supply is available in the face of uncertain peak demands (Productivity Commission, 2013).

Meanwhile, continued moves toward distributed generation, in addition to better pricing signals for consumers (time-based tariffs and implementation of smart metering) will reduce the need for continued investment that is not well utilised, ease pricing pressures and reduce cross-subsidies paid by those who do not use substantial power in peak times, to those who do. The extent of peak versus base load costs is represented by the ratio of high incremental supply costs to average costs. The Productivity Commission (Productivity Commission, 2013) has estimated that "(some 25 per cent) of retail electricity bills is required to meet a few (around 40) hours of very high ('critical peak') demand each year". As substantial proportion of the investments in centralised infrastructure to satisfy peak events may be avoided by a shift to distributed generation.

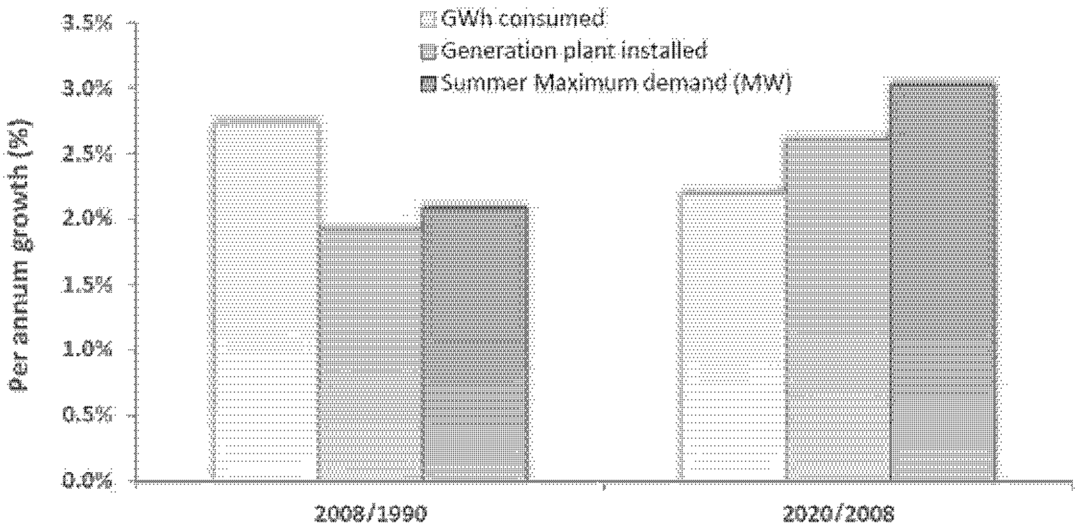


Figure 4 Australian Electricity System Growth

Source: (Ball et al., 2011)

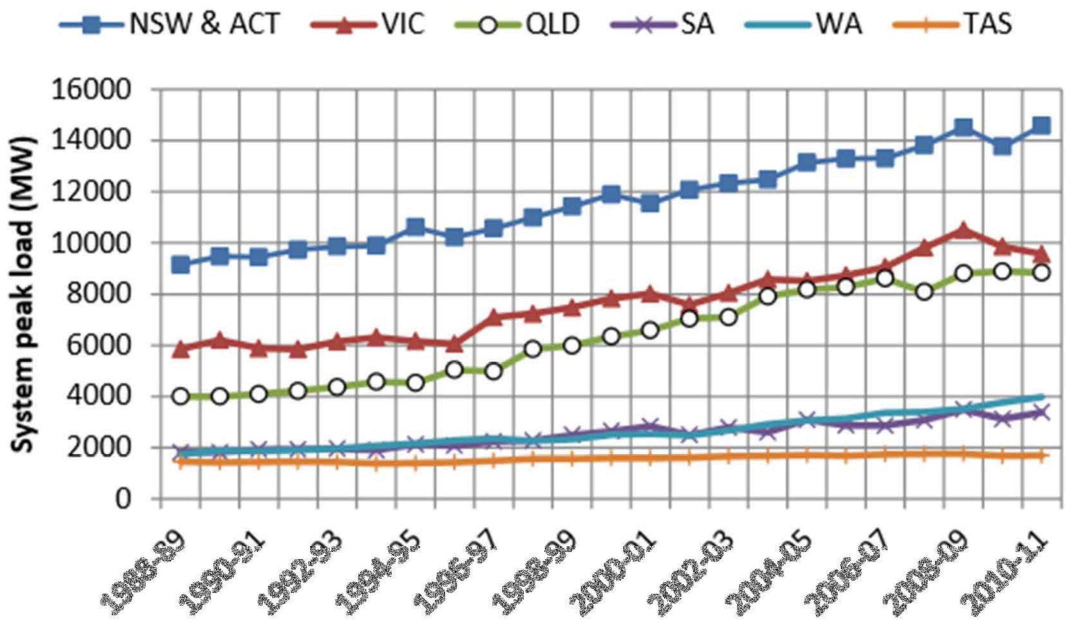


Figure 5 Rising Peak Demand, 1988-89 to 2010-11

Source: (Productivity Commission, 2013)

c) Reduced Energy Demand

Alongside the changing demand profile which has reduced peaks loads, overall demand for electricity has declined over recent years.

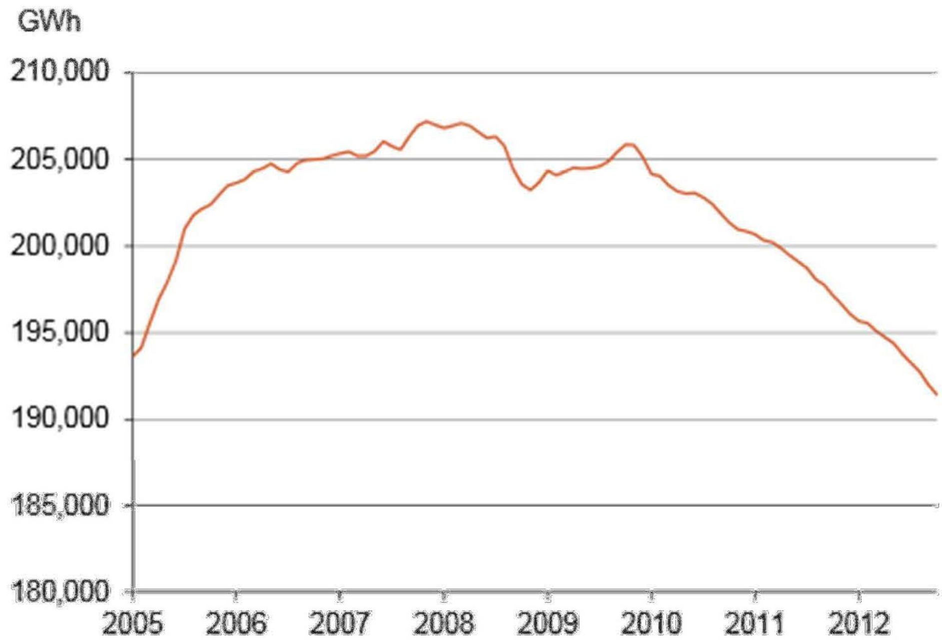


Figure 6 NEM 12 Month Rolling total Electricity Demand 2005 – 2013

Source: (Wood et al., 2013)

To planners, the trend of slower growth in consumption should have been evident from analysis of the long-term data, from an understanding of the shift from secondary to tertiary industry structure and from analysing the likely impact of regulated energy standards for equipment. However, under a regulatory regime that rewards network investment with guaranteed returns, incumbents continue to invest in network capacity (which, in turn, drives investment in generating capacity) in spite of signals that demand for electricity is plateauing.

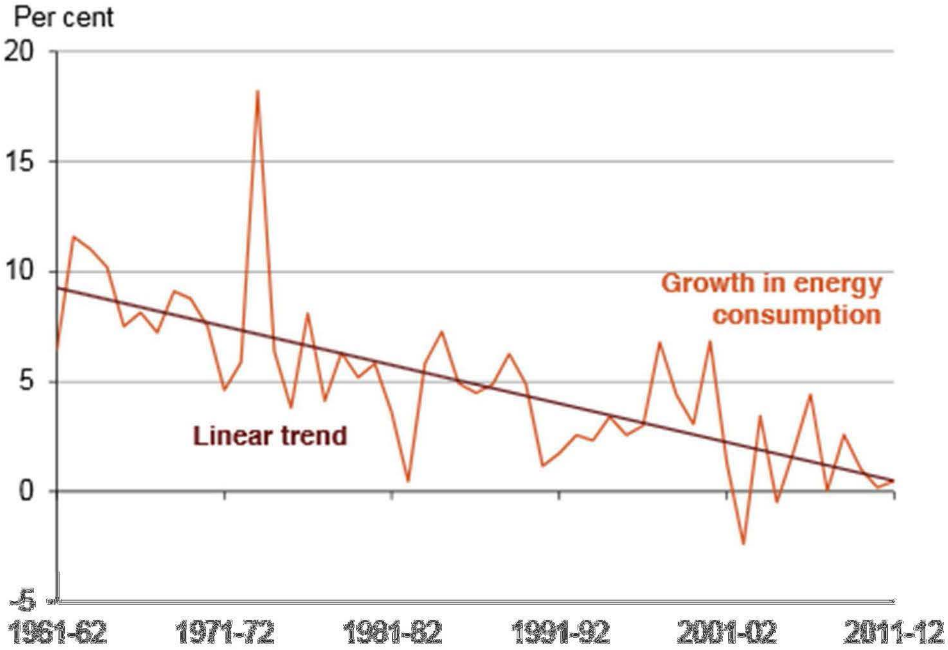


Figure 7 Growth in Electricity Consumption in Australia 1961 – 2012

Source: (Wood et al., 2013)

Structural change in Australia's economy is one major factor responsible for the decline. The manufacturing sector grew by 24% between 1990 and 2013, but failed to keep pace with the growth in the rest of the economy with its share of economic output declining from 13% to 6% (Wood et al., 2013). Changes in industry structure have involved a shift to services firms with lower energy intensity. Continued electricity and gas price pressure is likely to drive a further decline in the manufacturing sector and move it from its position as one of the largest sectors of electricity consumption.

d) Poor energy productivity/efficiency

Reserves of fossil fuel are limited. While it is estimated that there are still decades of supply available, the price of these depleting reserves will increase as a result of the higher costs of exploiting reserves, their increasing scarcity and the carbon costs levied on their use. In contrast, the ability to improve energy conversion efficiency and deliver energy at the lowest possible cost improves national economic growth and social wellbeing. There is a correlation between electricity use per capita and gross domestic product of a nation with the IEA estimating that each additional KWh of electricity intensity correlates with an increase of around US$3.50 (in 2008 dollars) of national GDP. Klimstra (Klimstra and Hotakainen, 2013) estimated that the leverage from additional electrification (particularly for developing economies) is between 23 and 70 times. Access to electricity provides large multipliers in output from human endeavour. By extension, technologies which convert energy more efficiently, reduce transmission losses, reduce interruptions and increase on-site availability of energy will deliver economy-wide benefits.

Australian power is predominately produced in thermal coal-fired power plants. During the process of power generation to consumption, 76% of the energy in brown coal is lost while 70% of the energy in black coal is lost, implying thermal efficiency of between 24% and 30%. Based on international comparisons (International Energy Agency, 2010b), state of the art technology could improve coal-fired thermal efficiency to in excess of 45% from the current fleet average of 31% while gas fired technology could deliver 58% thermal efficiency.

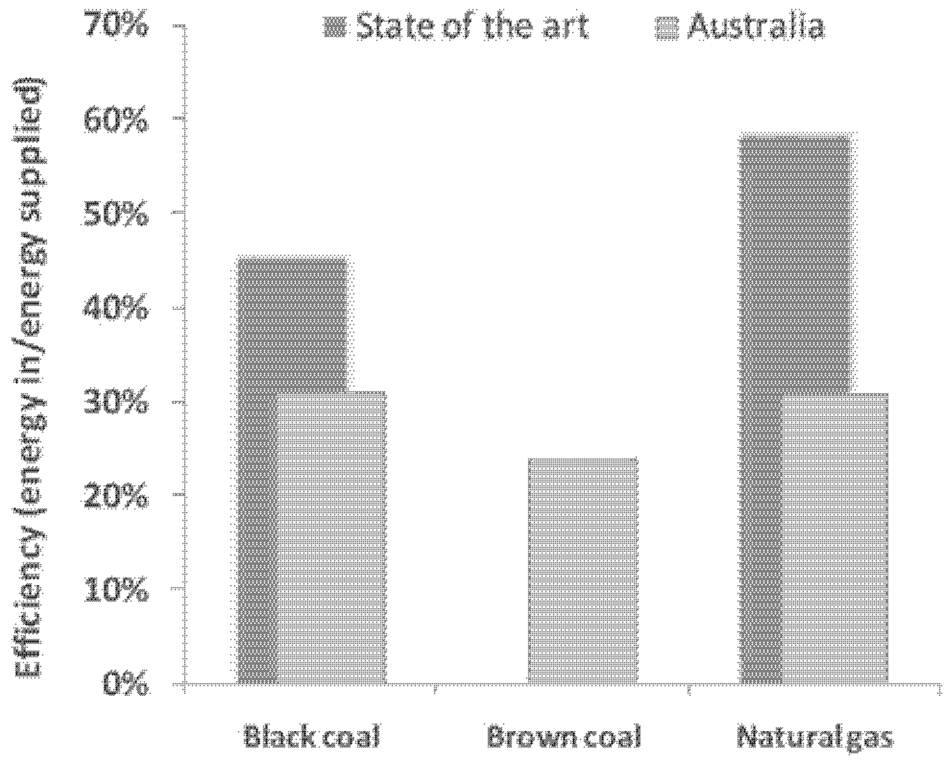


Figure 8 Australian Power Generation Efficiency

Source: (Ball et al., 2011)

The overall efficiency of the Australian grid is 32.6% (Brown et al., 2007) and it has been estimated (AGL External, 2013) that the NEM has more than 9,000 megawatts of excess power generation capacity – around a sixth of the market capacity. The excess is dominated by base-load and intermediate generating capacity (around 12,000 megawatts) but is offset by an undersupply of peak capacity of around 3,000 megawatts according to AGL (IBID). This supply imbalance has been amplified by the availability of intermittent renewable energy, suggesting a non-optimal mix of generation. Clearly, the ability to generate electricity to satisfy peak load by deploying cost effective and flexible capacity should be an objective of energy participants and the Government whereas intermittent and centralised base-load capacity must be de-emphasised.

Recent increases in network investment, without commensurate usable output growth, must be interpreted to mean that electricity productivity has declined significantly over the past several years notwithstanding the overall improvement in energy intensity over the comparable period. In relation to generation capacity, decreasing consumption combined with investments in coal, gas, and wind generation assets have led to an oversupply in the wholesale market with capacity now being mothballed or retired early. The need to renew aging assets remains, however, investment in "unproductive" assets suggest substantial inefficiency in the existing centralised electricity network. Grattan (Wood et al., 2013) estimates total assets in the NEM and the SWIS of around $86.9 billion, while Australian power networks contain around $4.9 billion in excess assets which cost the consumer around $444 million each year. Deferral of investment, and writing down the value of existing assets will substantially contribute to constraining the increase in future electricity prices.

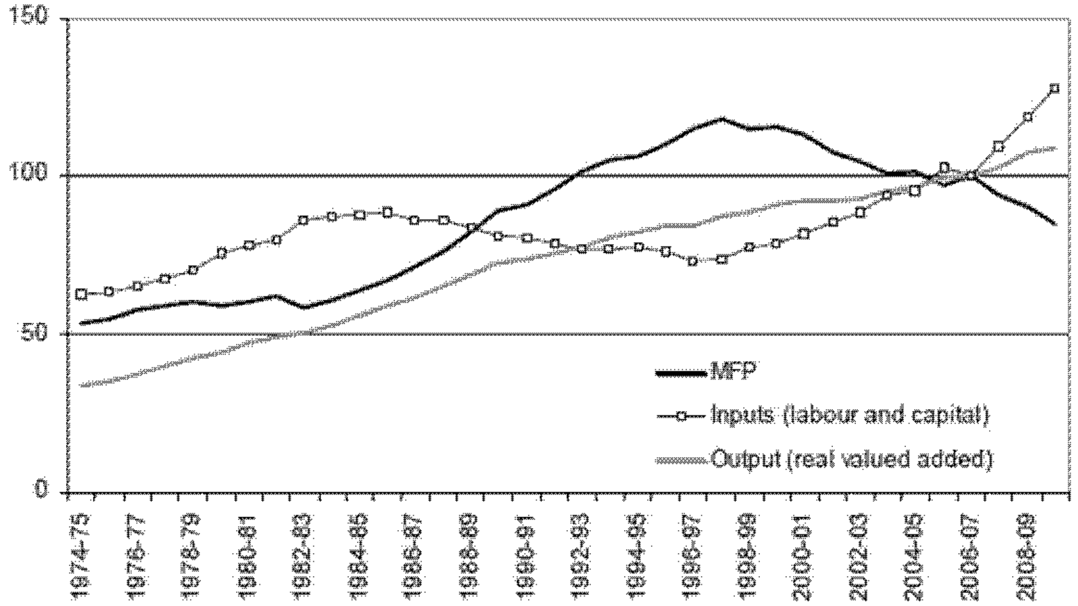
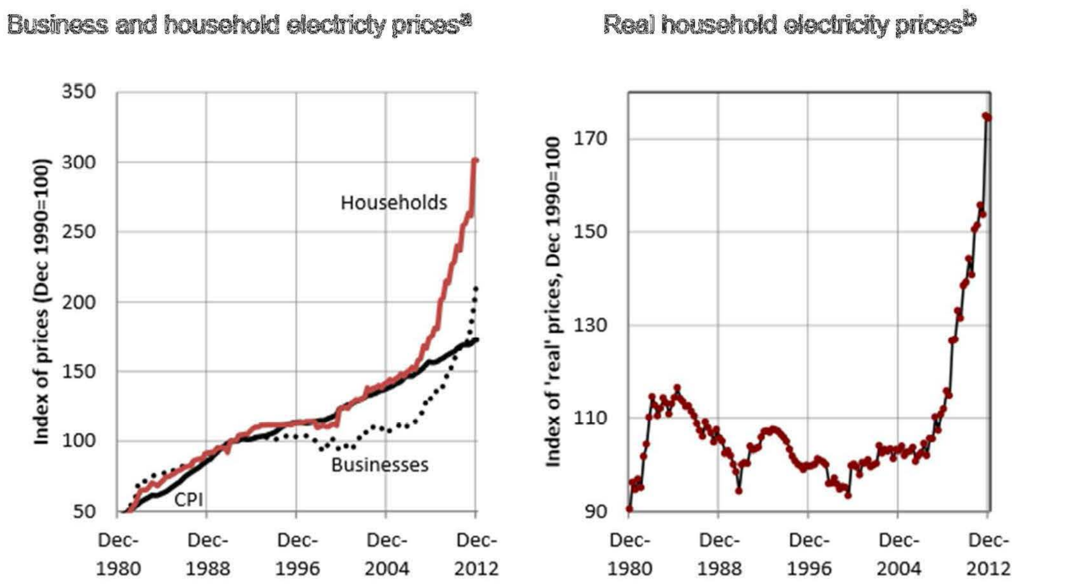


Figure 9 Electricity Sector Multi Factor Productivity

Source: (Topp and Kulys, 2012)

e) Rising electricity prices

The Productivity Commission (Productivity Commission, 2013) noted that average electricity prices rose by 70% in real terms from June 2007 to December 2012. Network cost increases were the main contributor, "partly driven by inefficiencies in the industry and flaws in the regulatory environment."



[a] Data are from December 1980 to December 2012, rebased so that December 1990 = 100. The data relate to all Australian electricity prices, not just those in the NEM, but the trends will be similar. [b] 'Real' prices are household prices divided by the CPI average for capital cities. The index shows how much electricity prices have increased above inflation.

Figure 10 Australian Electricity Price Increases 1980 – 2012

Source: (Productivity Commission, 2013)

Price rises in Australia have far outstripped international comparables, even Germany whose electricity system has undergone dramatic change as a result of low-carbon policies and the introduction of renewable generation.

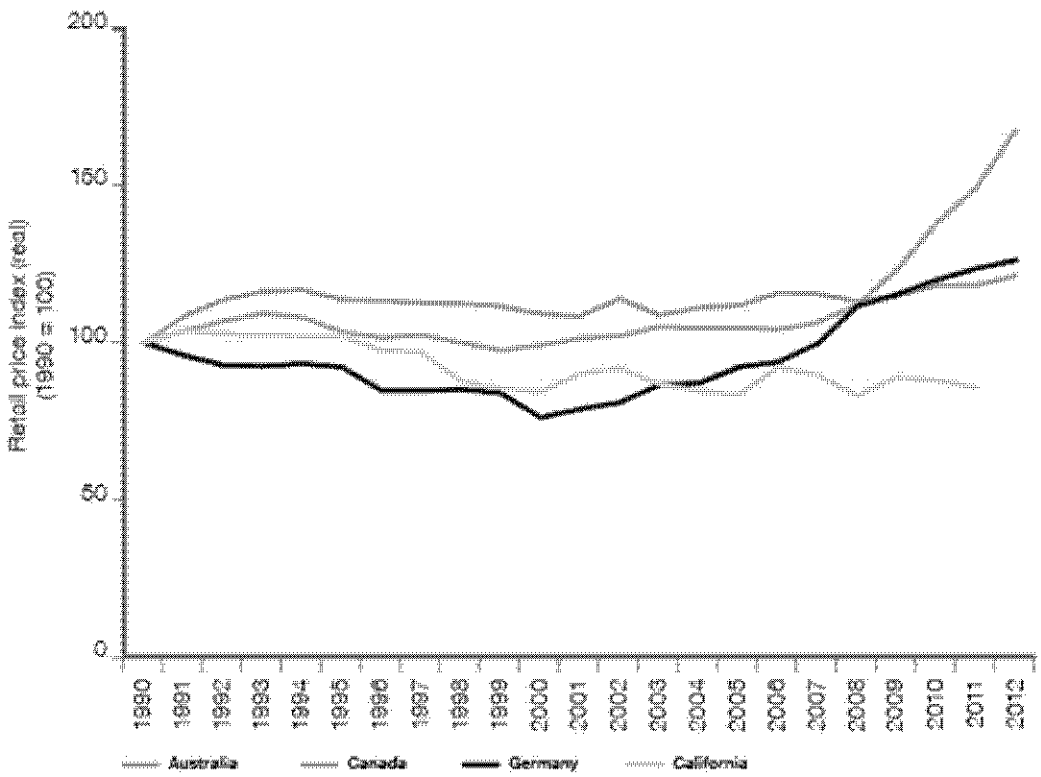


Figure 11 Average Annual Power Price Increases 1990 – 2011

Source: (Ball et al., 2013)

Extant regulatory reforms, including regulatory rule improvement and the proposed greater representation of consumers as outlined in the AER's Power of Choice review (Australian Energy Market Commission, 2012), have been too slow or too little. Reliability requirements, improved incentives for demand management, more efficient transmission network planning and conflicting state regulatory and ownership incentives have compounded cost increases. The delays and inadequate reforms have been estimated by the Productivity Commission (Productivity Commission, 2013) to "cost consumers across the National Electricity Market (NEM) hundreds of millions of dollars". In NSW, $1.1 billion in distribution network capital expenditure could be deferred at least 5 years by adopting different reliability frameworks. Similarly, savings in transmission network investment could save between $2.2 billion and $3.8 billion over 30 years. Demand side participation could save between $100 and $200 per household per year where capacity is constrained.

f) Climate Change

The Australian power generation industry was responsible for 34% of Australia's total greenhouse gas emissions in 2011/12 (O'Gorman and Jotzo, 2014) . Greenhouse gas emissions from electricity generation in Australia peaked in 2008 at 212 million tonnes of carbon dioxide equivalent (CO_2e), but fell to 180 million tonnes of CO_2e 2013/14, still accounting for one-third of total emissions (Department of the Environment, 2015) and remaining as the largest single source of Australian emissions as a result of black coal accounting for 58% of national generation and brown coal more than 31%.

The climate change debate has polarised the opinions of credible, intelligent people around the world and within Australia. It has destabilised politics (Dessler and Parson, 2009, Tranter, 2011), added uncertainty to business and alarmed the populous.

The scientific majority represented by the Intergovernmental Panel on Climate Change (Pachauri and Reisinger, 2007), generally organised and government funded, had substantially moved public opinion (Leviston and Walker, 2011) regarding the impact of carbon emissions. Within Australia, two seminal documents were received which provided detailed and substantial arguments concerning the need to address catastrophic climate events in the coming decades and offered some prescriptions on how to manage the required changes. The Stern Report (Stern, 2007) representing the Intergovernmental Panel on Climate Change and the 2008 Garnaut Review (Garnaut, 2008) in Australia provided clear and compelling information regarding the prospect of catastrophic events resulting from the levels of carbon and carbon equivalents in the atmosphere rising to 450ppm by 2050. In November 2014, the IPCC presented its Fifth Synthesis Report (Allen, 2014) which stated among other findings that it is likely that "the frequency of heat waves has increased in..... Australia" and announced that "evidence indicate(s) a strong, consistent and almost linear relationship between cumulative CO2 emissions and projected global temperature change to the year 2100..."

More populist arguments, such as the persuasive video (Guggenheim, 2006) that helped secure Al Gore a Nobel Prize, have been presented by ideologically motivated action groups and non-government organisations. Meanwhile, arguments that challenge the science by questioning the extent of observed historical or predicted climate change; the extent to which man-made emissions will or have influenced climate; and, the extent of adverse impacts of predicted global warming events are common (Plimer, 2009, Idso and Singer, 2010) , as are arguments that present climate change as a moral rather than a scientific issue (Dean, 2011).

Nonetheless, according to Cook (Cook, 2013a), over 97% of peer-reviewed papers endorse the scientific consensus that humans were causing climate change.

However, the scientific method renders these arguments mute. Only systematic observation, measurement and experiment; and the formulation, testing, and refinement of credible hypotheses would satisfy the burden of proof for a scientific theory (regarding climate change) to be acceptable.

While scientific merit has been demonstrated, in Australia, political leadership and public opinion has not universally recognised this.

2.4 The Australian Natural Gas Industry

Natural gas is predominately methane and is increasingly important as a source of energy around the world. It results in lower carbon emissions than other fossil fuels when used for similar purposes.

Historically, natural gas has been extracted from subterranean reservoirs (often also associated with oil), however, using new drilling and extraction techniques, gas embedded in coal seams, shale and rock formations can now be economically extracted. These latter sources are termed "non-conventional" and account for about 40% of the world's recoverable resources (Ian Cronshaw et al., 2013), 18% of total production and 22% of global energy consumption. Gas can also be produced from other sources such as biogas from the decomposition of waste matter.

Global gas consumption has increased by a factor of four over the past 50 years. Gas provides twice the energy of coal for an equivalent weight, while generating only half the amount of greenhouse gas without emitting by-products such as sulphur, mercury, ash and particulates. While the environmental benefits of gas are still debated (see discussion below), it is generally acknowledged that gas is significantly more environmentally benign than coal as a centralised energy source and gas-fired power plants are more responsive to changes in electricity demand (Rutovicz et al., 2011) and hence are often applied to satisfying peak demands. Gas is used for residential space and water heating, cooking, industrial process heat, the production of materials and transportation, in addition to power generation. However, when used for centralised electricity generation, the cost of energy is generally more expensive than coal.

According to the IEA (as referenced in (Ian Cronshaw et al., 2013)), gas accounts for about one fifth of global energy consumption at around 2,400 million tonnes per year. The international trade in gas has grown rapidly through pipelines and shipment of liquefied natural gas (LNG) with the latter representing about 10% of total global gas supply and about 60% of the interregional trade. LNG occupies just 0.15% of the volume of its gaseous equivalent making it economically viable to transport in tankers. LNG results from cooling the gas to around -162° at atmospheric pressure, where it condenses. However, the liquefaction, transportation and regasification processes are expensive and account for up to 80% of LNG's delivered cost.

Conventional gas production is growing in countries such as China (175 billion cubic metres ("BCM")), Qatar (56 BCM), Russia (50 BCM) and Turkmenistan (40 BCM) while it declines in Europe, as reserves in existing fields diminish. Non-conventional gas production is increasing in the USA and Australia where 150 BCM and 53 BCM respectively are expected to be produced by 2020.

Australia holds significant gas resources of around 3.8 trillion cubic metres with combined total identified gas resources (including conventional, CSG, shale and tight gas) estimated (Ian Cronshaw et al., 2013) at over 430,000 PJ which is enough to last approximately 184 years at current production rates.

Gas use for power generation in Australia has been overshadowed by coal. However new investment in centralised electricity generation has been predominantly gas-fired. As a result, gas demand has grown more rapidly than other fossil fuels. Gas now makes up around 21% of Australia's energy supply with total gas production in 2011–12 of 59 BCM and more than one third of this exported. Australia's three gas markets (Eastern, Western and Northern) are physically and economically separated from each other and most trade from these markets effected through bilateral contracts, along with shorter term trading markets in the East.

In 2009, a series of new LNG liquefaction projects were approved with seven projects (more than two thirds of new global investment in LNG production) underway in both Eastern and Western Australia. These plants will result in a five-fold increase in LNG exports compared with 2008 and will see Australia eclipse Qatar to become the largest LNG exporter in the world, providing around 20 per cent of global LNG supplies.

Global consumption of gas expected to grow by between 2% to 3% a year over the next five years (Warner ten Kate et al., 2013) and by around 50% over the period to 2035. There are several drivers for this growth:

- Global carbon abatement measures which favour substitution of coal-fired electricity with gas-fired electricity.
- Global energy security facilitated by more mature and interlinked global energy markets.
- Regional demand which can be satisfied economically from local sources. For example, European demand is dominated by pipelines from domestic fields and imports from Russia, Norway and North Africa, and LNG from Qatar. North America is self-sufficient with gas supplied from domestic and Canadian sources (and the potential to export). Japan and Korea import around 120 million tonnes or 50% of total global LNG production (with LNG fuelling more than 1/3 of Japan's capacity).
- Developing country demand with around 80% of projected global growth in demand coming from outside the OECD. China accounts for one third and Middle East consumption for one sixth of the global increase. Indian consumption is projected to increase by around 50%.
- Distributed generation as an important complement for centralised generation and distribution is likely to have gas-fired cogeneration as a central generating element.

2.4.1 Issues Affecting the Australian Gas Industry

There are also a range of supply, demand and market issues impacting on the Australian Gas Industry. These include:

a) Increasing competition among suppliers

LNG supply to Japan has grown about 20% since the Fukishima nuclear plant shutdown. Increased demand by India and China is being met via both pipeline and LNG. LNG production capacity is projected to grow rapidly from 240 BCM in 2006 to nearly 500 BCM in 2020 following investments in liquefaction facilities in Qatar, Australia and North America. Australia will rival Qatar as the world's leading LNG exporter from 2015 while US and Canadian exports will grow dramatically by at least 60 BCM and 32 BCM per year respectively from 2016. US LNG exports from the Sabine Pass (Louisiana) project alone are expected to reach around 22 BCM per year. By October, 2014, three other projects (Freeport, Texas; Hackberry, Louisiana; and Cove Point, Maryland) had received approval and three other export projects in the Gulf of Mexico, Oregon, British Columbia and Maryland had been submitted to the US Department of Energy - Federal Energy Regulatory Commission for approval. These capacity additions will provide buyers in Asia with increased pricing power and may render large LNG projects less attractive than originally envisaged.

b) Challenges to historical pricing methods

Each regional market has different pricing mechanisms. Pricing in North America is based on fundamental supply and demand with competition credited with keeping US gas prices the lowest in the OECD. The Henry Hub (in Louisiana) is where a number of major interstate gas pipelines converge and large storage facilities are located. Trading on Henry Hub is transparent, with many buyers and sellers providing accurate price discovery. The benefits of a wholesale gas market that provides market signals to enable participants to trade gas more readily and manage their risk has been recognised by the Australian Government (Department of Industry and Science, 2015) and a voluntary market (the Wallumbilla gas supply hub) has been established to increase transparency and competition in Australia's eastern gas markets.

In Asia, and for many years in Europe, gas pricing was oil-linked. Asian oil-linked prices are the highest in the world. Some analysts believe that the Henry Hub price could become a global spot price for LNG trade which would be a radical departure and bring moderating pressure on Asian prices. Indeed, should the USA move faster to export LNG to Asia, the downward pressure on price will strengthen. Asia-Pacific buyers are keen to exploit increasing supply competition by diversifying supplies from their dependence on Australia and Qatar (each predicted to supply 20% of global LNG trade by 2020) to North America and Russia.

c) Objections to exploiting non-conventional reserves

Coal seam gas is naturally occurring methane found in coal seams and Australia possesses sizeable reserves located in the large coal basins of Queensland and NSW. In 2012, annual CSG production in Queensland and NSW was 269 PJ and 6 PJ respectively and accounted for around 35 per cent of Australian east coast gas consumption (Upstream Petroleum and Offshore Minerals Working Group, 2013). To meet increasing domestic and export demand, the rate of drilling CSG wells in Queensland is intensifying (ACIL Tasman, 2013).

However, this rapid expansion has generated apprehension (Rutovitz et al., 2011) about CSG's social, economic, technical and environmental implications. Communities have been unprepared for the expansion and many are unwilling to accommodate the industry despite the introduction of legislation and codes of practice designed to minimise technical failure and protect communities and natural resources. The NSW Chief Scientist's Interim Report (NSW Chief Scientist and Engineer, 2013) into CSG activities in the State identified CSG as "a complex and multi-layered issue which has proven divisive chiefly because of the emotive nature of community concerns, the competing interests of the players, and a lack of publicly-available factual information" with "unanswered concerns surrounding landholders' legal rights, land access and use; human health; the environment, particularly relating to impacts on water; engineering and operational processes; and industry regulation and compliance".

The range of community concerns relating to CSG production include:

- Environmental damage - The potential for leaks and spills of toxic and contaminated water that may contaminate aquifers or catchments used for drinking water. Water pumped from coal seams is often saline and contaminated with metals and radionuclides, which can be toxic to plants, animals and humans. Even after treatment, the water can affect stream ecosystems if not matched to stream temperature and natural flow regimes.
- Water management - Depressurising coal seams can result in a range of potential impacts that may have volume and quality implications for users, result in cross-contamination between different aquifers, or cause migration of gas into surrounding aquifers, wells and water bores.
- Land and biodiversity management – Challenges include loss of biodiversity and loss of landscape hydrological and ecological functions.
- Community resistance – Objections to access restrictions and nuisance which, under current Australian mining legislation and regulation, prevents property holders from accessing ownership rights to sub-surface resources. While mining companies purchase land in order to avoid disputes with property holders, CSG requires irregular spacing of wells which makes acquisition of whole properties impractical. It has been suggested (Petkova, 2009) that only capital cities and large centres would gain from developing CSG while regional communities and landholders bear many of the costs and impacts.

In countering these community and environmental concerns, the Allen Consulting Group (Allen Consulting Group, 2011) found, in a report prepared for Santos, that development of the CSG industry in north-west NSW could generate around 2,900 ongoing full time jobs, increase gross state product by 0.2% per annum, add more than $15.2 billion out to 2035 and produce up to 210 PJs of CSG per annum and an extra 5 GL of water per annum for the benefit of agriculture. The Australian Petroleum Production and Exploration Association claims (Australian Petroleum Production and Exploration Association, 2013) that "the gas industry has created about 30,000 jobs in recent years, is working in partnership with more than 4000 landholders, and is today revitalising regional communities".

The National Harmonised Regulatory Framework for Natural Gas from Coal Seams (The Standing Council on Energy and Resources, 2013) provides guidance on acceptable practices for CSG operations particularly in relation to well integrity, water management and monitoring, 'fracking', and management of chemicals. A report by the Australian Council Of Learned Academics (Cook, 2013b) indicated that the actual observed risks associated with CSG are significantly lower than feared by the community as demonstrated by the table below.

Table 2 Key Risks for Hydraulic Fracturing

Table 1: Key risks for hydraulic fracturing and worst case frequency of occurrence.
(Source: Figure adapted from King 2012, cited in ACOLA Engineering energy: Unconventional Gas Production. A study of shale gas in Australia. Final Report. pp. 61 Table 4.2. May 2013)

	Key risks for hydraulic fracturing	Worst case frequency
1	Spill (20,600 litres) of a transport load of water without chemicals	[1 in 50,000]
2	Spill (1,890 litres) of concentrated liquid biocide or inhibitor	[1 in 4.5 million]
3	Spill (227 kg) of dry additive	[1 in 4.5 million]
4	Spill (1,135 litres) of diesel from ruptured saddle tank on truck (road wreck)	[1 in 5100]
5	Spill (13,250 litres) of fuel from standard field location refueler (road wreck)	[1 in 1 million]
6	Spill (80,000 litres) of well-site water (salt/fresh) storage tank – no additives	[1 in 1000]
7	Spill (190 litres) of water treated for bacteria control	[1 in 10,000]
8	Spill (190 litres) of diesel while refuelling pumpers	[1 in 10,000]
9	Spill (80,000 litres) of stored frack water backflow containing chemicals	[1 in 1000]
10	Frack ruptures surface casing at exact depth of fresh water sand	[1 in 100,000]
11	Frack water cooling pulls tubing out of packer, frac fluid in sealed annulus	[1 in 1000]
12	Frack opens mud channel in cement on well less than 2000 feet deep	[1 in 1000]
13	Frack opens mud channel in cement on well greater than 2000 feet deep	[1 in 1000]
14	Frack intersects another frac or wellbore in a producing well	[1 in 10,000]
15	Frack intersects an abandoned wellbore	[1 in 500,000]
16	Frack to surface through the rock strata (well less than 2000 feet deep)	[1 in 200,000]
17	Frack to surface through the rock strata (well greater than 2000 feet deep)	[no cases]
18	'Felt' earthquake resulting from hydraulic fracturing	[no cases in US]
19	Frack changes output of a natural seep at surface	[1 in 1 million]
20	Emissions of methane, CO_2, NO_2 SO_2	[high frequency]

The NSW Chief Scientist's Final Report, issued in September 2014 (NSW Chief Scientist and Engineer, 2014) concluded that "the technical challenges and risks posed by the CSG industry can in general be managed through careful designation of areas appropriate in geological and land-use terms for CSG extraction; high standards of engineering and professionalism in CSG companies; creation of a State Whole-of-Environment Data Repository so that data from CSG industry operations can be interrogated as needed and in the context of the wider environment; comprehensive monitoring of CSG operations with ongoing automatic scrutiny of the resulting data; a well-trained and certified workforce, and application of new technological developments as they become available."

d) Rising domestic prices & domestic supply issues

With new gas supplies being developed at a much higher cost than historical fields and Australia's domestic gas markets becoming more internationally integrated, there are concerns about the effect on domestic gas prices and gas availability.

As the Western Australian gas export market developed, prices rose from A$5.50 to A$9 per GJ. However, new supply emerged in response to these higher prices despite a domestic reservation policy that ensures the availability of supply to domestic users. The East Coast market has experienced historical prices of around A$2–$3 a GJ, however as domestic wholesale contracts expire, the pricing and availability of gas is uncertain and prices have been reported to have risen towards A$6 to $9 a GJ. In addition, some large industrial users have reported being unable to secure long term forward gas supplies , partially as a result of NSW Government restriction on CSG development.

All analysts see the "net back" price of East Coast Australian LNG equalising with Asian import prices. However, there remains uncertainty about supply and demand in Asia with signs that the US export market is liberalising and Japan retreating from high cost gas to lower cost coal (Sheldrick, 2013) as well as restarting some of its nuclear facilities. Approximately 1.6GW of additional coal fired electricity capacity was scheduled to come on line in Japan in late 2013, while its ten main utilities (who consume around 50% of total coal in Japan) imported 11% more coal in the first 10 months of 2013 than for the same period last year and consumed nearly 16% more. In October 2013, consumption was around 26% higher than the previous year.

There is a lack of transparency regarding contracted gas arrangements and therefore a wide range of projections of future domestic gas prices. Independent experts and industry participants including ACIL Allen, the Australian Energy Regulator and the Australian Energy Market Commission, Endeavour Energy, SKM MMA, ROAM, Port Jackson Partners and the Australian Treasury regularly publish their future price expectations based on different pricing models, assumptions, parameters and oil price forecasts.

There are some trends that appear across all projections. ACIL Allen assumed a sizeable price shock around 2014 when Queensland LNG exports commence, but expected a return towards production costs. The return towards production costs may take longer than forecast depending on the market's ability to rapidly expand production. Similarly, EnergyQuest's base scenario forecasts a considerable price jump as medium-term prices approach short run LNG netback prices. This jump is expected to last through the middle of the decade but prices are expected to return towards production costs once all the Queensland LNG projects are operating and fully producing from their own reserves (around 2019–20). EnergyQuest, like ACIL Allen, consider the key determinant of medium term pricing to be whether projects can source sufficient gas from their own reserves without having to purchase from the market (which would drive prices higher).

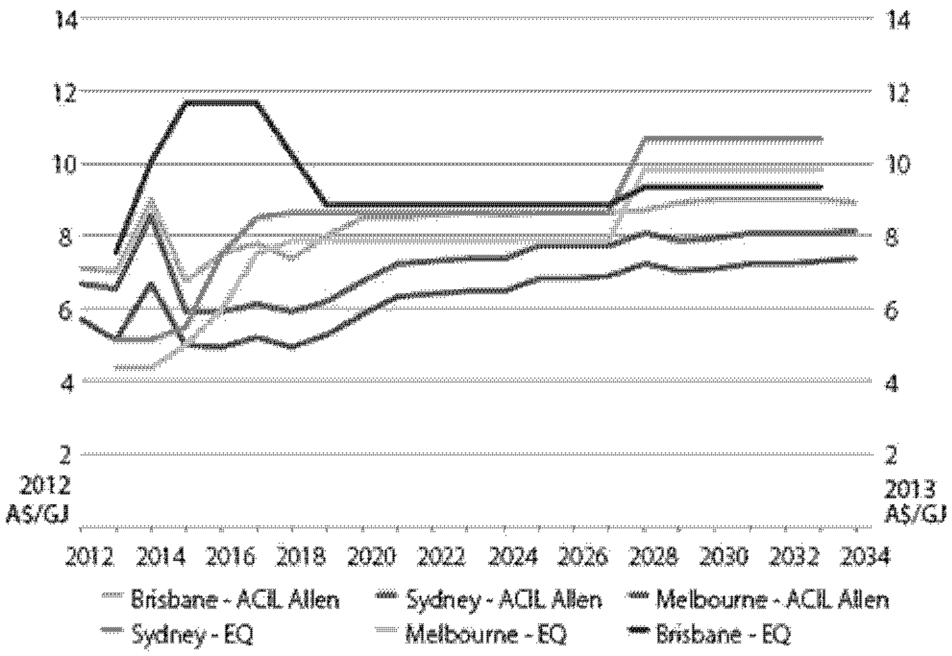


Figure 12 Projected Australian Gas Prices

Source: (Bureau of Resources and Energy Economics, 2013)

BREE (Bureau of Resources and Energy Economics, 2013) also expects Eastern Australian market prices to increase in the short to medium term, reflecting tight supply, competition for gas and uncertainty among market participants. Delays in commissioning the new LNG projects; the strategies employed by LNG producers to manage production and/or contract risks; and the extent and speed with which new gas resources, particularly in New South Wales, can be developed, will influence price and the rate of increase.

The National Institute of Economic and Industry Research ("NIES") (National Institute of Economic and Industry Research, 2012) has concluded that there is currently no policy regime in Australia that provides any "assurance of reliable, competitively priced supplies of gas for domestic industry" and that this will "erode Australian industry's competitive advantages while gas export revenues will be insufficient to compensate Australia for the loss of this advantage." Noting that gas is used extensively in manufacturing as well as in power production, the NIES expects that many industries will respond to higher prices by withdrawing production and investment, and that economic losses will be felt "within a few years". NIES has estimated that each PJ of natural gas that is exported rather than used for domestic industrial purposes will result in $255 million in lost industrial output (and economy wide impacts of $288 million per PJ) versus a $12 million gain in export output. NIES modelling indicates that, "by 2040 the gross production benefit for East Coast LNG expansion will be $15 billion annually, in 2009 prices. However, taking into account the negative effects of adjustment on other sectors, annual GDP will be $22 billion lower than it would be with secure and affordable gas". Combined with reductions in private consumption and tax receipts, the net benefit will be reduced by $46 billion. Further, with the recent significant and unpredicted decline in international oil and gas prices, the negative consequences of constrained supply will be combined with lower export earnings.

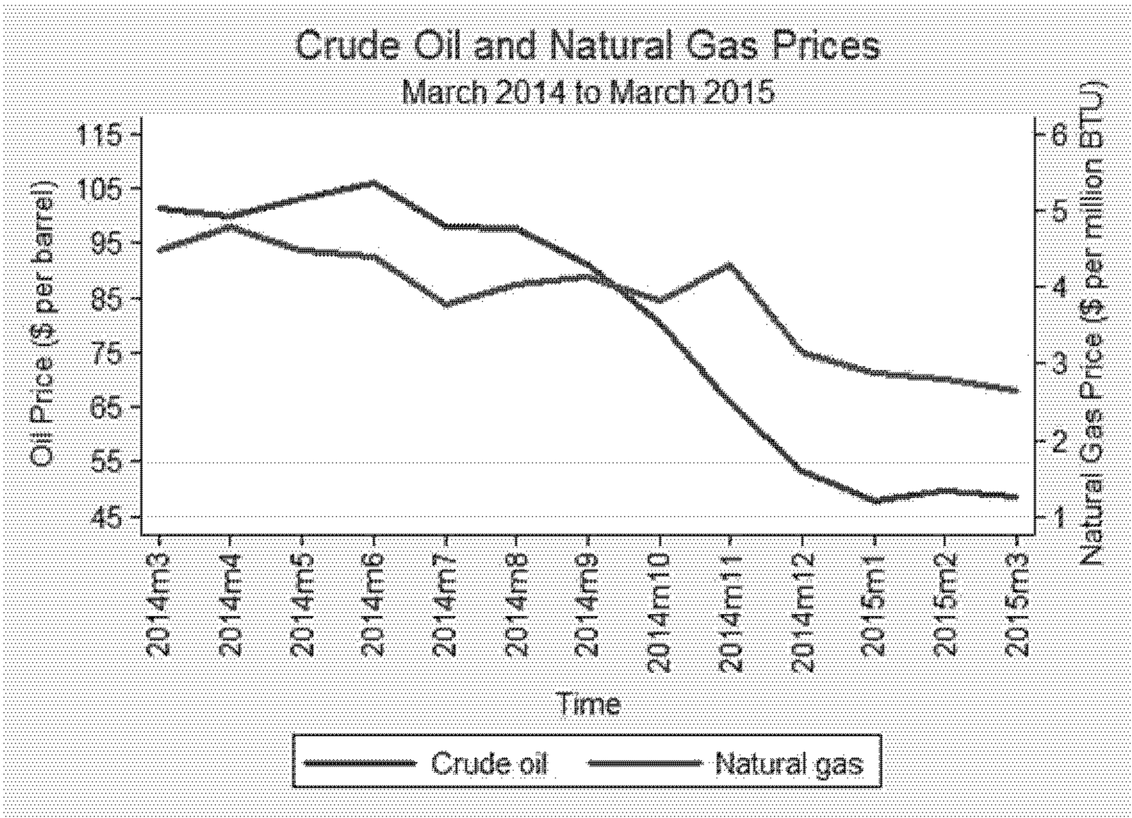


Figure 13 US Crude Oil and Natural Gas Prices

Source: (Steward, 2015)

e) Domestic demand impacts

The tight market and increasing prices could change some consumers' preferences for gas, with new gas-fired power plants deferred and large manufacturers, as well as residential consumers, seeking cheaper energy sources. Increasing electricity generation from renewable energy sources and falling growth in electricity demand will place a limit on gas-fired electricity generation demand. Similarly, pressure on the viability of large domestic gas consumers (such as manufacturers) has resulted from a strong Australian dollar and rising energy (electricity and gas) prices. Nonetheless, the share of gas-fired electricity is expected (Syed, 2012) to increase from 24.6% in 2013 to 26% in 2020 and 27% in 2035, increasing from 62 TWh in 2013 to 85 TWh in 2035 while the share of coal-fired electricity is projected to decline from 60.5% in 2013 to 51% per cent and 32.2% in 2020 and 2035, respectively. Australia possesses significant reserves of both natural and non-conventional gas. However, market forces, in the absence of policy from Federal and State Governments may result in domestic use of gas being limited through price and supply impacts.

2.5 Current Efforts to Address These Issues

The range of issues identified previously that impact upon the Australian electricity sector and the Australian natural gas industries demand responses. There is a need to improve energy productivity and efficiency, address emissions reduction through the deployment of clean technologies, address rising gas prices, and restrict excessive network expenditures while encouraging investment in technologies that generate improved economic and social outcomes for the country.

a) Regulatory reform

There are a number of institutions which regulate the limited number of electricity networks and participants in Australia. The Australian Energy Regulator ("AER") is a statutory authority constituted as part of the Australian Competition and Consumer Commission established under the Trade Practices Act to regulate retail, transmission, distribution and wholesale operations of the NEM. Retail prices are regulated under separate state authorities (such as IPART in NSW) or without intervention at all in the case of Victoria. The Standing Council on Energy and Resources ("SCER") is responsible for broad policy and the legislative framework for the NEM. The Australian Energy Market Operator ("AEMO") oversees the transmission network and operates the spot market that determines wholesale energy prices while the Australian Energy Market Commission ("AEMC") undertakes energy market reviews, provides policy advice to SCER, and sets the National Electricity Rules.

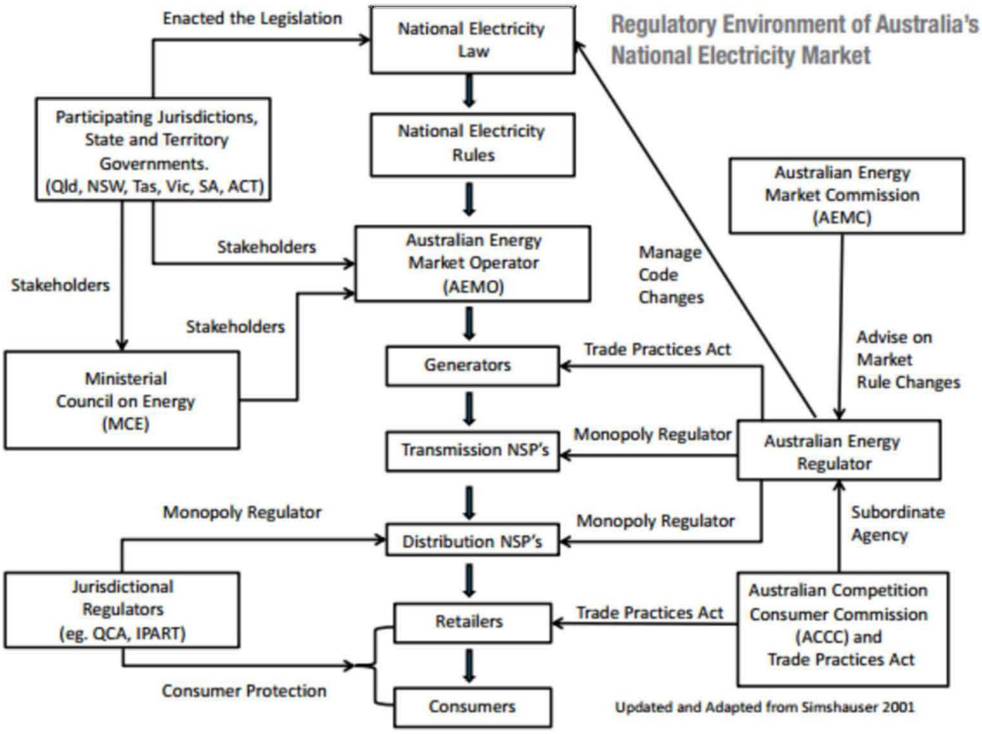


Figure 14 Regulatory Environment of Australia's National Electricity Market

Source: Simshauser et al. (2011)

Thus, the regulatory regime is complex, with varied institutional objectives. A range of regulatory reforms which would overhaul existing institutional structures (including both industry participants and the regulators themselves) to focus participants' responsibilities on the challenges associated with declining growth in demand, increasing prices, defection from the grid and the emerging availability of alternatives and substitutes must be rapidly implemented.

Integrate Policy and Oversight - Historically, there were a large number of generators, transmitters, distributors and retailers. While these have now become more concentrated through cross acquisition and mergers, policy remains fragmented with little overall oversight and flawed planning.

Overcome the conflicting objectives of State Owned Enterprises - Several network businesses remain publicly-owned. Unlike privately owned corporations for whom shareholder returns are paramount, public institutions often have diffuse and sometimes conflicting objectives such as social equity, local procurement, environmental standards, social obligations, employee benefits and governance which serve to reduce efficiency and distort incentive regulation.

Increase the pace of reform - The Productivity Commission (Productivity Commission, 2013) has noted that the pace of regulatory reform in Australia is slower than is desirable. For instance, the Power of Choice agenda included reforms such as cost reflective distribution network pricing principles; expanded competition; demand side participation; better access to customer electricity consumption data; and greater contestability in demand side participation. A final report published by the Australian Energy Market Commission (Australian Energy Market Commission, 2012) was released on the 30th November 2012 recommending significant reforms. Eighteen-months later, it appears (Australian Energy Market Commission, 2014) that no rule changes have been implemented and two further reviews have been undertaken.

Improve price transparency - Presently, volume-based pricing of electricity services prevail and hence consumers do not receive cost-reflective pricing signals. While residential consumers are engaging more with the electricity supply process (as evidenced by the take-up of on-site generation and energy efficiency) they remain unable to impact key system weaknesses such as peak power demands (which drive substantial system costs) and have limited incentive to do so.

Reform of regulated rates of return - The regime of regulated rates of return based on increasing asset investments inflates the present value of assets. The substantial increases in network investment and electricity prices over the past 5 years have generated relatively high levels of profitability of network businesses. Meanwhile, the underlying reliability standards that have underpinned network investment appear to have been misguided in the face of reducing peak and overall demand. This regime should be reformed to allow market to dictate that networks and generators recognise the reduced value of their assets (in the context of excess capacity and poor utilisation and productivity). Reform of regulated pricing (along with privatisation of the remaining state-owned institutions) would force revaluations and arrest future increases in energy costs for some time to come.

b) Coherent Government Policy

Australian Government policy in relation to energy appears not to have been developed in a strategic or cohesive manner. Confused, complex, contradictory and potentially expensive energy and environmental policies (ranging from state-based CSG restrictions, to LNG export policies, to carbon pricing, renewable energy targets and home insulation) have overshadowed substantive economic or social objectives. The 2013 energy review (Department of Industry, 2013a) and the subsequent 2015 Energy Policy White Paper (Department of Industry and Science, 2015) does not suggest that Government is taking a pro-active stance to address outstanding policy concerns, failing to identify a future vision for Australia's energy system and focussing on traditional energy sources, particularly fossil fuels. The three stated platforms of the Government's energy policy strategy are:

- "Increasing competition to keep prices down" through energy market reform, cost-reflective tariffs, consumer choice, privatisation of state-owned assets, development of the national wholesale gas market, regulation and facilitation of the development of unconventional gas resources; and
- "Increasing energy productivity to promote growth" by developing a national productivity plan; and
- "Investing in Australia's energy future" by improving workforce productivity and vocational education and training, streamlining approval and regulation of energy resources projects, providing better access to data, attracting foreign direct investment, and non-specific initiatives in relation to technology policy and priorities.

These priorities do not create an expectation that the major issues inherent in Australia's stationary energy or gas supply industries (as identified previously) will be materially influenced by Government. Perhaps it is unreasonable to hold expectations that energy policy (in Australia) is capable of addressing such issues. Experience from the 2004 Energy White Paper (Energy Task Force, 2004) would suggest this. The 2004 Energy White Paper resulted in policy outcomes that were limited to eliminating increases to the fuel excise regime (now reinstated in the 2014 Federal Budget); introducing demonstration funding initiatives known as the Low Emission Technology Demonstration Fund (LETDF) and the Solar Cities programs; foreshadowing limited energy market reform; and creating aspirations for the promotion of emissions reduction and energy efficiency.

Policy instruments are created with the expectation of meaningful outcomes, and some such instruments (such as the Mandatory Renewable Energy Target ("MRET") which later became the Renewable Energy Target ("RET")) have been credited with aiding the adoption of sustainable, low emissions, technologies, by driving the installation of over two million small-scale renewable energy systems and over 400 renewable energy power stations with a concurrent reduction in greenhouse gases. At the present time, even these instruments are not universally supported and the impact of government vacillation over suitable agreed targets has already had the effect of driving away potential private sector investments in the energy sector.

So, despite some successes, prevailing policy decisions do not appear to acknowledge the importance of learning from previous failures or successes.

c) Encouraging alternative energy sources

Technical, regulatory and commercial inhibitors to adopting new technology will constrain the Australian energy system from delivering long-term economic and social benefits to society. For example, in South Australia where substantial wind assets are installed, incumbent coal-fired generators stand to lose most from the further expansion of wind generation. With 1.2 GW of wind power capacity and the dynamic changes in output characteristic of wind (with changes of up to 400MW per half hour possible) the increasing use of gas-fired open cycle power plants or the integration of controllable distributed generation that can produce power on-site on demand, can provide the network balancing that is required. The right incentives, and avoiding the incumbents' vested interests in preserving the value of outdated or inflexible generating and network assets, may lead to greater capacity of clean, renewable wind resources, which would been viewed by most as a desirable long-term strategic objective. Thus, programs dedicated to increasing the capacity of more flexible, fuel efficient generation will enable an expansion of wind by avoiding additional pressure on base load coal-fired power.

2.6 Distributed Energy Technologies

Distributed energy provides energy services near the point of use rather than supplied from generation at remote locations. Distributed energy typically includes three key technologies:

- Distributed (or embedded) generation systems, including solar PV and cogeneration, which increase energy conversion efficiency and minimise energy losses experienced in distribution and transmission;
- Energy efficiency initiatives, including the application of incentives and tools that encourage and enable energy efficiency measures to be undertaken by energy consumers; and
- Demand side management of consumption facilitated by smart grids and intelligent network management and response.

2.6.1 Key Distributed Energy Technologies

Cogeneration and Trigeneration

While cogeneration is not new, its application to the Australian climatic, demographic and energy environment is a relatively new, and somewhat overlooked, solution to individual operator's problems and to the community's energy and environmental problems.

Cogeneration is the simultaneous production of two forms of energy - electricity and heat - from a single fuel source, at the point of usage. Distributed energy applications of cogeneration typically use a natural (or bio) gas-powered engines or turbines to generate on-site electricity. The waste heat from the engine is captured to provide heating for uses such as potable hot water, space heating or process heat such as for swimming pools. When combined with an absorption chiller that produces chilled water from the energy contained in heated water (or other heat source), the cogeneration system produces three forms of energy – electricity, hot water and chilled water – and is commonly called trigeneration.

Substantial energy savings are achieved through the "no-cost" generation of the heating & cooling load in a facility. The systems can be utilised for commercial, industrial, rural & agricultural applications and are able to run on a variety of fuel sources, most commonly natural gas and biogas.

The production of heat and electricity at the point of use allows for this energy production process to have extremely high levels of efficiency, offering major economic and environmental benefits, such as a reduction in carbon dioxide emissions by up to two-thirds when compared with conventional grid-suppled electricity, traditionally from coal-fired power stations. Cogeneration will usually provide an overall efficiency of approximately 85%, if all useable heat is recovered. This compares to the 30–35% efficiency of typical grid supplied electricity from a coal fired power stations and the estimated global efficiency of 31.5% (Burnard and Bhattacharya, 2011).

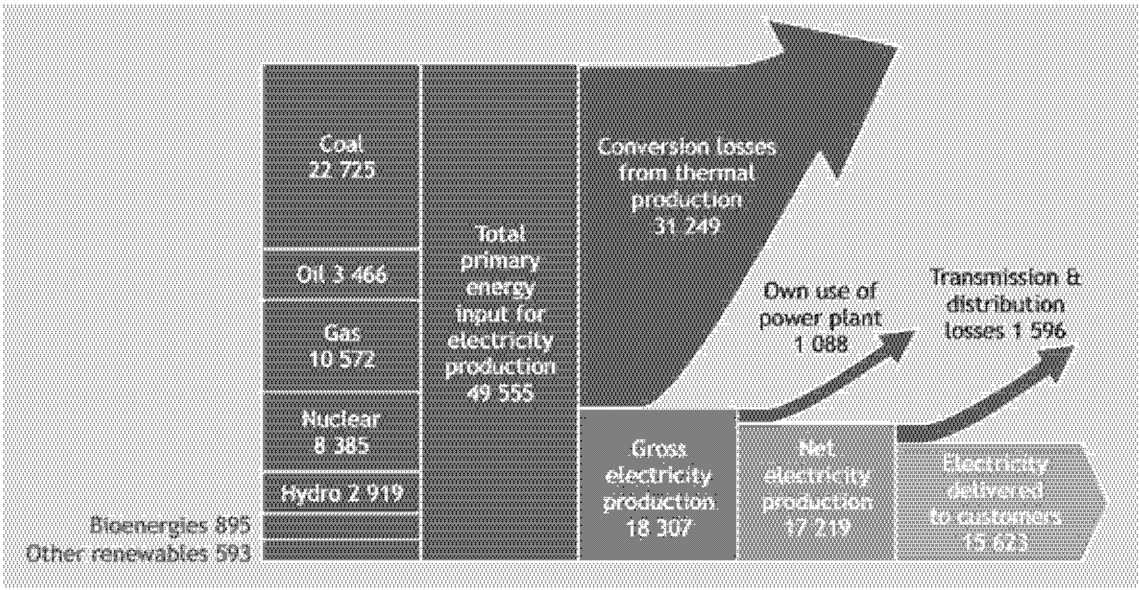


Figure 15 Energy Flows in the Global Electricity System (TWh)

Source: (International Energy Agency, 2008)

Cogeneration units may be installed in three different ways:

- Grid parallel, where the system operates in parallel to the existing central energy grid, thereby providing base-load power when grid provided electricity is most expensive.
- Island mode, where the system operates to provide energy for a particular facility, independent of the central energy grid.
- Emergency, where the system typically operates in parallel to the grid, but upon a grid failure, the system can be restarted to provide emergency power in Island mode to specified critical loads.

Suitable and cost effective sites for cogeneration and trigeneration will include those with a large and consistent base load electrical requirement, a constant heating and/or cooling demand, the availability of natural (or biogas) at relatively low cost, relatively high electricity charges, suitable regulatory drivers (for example, mandatory NABERS building efficiency ratings), and relevant non-financial drivers (sensitivity to environmental impacts, energy efficiency or low emissions credentials).

Investment in cogeneration equipment can deliver attractive financial returns when cost differential between electricity and natural gas prices is favourable. As well as producing electricity on-site at a lower cost than it is typically purchased from the grid during peak and shoulder periods, the cogeneration or trigeneration system provides heating and cooling at no incremental cost. When an existing site uses electric boilers or electric chillers to produce hot and/or chilled water the benefits of cogeneration and trigeneration are amplified. Electricity is produced at prices that are lower than grid-based prices while the demand for electricity (to produce the hot or chilled water) is eliminated or reduced through the direct use of free cogenerated heat energy.

The two most common cogeneration technologies are reciprocating engines and micro-turbines. Fuel cells are a form of cogeneration which are largely still to emerge from R&D into widespread commercial applications. Absorption chiller technology is mature and proven.

Reciprocating technology

A reciprocating cogeneration unit comprises a natural-gas fuelled, spark ignition engine coupled with a synchronous three-phase generator mounted on a common frame. Internal combustion engines were developed well over a century ago and have matured into robust, reliable and efficient mechanical devices.

The frequency output from the generator is determined by the number of revolutions per minute of the engine and the number (of pairs) of poles in the configuration according to the following formula:

*Generator Frequency = RPM (N) / Seconds per minute (60) * Number of Poles (P) / 2*

These generators typically have four magnetic poles and hence operate at 1,500 rpm to synchronise with the Australian grid with an output frequency of 50Hz.

Cogeneration systems are either supplied on a skid-bed, in an acoustic cabinet or in a fully self-contained weather proof and transportable container. Units range in size between 5kW to 4000 kW of electrical output and a similar amount of thermal output which is recovered from the engine's cooling system (turbo-intercooler, jacket water and oil cooler) as well as its exhaust system. The engine cooling system is converted into usable hot water at around 80-90 degrees by a suitable heat exchanger. The exhaust heat is recovered to deliver water at around 90 degrees or, by utilising a waste heat steam generator, to produce medium pressure saturated steam at around 180 degrees and up to 900 kPa.

Larger cogeneration units tend to be more electrically efficient with systems ranging from around 33.3% efficiency for units below around 100kW to over 41% efficiency for units above 1 MW. Thermal efficiency of smaller units is higher at 43% to 39% respectively. Overall efficiency (assuming all the thermal energy is used) ranges between around 75% to well over 80%.

Output is affected by the calorific value of the fuel used, the ambient temperature conditions and the air density. Properly maintained, internal combustion engines do not degrade significantly over time.

Principal advantages of internal combustion based cogeneration systems include high electrical efficiency, good partial load efficiency, usable high grade (exhaust) heat, fast start up and low fuel pressure requirements. However, these systems have relatively high maintenance costs and relatively high emissions.

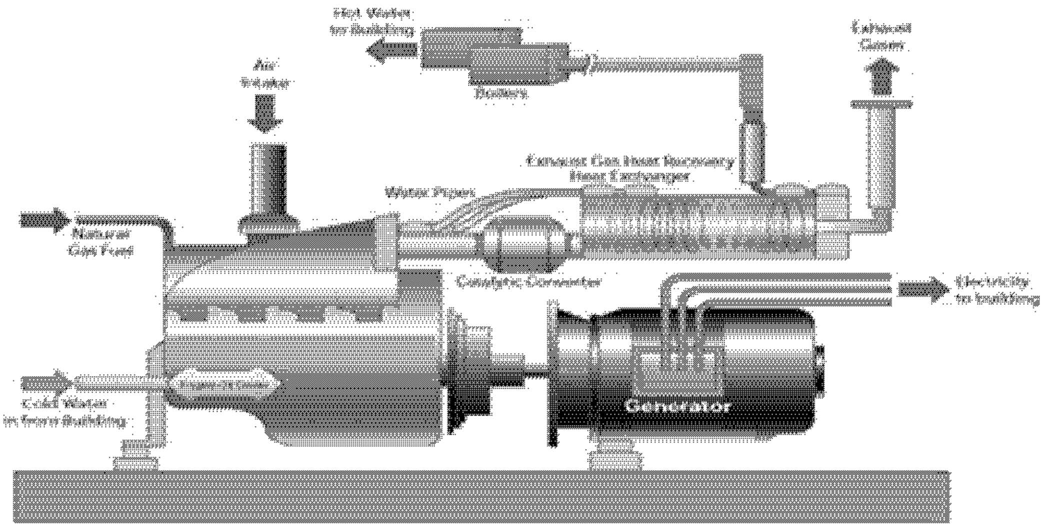


Figure 16 Typical Reciprocating CHP Schematic

Gas turbine and Micro turbine technology

Gas turbine technology has developed rapidly over the past five decades and is now the dominant form of motive power for custom designed cogeneration systems (Department of Energy & Climate Change, 2008). It is available in a wide range of power outputs, from less than 1 MW to more than 200 MW and is suitable for large industrial sites or large precinct installations. The application of gas turbines to cogeneration is relatively new compared to reciprocating engines. Large gas turbine generators are complex designs consisting of an air compressor, a combustor, a power turbine and an electric generator. The combustion of fuel, alongside compressed air, turns the turbine which drives a shaft that rotates the generator. Gas turbines produce exhaust gases at 400-550°C.

Smaller gas turbines, termed micro-turbines, are available in the range of between 30kW and 250kW in size. They are simpler in design than large gas turbines and combust compressed air and compressed natural gas under constant pressure conditions to force the hot, expanding gases to rotate the turbine and drive the generator (either directly or via a gearbox). The generator is cooled by the air flowing into the gas turbine while the exhaust gas is partially consumed in the process with the remainder captured in a fin-and-tube heat exchanger.

High speed generators use permanent magnet alternators and require the generated high frequency output to be converted to 50Hz using inverters. Gear driven synchronous generators are available for some models that produce power at 50 Hz.

Gas turbines, and particularly, micro-turbines have much lower electrical efficiency than reciprocating engines. Micro-turbine electrical efficiency ranges between around 22% to 27% as unit size increases while larger gas turbines have up to around 30.5% electrical efficiency. Thermal efficiency of micro-turbines is also lower than internal combustion engines at between 34% and 39% resulting in overall efficiency slightly greater than 60%. Larger gas turbines are more sophisticated and can capture more heat, and hence are only slightly less efficient than their reciprocating counterparts. Micro-turbine output and efficiency degrades over time. However, they are highly reliable, compact in size and weight and produce low emissions. The require medium to high pressure gas fuel, and are relatively expensive to acquire but relatively cheap to maintain.

Fuel cell technology

Fuel cells are electrochemical devices that oxidise fuel to produce electricity and heat. Natural gas is commonly used in fuel cells and is converted to hydrogen through a catalytic steam reformation process. The hydrogen is mixed with air in multiple fuel cell modules where it mixes with oxygen to produce direct current, water and heat. The direct current is converted to alternating current using an inverter while some of the heat generated is reused in the steam reformation process. The key components of the fuel cell include the fuel processing system which removes sulphur from the fuel, converts the methane into hydrogen and removes the remaining products (ammonia and steam). The power supply system oxidizes the hydrogen (sometimes with an added catalyst) to produce electricity and water. Temperature management systems monitor and control the temperatures of the processes and ventilate and cool the components. Electrical controls synchronise with the grid.

Fuel cells can produce low grade heat at around 60 degrees with higher grade heat available at between 120 degrees and up to 450 degrees depending upon the design. Electrical efficiency of fuels cells is in the range of 35% to over 40% as system size increases while overall efficiency (electrical plus thermal) is around 77%, slightly lower than reciprocating cogeneration systems.

Fuels cells maintain consistent electrical efficiency down to around 60% of capacity but have the disadvantages of electrical efficiency degradation over time and long ramp-up times. They have high capital costs, relatively low power density and a high proportion of low grade (less usable) heat output. On the other hand, they produce no direct emissions, low noise and require only low pressure gas input.

Absorption Chilling

Absorption chilling is a technology that produces cooling from heat. The energy source to produce the cooling is the thermal energy contained in the input liquid or gas. The heat source can be hot water, steam, or hot exhaust or combustion gases.

Absorption chillers use chemical substances that absorb refrigerants based on the strong affinity of certain pairs of chemicals to dissolve in one another. Most commonly, lithium bromide (absorber) and water (refrigerant) are used, though ammonia and water are also used.

In an absorption chiller, a continuous refrigeration cycle operates. A concentrated lithium bromide solution (in the *absorber*) draws refrigerant (water) vapour from a low pressure vessel (the *evaporator*) and absorbs it, diluting the solution. This process generates heat which needs to be removed. The diluted solution is pumped to a higher pressure and passed from the absorber, via a heat exchanger, to a *generator*. Heat (often waste heat from a cogeneration unit) is applied to the *generator*, driving off the absorbed water which is passed into the *condenser* while the lithium bromide is returned, via the heat exchanger, to the absorber. The condensed water is returned to a near vacuum low-pressure vessel - the *evaporator* - where the refrigerant is evaporated. The process of evaporation cools coils in a heat exchanger which transport chiller water through a secondary circuit.

Absorption chillers have few moving parts (typically just one main pump, an anti-crystallisation system for the absorber fluid and a vacuum pump to maintain pressure in the evaporator) and hence require little additional electrical power to operate. They do not require the use of potentially environmentally harmful refrigerants (as are needed in electric chillers), are quiet in operation, have no substantial moving parts and minimal electrical requirements. Consequently, they are reliable and have low maintenance requirements.

However, they have relatively low thermal efficiency (with coefficients of performance of between 0.7 and 1.4 depending upon configuration) compared with electrical chillers that offer COP's of up to 3.5 - 8. Having said this, since the source of energy for trigeneration based absorption chillers is often heat that would otherwise be wasted or rejected, the relatively low COP's must be compared with the alternative of producing electricity purely to produce thermal cooling.

Absorption chillers can produce chilled water down to around 5-6 degrees, suitable for air-conditioning and industrial processes but not for freezing.

Solar PV

A small number of relatively mature solar PV technologies dominate the market, namely crystalline silicon (c-Si), amorphous silicon (a-Si) and thin film cadmium telluride (Cd-Te). Currently c-Si dominates with around 80% of the market, but emerging technologies such as thin film copper indium gallium diselenide (CIGS), thin film copper indium diselenide (CIS), and concentrating high efficiency triple junction (CPV) are predicted to gradually erode market share of first generation silicon technologies However, while emerging technologies have been anticipated for many years to displace low cost crystalline silicon, this may occur over several decades. Commercialising new technologies is complex and expensive, and often mature technologies (such as c-Si and cogeneration, for example) provide an important gateway to low cost and low risk innovation in the energy system.

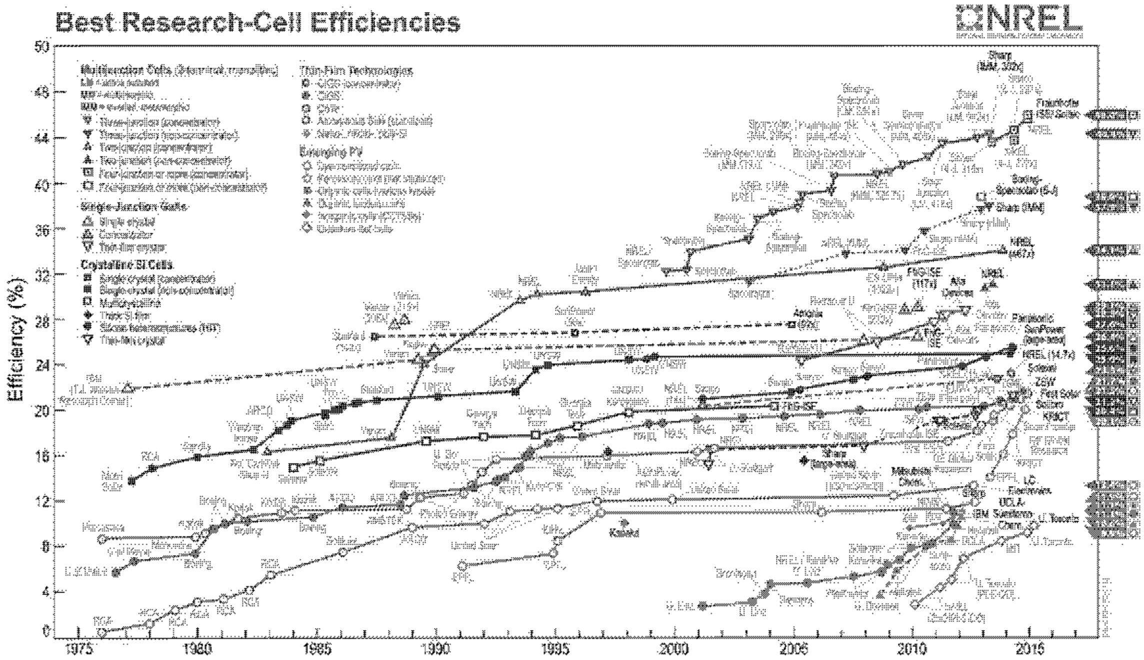


Figure 17 Best Research Cell Efficiencies

Source: (National Energy Technology Laboratory, 2015)

World production capacity for PV exceeded 16GW in 2010 with estimated cumulative installed capacity of 40GW and was expected to exceed 22GW in 2011 with an associated ~$7B of capital investment in manufacturing capability. The European PV Industry Association (Masson, 2014) predicts a total global installed capacity of between 321 and 430 GW in 2018. The IEA predicts a global installed capacity in excess of 400 GW by 2035.

Costs for PV modules have declined rapidly. Current module prices for c-Si and CdTe are less than $2/W with manufacturing costs at less than $1/W. Correspondingly the utility-scale "system" prices (including all balance of systems) have now dropped to less than $4/W resulting in an estimated levelised cost of energy ("LCOE") over plant lifetime of $200-$300/MWh dependent upon location and financial assumptions. Solar PV prices in Australia stand at around $1.90/W fully installed (with small scale installations of less than 100kW receiving a subsidy of $0.69/W) (Solar Choice Staff). Looking forward, the exponential growth in production is set to continue leading to sub LCOE of $150/MWh being plausible by 2015. The historical cost curve for PV demonstrates a fourfold decline from 2005 to 2011 alongside a tenfold increase in production. While continued declines are likely, absent a new technology discontinuity, the projected unit prices are not anticipated to decline as rapidly as they have over the past decade. Nevertheless, various analysts have identified learning rates for the production of PV of between 16 – 22% (Candelise et al., 2013) and de La Tour (de La Tour et al., 2013) has predicted a 67% decline in prices between 2011 and 2020 based on an experience curve model using historical prices, cumulative production, R&D knowledge stock and input prices for silicon and silver.

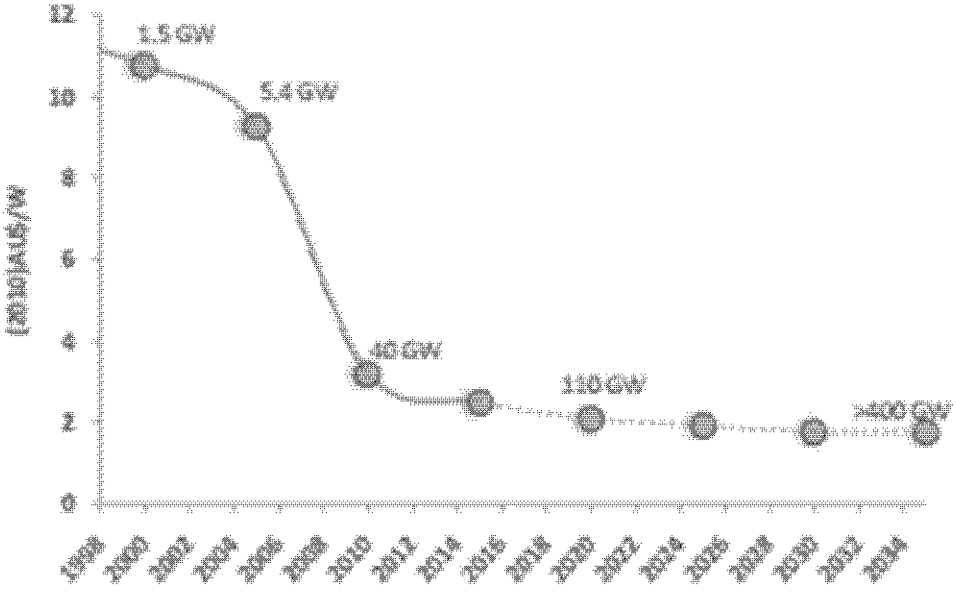


Figure 18 PV Module Cost Trends 1993 to 2035

Source: (Ball et al., 2011)

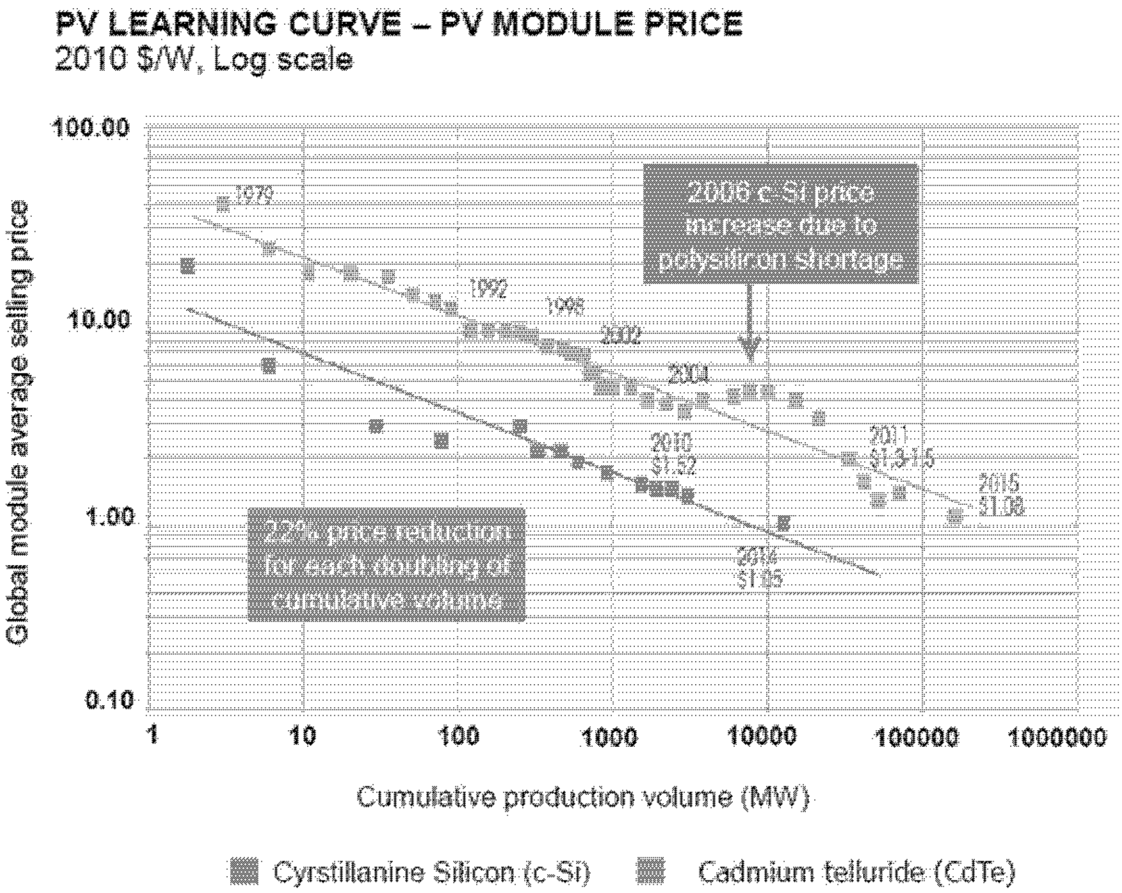


Figure 19 PV Module Learning Curve

Source: (SBC Energy Institute, 2013)

Alongside the solar PV modules, the installation of a distributed solar PV system requires an inverter, mounting hardware, cabling and connection to the main circuit board of the building in which the system is installed.

The energy output of solar PV cells depends upon the latitude of the site, specific insolation characteristics of the location including local weather and clouding factors, and the orientation and angle of deployment of the solar cells. In Australia, many cities with substantial populations are located in favourable latitudes and hence the available capacity factors for solar PV in Australia average around 16%. By contrast, Germany, with the highest penetration of installed PV can only achieve an average capacity factor of around 6%.

Solar energy production fortunately coincides with daily peaks in electricity usage. That is to say, maximum capacity factors can be achieved when maximum energy production is required during the middle of the day. Solar panels are oriented with respect to the sun's path in the sky. The position of the sun depends on the time and date, as well as the longitude and latitude of the panels' location. Panels can be oriented with respect to their elevation ("altitude") or angle with respect to the horizontal, and azimuth or angle with respect to North. In the southern hemisphere, solar panels are substantially oriented to the north. Lower overall energy production will be achieved in summer (but more in winter) if the panels are mounted at lower elevations. Lower overall energy production will be achieved (overall) but for longer durations during the day if the panels are arranged at more westerly azimuths. Thus, as the cost of panels' declines, it may be more beneficial to produce an overall lower output for a longer duration by orienting the panels at a less than optimum azimuth angle.

Ultimately, however, solar PV will suffer from dependency upon solar irradiation and this is affected by diurnal and seasonal patterns, local effects (cloud and dust), as well as degradation over time due to dust and dirt contamination. Further, since there may be prolonged periods where solar irradiation is almost absent (during extended rainy periods), PV cannot provide a suitably redundant source of energy in the absence of complementary despatchable energy generation and storage. In relation to storage, presently, long-term storage (more than a day or so) is not financially feasibly using available storage technologies. However, storage combined with PV does appear to be feasible to overcome short term variations in energy production (due to clouds passing overhead) or energy demand peaks.

Storage

Economic storage of electricity would overcome many of the cost and system flexibility issues associated with present centralised power generation and enable a much more flexible and efficient decentralised power grid. The applications of storage in the network are manifold. These include storing energy when it can:

- be generated relatively cheaply, particularly with renewable resources such as solar and wind;
- overcome contingencies such as the sudden loss of a generating component or load which avoids investment in over-capacity;
- cover peak load events on a daily or even annual basis, again, avoiding over investment in capacity;
- be harvested in one season and applied when higher seasonal demands will be experienced later.

An IEA working paper (Inage, 2009) predicts 100-150 GW of additional global storage capacity will be needed by 2035 for balancing power systems assuming renewable (intermittent) sources contribute around 20% of power. As noted by Chambers (Chambers, 2014), the market opportunity for storage is large with the US Department of Energy identifying nearly 1.1GW of operational energy storage (excluding pumped hydro) as well as around 600MW under construction and over 700MW announced, and the advanced battery market alone estimated to reach over US$60billion in 2020.

Alternatives available for storage of electricity include mechanical systems (pumped hydro, compressed air, flywheels); chemical storage (batteries, chemical conversion) and electrical storage (capacitors). Presently, the cost of integrating these technologies is relatively high, however, many project battery storage to demonstrate significant learning effects and consequent cost reductions.

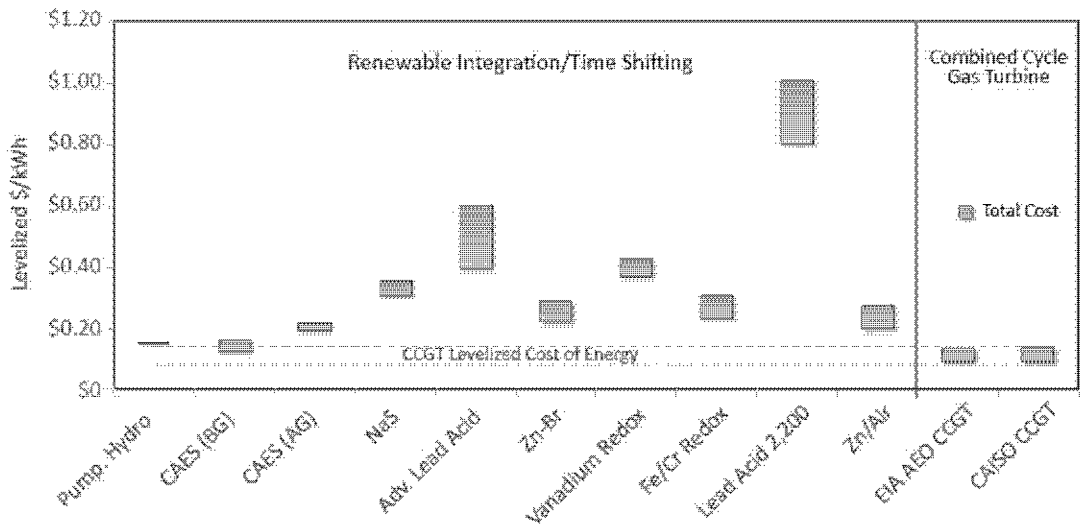


Figure 20 Levelised Cost of Delivered Energy for Electricity Storage

Source: (Ball et al., 2011)

Mechanical storage

Pumped hydro is widely used and the cost of medium and long term storage using this technique is acceptable at around E$2080 per MW (Klimstra and Hotakainen, 2013). Pumped hydro has acceptable efficiency of around 80-85% and with a long technical life of the storage medium, pumped hydro is viable for smoothing peaks but generally not considered cost effective for any longer than medium term (more than a few days) storage

Compressed air energy storage uses excess electricity to compress air to a pressure of around 70bar at ambient temperatures. Since compressed air has a low energy density, it is likely to only be viable if cheap natural storage such as salt or hard rock caverns and aquifers are available. Storage in steel or composite tanks is expensive and cumbersome with the mass of materials being proportional to the pressure and volume of air stored. The stored air is later used as combustion air for a gas turbine generating electricity. Storing air requires a means of extracting the heat from the air as it is compressed. This heat can be usefully applied to hot water provision. Compressed air storage is not widely used – two plants in Germany (290MW) and the USA (110MW) demonstrate "turn-around" efficiencies of between just 62.5% and 78.5% respectively [ibid].

Flywheel Storage has the benefit of millisecond response times and hence is feasible for improving power quality. It offers high power density, scalability and low maintenance and efficiency as high as 95%. However, it suffers from low energy density and high cost.

Chemical storage

Energy can be stored chemically in batteries or by conversion into combustible gasses such as hydrogen.

Battery storage is progressing through a technology cost curve and learning curve resulting in substantial improvements in cost per KWh, discharge and charge rates, energy density and lifecycle degradation. Electrochemical batteries at utility scale are available in several different battery chemistries (Sodium-Sulphur and flow batteries including Vanadium Redox and Zn-Br), and while they remain expensive, they offer benefits such as instantaneous ramp up and acceptable turn-around efficiency (around 75%) which makes their use compelling in certain configurations such as load smoothing alongside solar PV generation where the costs of peak solar PV capacity is close to the cost storage. Increasingly, advanced lead-acid and Lithium-based batteries, with efficiencies of over 90% are being used to provide load shifting, grid support and enhance power quality.

Conversion of electricity to hydrogen can be relatively simply accomplished by electrolysis. Conversion to CH_4 (methane) while technically readily feasible using the products of combustion (CO_2) and electricity, or of course, digestion of bio-waste, is not economically viable. Hydrogen as a storage medium is less attractive than stored methane based gas as a result of production losses, low volumetric energy density and overall low turn-around efficiency of between 25-40%.

<u>Electrical storage</u>

Electrical charges may be readily stored in a capacitor consisting of two conductive plates separated by a dielectric medium. The energy density of a capacitor is severely limited (to around 0.0003 KWh/kg) and the cost per KWh is prohibitively expensive ($7-10,000 per kWh of stored energy). In laboratory settings, energy density may be improved more than ten-fold. Capacitors can discharge and charge rapidly and so may be applicable in environments demanding rapid cycle times for peak event smoothing.

Developers have taken advantage of the energy density and improving price performance of electrochemical batteries and the unique (albeit high cost) characteristics of capacitors to combined these technologies into batteries that offer the benefits of both. For example, the CSIRO has developed the Ecoult battery has been licenced to major global battery manufacturers and used for bulk storage, load shifting and power quality support.

Table 3 Characteristics of Alternative Storage Technologies

Technology	Capital cost per Kwh	Capital cost per KW	Turn-around efficiency	Ramp-up time	Life cycle losses	Life
Pumped Hydro	Low	Low	High	Moderate	None	Long
Battery	High	High	High	Low	Moderate	Moderate
Capacitor	Very high	Very high	High	Low	Low	Long
Hydrogen	Moderate	Very high	Very Low	Moderate	None	Long
Flywheel	Very high	High	High	Low	High	Short
Compressed air	Moderate	Very High	Low	Moderate	Low	Long

Source: (Klimstra and Hotakainen, 2013)

Demand Management

Demand management services do not generate energy on site but can minimise technical constraints and system interruptions by adjusting loads while minimising the power capacity required to satisfy demands. As such, demand management (alongside distributed generation and energy efficiency measures) is generally included among distributed generation technologies and demand side participation in the network.

Measures to reduce peak demands were implemented in the USA during the 1970's when time-of-use tariffs were implemented for large energy users in California. Progress in IT and home automation are mature enough for demand management technologies to proliferate through the electricity network and make an effective contribution to modulating overall demand on the network. Consumption can thereby be shifted to times of day when the cost of producing and despatching energy is lower or where spare capacity is available.

Demand may be impacted through the provision of consumer incentives such as time of day differential rates or programs for direct load control of appliances and equipment implemented remotely by the network operator.

The flexibility to adjust consumption patterns to reflect internal, external, diurnal or seasonal impacts (such as production scheduling, tariffs, shift or operating hours, temperature related, etc.) has been demonstrated to deliver substantial savings. In 2008, Adelaide Brighton Ltd estimated that its management of electricity cost risk had led to savings of over 35 per cent in its electricity costs since 2001 compared to the lowest-cost retail contracts it found available (Australian Energy Market Commission, 2012).

Key components of a demand management system include:

- Control hardware and software, implemented at an energy centre or network level, including SCADA and analytical software which includes forecasting capabilities based on usage patterns and weather events.
- Smart meters installed at each site which can be read remotely via optical fibre or wireless technology. Smart meters offer the ability to send consumers (interval) price signals, to institute remote management, to control credit risk, to manage fraud, to monitor the health of a site's distributed generation facility, to measure quality of supply, detect grid faults and integrate with automation technologies. This enables consumers to plan their demand on the basis of the tariff applicable at any given time.
- Smart thermostats to limit consumption at peak times.

- Lighting control systems which respond automatically to demand management signals by modifying lighting consumption without necessarily turning lights off entirely and which are demonstrated to have the ability to reduce lighting power demand by up to 40%.
- Under-voltage and under-frequency controls to automatically load-shed devices when the frequency or voltage signal crosses a (configurable) threshold.

2.6.2 The Potential Role of Distributed Generation

Distributed energy has been projected (Langham et al., 2011) to assist substantially in overcoming the electricity and gas industry challenges identified above, in particular, in increasing energy efficiency, reducing emissions and reducing investment on network infrastructure. Distributed generation may have a substantial impact in overcoming a range of market, economic and environmental issues.

Appropriate price signals for consumers can be imposed to further drive down peak consumption and, hence, reduce network investment requirements. This will involve investment in smart metering technology to adequately bill for time-based usage. Capturing the benefits of smart metering will mean greater deployment of other demand-side initiatives such as active demand management.

Smarter energy system design will increase system reliability and security, preventing the frequency and duration of outages by enabling more rapid recovery and greater system robustness in response to the triggering events.

Design of generation, transmission and distribution network needs to account for the constraints in delivering power to where it is required and flexibly responding to changing demands and sources of energy. So, the ability to integrate new, lower emitting generating sources; phase out older unsustainable generators; and incorporate distributed generation (which does not rely on existing transmission infrastructure) is important to ensure Australia's energy system can cope with future challenges.

Distributed generation in the form of cogeneration and waste heat chilling stands at the centre of distributed energy initiatives (Lilley et al., 2012).

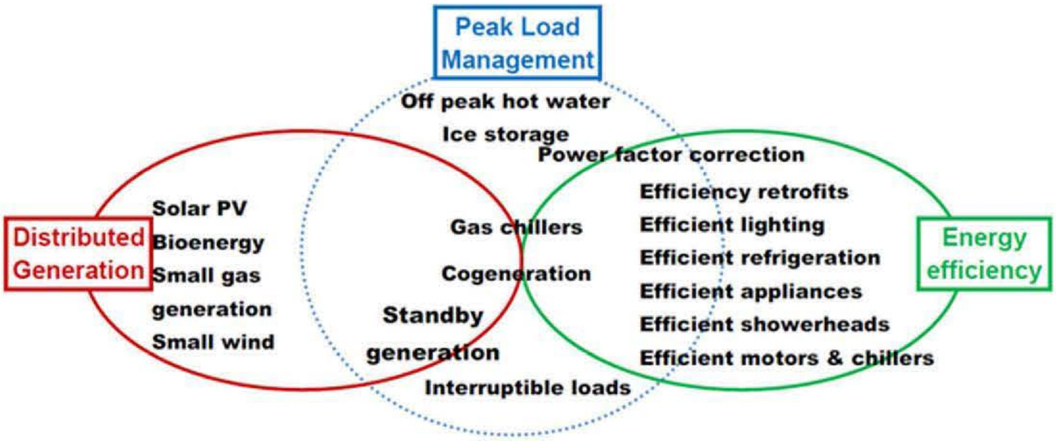


Figure 21 Examples of Decentralised Energy Resources

Source: (Langham et al., 2011)

Distributed or embedded generation in the form of cogeneration and standby generation are typically connected to low voltage (<22 kV) distribution networks. They offer the advantages of comparatively low installed cost, high electrical efficiency, suitability for intermittent operation, good part-load efficiency, high and low-temperature waste heat streams that can be salvaged for heating or chilling applications and easy serviceability. They can provide power for peak loads, emergency backup as well as base-load power generation. They can run on a variety of fuels including diesel, natural gas, biogas, compressed natural gas and petrol.

Distributed generation via gas fired cogeneration engines hold a number of advantages over traditional centralised generation.

Table 4 Comparison of Centralised Generating Technologies and Cogeneration (CHP)

Indicator	Black Coal	Brown Coal	CCGT	Gas-fired CHP
Capital Investment	\$2000/kW	\$2200/kW	\$1000/kW	\$1000/KW
Fuel efficiency	40%	36%	55%	47%[6]
CO2 emissions	820 T/MWh	1030 T/MWH	370 T/MWH	450 T/MWh
Lead time to commission	40 months	45 months	24 months	10 months
Start-up and synch time	5 hrs	5 hrs	5 mins	1 min
Ramp up rate	3%/min	2%/min	5%/min	20%/min

Source: (Klimstra and Hotakainen, 2013)

[6] Total fuel efficiency is of the order of 90% when the salvaged thermal energy of the generator is able to be utilised, either for domestic hot water, space heating or cooling or industrial use

One measure of the cost of additional capacity in the network is the upfront investment needed to add incremental capacity, or "short-run marginal cost of network or generation replacement". In certain situations or locations where supply is constrained, new investment may be well justified. The marginal cost for a generator may be the total cost of building a new gas-turbine peaking generator or, for the network operator, the construction of a new substation. The Productivity Commission (Productivity Commission, 2013) concluded that the best estimates of the short run marginal cost of additional capacity is \$900 per kW for generation, \$470–\$900 per kW for transmission and \$2200–\$3300 per kW for distribution. So, the short-run marginal costs of delivering peak power to consumers could be as high as \$3600–\$5100 per kW. Alternatively, distributed generation at the sub-2MW scale can be implemented at a cost of around \$1000 per kW of electrical capacity while an additional kW (approximately) of thermal capacity is available for free. Since the system generates energy at the point of use this is equivalent to the all-up cost of generation, transmission and distribution. In isolation, or in combination with modest reductions in demand arising from demand management, deferral of substantial, and relatively high cost, grid investments are possible. In geographic areas and user installations where large lumpy investments must be made to the centralised generation infrastructure, relatively small amounts of demand side participation (demand management or distributed generation) may be sufficient to overcome constraints such that grid-based investments may be deferred for years.

Another measure of the cost of additional capacity is the "long-run marginal cost" or the annualised cost of supplying the required capacity over the life of the asset. The Productivity Commission (Ibid) also determined that the best estimates of long-run marginal cost of providing an additional kW to an end user in peak periods is between \$150 to \$220 for distribution infrastructure, \$30 to \$70 for transmission capacity and up to \$90 for generation infrastructure for each additional kW per year. In aggregate, the long-run marginal cost of delivering peak power to consumers is therefore somewhere in the range of \$270–\$380 per kW per year. Foster (Foster and Hetherington, 2010) suggests that levelised cost of electricity (which incorporates the long run marginal cost of capacity) of new build cogeneration and tri-generation is competitive with grid generated electricity.

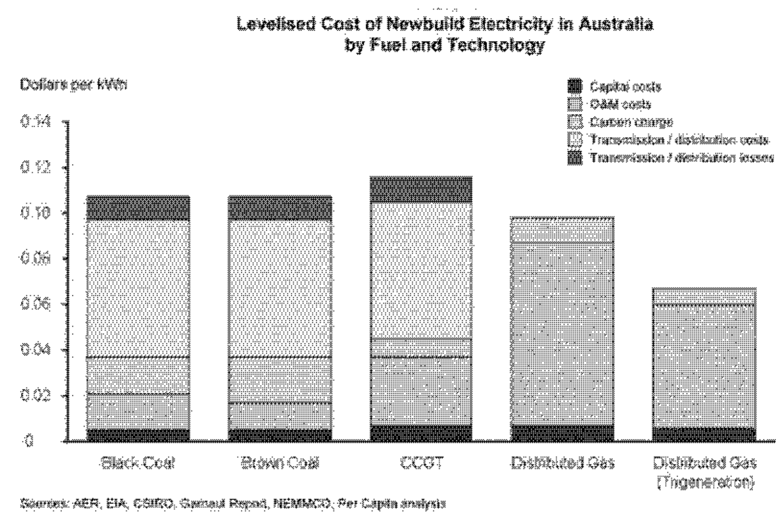


Figure 22 Levelised Cost of New Build Electricity in Australia

The levelised cost of electricity ("LCOE") is a widely-used measure of the cost of electricity generation technologies and is sensitive to assumptions about factors such as capital costs, the useful life of assets and the technical efficiency of generation technologies. Estimates of LCOE vary widely. The Electric Power Research Institute (Electric Power Research Institute, 2011) estimated that the LCOE of coal-fired electricity (without CCS) was A$78–91/MWh, combined-cycle gas turbines was A$97/MWh, wind was between A$150–214/MWh and medium-sized (five megawatt) solar PV between A$400–473/MWh in 2010.

Bloomberg and the World Energy Council (Salvatore, 2013) have estimated the Australian LCOE in Q2 2013 for onshore wind at between US$71 and $99/MWh and lower than both CCGT at around US$92 to $108/MWh and coal-fired generation at between US$93 and $126/MWh. PV remains high at around US$127 to 191/MWh. Notably, it estimates LCOE for cogeneration at around $70 /MWh.

In addition to the comparable costs associated with deployment of cogeneration, the emissions intensity of cogeneration at around 0.45 t-CO2/MWh is lower than for black and brown coal-fired centralised generation at around 1.05 t-CO2/MWh and lower than actual NSW and Victorian power generation at 0.87 and 1.17 t-CO2/MWh respectively. (Department of Industry, 2013b).

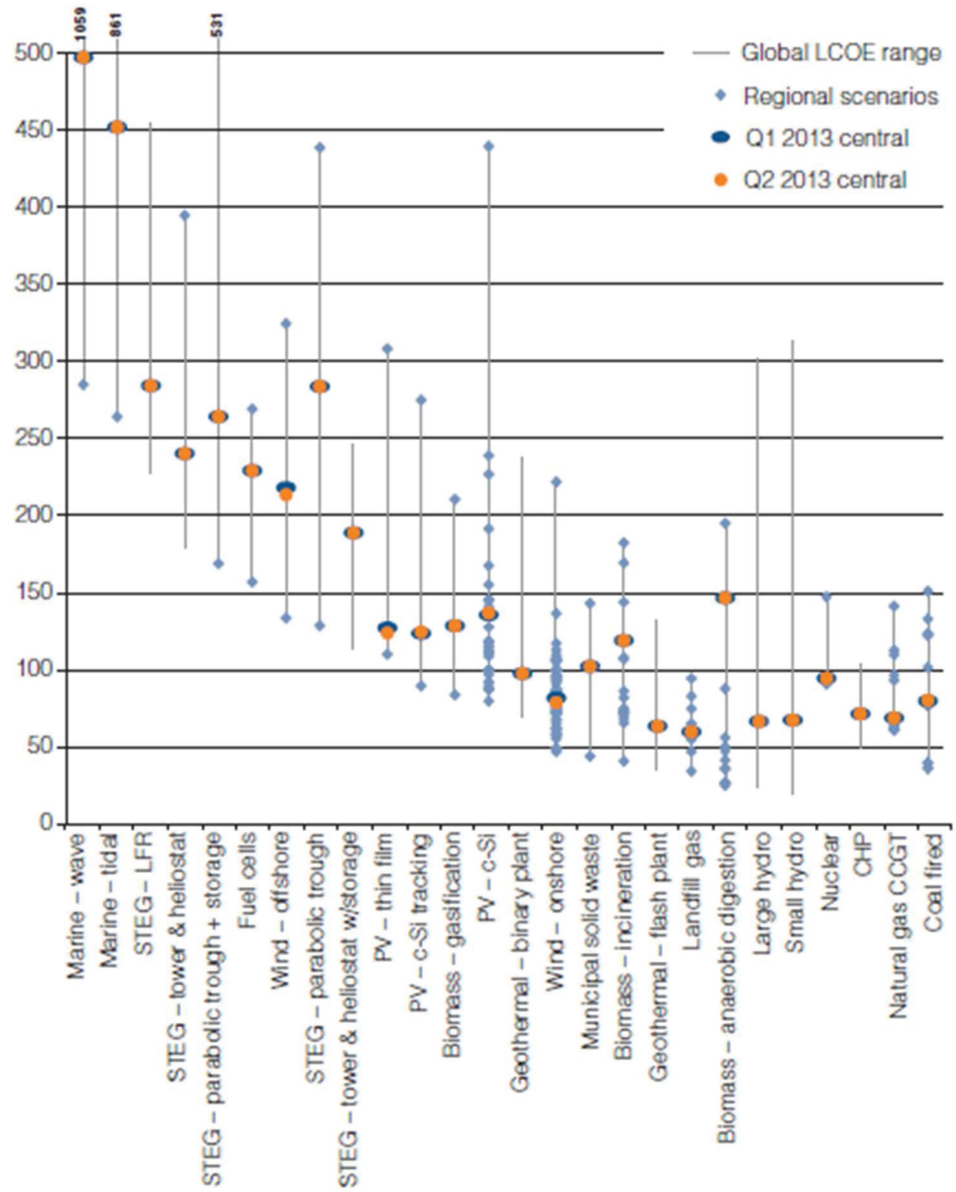


Figure 23 Global Levelised Cost of Energy Q2 2013

Source: (Salvatore, 2013)

Table 5 Comparison of Key Generating Technologies

Source Technology	Technology	Capital Cost/KW	Supply Cost/mWh	Efficiency (useful energy out/energy in)	LCOE ($ per MWh)	Emissions intensity	Comments
Centralised Generation	Thermal Coal	Moderate ($1000 - $1400 (1) per kW)	Moderate	Low (~33-42% electrical)	A$78 - $91	High	Low grade heat unusable
	OCGT	Low ($300 – 723 (2) per kW)	High	Low (~35-43%) electrical		Moderate (approx. 40% of TC)	Low capital cost, high operating cost, substantial capital cost avoidance for peak power generation. Low capacity factor
	CCGT	Low ($550 - $1062(2) per kW)	Very High	High (~50-59% electrical)	A$97	Moderate (approx. 40% of TC)	Low capital cost. Easily scalable.
	Renewables	High	High	Very high	A$150 - $473	Very low	Working down cost curve – wind competitive, PV and solar thermal to be demonstrated competitive
Distributed Generation	Gas fired cogen (recip)	Moderate ($800-$1200 per kW)	Moderate	High (<43% electrical;<40% thermal)	A$136 - A$146(3)	Low	Base-load, DR and Peak Shaving. High efficiency only when waste heat is utilised
	Gas fired cogen (turbine)	High ($1500-$2000 per kW)	Moderate	Moderate (<30% electrical;<40% thermal)		Low	Base-load, DR and Peak Shaving. Effective where large quantities of waste heat can be utilised
	Gas fuel cell	Very high ($2700 - $4500 per kW)	Moderate	High (<46% electrical; <30% thermal)		Low	Base-load. Emerging technology
	PV (>1MW)	High ($2500 per kW)	Low	High	US$127 – US $191	Low	

(1) (Kehlhofer et al., 2009)

(2) (Willcock et al., 2013)

(3) SGE Analysis - No value attributed to heat energy

The CSIRO (Lilley et al., 2012) has modelled the potential economic impact and greenhouse gas savings of distributed generation. CSIRO has determined that widespread distributed generation may be incorporated economically within the Australian power system with substantial growth in solar PV from around 2018 leading to renewable technologies providing up to 17% of the energy created or 28% of installed capacity in 2050. The penetration of Cogeneration for base-load and reliable power, as well as to overcome peak load demands on the grid, is envisaged as a key part of the energy mix, particularly in the industrial and commercial sectors.

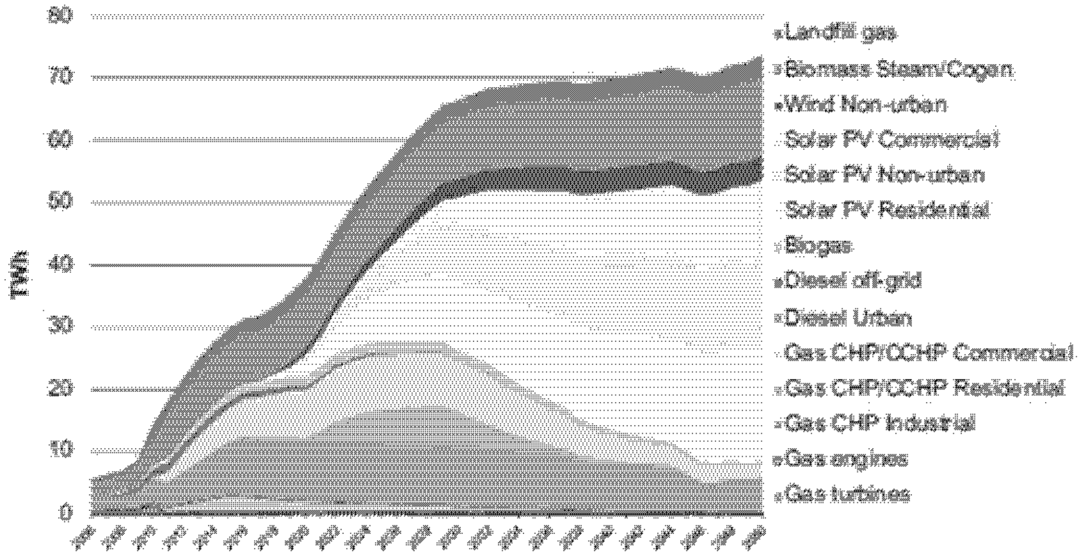


Figure 24 Distributed Generation Projections to 2050

Source: (Lilley et al., 2012)

CSIRO's analysis suggests that this penetration of distributed generation can provide significant economic and environmental benefits through reduced expenditure on centralised plant and transmission infrastructure, lower volatility in wholesale prices and deferred network augmentation by reducing peak loads, even taking account of potentially increased expenditure requirements to accommodate fluctuating voltage profiles and fault current levels.

2.7 Australian Industry Transition to Distributed Generation

The current policy environment seems not to recognise the economic value of distributed generation even though distributed generation "may relieve network congestion, meet peak demand or improve system reliability, thereby avoiding or deferring network investment" according to the Productivity Commission (Productivity Commission, 2013). Poor regulatory oversight combined with incumbent self-interest produces incentives for distribution networks, and pricing signals to consumers, which degrade the economic value of distributed generation. Further, the ability for distributed generation to substitute for network investment is frustrated by regulatory obstacles.

At the same time subsidies and feed-in-tariffs for rooftop photovoltaic units have led to inequitable incentives and inefficiency. While the penetration of rooftop PV has been rapid, this form of generation has resulted in minimal network savings. The existing time-invariant electricity tariffs do not encourage householders to optimise power generation (by appropriately orienting their PV arrays) so as to coincide with periods of peak demand (typically, late afternoon during summer). Further, there has been little thought to incentivise the take-up of distributed generation or energy storage so as to yield network savings by avoiding additional network investment in those geographic parts of the network subject to the greatest constraints.

CSIRO (CSIRO, 2013) projects on-site generation will reach between 18–45% of total generation by 2050. As generation capacity moves from centralised generators to the end user, network utilisation will continue to decline. As distributed power and especially off-grid storage become increasingly financially viable, disconnection from the grid will become commonplace. In some instances (for example, in certain off-grid micro-grids, per Section 4.3 of this document) it appears to be viable today. A recent study in northern Queensland (Arif et al., 2013) demonstrated that in comparison with stand-alone diesel generation, integrated solar PV and (battery) storage with diesel backup reduces greenhouse gas emissions and other pollutants (by more than 99%) and is nearly 80% cheaper per kWh than the diesel alternative. Grid connected, integrated (PV plus storage) residential systems demonstrated a cost per kWh of approximately 55.6c which is comparable with the published Sydney peak rates for domestic electricity supplies by AGL of 51.12 c/kWh, while reducing greenhouse gas and other emissions by over 46%.

Instead of embracing a future of increasingly disconnected consumers, incumbents confront the prospect of widespread on-site generation and reduced demand with even higher network and volume charges. Over time, should these pricing approaches be approved by the regulators, the cycle of reduced demand and connections leading to increased fixed charges will drive increased take up of lower cost on-site generation and further defections from the grid – the so called "death-spiral". Networks could be left with billions of dollars of stranded assets while governments come under pressure to bear the cost. Meanwhile consumers will increasingly seek out distributed generation options to ensure continuing affordability of electricity.

Given the diminishing value of centralised generation and network assets, the only solution to the death spiral appears to be a recognition that perceived asset investments today should not be valued as highly as they are represented. Recognising the diminishing value will, in turn, reduce the expectation for revenue based on regulated returns on asset values. However, this will involve painful re-adjustments of value expectations by shareholders of these companies – some of whom are State Governments.

It appears that deployment mechanisms and a supportive regulatory framework, rather than technology, will determine how successfully Australia will transition from an inflexible centralised energy system to a distributed generation system. The following chapter will examine deployment in more detail, considering the theoretical frameworks that have been applied to technology adoption in general while Chapter 4 will explore the historical adoption of sustainable energy technologies in Australia. Chapter 5 will examine the key impediments to deployment of distributed technologies.

Chapter 3 New Energy Technology Deployment Mechanisms

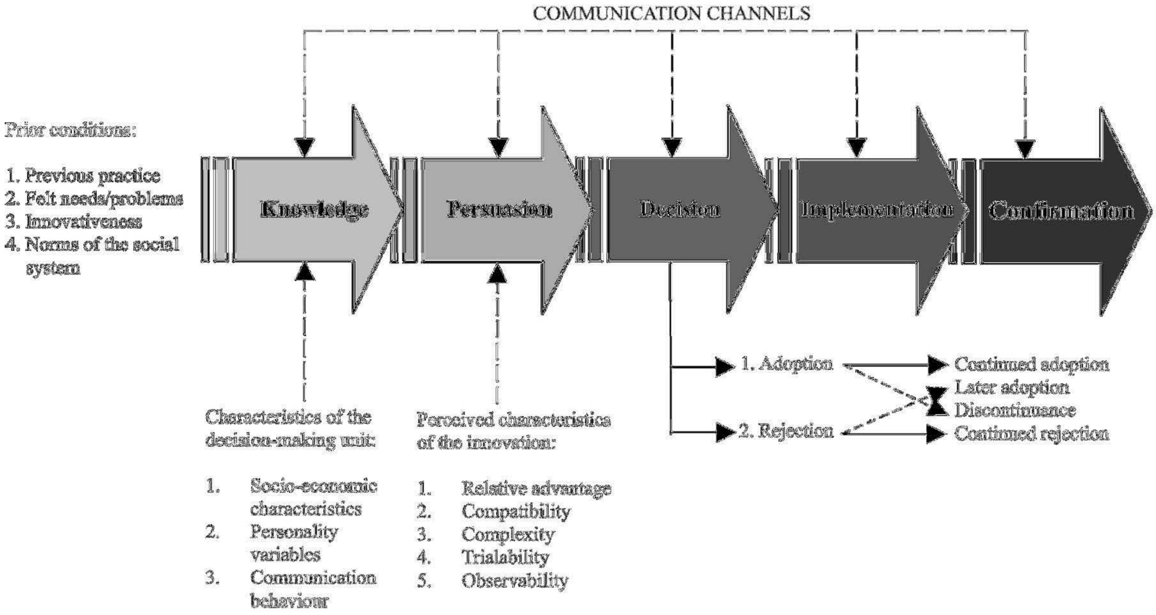
This chapter will explore the underlying theories that may explain the adoption of innovative energy technologies.

Michael Grubb (Grubb et al., 2006) noted that the "development and diffusion of low carbon technologies will be central to stabilizing the climate over the 21st Century". Technology diffusion arises from a mixture of factors and policy instruments however it is "...hard to derive ... conclusions about the specific policy instruments—or mix of policies—that would stimulate optimal kinds of technology and infrastructural investment."

Diffusion is influenced by factors which force adoption due to a compelling market need or value proposition. Technology diffusion adds a layer of complexity as a consequence of the dynamic nature of technical innovation that creates waves of new technology adoption as a result of improved ability to satisfy needs or gain market ascendancy on the one hand and the ability of the technological innovation process to drive improved Price:Performance (e.g. Moore's Law for semi-conductors) or of increased penetration to drive reductions in cost with increasing volume (learning effects).

The rapid expansion of diffusion research in marketing in the 1970's is largely attributable to applicability of the Bass Model of Innovation Diffusion (Bass, 1969) to new product development. This model emphasised communication channels as the key factor in the diffusion process, with diffusion the result of two types of communication processes - mass media and word-of-mouth. Mass media plays a large role in persuading early adopters (innovators) and word-of-mouth dominates adoption decisions of those that follow (imitators).

Everett Rogers (Rogers, 1983) proposed a model of innovation that relies on the individual decisions of large numbers of individual economic units (be they individuals or firms) to drive diffusion through a number of stages from initial knowledge to widespread adoption.



Source: After Rogers (1995)

Figure 25 Rogers Innovation Model

People share knowledge and influence or persuade the trial and use of technology. On that basis, they make decisions to purchase or adopt the technology and through such implementation they affirm their decisions by extended use of the technology. The users are often classified by their characteristics as innovators, early adopters, the majority and laggards. See, for example, the following distribution which Rogers proposed.

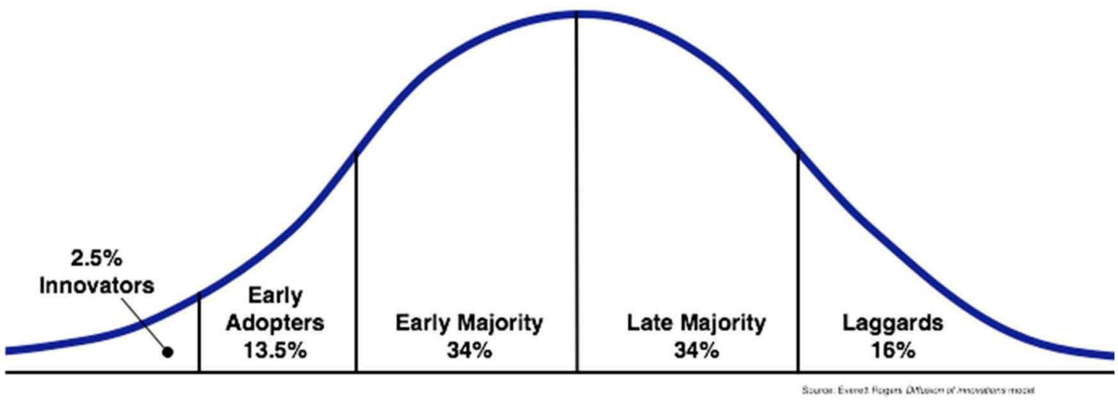


Figure 26 Rogers Classification of Technology Users

Each category of adopter acts as an influencer and reference group for the next. As technologies move from early adopter to early majority, the referencing between the two groups changes from awareness to referencing and word-of-mouth. The "chasm" (Moore, 2002) between the early adopter phase and the early majority phase is critical to the success of products and firms and the point at which this chasm is crossed defines the stage at which mass take-up of technologies may occur.

The aggregation of buyers and the millions of decisions that they make during the various phases of diffusion and adoption results in an adoption curve for a particular technology. These adoption curves are often called S-curves.

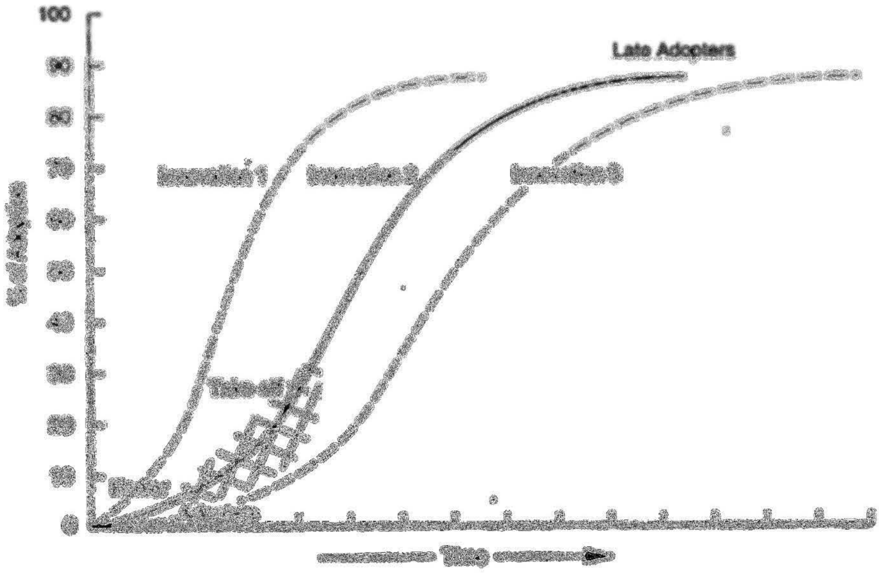


Figure 27 S-Curves

Infrastructure and energy diffusion is complex since the elements of bringing technology to the market from the lab, the influences of government policy, incumbent monopolistic and oligopolistic behaviour, entrenched infrastructure and a raft of investor and corporate interests make the path to market adoption difficult to chart. However, this added complexity doesn't mean that traditional S-curves may not still be valid. Other infrastructure-heavy and regulated industries have exhibited S-curves and the replacement of entrenched technologies, though the timelines may be measured in centuries for, say, transportation (Grubler, 1990) versus, say, home entertainment (Lebergott, 1976).

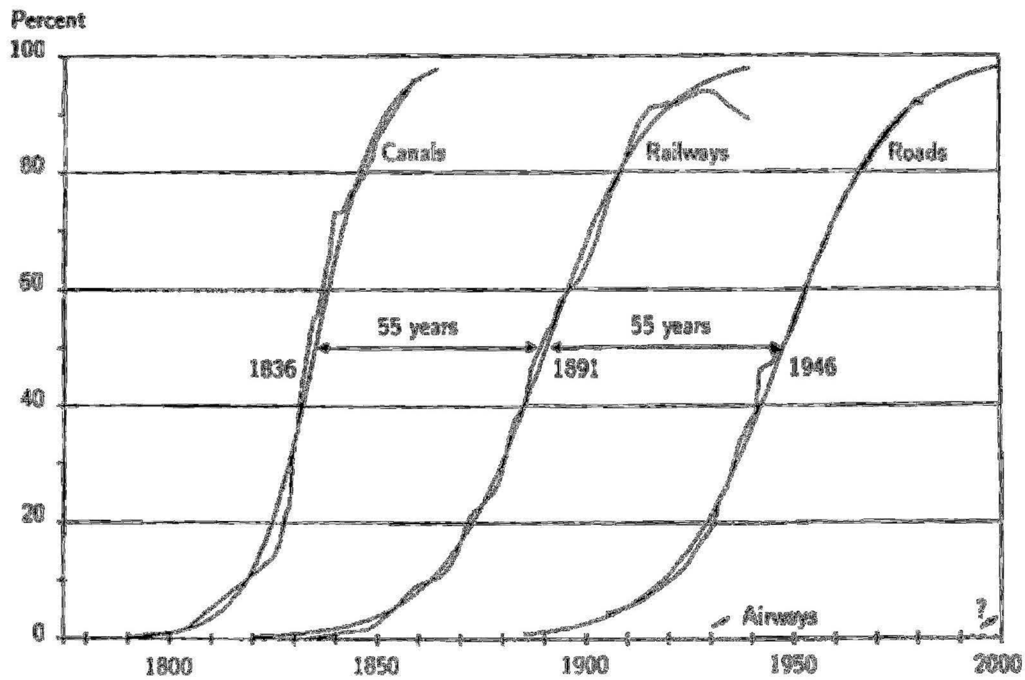


Figure 28 S-Curve for Transport

Source: (Grubler, 1990)

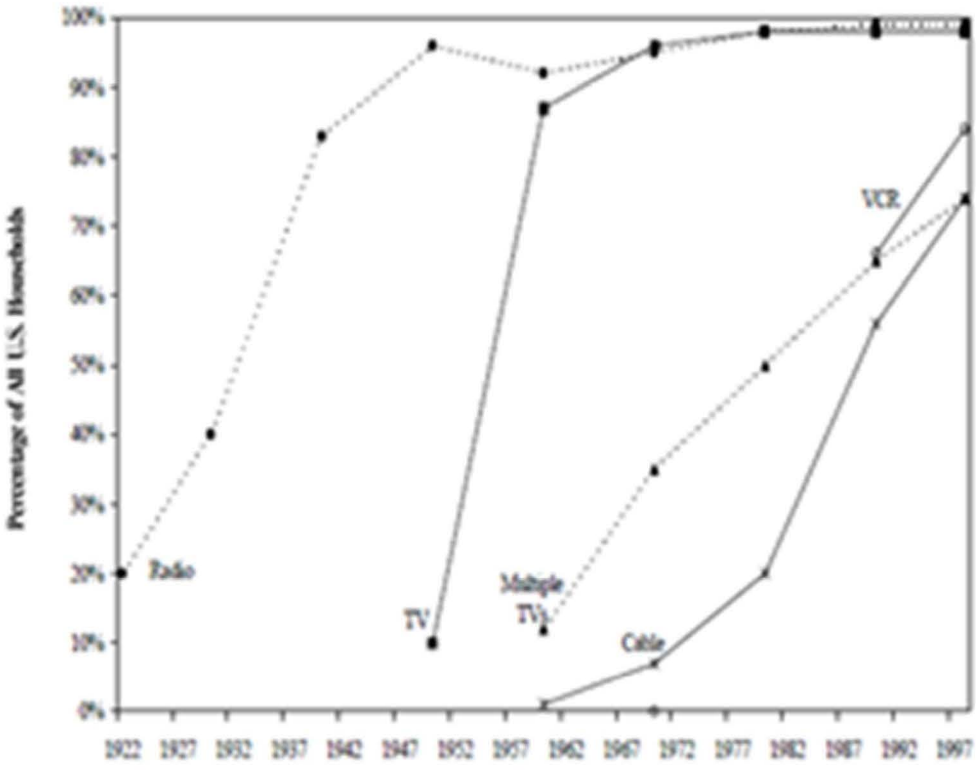


Figure 29 S-Curve for Home Entertainment

Source: (Lebergott, 1976)

In fact, at least conceptually, we know that emerging energy technologies will follow an adoption curve. However, the path to a mature technology in widespread use is still not clear.

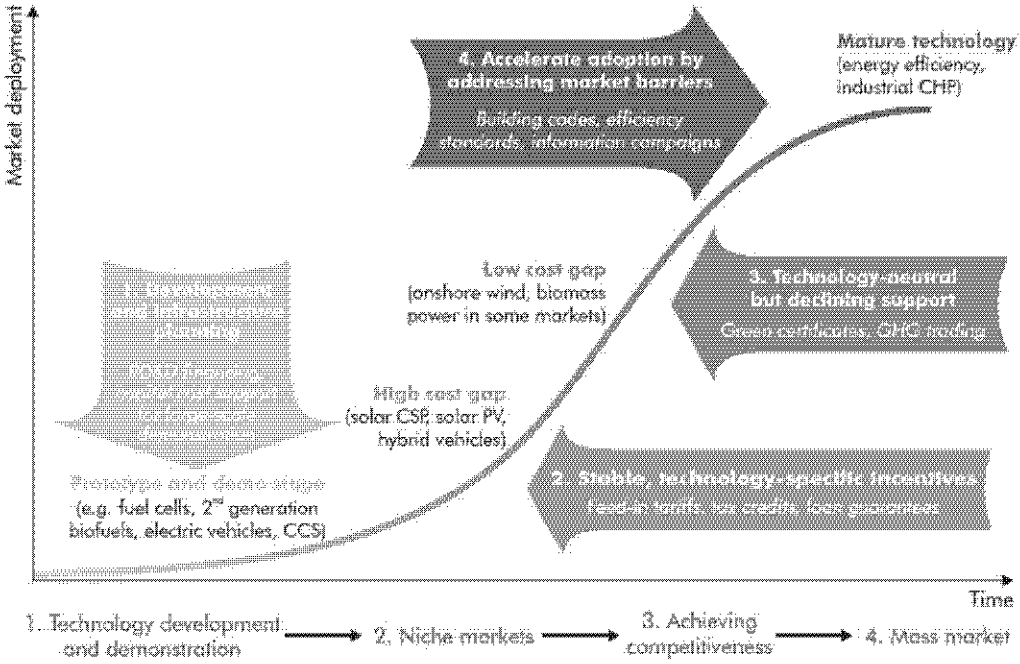


Figure 30 Diffusion of Energy Technologies

Source: (International Energy Agency, 2010a)

Perhaps one reason it isn't clear is that learning effects in the (low-carbon) energy technology sector haven't been demonstrated. Maalla (Ben Maalla and Kunsch, 2008) extended the Bass model to estimate the possible diffusion of (micro) combined heat-power generation as a substitute for centralised electricity generation and local boilers in the residential sector in Europe. They found that regulatory frameworks that provide incentives for cogeneration (such as pricing excess electricity production or up-front grants) can facilitate adoption through accelerated learning effects. Learning rates are important determinants of the rate at which technologies can be adopted, based on their investment returns, which, in turn, will be partially determined by the cost of deployment. Learning effects influence the rate at which costs reduce as production volumes increase. Based on studies (Jamasb and Kohler, 2007) in the electricity industry, new technologies, early in their development, exhibit learning rates or cost reductions of up to 35% for each doubling of capacity. As the technologies mature, these learning rates start to decline. Unlike the semiconductor industry, the decline in learning rates appears to occur much more quickly and is more precipitous. This may be because of the fundamental physics of the innovations being created, or a combination of other factors such as industry structure and market or industry regulation. So, for example, while solar PV prices have benefited from large learning rates, breakthrough efficiencies that will drive even greater cost reductions seem rare.

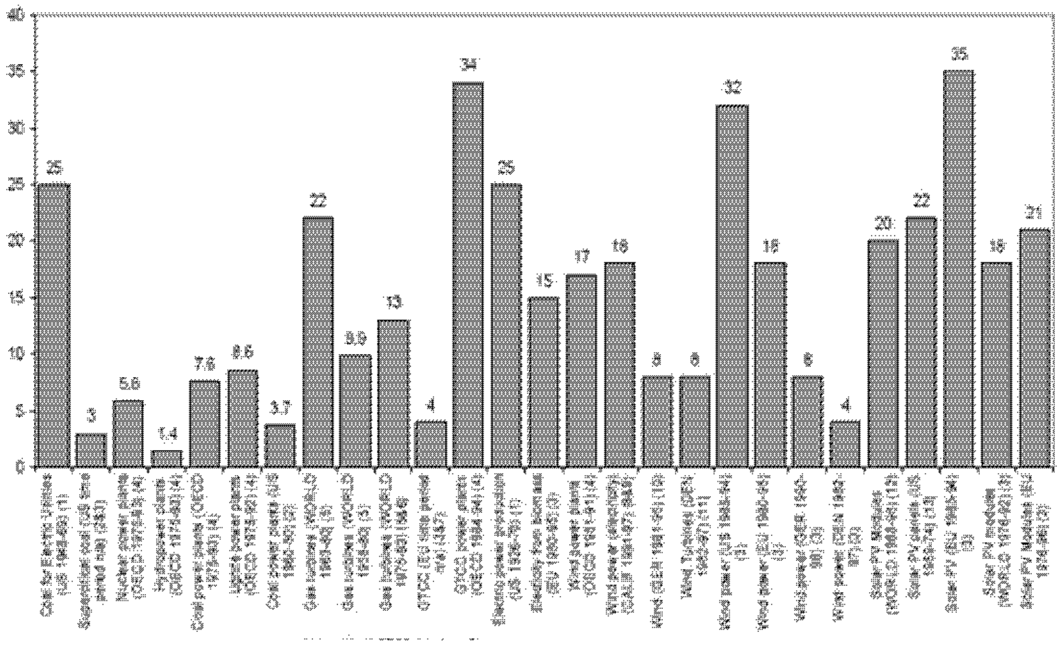


Figure 31 Learning Rates in Electricity Production Technologies

Source: (Köhler and Jamasb, 2007)

With a range of uncertainties that influence the widespread adoption of emerging energy technologies and an industry structure that provides incumbents with little incentive to innovate or deploy competing technologies, government policy has taken a role in providing an incentive for innovators, proponents and early adopters to evaluate the benefits of promising technologies, as suggested by Maalla. The adoption curves proposed by Everett, Grub and Bass must take into account these policy interventions and external factors that impact mass adoption.

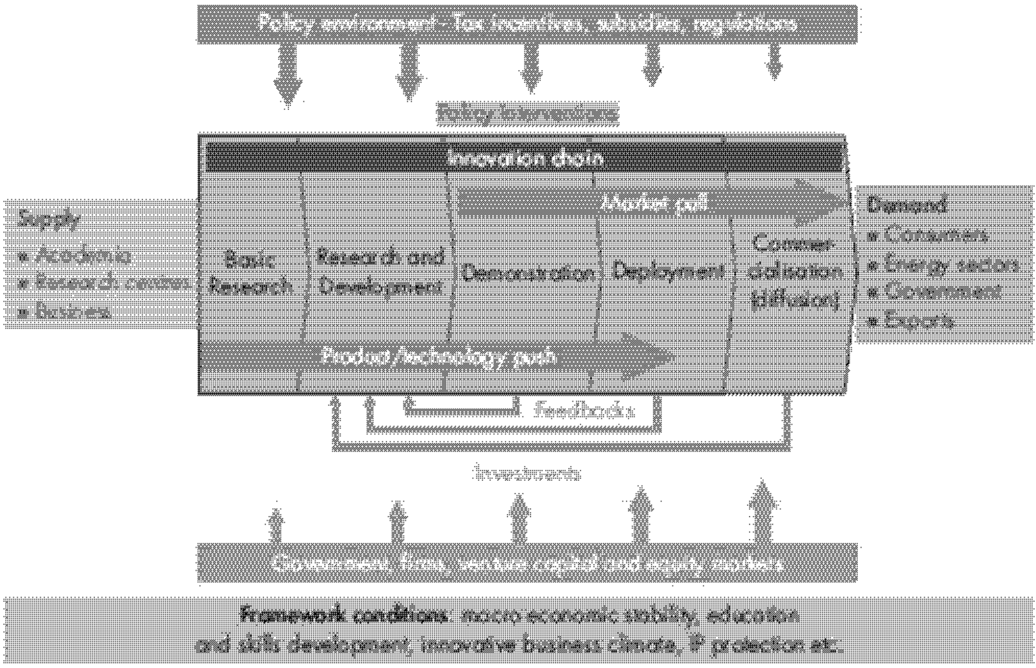


Figure 32 Factors Influencing Innovation in the Energy Sector

Source: (International Energy Agency and Tanaka, 2008) (Adopted and modified from Grubb and Foxon)

The evolution of theory regarding adoption of technology, and in particular, energy related technologies has resulted in successful characterisation of the rate of adoption from incipient to mature technologies and the influence of factors such as learning rates in production and technology evolution as well as the influences of private capital and the prevailing policy environment. With this broad adoption framework we can now examine the actual adoption rates of energy technologies in Australia, and the relevant influences of the public policy environment, programs and incentives as well as access to, and factors influencing the availability of, private investment capital.

Chapter 4 Adoption Patterns of Sustainable Energy Innovation

This chapter will explore the historical actual adoption patterns of new energy generation technologies in Australia and the opportunities for further penetration. A particular focus will placed on low carbon and distributed energy. Tracking the historical path of innovation of a range of sustainable technologies is informative and will assist in forecasting the likely future adoption of such technologies. Projecting future adoption of decentralised technologies such as cogeneration and solar PV may be guided by the theoretical frameworks outlined in Chapter 3. In particular, Rogers' distribution of adopters may provide guidance for the anticipated rate of penetration for technologies that have a track record of implementation.

4.1 Actual Penetration of Low Carbon Technologies in Australia

A more varied combination of electricity generators, including a mix of centralised wind, large-scale solar, combined cycle gas turbines ("CCGT"s) and, potentially, carbon capture and storage ("CCS") at conventional coal-fired power stations as well as a mix of distributed energy technologies including gas-fired cogeneration and solar PV is likely to evolve in Australia over coming years.

<u>Wind</u>

Australia was an early leader in wind generation with the deployment of small DC systems for remote rural applications in the 1940s, with the Dunlite company in South Australia manufacturing generator sets using converted generators from old motor vehicles and a number of Australian manufacturers producing commercial units in the kW range for remote area applications in the 1980s. The first wind farm in Australia was developed using locally manufactured 60 kW machines in 1987 in the relatively remote West Australian town of Esperance with grid-connected wind farms established in Crookwell in 1998 (eight imported Danish 600 KW wind turbines) and Blayney in 2000 (fifteen turbines) in 2000. Funding was largely provided by the Federal and State governments.

Wind turbine prices have fallen substantially since the 1980's driving significant reductions in the cost of generating wind energy.

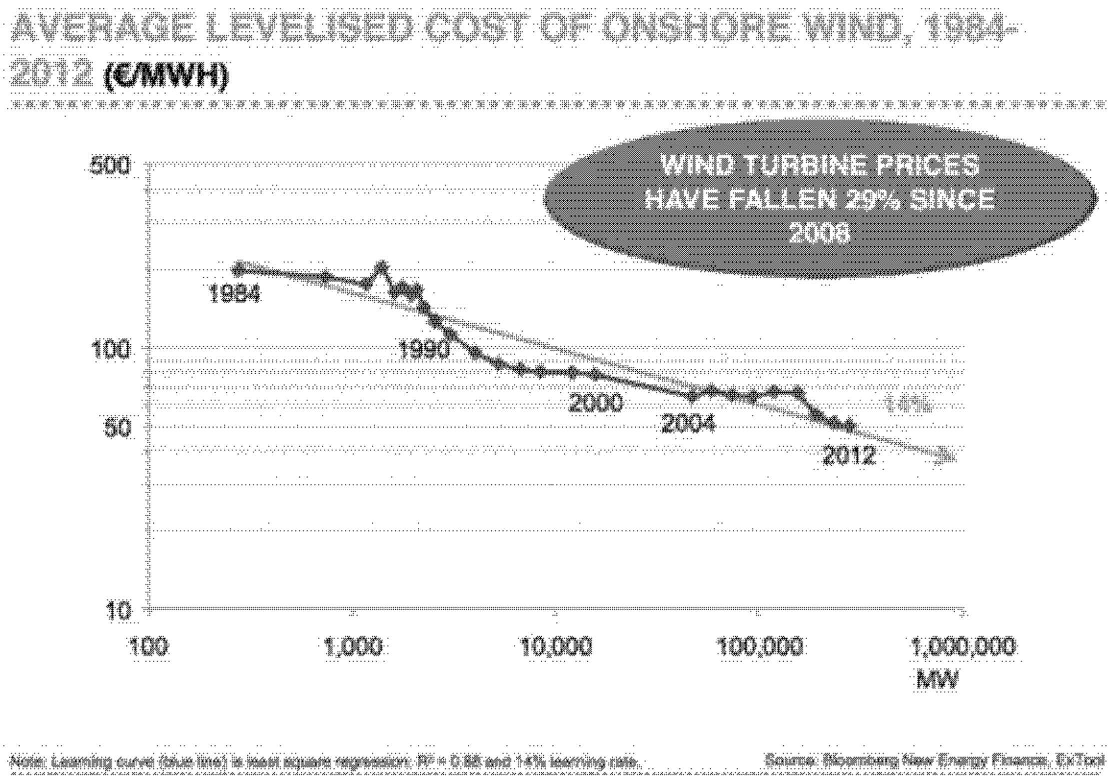


Figure 33 Wind Cost Reduction and Learning Curve

However, the most significant driver of wind deployment in Australia has been the Mandatory Renewable Energy Target (MRET) that commenced in 2001 and specified that 9500 GWh of electricity should come from new renewable generation in 2010. While modelling undertaken for the scheme suggested that wind would play only a minor role by comparison with biomass in providing these RECs, it proved to be highly competitive, in part driven by international progress in wind turbine development and in part by excellent wind resources.

Almost 1700 MW of wind was under construction, or committed in early 2013 including the Macarthur Wind farm in Victoria which, at 420 MW, is the largest wind farm in Australia with one-hundred-and-forty 3 MW turbines (Clean Energy Council, 2013b). Wind generation totalled around 7970 GWh in the NEM from mid-2012 to mid-2013.

Total investment in wind was an estimated $ 5.3 billion to mid-2012 (SKM, 2012) including an estimated $630 million in 2011 and $930 million in 2012. Investment is projected to reach $1.6 billion in 2013. As a very rough measure, public support for wind is around half this total cost of investment (given the revenue split for wind farms between energy and REC). MRET was expanded to a 45000 GWh target for 2020 in 2010, then subsequently split into a large-scale and small-scale target. The large-scale target, within which wind will compete, is now 41000 GWh for every year between 2020 and 2030 and has been by far the most important driver of wind generation investment. There is, however, considerable uncertainty regarding future investment in this sector as a result of changing policy targets.

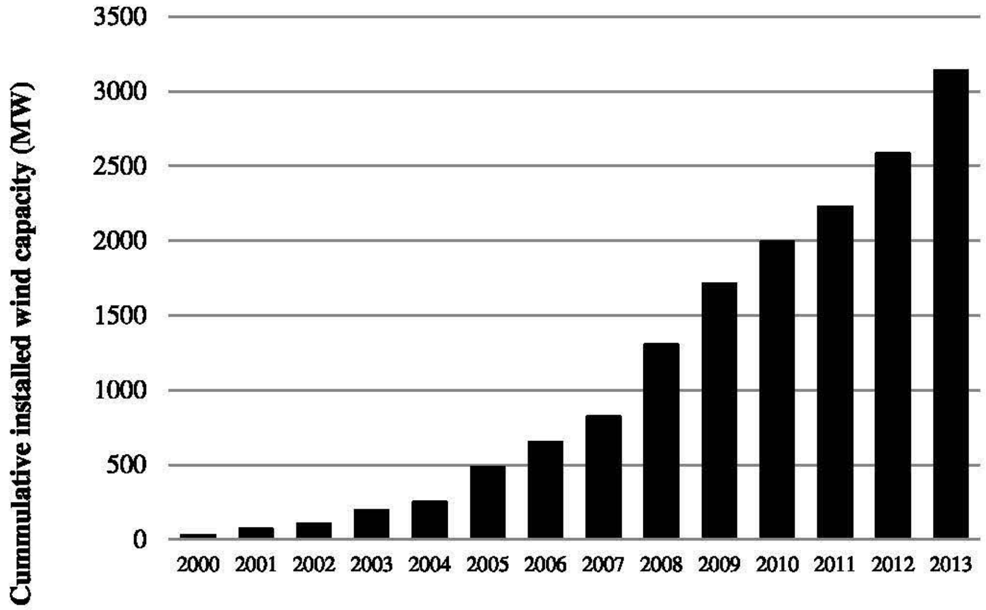


Figure 34 Australian wind capacity growth over the past decade

Source: (Energy Supply Association of Australia, 2013) (Clean Energy Council, 2013b)

Large-scale and Rooftop Solar

Large-scale solar includes three main technologies, solar photovoltaic (PV), concentrated solar thermal (CST) and concentrated PV (CPV). All of these technologies are technically viable and have been demonstrated at large-scales (at least 1 MW) around the world. The unique scalability of solar PV allows for very diverse power applications from small residential and commercial installations at < 10 kW up to utility scales of the order of hundreds of MWs. Small-scale PV systems represent the major share of the total installed capacity while CST and CPV installations start at larger scales (>200 kW) (Clean Energy Council, 2013a). However, large-scale solar power has the potential to make a substantial impact on Australia's power generation mix. Australia is one of the richest countries in terms of the amount of solar energy that is available with most of the continent receiving in excess of 4 kWh per square metre per day of insolation during winter months. Economics are dominated by the upfront costs with no fuel and low O&M costs. Recent rapid expansion in the deployment of solar PV has resulted from significant manufacturing cost reductions and generous government support mostly in the form of FITs that typically have guaranteed returns for 10-20 years.

Innovation in PV technology continues apace from early developments in the mid-70's to increasingly rapid deployment over the past 5 years in many countries including Australia. Improvements in cell efficiencies and, more importantly, learning effects driving substantial reductions in costs, have been responsible for the increasingly accelerating growth in uptake.

Fraunhoffer (Wirth, 2013) has estimated learning effects in solar PV have resulted in an average decline per module of 20% for every doubling of production capacity.

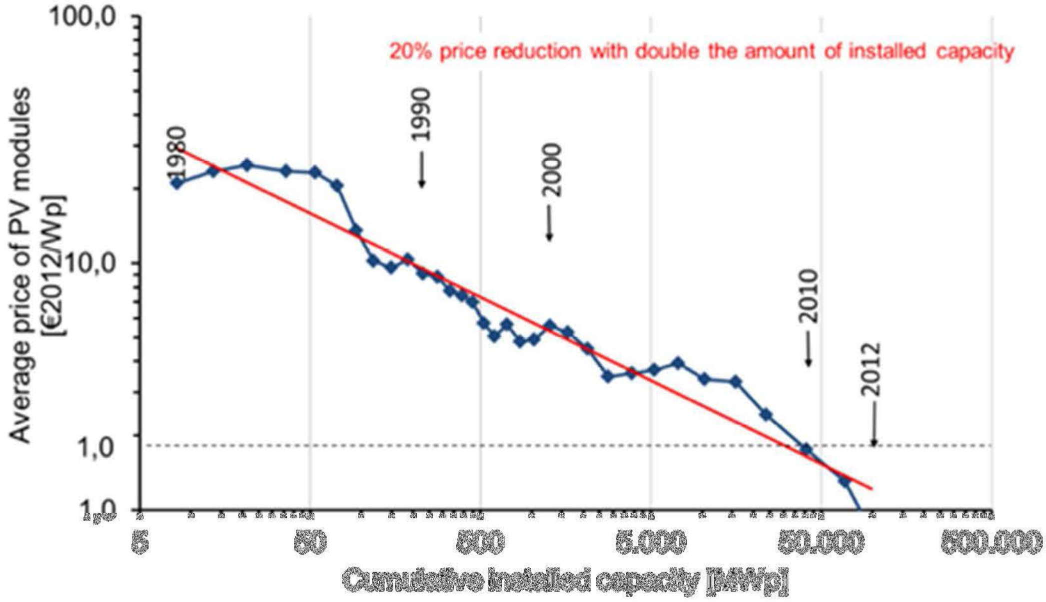


Figure 35 Historical Price Development of PV Modules

Source: (Wirth, 2013)

Globally, the market for solar PV has expanded rapidly with substantial growth forecast.

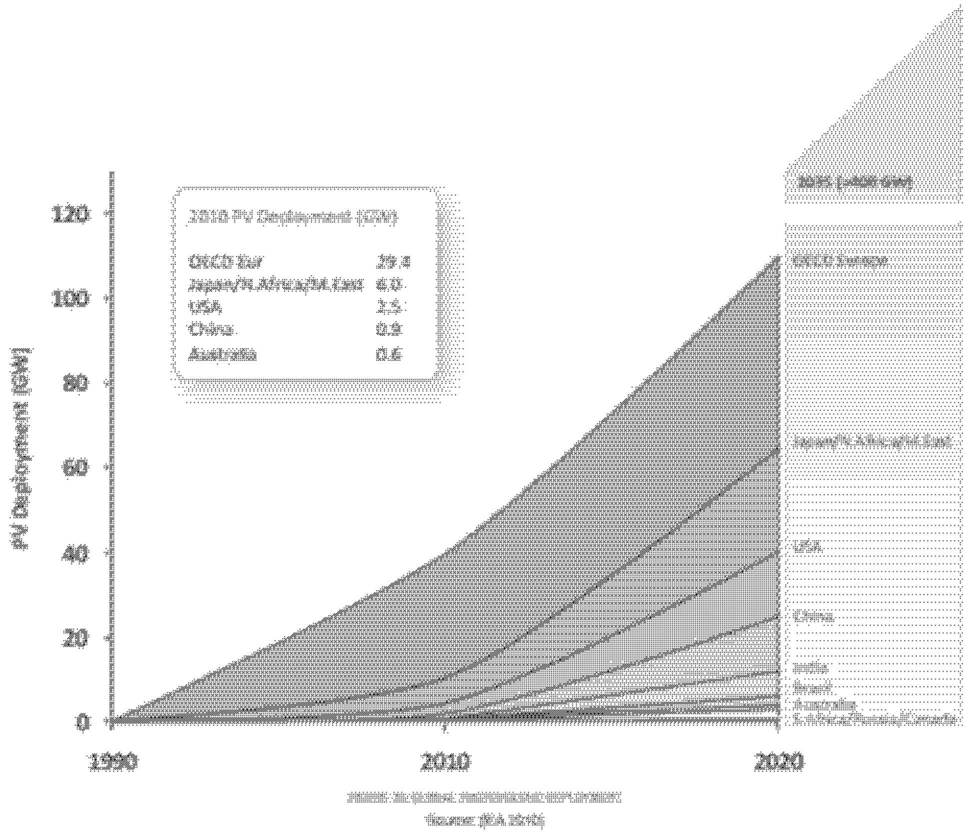


Figure 36 Global PV Deployment

Source: (International Energy Agency, 2010a)

The two primary policy drivers that support the deployment of large scale solar in Australia are the MRET and capital grants. Grant schemes include the Federal Government's Low Emissions Technology Demonstration Fund (LETDF) and the $1.5 billion Solar Flagships Program administered by the Australian Renewable Energy Agency (ARENA) with additional funding committed by State governments. As at March 2013 there were 39 known large scale plant installations with a total installed capacity of 35 MW of which 24 MWs was installed in 2011-12 (Clean Energy Council, 2013a) and 23 MW provided by systems larger than 1 MW each. The largest are a 10 MW PV plant at Greenough River in WA and a 9.3 MW CSP plant boosting the output at Macquarie Generation's Liddel coal fired power station in NSW. Both projects have received substantial government subsidises

Meanwhile, State based Feed-in-Tariff schemes alongside price reductions and innovative financing models have driven the growth of rooftop solar to around 1.3 million dwellings reported (Warburton et al., 2014) to have solar PV installed. According to the ABS (ABS, 2013a) the total number of dwellings in Australia is just over 9 million of which around 85% are detached or semi-detached. This suggests a penetration of around 14%. This is close to the theoretical point at which a technology might be considered saturating the Innovator and Early Adopter populations and suggests that much more rapid, wide-scale adoption of solar PV in Australia is approaching, with decisions driven by consumers based on social proof and self-referencing recommendations. As the technology has transitioned from "early adopter" to "majority" the incentives provided by FiT's have been able to be removed while the market continues to grow.

Combined Cycle Gas Turbine

Combined Cycle Gas Turbines (CCGT) employ gas turbines, driven based on aviation applications, and were first introduced for electricity generation in the 1970s. This technology employs heat recovery systems fed by waste heat combined with a steam turbine to enhance generation efficiency with plants now approaching 60 % electrical efficiency resulting in overall emission intensity of between 30% to 50% of a conventional (brown or black) coal fired plant (Grafton, 2012). The capital costs of these plants are also significantly less than that of coal plant and they are therefore increasingly favoured where gas is low cost and/or coal is higher cost, and for intermediate capacity factor operation (IEA, 2012).

Gas generation has contributed more to new global capacity than any other technology over the past decade (IBID). Within Australia, South Australian and Victorian publicly-owned utilities installed gas-fired generation (of the less efficient open cycle technology) in the 1970s and 1980s, while NSW and Queensland had little gas-fired generation until the last decade and were dominated by coal. The 1986 McDonnell inquiry into the NSW electricity industry noted that much greater use of gas generation would have significant economic benefit for the State. The first significant CCGT was built in SA in 2002 and today Western Australia, South Australia, Queensland, NSW and Tasmania all have CCGT plants. In South Australia deployment was driven by the availability of gas and lack of new low cost coal options while in Queensland it was the 13% Queensland Gas Scheme that commenced in 2005 and required 13 % of Queensland electricity demand to be met by gas-fired generation. The NSW Greenhouse Abatement Scheme provided support for gas generation projects anywhere in the NEM, while direct state government support was a driver in Queensland (Townsville Power Station) and Tasmania (Bell Bay Station).

Total CCGT capacity is about 4 GW and output has quadrupled since 2001.

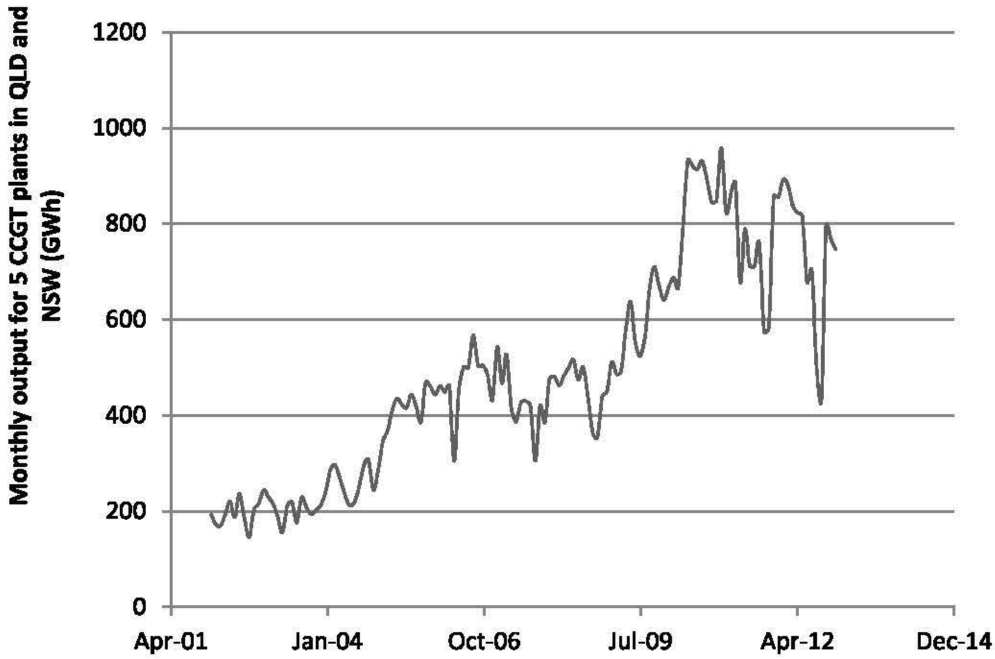


Figure 37 Energy contribution of CCGTs in NSW and QLD from 2002-2012

Source: (AEMO, 2015)

4.2 Potential Penetration of Distributed Technologies - Cogeneration

Thomas Edison built the Pearl Street Station in 1882. This is considered to be the world's first power plant and it applied the electricity and thermal energy to the subways of New York City, constituting the world's first cogeneration installation. Diesel fired reciprocating engines have been used to provide precinct electricity and thermal energy in Europe since before World War II. Biodiesel and biogas cogeneration gained popularity in Germany over the past 4 decades as a result of policy incentives, including the EEG program that has driven the availability of biofuels as well as technology improvements in engine performance. Over the past 2-3 decades, natural gas reciprocating and turbine technology has become widespread making the technology available and commercially viable in an environment of growing gas supply and demand. Cogeneration adoption from original innovation to widespread application has taken more than a century and, in Australia, penetration of Cogeneration is estimated to be at less than 10% of its technical potential. Similarly, absorption cooling was invented by the French scientist Ferdinand Carré in 1858, however, as the cost of manufacture rose, the centres for production of these devices moved to China and India. Innovation in these products has been limited to materials, methods of manufacture and fuel sources.

Just over 8% of world electricity generating capacity, around 325 GW, is Cogeneration. This is typically installed in industrial and commercial settings, precincts or residences (micro-CHP).

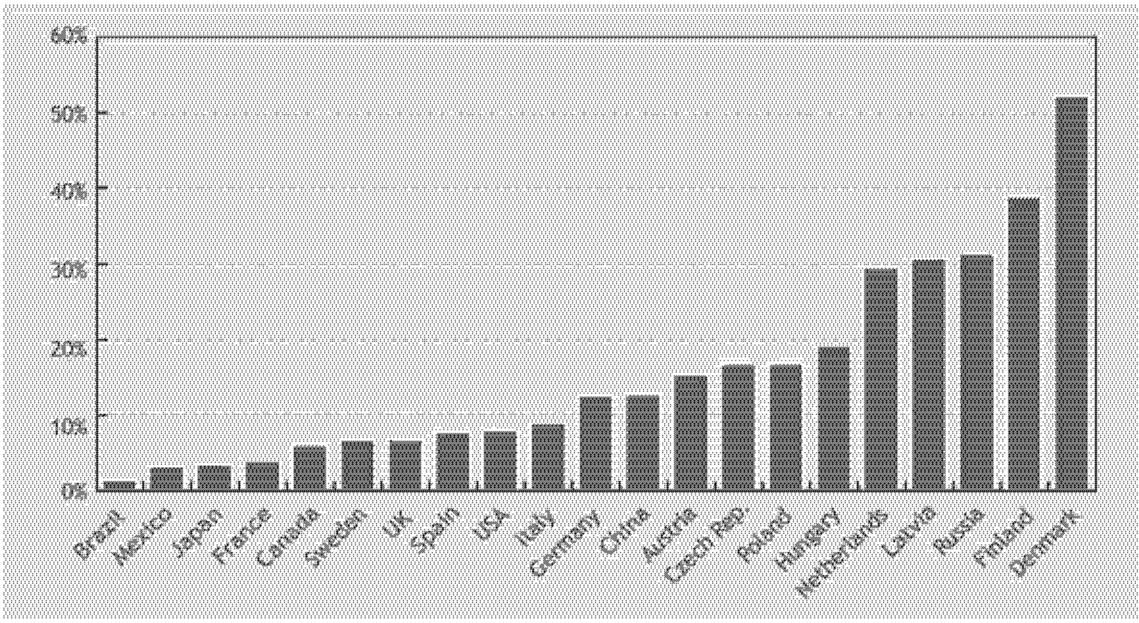


Figure 38 Cogeneration (CHP) Share of Power Production in Different Countries

Source: (International Energy Agency, 2008)

Cogeneration is most widely used to supply electricity and heat for self-consumption (i.e. "behind the meter") to individual industrial users (paper, printing, chemicals, metal and oil refining, and food processing account for around 80% of world installed capacity) and commercial buildings such as universities, clubs, aquatic centres and hospitals. These sites are ideal as they demand a constant supply of electricity and heat over prolonged hours during the year. The prospects for growth of Cogeneration in the industrial and commercial sectors are strong. Natural gas provides the fuel for more than 50% of installations and biofuels are growing in penetration. For example, Brazil, a hydropower-based economy, could see biomass fuelled cogeneration enter the industrial sector with the potential to produce up to 17% its Brazil's electricity by 2030 (Chiu, 2009).

Precinct based district heating with cogeneration is common in northern Europe where the climates are relatively cold and the population density is high. District heating and cooling either heats buildings through steam or hot water in insulated pipe networks or cools them by distributing cool water produced by waste heat powered absorption chillers. Hence, lower ambient temperatures assure the extensive utilisation of the harvested heat while high population density minimises the capital cost of plant. More than half of Western Europe's cogeneration is connected to district heating and cooling systems with 52% of Denmark's electricity in 2003 (5,690 MW) being met by cogeneration and around 13% of Germany's electricity (21,203 MW) generated from cogeneration in 2005. Longer term projections suggest Germany's use of cogeneration could rise to 57% with the vast majority of cogeneration found in industry and powered by a mix of natural and biogas. In Italy, a market research study (Tomaselli, 2007) conducted by the Association of Energy Services Companies in 2006 found that the greatest market potential was in the small scale cogeneration sector with around 3.5 GW of Cogeneration in commercial shopping centres, sports centres with heated swimming pools, hotels and hospitals and old-people's homes. ENER-G in the UK claims (Chassange, 2013) to have sold over 2300 units to date and has a 60% share of the UK market. ENER-G claims to have sold a total of 150 units in 2012 with 70% of sales to its domestic UK market and 30% being exported. Based on these figures, the total UK market might be estimated at around 175 units per annum.

In Eastern Europe, cogeneration accounted for almost 19% of total power production (based on national data for 2001 through 2004), with an installed capacity of approximately 35,000 MW. In the USA, cogeneration accounted for 8% of power production and 84,707 MW of capacity operating in 2003 most of which was in large scale industrial applications. In China, around 13% of the nation's electricity capacity (28,153 MW) and 60 percent of urban heating is generated with cogeneration. The Chinese National Development and Reform Commission has set a goal of 200 GW of cogeneration by 2020 which would account for around 22% of the expected installed capacity.

In Australia, in 2008, it was estimated (Usher et al., 2008) that there were 151 cogeneration and trigeneration implementations in NSW with a total capacity of more than 2,667 MW mainly in the metal, paper, chemical and sugar processing industries as well as the health sector. Bagasse (the fibrous waste material from sugar cane processing) is used as a fuel source in northern Queensland to provide generating capacity of nearly 200MW which is used to power eight sugar mills and export the remaining power to the electricity grid. Bagasse accounts for over 60% of Australia's bioenergy capacity and around 40% of its renewable cogeneration capacity. According to Climateworks (Climate Works Australia, 2011), "Despite its significant potential to meet power demand challenges, cogeneration remains underutilised. Australia currently has approximately 3338 MW of cogeneration installed, 592 MW of which is fuelled by renewable sources."

At around 3.3 GW of installed capacity, the penetration of cogeneration in Australia is around 6% of total generating capacity of 51 GW. Taking the IEA's average penetration of 10% as a guide (International Energy Agency, 2009), it may be inferred that the potential capacity for future installations of cogeneration is around 3GW which is supported by analysts (Zauner, 2012) estimates of the technical potential for cogeneration in Australia. Despite Australia's temperate conditions there are many locations where district heating in winter and commercial air-conditioning needs can be satisfied with cogeneration and trigeneration to provide substantial environmental and financial benefits.

In the USA it was estimated (Hedman and Hampson, 2010) that around 34% of cogeneration capacity is in units of less than 1mW in size and hence it is assumed that that Australian incremental capacity will comprise around 850 units with a capacity of less than 1 MW per unit and around 1650 units above 1 MW in capacity. At current prices, the investment required to deploy these systems would be around $4 – 6 billion (ignoring replacement of existing stock which would be approaching its generally accepted 15-20 year life-cycle).

There are a large number of potential sectors where installation of cogeneration can offer compelling financial and environmental benefits. These include:

- Aquatic Centres
- Food & beverage Manufacturers
- Hotels / Hospitality
- Council / Government Buildings
- Schools and Universities
- Airports
- Dairy, Chicken and Pig Farms
- Water Treatment & Utilities
- Leisure and Sporting
- Clubs – Sport, Social
- General Manufacturing
- Data Centres
- Hospitals
- Shopping Centres
- Commercial Buildings
- Paper, Timber and Woodchip Growing and Processing
- Mining
- Printing & publishing

The dimensions of these markets are large. For example, there are more than 218 aquatic centres in NSW and 199 in Victoria (Australian Swimming Pool Association). Larger aquatic centres (perhaps 30% of the identified 417 NSW and Victorian sites) are ideal candidates for cogeneration. There are 1500 registered clubs in NSW (Clubs NSW) which generated total revenues of around $5.4 billion in 2007 (Allen Consulting Group, 2007) and invested around $858 million in capital expenditure. Around 170 "not-for-profit" clubs generated more than $5 million in gaming revenue (which accounted for around 2/3 of total revenue) and energy expenditure has been found to represent about 10% of a club's operating costs. Hence, it is assumed that these 170 Clubs expend upwards of around $700,000 per annum on energy.

According to the Australian Bureau of Statistics (ABS, 2008a) the hotel, motel and resort sector generated $9.87 billion in revenue 2006/7 with around 313 resorts, 550 hotels and 583 serviced apartments and numerous other small operators. Around 345 large establishments employ more than 50 people and generated $5.6 billion in revenue (average of around $16m per establishment). On average, electricity, gas and water charges made up 6.8% of total operating expenses but for hotels, resorts and serviced apartments, which offer more amenities to guests, the expenditure on electricity and gas are likely to be higher. Assuming energy consumes around 10% of a hotel or resorts operating budget and operating profit margins of around 20%, then it may be assumed that the average large establishment expends more than $1million in energy related costs.

The Australian manufacturing sector generates more than $410 billion in annual revenue. The sector is broad and cogeneration has a definite role to play in reducing some manufacturers' energy expenditure and carbon emissions. The food and beverage sector is the largest sector in the industry (Australian Food and Grocery Council, 2011), generating over $86 billion in revenue every year and 5,111 (2010/11) enterprises employing over 225,000 staff. Within this sector alone there are 840 meat processing businesses with average revenues of around $23m per annum, 520 dairies with an average of around $21m in revenue per year, 415 bakeries generating around $19m per year, as well as over a hundred soft drink and confectionary plants. According to the Australian Bureau of Statistics (ABS, 2008b) businesses employing fewer than 20 staff comprise more than 90% of the manufacturing sector as a whole and 79.9% of food, beverage and tobacco manufacturers. On this basis, there are over 1,000 medium and large food and beverage manufacturers in Australia who would probably have sufficiently large energy demands to be candidates for cogeneration or trigeneration.

Analysts agree that the distributed generation will play an increasingly important role in Australia's energy system. CSIRO (CSIRO, 2013) has proposed four scenarios for Australia's electricity system to 2050 with different characteristics and consequent costs. Each scenario projects higher penetration of distributed generation than presently exists with the greatest penetration, at nearly 50% of capacity, arising from informed consumers pressuring service providers to provide a wider range of choices including diverse, lower cost, on-site generation options.

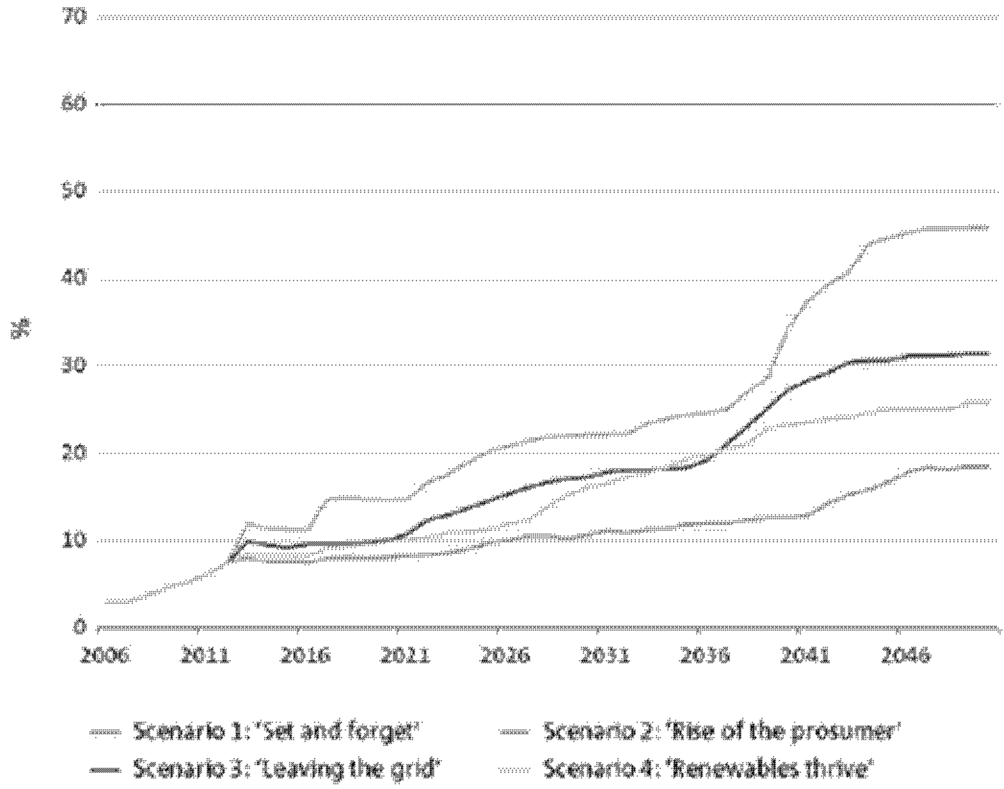


Figure 39 Projected Share of Onsite Generation in Australia

Source: (CSIRO, 2013)

The Institute of Sustainable Futures (Dunstan et al., 2011) projects that distributed energy approaches could provide up to 40% of Australia's total energy demand by 2020 based on the economic potential of each category, assuming favourable market and policy conditions. The largest contribution to these totals in energy terms is energy efficiency (60%), followed by cogeneration/trigeneration (27%). The Institute has estimated that up to $14.9 billion (2010) in network expenditure could be avoided by exploiting distributed energy alternatives with $1.5 billion avoided in Victoria alone.

SKM (Zauner, 2012) has estimated the technical potential to displace 4,915 MWh to energy with cogeneration or around 5 GW of electrical capacity located in around 1000 different plants throughout Australia with the majority below 10MW and a further bias below 1MW.

Industrial cogeneration opportunities, combining gas-fired electrical generation with heat to displace existing industrial thermal equipment has been demonstrated to offer significant economic benefits and investment returns alongside dramatic reductions in carbon emissions.

Commercial trigeneration, with waste heat absorption chillers supplementing electric chillers can have similar financial and emissions outcomes.

Precinct cogeneration has also been demonstrated to be economically and technically viable when combined with renewable energy (particularly solar PV) and storage. With Australia's continued high rate of population growth and housing development, precinct cogeneration is likely to emerge as a new growth area for combined heat and power in specific climatic regions.

4.3 Rate of Diffusion of Low Carbon Technologies in Australia

Floran (Floran et al., 2014) characterised the diffusion of Wind, CCGT and Solar PV in the Australian NEM over the past decade, and developed the familiar S-curves described by Grubb and Rogers. These S-curves result from the particular mix of supply factors (costs and learning) and policy interventions responsible for driving penetration and suggest penetration of relevant technologies can occur over decades (as is the case for centralised technologies such as wind and CCGT) or years (as has been the case for rooftop PV).

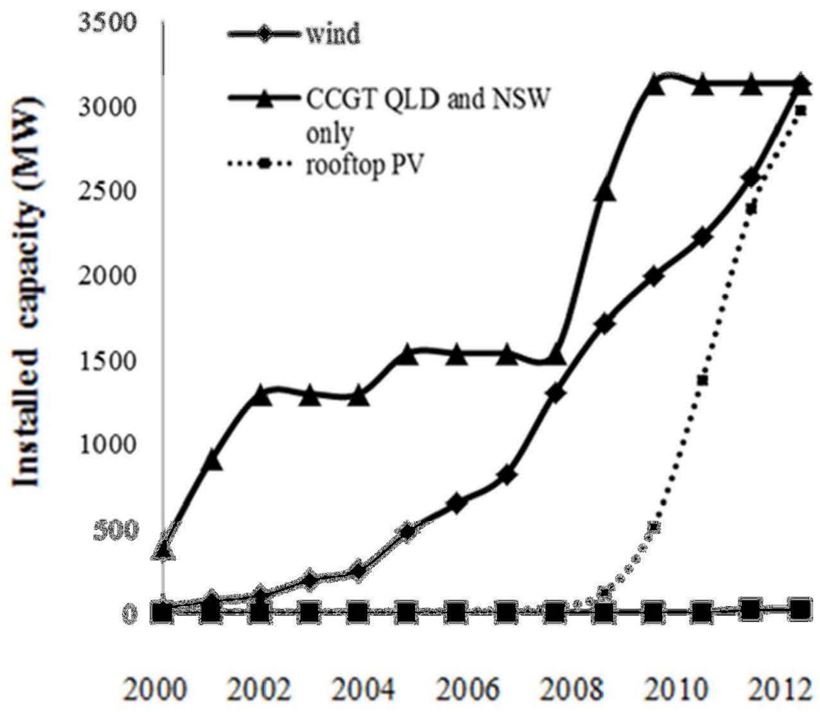


Figure 40 Adoption curves for low-carbon technologies in Australia

Source: (Floran et al., 2014)

The present generating capacity of each of cogeneration, wind, CCGT and Solar PV has reached around the same level, at around 3 GW, compared with around 54 GW of total generating capacity. Absent from this mix is Carbon Capture and Sequestration, despite the substantial investments committed to these technologies. While there are currently a small number of CCS plants around the world, none are in the power sector, though two were due to commence commercial operations in 2014 in Canada and the United States (Global CCS Institute, 2013). The projects in the power sector that are currently under construction have received substantial subsidies from the government in the form of capital grants. Australian Commonwealth and State governments have made substantial financial commitments to support the demonstration of commercial-scale CCS in the power sector under the CCS Flagships program, the National Low Emissions Coal Initiative (NLECI) and the Low Emissions Technology Demonstration Fund (LETDF). It appears that operational CCS technology is still decades away, despite the initial promise of the technology.

However, there remains substantial potential for growth of other low-carbon technologies with the technical potential for cogeneration of around double the existing penetration and potentially greater potential penetration of other low-carbon technologies, driven by "two key uncertainties – most importantly ongoing energy and climate policy development....; and other market developments including gas availability and price, and future electricity demand growth, or perhaps even decline in the short term." (Floran et al., 2014)

The factors impacting sustainable energy penetration are many and often difficult to identify, with vested interests of incumbents, high switching costs, ambiguous government policy and other "lock-in" effects delaying or stopping wide-scale adoption. These challenges and uncertainties will be examined in the next Chapter.

Chapter 5 Challenges to Adoption of New Energy Technologies

This chapter identifies the impediments preventing broader adoption of new technologies in the energy sector. These impediments include technical integration issues; risks associated with early adoption and the requirement to demonstrate the viability of technologies prior to wide scale adoption; incumbent interests which delay or prevent new entrants and technologies from effectively competing with their established and, often, exclusive system infrastructure; and market and pricing issues which make emerging technologies financially less competitive that established and mature technologies (at least in the early stages of their adoption).

5.1 Technical Impediments

Technical impediments often prevent or delay widespread adoption alternative technologies. For example, in the case of distributed generation, three factors are relevant:

Firstly, historically, electrical transmission and distribution networks have been designed for electricity flows from the generator to the consumer via the transmission and distribution networks. The network has been designed to provide power based on the forecast loads and distribute energy at published voltages levels while ensuring power quality and reliability. Accommodating distributed generators adds forecasting complexity and may increase the variability of voltages and frequencies.

Secondly, increasing amounts of distributed generation may result in power production that exceeds the total demand from consumers at different times of the day. This may result in a backward flow of electricity into the distribution substation which will result in rises in voltage levels within the network.

Thirdly, distribution network voltages are controlled by adjusting transformer taps or by installing voltage regulators. These have discrete adjustment steps and electromechanically change settings within tens of seconds. However, distributed generation in the form of solar PV is variable with power and voltages changing over milliseconds. Large amounts of PV can drive transformer tap regulation and line voltage regulators to continually hunt for the best voltages which can reduce the equipment life and contribute to instability.

However, these issues can be managed by incremental investments by incumbents and thoughtful analysis. Incumbents will need to invest in equipment that detects faults and protects against overloads from back-flows; manages mid-scale PV systems; provides real-time data; and improves weather forecasting. They will need to analyse alternative distributed generation scenarios and design their networks to take account of a more dynamic technology environment than hitherto required. Alongside the technological and capital investment requirements, incumbents may look at alternative business models (moving from infrastructure managers to service providers) which may involve a transfer of assets from network operators to consumers. While incumbents frequently cite potential network limitations and highlight the risks of decentralised generation, European experience with integration of substantial quantities of PV penetration (25GW in Germany, 12GW in Italy and 5GW in Spain) suggests that the obstacles are surmountable.

5.2 Lack of Incentives for Early Adoption

Since the Second World War, large-scale technological innovations have become more and more expensive, complex and risky. Private investors are often unwilling to support promoters deploying technologies until these can be demonstrated at production scale at relevant reference locations and in a manner that portends to the project's operational effectiveness, technical efficiency, long-term operating economics and ongoing reliability and maintainability. Certainty in pricing and scale reduces investor risk, informs both producers and consumers and attracts large scale investment.

Thus, the path to commercialisation is often facilitated by public policy initiatives which, on the one hand, have the objective of exposing technological and operational/commercial risks associated with deployment and, on the other hand, remove commercial uncertainties through underwriting some proportion of the commercial returns that investors in project deployment seek (through the use procurement mechanisms and price guarantees). Programs which are directed at reducing technical or project risks through demonstration, or price and market risks through guaranteed procurement, have been widely adopted in order to accelerate the commercial deployment of emerging technologies.

However, evidence supporting the need and effectiveness of both demonstration and procurement-based funding is more ambiguous than generally believed. There is little rigorous analysis to prove that demonstration (at least in the energy sector) is necessary to encourage private funding and wide-scale deployment.

Similarly, there is limited analysis of the cost-effectiveness of deployment-based mechanisms. These are complex research questions yet most evidence is anecdotal. In particular, the argument that private investors won't pay for demonstration but will drive deployment after successful demonstration requires further scrutiny, as does an exploration of potentially better options than demonstration funding to drive deployment.

5.3 Incumbent interests

Established and powerful incumbents, who often benefited from public subsidy during their formative years, often present barriers to adoption of new technology. The IEA (International Energy Agency, 2008) noted that in relation to its assessment of the potential contribution of cogeneration to reducing costs and emissions, the establishment of more pro-cogeneration policy regimes was required and would include removal of regulatory, financial and informational barriers and introduction of targeted incentives to overcome incumbent resistance. Obstructive technical regulations; laws and financial incentives that favour established technologies and incumbent generators; and lack of awareness about technology all act to embed incumbents and reduce technological innovation.

5.4 Market and Pricing Issues

The relative prices of conventional grid based electricity and competing fuel prices or capital costs for alternative embedded technologies are a key determinant of the rate of adoption of alternative technologies.

In the NEM, there were substantial (approximately 60%) increases in delivered electricity prices from around 2010 till 2014. Delivered electricity prices are made up of four components – network charges, environmental charges, wholesale electricity charges & operating charges. The predominant factors affecting increases in prices continue to be environmental and network charges in the medium term. Prices have increased significantly, thanks largely to "a large increase in capital expenditure on electricity networks over the past five years…In the period between 2010–14, capital expenditure is expected to reach almost $30 billion…higher network tariffs are largely due to 'peak demand, higher commodity prices, replacing ageing assets and higher costs of capital due to the Global Financial Crisis" (Nelson, 2013). According to the AEMC (Graham, 2012), "The drivers of electricity price increases in recent years have been primarily network costs and the costs of meeting the environmental objectives of all levels of government." Network charges rose by 16-18% in 2012-13 in NSW for large customers and further sustained increases in network charges of around 10% pa are expected for 2014-16. In the longer term, there is even greater uncertainty about electricity prices. The University of Technology (Ison et al., 2011) projected NSW electricity price increases up to around 60% by 2019/20 while others indicated that network costs would cause price rises of up to 66% in NSW and Queensland by 2015. Recently, prices have stabilised, though network investments that were committed to remain to be completed and network operators will seek to recover a return on these investments in due course.

Meanwhile, there is significant uncertainty in predicting future gas commodity prices in the eastern states, although an increase in delivered price is certain. ACIL Tasman has projected three different price scenarios and considers that initially "gas prices are likely to reflect marginal supply costs (the low price scenario) before transitioning subsequently to netback prices (the medium price scenario)…. In the current market environment, key drivers of commercial gas prices are the level of east coast LNG development, the gas prices that those LNG facilities can support, and the future performance of the CSG fields that supply the LNG plants". Factors that may ease the upward pressure on gas price include low barriers to entry in the eastern market, exploitation of new reserves and competition within the domestic market. ACIL Allen notes "the extensive gas transmission network linking basins and markets on the east coast should ensure the efficient transfer of supply from lower to higher demand segments of the eastern market". Despite a near term increase in the wholesale price of gas, overall increases in the delivered price of around 8-10% per annum is plausible.

In relation to long term gas prices, ACIL Allen has projected relatively stable prices after a short-term increase. The key long-term domestic gas and electricity price considerations are:

- Increasing export demand and supply considerations will expose Australian domestic prices to international rates and force up the price of domestic gas.
- Other alternatives available to Asian customers of LNG (particularly Japan which is Australia's largest gas customer) will be exercised should gas prices not remain competitive. Such moves from gas to alternatives will act to depress Asian gas prices.
- Joint selling by major gas producers in the North West shelf is believed to have reduced competition and led to high prices. Authorisation by the Australian Competition and Consumer Commission that continues this activity ends in December 2015 and may lead to a reduction in prices.
- The electricity generation sector will continue its trend towards lower carbon and higher cost generation including renewable resources such as wind and solar and low-emitting technologies such as combined cycle gas turbines and carbon capture and sequestration which will be relatively expensive to integrate into the network.
- New stationary energy generation will be gas-fired and is expected to provide 34% of total generation in 2034 (Ian Cronshaw et al., 2013). As a consequence, natural gas

pricing will become the single most influential determinant in electricity prices in the long term.

Taking these factors into account, SEED Advisory (Johnston, 2012) concluded, after reviewing forecasts by SKM MMA and ROAM Consulting that NEM wide electricity price rises from now to 2030 will average 2.6% per annum. By comparison, gas prices (in NSW) will rise between 1.3% - 2% per annum over the same period – potentially at just half the rate of comparable electricity price rises.

While long terms price projections favour a move from traditional centralised generation to distributed generation incorporating gas as a transitional energy source, the difficulty in accurately predicting future gas and electricity prices and illiquid markets for forward purchasing of these commodities makes the entry of new technologies problematic.

The key impediments to rapid penetration of alternative low-emitting and distributed technologies appear to be technical impediments in integration of new technologies, lack of incentives for early adoption, and the advantages held by, and interests of incumbent suppliers alongside market forces impacting on the costs of existing sources of electricity and alternative fuels (in particular natural gas) as well as the capital costs of technology and its operation and maintenance. Many of these impediments can be influenced by relevant government policy tools as described in the next Chapter.

Chapter 6 Government Policies to Enhance Deployment of New Energy Technology

This chapter explores alternative Government policies, in particular support for demonstration, as a means to overcome these challenges.

It is inherently difficult to measure the success of policies which involve comparing existing situations with an unobserved alternative outcome. Estimating the effects of policy instruments requires an assessment of what would happen in the absence of the policy, which is theoretical at best. Uncertain supply and demand responses to policy, imprecise models to measure responses, engineering and behavioural influences all confound prediction. Supply side policy impacts on carbon abatement rely on displacement of marginal generators with emissions intensities greater than those which displace them. However, in some instances, the displaced generation may have lower emissions and hence the policy outcomes are perverse. The timeframes over which public policies are introduced and take effect have an impact on measurement and assessment of outcomes. All the while, the overall cost to the economy and unintended consequences on stakeholders are relevant considerations.

Policy interventions are used to drive the adoption of renewable and sustainable energy innovation. In practice, these interventions have been either:

- Explicit price based mechanisms imposed on the emission of carbon and other greenhouse gasses (e.g. an "Emissions Trading Scheme" or a carbon tax), or
- Regulatory restrictions on environmental emissions including "Renewable Energy Targets", technology standards, environmental standards, energy efficiency labelling, energy efficiency standards for new buildings, mandatory energy reporting for large energy users, or
- Subsidies to lower-emissions generators through renewable energy certificates ("REC"), feed-in tariffs ("FiT"), production tax credits, grants which subsidise the capital costs of investment through direct cash grants, investment tax credits, government loans and loan guarantees (e.g. "Clean Technology Investment Program grants") and market-based procurement mechanisms (e.g. "Direct Action").

Table 6 Alternative Policy Interventions

Price Based Mechanism	Regulatory Mechanisms	Subsidies, Procurement and Grants
Emissions Trading - Cap and Trade Emissions Trading - Baseline and Credit Carbon Tax	Electricity supply or price regulation Technology standards Energy Efficiency regulation Mandatory assessment or audit Greenhouse gas regulation Information and benchmarking Labelling Advertising and education Voluntary agreement Intergovernmental regulations	Capital Subsidies Feed-in-Tariffs Tax rebates and credits Low interest or guaranteed loans Grants Fuel or resource taxes R&D grants and tax credits Demonstration grants Diffusion and Commercialisation grants Renewable Energy Targets Renewable Energy Certificates Government procurement

In practice, emissions are regulated by some combination of the above policies. Indeed, in 2011, the Productivity Commission (Productivity Commission, 2011) identified 237 different policy measures active within Australia among the 1096 carbon policy measures identified in the nine countries it reviewed. More than 300 different policy measures were identified in the United States and 100 in the United Kingdom with the plethora of policies highlighting the potential for overlapping policies with high administration and compliance costs. Most of the policies identified Australia, China, Germany, India, Japan, New Zealand, South Korea, the United Kingdom and the United States have been targeted at electricity generation and road transport emissions.

All policies imply a cost of reducing greenhouse gas emissions. As a proportion of GDP, Germany was found to have allocated more resources than other countries to abatement policies in the electricity generation sector, followed by the UK. Australia along with China and the US were in the mid-range in terms of total investment in achieving abatement. Similarly, Germany appears to have delivered greater emissions abatement from its electricity sector than the other countries considered. The cost of abatement for emissions trading schemes was found to be relatively low compared with small-scale renewable (PV) generation, as had occurred in Australia under various Feed-in-Tariff schemes.

Specific to electricity generation, the most widely applied emissions-reduction policies are:

- Mandatory renewable energy targets which apply in Australia, Germany, UK, Japan, South Korea, China (aspirational rather than mandatory) and over 41 states in the USA;
- Feed-in tariffs which apply in Japan, the UK, South Korea, German and many Australian and US states;
- Capital subsidies which vary widely from assisting in the provision of large-scale generation capacity, to helping individual households and small businesses install small-scale generation;
- Fossil fuel taxes (Japan and India), differentiated electricity taxes (United Kingdom), and preferential loans for investment in renewable generation.

Emissions trading is well established in the UK and Germany (under the EU's ETS which commenced in 2005) covering power stations and various other industry sectors. New Zealand introduced an ETS in 2008 covering power stations and a broad range of industries. Japan and South Korea have announced the introduction of emission trading schemes while trialling pilot schemes in several provinces. Several state or regionally based North American ETS initiatives have been designed (e.g. the US Regional Greenhouse Gas Initiative, Western Climate Initiative and California's ETS).

In the UK, a "green tax" called the Climate Change Levy applies to electricity, gas and solid fuels used in industry with exemptions when these fuels are supplied to or from cogeneration, the electricity is generated from renewable sources or other specified exclusions. In Denmark and Germany distributed generators gain access to the electricity grid through standardized technology and Cogeneration (and renewable generators) get priority when grid operators determine which power plants should operate, with utilities required to purchase

Cogeneration-generated electricity at the higher cost of the average alternative generators rather than the actual generation cost. In Denmark, feed-in tariff are in place to promote biomass fuelled cogeneration. In the Netherlands and Germany Cogeneration is allocated emissions' rights which promote the use of Cogeneration and acknowledge its efficiency advantages.

Among the conclusions of the Productivity Commission was that the EU ETS has resulted in relatively low-cost abatement where it has induced switching from coal to gas-fired electricity generation, while policies supporting small-scale solar technology were very expensive in all countries examined. Policies that encourage large-scale renewable energy projects were found to be the next least costly. Notably, China's policy of shutting down inefficient and older coal-fired power plants and replacing them with more efficient plants has been cost-effective because the savings in operating costs from using more efficient technologies outweigh the costs of new plant. The cost of abatement in the UK and Germany was found to be highest because of the generous subsidies that the two countries provide to renewables, however, the UK's fuel switching incentives achieved abatement at relatively moderate cost.

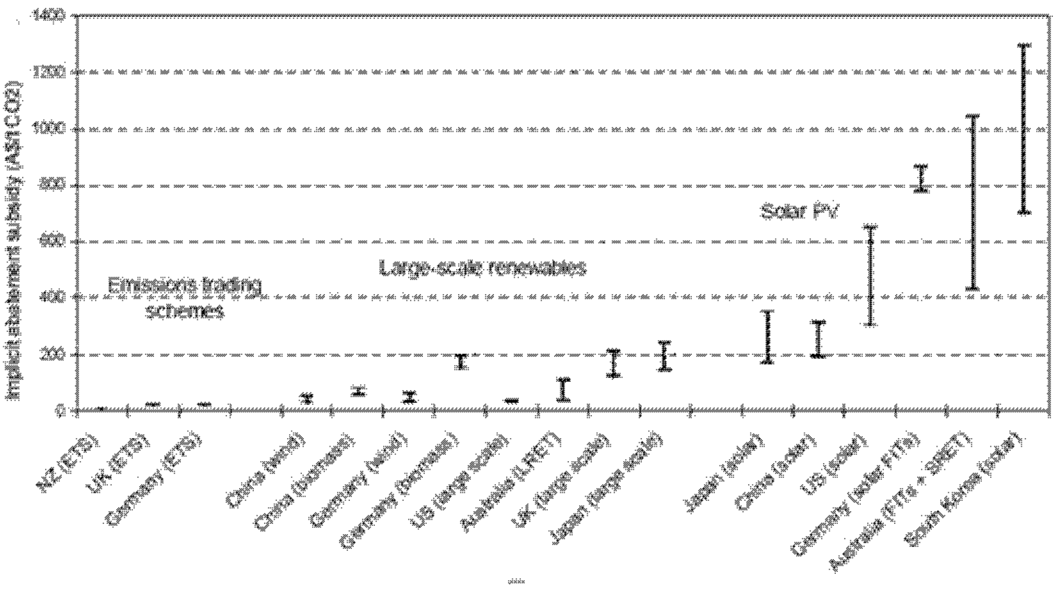


Figure 41 Implicit Abatement Subsidies by Technology and Country (Electricity Generation 2009, 2010)

Source: (Productivity Commission, 2011)

6.1 Carbon Price Based Mechanisms

It is generally recognised that the most direct and efficient way to discourage consumption of high-emission products in favour of low-emission ones, is through a global, broadly-based carbon tax or trading scheme. Placing a 'price' on emissions means that an additional cost must be taken into account in all decisions involving production and consumption of competing products that have varying amounts of emissions embodied in them or which emit varying amounts of carbon in their use. Production of emissions-intensive products will decline as consumers reduce their purchases in response to higher prices, and as producers switch to comparatively cheaper, low-emission production technologies and intermediate inputs. Because these adjustments can be made on the basis of consumer and producer assessments of relative costs and benefits to them, any given amount of abatement will be achieved at least cost.

Emissions trading schemes (ETS) limit the total quantity of emissions, but in effect work in a similar fashion to taxes, by directly raising energy prices to consumers and implicitly subsidising producers of 'clean' products. Therefore, any ETS has a 'tax equivalent' that would deliver precisely the same amount of abatement from the same sources for the same resource cost. Assuming perfect compliance and perfect knowledge of marginal abatement costs of all market participants, the two approaches also would have identical distributional impacts, delivering the same revenues to government, if permits were auctioned.

Typically, emissions trading schemes apply only to particular sectors, such as electricity generation. Limiting total emissions is key, otherwise the effective prices of emission permits (the carbon price) will be too low to influence behaviour. Emissions trading schemes that focus on the electricity sector increase the price of non-renewable energy and reduce energy consumption overall (assuming some price sensitivity of demand) while implicitly subsidising lower emissions-intensity energy production. Non-renewable energy production faces pressure from lower overall energy demand and the increased competitiveness of renewable energy production.

An emissions tax in the electricity sector effectively taxes consumption of all energy. The revenue raised from taxation of high emissions-intensity energy production accrues to government, and the revenue from higher prices for low emissions-intensity energy production accrues to producers as an effective subsidy. The rate of subsidy, or producer 'price uplift', for renewable production is equal to the rate of tax on emissions-intensive production.

6.2 Regulatory Measures

While the most well-accepted policy instruments to control emissions involve a mix of carbon price mechanisms (markets or taxes) and subsidies, grants or public tendering for emission reduction, a third strategy involves regulating or limiting emissions from certain industries or sectors.

Emission performance standards provide a baseline across all sectors that ensure average reductions in emissions across all sectors of the economy (Shammin and Bullard, 2009). Firms which do not achieve the regulated reductions suffer penalties for non-compliance, have to purchase emissions permits in a competitive market or invest capital in order to reduce emissions.

In particular, emissions from the transportation sector are widely regulated around the world with the truck and auto industries the major focus. According to the International Energy Agency (International Energy Agency, 2012), transportation accounts for 22% of global carbon emissions. While emissions from international transport, marine and aviation bunkers, increased by around 80% in 2011 compared with 1990, emissions from the road sector only increased by 52% since 1990. On the other hand, stationary sources account for 42% of global emissions, and regulatory restrictions on these sources are yet to demonstrate substantial reductions in emissions with emissions from this sector almost doubling between 1990 and 2011 from around 7.5 $GtCO_2(e)$ to 13 $GtCO_2(e)$. Where emissions in the sector have declined, these reductions have resulted from reduced demand, often as a consequence of greater energy efficiency standards imposed on certain appliances and equipment.

Regulatory measures are complex and multi-faceted, making their adoption and enforcement problematic. For example, the US Clean Air Act is a massive and complicated regulatory statute with interconnected programs that cover different types of pollutants. The Act is designed principally to regulate emissions from stationary sources (Abadie and Chamorro, 2008) through a mix of air quality standards, regulatory mechanisms, technology standards and emissions permits for new and modified plant. The Act's applicability to greenhouse gas emissions has been the subject of much debate and interpretation, dating at least back to 2003 where the State of Massachusetts successfully petitioned the EPA to include such emissions in its regulations (Wallach, 2012). Subsequently, new technology and emissions targets covering stationary electric generating units (EGU) were proposed by the EPA in April 2012 (Environmental Protection Agency, 2102) affecting an estimated 6 million stationary sources. Permissible emissions for new stationary generation are restricted to CO_2 per MWh of 450 kg compared with coal plants (without CCS) which emit approximately 820 kg CO_2/MWh. Consequently, new coal fired power plants (those which have not yet applied for permits), the dominant form of US electricity generation, will be effectively prohibited under the Act.

The EPA also regulates National Ambient Air Quality Standards (NAAQS) based on the assessment of the level of endangerment of each pollutant. Defining pollutants as 'Criteria' pollutants triggers a range of regulatory mechanisms. Currently, greenhouse gases are not defined as criteria pollutants. If they were, the EPA could require States to adhere to emissions plans to reduce the levels of GHG's to EPA designated levels or face sanctions, including loss of federal highway funding (Lippke and Perez-Garcia, 2008). Regulated local mitigation could impact global climate change, although the reasonableness of requiring States to uniquely accept the burden for reducing global emissions has been questioned. While the EPA hasn't promulgated such rules it isn't clear that is has total discretion in the matter and a challenge similar to that by Massachusetts could result in this outcome.

Elsewhere in the USA, such as in the State of California, the Global Warming Solutions Act (2006) provided its own stringent GHG emissions reduction targets, effectively prohibiting new coal-fired power stations without CCS. A number of states place limits on the emissions intensity of new electricity generators and cogeneration is promoted through eight "Cogeneration Regional Application Centers" and the "Combined Heat and Power Partnership".

The Danish government incorporates heating provisions into city planning which are combined with investment subsidies for Cogeneration retrofits while German authorities exempt buildings with Cogeneration-based district heating and cooling from renewable energy requirements in building codes.

In the United Kingdom, the government's Carbon Reduction Commitment aims at reducing the emissions from non-energy intensive organizations in both private and public sectors. While the cap and trade scheme is the cornerstone of this commitment covering large public and business consumers there is also an element of regulation on emissions. The measures are intended to yield a greenhouse emissions target of 80 % below the 1990 levels by 2050. The government aims to generate 40 per cent of its electricity from low carbon sources which is double the 2010 proportion of low carbon generation in electricity production. Under the policy, emitters must pay for the emitted greenhouse gases above the regulated limits.

Further, any new coal-fired power stations of over 300 MW are required to be 'carbon capture ready'.

The Chinese government established a five year plan that set compulsory pollution and energy targets. The government has indicated the need to set ambitious carbon-intensity targets which may result in the closure of inefficient plants, elimination of incentives for energy intensive exports, removal of subsidies for high emissions and inefficient plants. In addition, according to Enger (Enger and Bradley, 2010) the Chinese government facilitates capital investments in low-emitting technologies with its "Large Substitute for Small" policy requiring the decommissioning of small, inefficient thermal power plants to allow the construction of larger, more economically efficient and less emission-intensive plants. These policies have resulted in the closure of many small plants (below 50 MW) and larger older plants (below 100 MW more than 20 years old) along with plants of less than 200 MW that have reached the end of their design life.

Most countries have implemented minimum energy performance standards for new appliances and equipment and prohibit the sale of equipment which does not meet these minimum standards. For example, by imposing minimum energy performance standards on lighting, Australia phased out the sale of incandescent light bulbs by 2010. Australia and New Zealand have both adopted standards for around 20 product categories. The USA first implemented a federal energy standard in 1987 with around 40 product categories (domestic and commercial) now covered. In 2005, Europe implemented performance standards and Japan, South Korea and China all apply energy efficiency standards to more than 20 household and commercial products.

New residential and commercial building energy efficiency is regulated in most countries. However, due to different climatic regions, standards vary across and within countries. In regions with more moderate climates, energy efficiency investments result in lower returns. Australia, the UK and Germany require disclosure of the energy performance of houses and commercial buildings at the time of sale or lease, to increase the previously limited information available about a building's energy efficiency. While standards have been imposed in many provinces in China, compliance is reported (Yanbing and Qingpeng, 2005) to be low with only 6% of new buildings compliant.

Energy efficiency reporting requirements are frequently imposed on large energy users, often informed by energy efficiency audits. These requirements are designed to encourage users to identify and undertake energy efficiency improvements and demonstrate the resulting benefits to others. Japan requires large factories to implement energy rationalisation plans and undertake energy audits. South Korean businesses must conduct energy audits every five years. China's top 1000 energy users have committed to energy savings for which they are held accountable. Around 200 companies in Australia are required to undertake energy efficiency opportunity assessments every five years.

Energy efficiency is identified as potentially offering very low cost (or negative cost) carbon abatement, and hence the imposition of standards that require large energy users to seek out such opportunities seems redundant. However, compliance appears to assist corporations in identifying additional marginal opportunities or accelerate future initiatives

6.3 Subsidies, Grants and Market-based Procurement Mechanisms

Procurement based programmes encourage the commercial scale deployment of renewable and sustainable energy technologies through the provision of either fixed or competitively priced energy supply underpinned by a long-term power purchase agreement ("PPA").

Traditional Feed in Tariff ("FiT") programmes pay standard prices to all energy suppliers, typically limited by a maximum supply capacity or total programme cost. A FiT is a simple, comprehensible, transparent contracting mechanism for small renewable generators to sell power to a utility at predefined terms and conditions, without contract negotiations. FiT programmes use administrative processes to set a fixed price for the purchase of electricity. FiT programmes may benefit from lower transaction costs. However, it isn't clear that these programmes yield the lowest price for electricity consumers. Establishing the appropriate Feed-in-Tariff is difficult. If set too high, the returns to suppliers are too high at the expense of taxpayers and electricity consumers. If too low, new investment will not be viable. The standard-contract supply basis of most FiT programmes also cause complications for utilities who have little control over where power is generated, whether it's needed, or whether it fits in with its resource planning (i.e. provides base load or intermittent supply).

More recently, feed-in premium ("FiP") programs have gained acceptance, particularly in Europe (Czech Republic, Denmark, Germany, Italy, the Netherlands, Estonia, Finland, Slovenia, Slovakia and Spain) whereby renewable electricity is sold on the spot market with producers receiving a premium that is either fixed (or independent of market price) or variable. Unlike FiT's, FiP's result in a better supply response to market price signals resulting in greater production when demand is high or when available production from other sources is low.

These schemes encourage more suitable engineering solutions (wind power site selection, PV orientation, etc) to better integrate with existing capacity and anticipated demand. The mechanisms can be used to differentiate between technologies and volume of production, since they are generally more suited to dispatchable energy technologies (such as biomass or geothermal) while adding cost for technologies such as wind and PV which would require storage to be competitive. Feed-in-premium schemes add uncertainty for energy producers and therefore may result in higher financing costs.

Fixed feed-in-premium schemes are simple, but like feed-in-tariffs, appropriate pricing is difficult to determine. The risk of over-compensation when electricity prices are high and under-compensation when prices are low may be mitigated through price floors and caps while sliding premiums are constantly adjusted over time and by reference to predefined tariff levels. In the UK, a sliding feed-in-premium scheme (Contracts for Difference) provides financial incentives to low carbon technologies including renewable energy, carbon capture and storage and nuclear energy. This mechanism assists government and operators to target long-term agreed energy prices (for each technology) with bonus' paid if electricity prices can be generated at a price lower than the target price or paid back if higher.

The Productivity Commission (Productivity Commission, 2013) concludes that "subsidies to particular forms of distributed generators have few benefits for the network and, in the face of carbon pricing, play a redundant (and inefficient) role as a measure for reducing emissions. Governments should therefore phase out as quickly as practicable subsidies for rooftop photovoltaic units and other forms of distributed generation delivered via premium feed-in tariffs and the small-scale component of the Renewable Energy Target Scheme. State and territory governments should change the feed-in tariffs for any uncontracted small-scale distributed generators exporting power into the grid, so that their tariffs reflect the market wholesale prices at the time of energy production, and the (net) value to network businesses from reducing loads on their equipment at critical peak periods." A challenge against these proclamations is the inability to avoid gaming by incumbents and accurate measurements of benchmark prices.

On the other hand, wholesale competitive procurement (or competitive tendering) may benefit taxpayers and energy consumers. Setting supply targets and facilitating a competitive process based on selecting supply that delivers lowest cost, best fit and technology choice, uses competitive pressure to lower total costs while guaranteeing volume of supply across selected technologies and avoiding market distortions. The obligation to procure the target energy supply over the programme period reduces programme execution risk and uncertainty.

Reducing uncertainty lowers the cost of capital. Even small increases in the cost of capital (caused by a higher perceived risk due to policy, market or technological uncertainty) can significantly increase the cost of project implementation and therefore the cost to consumers.

In 2013, the ACT Government implemented a solar auction scheme which resulted in 49 first stage proposals and 25 second stage proposals for the development of up to 40 MW of large-scale solar capacity (ACT Government - Environment and Sustainable Development Directorate) and has resulted in a competitive energy price of around $186/MWh. The Government specified the desired aggregate capacity of the desired technology, and requested tenders from developers. The Government selected the preferred projects based on achieving the target capacity at lowest cost, combined with an assessment of ability to deliver in a timely manner, and possibly any co-benefits associated with the project.

A mechanism of this nature has the benefit that project developers receive certainty of a set revenue level throughout the lifetime of the project, providing high certainty and therefore a low cost of capital (reducing costs to the Government, and therefore to consumers).

Such programs overcome the so-called "energy paradox" which results from investors under-estimating the benefits of investing in cost-effective energy-efficient or lower-cost generation. This may be a consequence of investor misperceptions, unobserved costs of additional energy efficiency (such as search costs, high cost of capital, or a preference for other product attributes), imperfect information or excessive discounting. Investors often undervalue increased efficiency and perceive marginal benefits to be lower than true benefits resulting in underinvestment. To avoid this, mandatory energy efficiency or emissions standards, short term capital incentives, pricing certainty and demand certainty may assist in achieving the desired implementation and investment levels and deliver overall net benefit.

Notable early commercialisation and procurement-based programs in the clean energy sector include the U.S. Department of Energy Loan Guarantee Program, The California Solar Initiative and Renewable Auction Mechanism, South African Independent Power Producers (IPP) Procurement Program as well as Germany's long-standing Stromeinspeisungsgesetz and more recent Erneuerbare Energien Gesetz ("EEG").

The Californian Self Generation Incentive Program ("SGIP") (California Public Utilities Commission, 2007) is one of the most successful incentive programs in the USA. Under the SGIP, 544 projects were completed delivering a total capacity of 252 megawatts. In 2011, these facilities provided over 760,000 MWh of electricity on the customer's side of the meter, while substantially reducing emissions. The program was initially conceived as a peak-load reduction program with around 40% of the available capacity being delivered during peak events. The SGIP does not support solar photovoltaic technologies but does include energy storage technologies and provide additional incentives for locally-supplied products. The program identifies distributed energy resources which contribute to carbon reduction goals. The portfolio of eligible technologies and incentives include wind turbines and waste heat to power (subsidised at $1.19 per watt capacity) and cogeneration (subsidised at $0.48c per watt of capacity) and emerging fuel cell technologies (subsidised at just over $2 per watt). The program has expended around US$309m since inception and resulted in around 180 MW of cogeneration capacity, nearly 40MW of fuel cells and additional gas turbine and wind power and is credited with reducing carbon emissions by over 46,000 tonnes per year.

The Direct Action program (Department of the Environment, 2014) involving emissions reductions auctions that pay project proponents for delivered emissions reductions after they have been validated while encouraging price competition through a bidding (auction) mechanism, promises significant emissions reductions and technology deployment benefits. However, the mechanism must promote innovation and commercialisation of promising technology and, in its currently proposed form, Direct Action does not impose technology targets alongside its supply and emissions targets. Without incentivising technology introductions, corporations (beneficiaries of the emissions reduction payments) will seek to limit development risk and may impose unreasonable demands on project developers which become barriers to relatively unproven technologies or developers with limited commercial experience[7]. While low cost abatement may be an objective of Direct Action (and other procurement-based programs), low cost abatement under the Emissions Reduction Fund ("ERF") guidelines may not generally offer the level of additionality that higher cost, more risky activities may offer. Hence, procurement based on the lowest cost of abatement may produce little additional abatement without encouraging riskier, technology based deployments.

Policy design must take account of other objectives (rather than just low cost abatement) including regional or sectorial development, employment growth, development of industry resilience and health benefits.

6.4 Demonstration Programs

[7] For example, under California's RAM Program PG&E tendering conditions include a minimum level of developer experience (being at least one other project of similar technology and capacity) and technology risk (for example, in use at least two operating facilities of similar capacity worldwide).

Demonstration has been adopted as a common policy element by government in order to address perceived weaknesses in the innovation process between research and commercialisation.

As opposed to research projects aimed at generating basic knowledge, demonstration projects are typically aimed at addressing the uncertainties and risks associated with innovation which prevent potential users from adopting new technologies. By increasing the opportunities for joint fact finding and, particularly, by revealing more about the impact and operation of various new technologies, demonstration projects are claimed to promote public learning and enable the rework of design characteristics based on performance, environmental or visual impacts. Demonstration projects can enable scale up from the laboratory to commercial scale and help with learning about, and changing institutional and wider societal barriers to adoption. Demonstration projects test technology, products, processes and systems and they promote market diffusion and commercialisation. The wide-ranging technical, economic and commercial/ market objectives attributed to demonstration projects explain the complexity in assessing their success.

Western economies (recently followed by China's guided economy) have sought to bridge the chasm between laboratory-scale technology trial and commercial rollout, through the use of publicly funded demonstration projects and market measures which seek to limit the risk by commercial actors willing to invest in commercial deployment. Demonstration initiatives first received support in the USA and Europe in the defence equipment industry and are now widely applied in the energy and environmental field for projects such as utility-scale solar and advanced wind power (Department of Energy, 2010), water desalination, and CO2 sequestration (Natural Resources Canada, 2010) among others.

Many countries fund programs that subsidise the research, development and commercialisation of renewable electricity generation technologies. For example, the UK Marine Renewables Deployment Fund provides £50 million to support research into wave and tidal technologies and many countries (including China, Germany, South Korea, the UK and the USA) fund the research and development of clean coal technologies. Australia's National Low Emissions Coal Initiative and the Global Carbon Capture and Storage Institute fund research and development programs for carbon capture and storage to accelerate the development of industrial-scale CCS projects internationally. Many of these programs have failed to achieve tangible progress since their inception.

Unlike research and development funding, technology demonstrator projects are typically short term projects that help demonstrate the level of maturity of technologies in support of capability management decisions. They provide evidence for concept assumptions, foundation reviews, project and critical design reviews. Technology demonstration projects have also been defined as "a finite initiative to test a technology according to project objectives" (Karlström and Sandén, 2004).

According to the UK Ministry of Defence (UK Ministry of Defence) technology demonstrator projects are "short term projects (or project activities) that help demonstrate the level of maturity of technologies in support of capability management decisions. They provide evidence for concept assumptions, foundation reviews, project and critical design reviews ... " Technology demonstration projects have also been defined as "a finite initiative to test a technology according to project objectives" (Karlström and Sandén, 2004).

Demonstration projects typically embody some common characteristics including; the perceived or actual existence of technical, manufacturing, production, commercial or operational risks; substantial project/capital expenditure requirements; public benefits of successful outcomes; dependence on public or large corporate infrastructure; joint sharing of risk and investment between public and private sources.

Demonstration is an element of technological evolution. Research, development and demonstration take place at an early stage of technical development, preceding the commercial use of a nascent technology(Sagar and Van der Zwaan, 2006). Demonstration programs typically consist of a portfolio of projects focussed on a common technology arena or solution to a barrier to adoption. Such barriers might include price distortions, initial cost barriers, provision of information to consumers and infrastructural barriers as well as political barriers to building coalitions among stakeholders and diffusing learning benefits (Harborne et al., 2007). Demonstration programs are often designed by governments to overcome these barriers. Programs may be competitively based (selecting alternative technical solutions, or stakeholders, or geographical sites) or collaborative (demanding diffusion of learning, sharing of intellectual property and stakeholder collaboration). This has in some circumstances supplanted the historical paradigm of innovation whereby governments assume a major role in basic science while industry undertakes the task of taking products into the market.

Demonstrations explore the commercial applicability of a relevant technology which has actual or perceived risk in the ability to scale, be produced in commercial quantity, or meet critical functional or operational criteria. Samuel Morse received $30,000 in 1834 to demonstration a telegraph systems between Washington DC and Baltimore MD. In the military, demonstration projects have been used since the first world war to demonstrate the capabilities of weaponry ranging from early piston engine fighters to naval vessels and more recently multi-role jet aircraft with the primary purpose of demonstrating operational performance of prototypes prior to investing at production scale. Demonstration projects in the life sciences were introduced in Europe in 1994 with the intention of accelerating the exploitation and dissemination of new technologies (The European Commission, 2000). Environmental demonstration projects have been directed at demonstrating the environmental and operational consequences of production-scale implementation of water treatment technologies. In energy, demonstration programs emerged after the Middle East oil embargo to extend research in nuclear technology, implement renewable large scale renewable energy initiatives and prove sustainable technologies, in particular integrated carbon sequestration.

The US Clean Coal Technology Demonstration Program ("CCTDP") was founded in 1986 as the first of the major clean coal demonstration programs whose primary objective was to address acid rain. The primary goal of this multi-billion dollar program was to develop and demonstrate, at a commercial scale, a family of clean coal technologies. The program recently concluded with 33 reportedly successfully completed demonstration projects that meet or met existing environmental regulations, compete in the electric power marketplace, and provide a technical foundation for meeting future environmental demands (National Energy Technology Laboratory, 2014)). The Department of Energy claims the CCTDP as a model of government and industry cooperation which successfully met the DOE mission of fostering a secure and reliable energy system that is environmentally and economically sustainable. More recently, the US Department of Energy allocated US$600 million out of a total anticipated expenditure of $1.5 billion for 16 energy storage and 16 regional demonstration projects under the Smart Grid Demonstration Program (U.S. Department of Energy, 2015), for "new and more cost-effective smart grid equipment, tools, techniques, and system configurations that can significantly improve upon today's technologies." The largest grant it will give under that pool of grant funds is $100 million.

In 2007, the French Government launched, the Grenelle de l'Environnement process (Celine Najdawi, 2012) "which brought together the stakeholders of environmental issues and sustainable development in order to agree on common long-term decisions". An initial demonstration fund "of €325 million was granted for the period 2009 to 2012 in order to support projects in the field of environmental innovation". Subsequently, the French government committed a further €1.125 billion to the French Environment and Energy

Management Agency for the support of demonstration projects in the field of renewable energies, low carbon energies as well as green chemistry.

In Australia "Capability and Technology Demonstrator" projects which demonstrate whether higher risk technologies enhance military capability have been undertaken cooperatively with other governments. The past decade, has seen federal governments of both persuasions announce the $523m Low Emissions Demonstration Fund ("LETDF") and the $1.5bn Solar Flagships programs. These programs may be compared with international initiatives such as South Africa's Independent Power Producers ("IPP") Procurement Program and the U.S. Department of Energy Loan Guarantee Program. With a range of other relevant Australian programs in various stages of implementation (including, for example, the $1.9bn CC&S Flagship program, the Australian Geothermal Drilling Program, the $10bn Clean Energy Finance Corporation) the implications of effective demonstration program design are significant.

6.4.1 Case Study - LETDF

Technology demonstration projects are not well known in Australia, so much so that they may be considered almost an ad-hoc creation of recent Australian public policy. The records show few initiatives which would qualify as demonstration programs within a complex Australian public innovation system environment over the past 20-30 years. The Low Emissions Technology Demonstration Fund satisfies the common characteristics of demonstration projects outlined earlier. It was followed by the Victorian Large Scale Demonstrator Project ("LSDP") program.

The LETDF was launched by the Minister for Industry, Tourism and Resources on 11th October, 2005 having been announced in June 2004. The context for this policy initiative was a social/political environment of some disillusionment with the then Government's environmental policies. Some viewed the Government as an environmental recalcitrant – being one of only two developed countries failing to sign the Kyoto protocols, and it faced overt condemnation from environmental interest groups as an indicator of more general public disaffection on this issue. With this in mind, the LETDF may have been viewed as an initiative which was as much designed to enhance the Government's environmental credentials as to make a meaningful impact on the adoption of low emissions technologies. The Howard government announced the LETDF to operate from 2005–2020 with the proclaimed objective of supporting the demonstration of new low emission technologies with significant long-term greenhouse abatement potential as part of a more general set of initiatives in relation to the environment. The Government would provide funding to "help

Australian firms commercialise world-leading low emissions technologies". The LETDF program itself would provide $522.9 million over 16 years to projects that accelerate the demonstration of new low emission technologies to achieve significant greenhouse abatement over the long-term. The fund was designed to be technology neutral and include low emission fossil fuel electricity generation, geo-sequestration, hot dry rocks, energy efficiency and intelligent transport systems and there was no specified funding limit on each project. The LETDF would provide joint private sector and public funding of qualified projects and would be jointly managed by the Department of Environment, Water, Heritage and the Arts and the Department of Industry, Tourism and Resources.

The stated objective of the LETDF was to "demonstrate the commercial potential of new energy technologies or processes or the application of overseas technologies or processes to Australian circumstances to deliver long-term large-scale greenhouse gas emission reductions."

Victoria's Large Scale Demonstration Project was announced in May 2005 as one of the initiatives under the State Government's $187m Energy and Technology Innovation Strategy ("ETIS"). The LSDP would leverage the Commonwealth's LETDF but in contrast to the LETDF, the Victorian Government's objective was to ensure that "the State maintains a reliable, efficient and economic generation system." In its 2004 report (Department of Infrastructure and Department of Sustainability and Environment, 2004) into the environmental challenges of energy management policy in the State, the Victorian Government identified that additional base load brown coal fired power generation will be required from 2015. However, in order to have economically and environmentally-competitive brown coal power generation technologies in commercial operation by 2015 the demonstration of those technologies in pre-commercial scale (approximately 100 MW) by 2014 would be required. The underlying rationale for this was that private investors and operators needed "bankable" projects around 2012 on which they can build investment cases to deliver commercial-scale generation plant around 2020. The Victorian Government subsequently announced a further $110 million fund to establish new large-scale, pre-commercial Carbon Capture Storage (CCS) demonstration projects.

The LETDF and LSDP objectives do not clearly address any of the identified criteria of demonstration projects outlined earlier in this paper, such as shared learning, dissemination of knowledge, creation of stakeholder coalitions or the ultimate transfer of risk from the public to the private sector. Further, no details of selection processes were announced.

Applications for funding in round one of the LETDF closed on 31 March 2006. Thirty applications were received from electricity generators, oil and gas producers, iron and steel producers, the oil and gas services sector, and the transport sector for low emissions technologies covering brown and black coal, natural gas, transport and renewable energy. The department established a panel of experts to assess the merits of each application. This process was managed by AusIndustry.

Responsibility for the LETDF was transferred to the Department of Resources, Energy and Tourism ("DRET") in 2007. No further funding rounds were held and DRET's annual report 2007/8 noted that grants totalling $410 million were offered to six companies. In June 2008 five projects were announced as final qualifiers for LETDF funding totalling $345m. $96m was budgeted for investment in 2008/9 and $137m in 2009/10. It's not clear how much of this was acquitted, however, it is estimated that less than 25% would have been spent in these periods. The revised 2010/11 budget indicates a planned expenditure of just $38m (versus $137m) in 2009/10 and a total expenditure of $281m - just over half of the original program headline budget of $522m.

In May, 2011, DRET announced that three out of the original six projects were being supported under the LETDF with one project having its funding offer withdrawn, a second having its funding support transferred to an alternative program (NLECI) and a third having its funding agreement terminated.

The approved projects were (1) HRL - an Integrated Drying & Gasification Combined Cycle Clean Coal 400 MW power station to be built in the La Trobe Valley in Victoria; (2) International Power - a brown coal drying and carbon capture and sequestration project to be implemented at the Hazelwood power station in the La Trobe Valley in Victoria; and (3) Solar Systems - a Large Scale Solar Concentrator Power Project to be implemented in north west Victoria; (4) Gorgon - a carbon dioxide Injection Project at the Gorgon gas fields in Western Australia; (5) CS Energy - an oxy-firing and carbon sequestration project at the Callide A power station in Queensland; (6) Fairview Power - selected to obtain a $75 million grant extract and burn methane from coal and inject and store the carbon dioxide emissions underground in Queensland.

Three of six approved projects were to be co-funded by the Victorian Government under the LSDP initiative. Funding was committed to three proposed projects. In April 2008 the government announced an extra $72 million towards large scale sustainable energy demonstration projects and said it "would be seeking proposals for large-scale, pre-commercial demonstrations of sustainable energy technologies such as solar, energy storage, biofuels, biomass conversion, geothermal energy efficiency and clean distributed energy". It solicited requests for proposals in December 2008 and these are currently being assessed with the outcomes to be announced in late 2009 / early 2010. The selection process for LSDP funding included an initial assessment by two independent assessment panels - one commercial and one technical - over a period of weeks, with the shortlisted projects assessed by an international independent assessment panel.

The first jointly funded LETDF/LSDP project was to be an Integrated Drying & Gasification Combined Cycle ("IDGCC") power station proposed by HRL Limited, an unlisted, Australian owned, energy, technology and project development company. HRL proposed to build a 400 MW demonstration plant in the La Trobe Valley in Victoria implementing a new technology for integrated drying and gasification of moist reactive coals (by heating the coal to ~700 degrees and forming a synthetic gas) to produce power at a higher efficiency than conventional power plants, with an estimated 30% lower cost of electricity production, 30% less CO_2 emissions, and 50% less water consumption. Already demonstrated at the 10 MW scale, this project was aimed at demonstrating the technology at full scale. The Australian Government would contribute $100 million and the Victorian Government an additional $50 million. The project was due to commence in 2007/8.

The second was a coal drying demonstration project proposed by the UK headquartered International Power, the owner of the Hazelwood power station in the La Trobe Valley in Victoria. The project would demonstrate technology to dry the brown coal which would be used as feedstock for one of the boilers at the Hazelwood power station. Subsequently capture and sequestration technologies would be applied to the resulting reduced CO_2 emissions. The project would use internationally available technology in these applications and adapt them to local conditions with an expectation that, if successful, these technologies would be applied to the remaining seven generating units at Hazelwood and may be retrofitted to other brown coal plants in the LaTrobe Valley. The total project cost was originally estimated to be $369 million. The Australian Government would contribute $50 million and the Victorian Government an additional $30 million. Construction was intended to commence in 2007 and be completed by the end of 2009 according to the Victorian Government.

The third project was proposed by Solar Systems Generation, a privately owned Melbourne-based company. The proposed project was the construction of a zero-emission 154MW solar concentrator power station in north-western Victoria. Claimed to be the biggest and most efficient solar photovoltaic power station in the world it would utilise a technology called 'Heliostat Concentrator Photovoltaic' ("HCPV") technology which was claimed to enable 1500 times more electricity generation from photovoltaic cells than the same area of conventional flat plate solar panels. The project would result in a significant scale-up of manufacturing of high-tech plant components in Australia with a new manufacturing facility built for construction of this project and subsequent power stations expected to be ordered from Australia and overseas. The total project cost was originally estimated to be $420 million. The Australian Government would contribute up to $75 million and the Victorian State Government another $50 million. The project was to commence in 2008 and reach full capacity by 2013.

Three other projects were to be funded by the LETDF alone. The first was the Gorgon carbon dioxide injection project proposed by Chevron and its joint venture partners Shell and Mobil. The project is part of the Gorgon gas development off the north-west coast of Western Australia and involves the injection of carbon dioxide into a nearby saline aquifer underneath Barrow Island. The project is at commercial scale and involves capturing carbon dioxide from reservoir gas, compressing and dehydrating the CO2, transporting the CO2 by pipeline to a saline aquifer under Barrow Island and injecting it into the aquifer while monitoring the injected CO2 to ensure health, safety and environment security. Carbon sequestration is emerging as a credible technology in the oil and gas sector where capture of CO2 is relatively straightforward and sequestration is being applied in several oil and gas fields such as in the North Sea where liquid CO2 is sequestered in depleted oil reservoirs. Injection of CO2 into a low permeability saline aquifer is relatively unproven and this is expected to be the world's largest geological sequestration project of its type, removing about 3 million tonnes per annum of reservoir CO2. The total estimated project cost was expected to exceed $841.3 million with the Australian Government contributing $60 million.

The second LETDF-alone project was an oxy-firing and carbon sequestration project proposed by CS Energy (which owns the Callide A power station at Biloela in central Queensland) along with a consortium of partners including Japanese companies JCoal, JPower and IHI, the Australian Coal Association, Xstrata Coal, Schlumberger, the CO2CRC and the CRC for Coal in Sustainable Development. The project involves the retrofit the existing Callide A coal-fired power station with a set of new technologies which produce oxygen that is used to oxy-fire pulverised black coal whose combustion gasses are captured with the resulting CO2 separated, liquefied and transported to a suitable geological storage site. The demonstration project would store up to 30,000 tonnes of carbon dioxide over three years. The total cost of the project was expected to be $188 million with the Australian Government contributing $50 million. This project was transferred to the National Low Emissions Coal Initiative (NLECI) also administered by the Department of Resources, Energy and Tourism.

The final project, which appears to have had its funding offer withdrawn, was Fairview Power which was to have demonstrated coal bed methane extraction and CO2 storage. The project was expected to have a total cost of $445m with $75m provided by the Australian Government.

Determining the status of projects funded under the LETDF is challenging. The Department of Resources, Energy and Tourism doesn't publish operational updates of the approved projects on its website or in its annual reports. Similarly, the most recent program updates on the Victorian LSDP are from mid-2008. The Victorian Department of Primary Industries advised (Jan O'Dwyer, 2009) that "there was only one large scale sustainable energy demonstration project funded from ETIS1 - Solar Systems" with $50 million "allocated to the project by the Victorian Government with funding also provided by the Commonwealth." The DPI was unable or unwilling to provide details of the funding payments made, however, it is believed that only $500,000 had been provided to Solar Systems by either the Federal or State Government.

The author requested information from the DRET however nothing was forthcoming. The lack of public disclosure has been reported by others too – "Neither Martin Ferguson's office nor the Department of Energy were prepared to comment on the Fund. Indeed, the Department of Energy's spokesman, Tom Firth, either could not or would not disclose whether the other four projects had met their milestones or received their promised funding." (Eltham, 2009) DRET has reportedly performed a process review of the program but not dealt with the projects themselves.

According to the Australian National Audit Office (McVay, 2009) DRET has not completed any reviews of the LETDF. However, the ANAO released a report into the Administration of Climate Change Programs(The Auditor-General, 2009) in April 2010 which included an assessment of five climate change programs, which nominally allocated $1.679 billion including the $500m LETDF program. The report's findings were "designed to assist in the implementation of these and future programs as well as convey lessons that may have application to other grant programs in the departments concerned." Relevant to the LETDF was the audit's inquiry pertaining to the "development of program objectives and assessment of program risks;

assessment and approval of competitive grant applications;.... and measurement and reporting of program outcomes."

ANAO officers believed that the program was "moving very slowly and that no outcomes have yet been achieved" but that this was understandable given it was still "early days" with the LETDF and with most of the agreements only recently signed. The report concluded that the LETDF was "not sufficiently advanced for any meaningful comments on overall program results to be made to date." Surprisingly, it also concluded that "The assessment and selection of climate change projects... was transparent, with criteria used to assess all proposals. Generally, there was a high degree of rigour and technical expertise applied to the assessment process." This conclusion was not obvious from the various published material available on the LETDF or discussions with those involved in the project application process. The report also concluded that "performance reporting could have been substantially better in terms of accuracy and consistency".

The Wilkins Strategic Review of Australian Government Climate Change Programs (Wilkins, 2008b) which concluded that "many programs appear to have been introduced to address short-term announcement imperatives rather than in response to evidence of a need to act. As a result, the growth in the number of programs has been 'lumpy' over time. The 2004 Energy White Paper initiatives are an example of this – the speed with which the package of programs was formulated resulted in much of the program design work being undertaken following the announcement of the package. This has led to delays in the implementation of some programs – most notably the Low Emissions Technology Demonstration Fund (LETDF). Despite having been announced in 2004, at this point the Review cannot conclude that the program has achieved clear results." Wilkins concludes that "support for technology demonstration and commercialisation, such as LETDF, which involves one-off funding decisions, does not fit well with the model used for financing and delivering large technology demonstration projects in the commercial sector."

Existing programs supporting the development and demonstration of low emissions technologies appear unlikely to deliver a sufficient portfolio of technologies that will facilitate Australia's transition to a low-carbon economy. This can potentially be attributed to the lack of flexibility in approach and scope inherent in most existing programs – a majority of which are grant programs and directed toward specific energy technologies.

Based on interviews with representatives from Solar Systems and Gorgon and a review of company annual reports and press releases it may be concluded that LETDF has not (yet) delivered.

Firstly, LETDF has been slow to finalise its commitments to projects which the Government apparently, at the time of assessment, found to be promising and few projects were ultimately consummated. The ANAO report found that "... there were substantial delays in negotiating the agreements, subsequent to funding approval. Delays of two years were not uncommon. " While it is not clear to the public, it appears that contracts for LETDF funding have only been finalised in relation to three projects (HRL, Gorgon and International Power). Solar Systems had executed definitive agreements for LETDF funding, however, in August 2009, the company entered voluntary administration after an unsuccessful search for equity investment over a period of about 18 months. It is unlikely that any significant funding from LETDF (or the Victorian LSDP) was ever received by the company. It is unclear whether a more timely commitment of LETDF funding would have avoided this outcome, however this question has been asked ....."*Did Australia's largest solar power project collapse because of government inaction?*" (Eltham, 2009). Following the withdrawal of funding for Solar Systems, the next ranked project was approved for funding. In September 2009, the proponent of a second project entered voluntary administration and the status of that project is unclear. Solar Systems was purchased out of administration by Silex Systems Limited and in October 2012 announced (Hemsley, 2012) it would go forward with its 100MW plant with a $10m grant under the LSDP and the $75m originally committed under the LETDF. However, less than two years later, Silix announced (Goldsworthy, 2014) that it would "suspend plans for the 100MW Mildura Solar Power Station" and terminate funding for the project, of which $75m administered by ARENA was presumable from the LETDF program and $35m was from the Victorian Government. Later, it was reported (Mark, 2014) that "low wholesale electricity prices and the uncertainty surrounding the Renewable Energy Target" were the main factors behind the decision to abandon the project.

It appears that Fairview Power's funding approval was terminated early in the selection process and that CS Energy's Callide A Oxy-fire retrofit was transferred to the NLECI.

According to Chevron, who controlled the Gorgon Project (Torkington, 2009), the LETDF funding contract had not been executed as at late August 2009. The company was awaiting State Government approvals and LETDF contractual commitment was subject to final investment decisions by commercial partners in the project. There is some argument that the delay may have diminished the benefit of the proposed demonstration funding.

The contractual status of other approved projects is unknown. While press releases (International Power, 2009) suggest that some progress has been made at Hazelwood with the installation of a $10 million pilot project, this seems inconsistent with the original project estimates of $369m and LETDF grant of $50m. According to the ANAO "LETDF spent less than five per cent of its budget over a five year period" and in comparison with the originally allocated $500m budget for LETDF only "$335 million has been approved ... with total project costs estimated at approximately $2.6 billion. Actual expenditure in comparison to the original budget estimate has been minimal, with only $23.8 million actually paid out"

Secondly, considering the timeframes and process for the LETDF to reach this point, one must wonder what the status of the "unsuccessful" 25 LETDF applicants is and the 62 initial registrations that were received (of which 17 "were assessed as being ineligible" and "15 decided not to proceed" according to the ANAO). The government had selected 6 projects from among thirty applicants. Of these, only one appears to have had any real traction while at least two others did not proceed. So, despite the intention to fund a diverse mix of technology agnostic projects at the inception of the LETDF, the outcome some nine years later has been non-specific progress in relation to one project focussed on efficient burning and subsequent sequestration of carbon emanating from a coal fired power plant. The range of alternative technologies that may have benefited from LETDF funding would, no doubt, have included solar, tidal, alternative fuel, geothermal, wind and a range of other promising technologies. Perhaps recognising this failure, the Government announced a successor grants programme called the Renewable Energy Demonstration Program (REDP) to which it allocated (subject to successful commercial negotiations) $235 million to four commercial-scale renewable energy projects which include two geothermal technologies - MNGI[8] and Geodynamics[9], one wave-power technology (Victorian Wave Partners P/L[10]) and one integrated renewable energy plant (Hydro Tasmania[11]).

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[8] MNGI Pty Ltd has been allocated $62.762 million to develop a 30MW engineered geothermal system based on Petratherm's 'Heat Exchanger Within Insulator'. The project is located adjacent to the Beverley uranium mine

[9] Geodynamics Limited has been allocated $90 million to demonstrate a 25 MW Geothermal energy plant in the Cooper Basin. The Project will be the world's first multi-well hot fractured rock power project.

[10] Victorian Wave Partners Pty Ltd (a joint venture between Ocean Power Technologies and Leighton Contractors) has been allocated $66.465 million to construct a 19 MW Victorian Wave Power plant which will be the first commercial scale ocean energy project in Australia.

[11] Hydro Tasmania has been granted $15.280 to demonstrate the potential for integrating wind, solar, storage and biodiesel generator technologies into an established electricity network on King Island.

Other criticisms of the design of the LETDF program are the limited extent of funding contribution as a proportion of total project costs and the real contribution or impact of LETDF funding to project success. John Torkington (Torkington, 2009) advised that the total investment as of 2009 on the Gorgon project had been about $2 billion since initial studies of the opportunity began over a fifteen years ago. The investment on CO2 injection alone had been nearly $200m and the expected investment in the carbon dioxide separation, transport, sequestration and ongoing monitoring will be approximately $2 billion when complete. In this context, the LETDF funding of only $60m will have "made no difference to whether the project would proceed or to the facilitation of the project". While a funding approach where the Government makes a commitment of a significant proportion of project costs could be a determining factor in whether a project proceeds or not, such an approach would be at odds with the requirement to pass risk from the public to the private sector. It is believed that Chevron had indicated disappointment that its expectation that the Government would provide 1:2 matching funding for its sequestration proposal at Gorgon was not fulfilled. Carbon Capture and Sequestration projects alone may require of the order of $4-5billion in investment to prove up.

The LETDF process attracts criticism due to the absence of transparency regarding the selection process and criteria for approved projects. Obviously, commercial confidentiality must be maintained in the evaluation of project proposals where detailed economic and intellectual property details are likely to be disclosed. However, while the ANAO is generally complementary about the process, criteria and transparency of the assessment process for LETDF, there is little or no material published which provides guidance for unsuccessful applicants, discloses selection criteria or the make-up and biases of selection panel members.

There is little information providing accurate reporting of evaluation and contractual status and no convenient publicly available reporting on LETDF project status or the progress of approved projects and little scrutiny of expected project outcomes. ANAO reports that in relation to the climate change programs it reviewed "performance reporting is inconsistent and inaccurate". A review of budget estimates versus actual expenditure from 2007/8 to the scheduled program closure date of 2015 suggests that the progress and success of approved projects, and the LETDF program as a whole, is not being actively measured or monitored. The LETDF budget in 2007/8 (DRET, 2008) was $15m versus $1m actually spent; in 2008/9 (DRET,

2009) it appears that $25.1m was budgeted against only $8.7m spent; in 2009/10 (DRET, 2010) $38m was budgeted and nothing was spent. In its 2010/11 report (DRET, 2011) DRET advises that the LETDF had committed $235m to three projects. However, in 2010/11(DRET, 2011), 2011/12 (DRET, 2012), and 2012/13 (DRET, 2013) it appears that nothing was budgeted (or spent) for this program. The only reference to the LETDF in the 2012/13 annual report (DRET, 2013)states that "The Gorgon CO Injection Project is progressing well with some rescheduling due to project optimisation. The first progress payment under the Low Emission Technology Demonstration Fund is expected to be made in November 2013"

6.4.2 Implications for future program design

The Grattan Institute (Daley et al., 2011) has determined that "Over the past decade Federal and State Governments have announced around $7.1 billion dollars to grant tendering schemes aimed at reducing greenhouse gas emissions. Yet only a small fraction of the money has ever been allocated to viable projects. Most projects selected are never built." Demonstration programs are a meaningful subset of such grant tendering schemes. While Grattan did not assess the economic efficiency of demonstration funding it did conclude that "Every million dollars of announced funding produces on average just $30,000 worth of operational projects within five years and $180,000 within ten."

Despite this and other design and implementation failures, Government policy continues to employ demonstration programs as a significant tool to bridge the gap between technology development and market adoption. In Australia alone, a further $2.5bn in demonstration program funding was committed to the energy sector (excluding the $2.4bn CCS flagship program). For example, the $1.5bn Solar Flagships was announced on 18 June 2011. Round one of the program received 52 applications worth about $80 billion. It was intended that two projects would be selected to deliver 400 MW solar generation (Australian Labor Party, 2011). The Moree Solar Farm, a 150-megawatt PV project (Pacific Hydro, BP Solar, FRV) was due to receive $ 306 million but was cancelled because it failed to attract private funding and negotiate a suitable PPA. $465 million of Flagship funding and Queensland State Government funding ($75 million) was committed to for the Areva-led 250 MW CSP Solar Dawn project that also failed to negotiate a PPA. The total cost of the proposed project was estimated at $1.2 billion. When reopened, AGL and First Solar were awarded $166.7 million in federal funding (plus $64.9m of NSW Government funding) for a project that is expected to cost a total $450 million that is planned across two sites (53 MW at Broken Hill and 106 MW at Nyngan).

According to AGL (AGL, 2015) "Construction of the plant started in January 2014 and is expected to be completed by the end of June 2015. In March 2015, the Nyngan Solar Plant began generating power with the first 25 MW of renewable energy feeding into the National Energy Grid" while at Broken Hill construction of the 53MW photovoltaic plant has commenced and is expected to take 16 months. It is not clear exactly how much money has been expended under the Solar Flagships program, however it is unlikely to be close to the $1.5bn initially announced.

The $180m Victorian Energy Technology Innovation Strategy ("ETIS") was announced with "the single objective of driving prospective sustainable energy technologies down their respective cost curves and, in so doing, ensur(ing) that a portfolio of low cost, low emissions technologies are available for commercial deployment to minimise the economic impact of a cost on carbon." (Victorian Government, 2010) The Renewable Energy Demonstration Project ("REDP") announced $235 million in funding to four commercial-scale renewable energy projects which were expected to "deliver approximately $810 million in renewable energy investment in Australia" in the wave, geothermal and an integrated renewables[12]. Little has been heard of the success of these programs in delivering their stated objectives.

Based on the analysis above, the efficacy, efficiency and desirability of demonstration projects in Australia in the field of energy technology must be questioned. While it may not be fair to judge the value of demonstration projects based on an assessment of the success or failure of the programs (notwithstanding the Wilkins Review conclusions or those of the Grattan Institute), they must certainly inform program design, implementation and assessment. Some key questions regarding government support programs include:

- How should the success or failure of a program be measured? Should a substantial government initiative such as LETDF demand hard measurable objectives in relation to

[12] MNGI Pty Ltd (Petratherm)-$62.5m; Geodynamics Pty Ltd-$90m; Victorian Wave Partners Pty Ltd-$66.5m; Hydro-Electric Corporation (Hydro Tasmania)-$15.3m.

deployment of technology, commercialisation, private sector investment and the related timeframes for these?

- What is the relative economic efficiency of support measures such as demonstration project funding? If grant programs are not the most efficient means for promoting the transition from pilot to production scale deployment, what other means exist that are better? Should the Government, for example, directly increase funding to agencies to make risky investments in new technology or infrastructure? Or, should the government do, as agencies such as the EPA in the USA have done, and provide funding guarantees for private and public sector operators to undertake such risky investments?

- What is the relevant commitment and financial contribution (or other contribution such as expedited regulatory approval processes, etc) that the government should make to ensure that selected projects proceed to successful implementation (whether or not successful technologically or commercially)? Is the extent of commitment purely a factor of the size (or relative size) of financial assistance versus total project expenditure or does it vary depending on the nature of the project, an assessment of the project risks, an assessment of the private sector funding environment and other macro factors such as carbon pricing, scarcity of alternatives, etc?

- How should programs be assessed in terms of the relative benefits they provide to successful applicants (and thus, hopefully, to the general economy and environment) versus the risk should the program fail to operate in a timely manner and thus delay the imperative to make hard decisions or result in other promising technologies or initiatives being buried or failing to attract requisite investment having been passed over for publicly funded support? Can the painful conundrum of government "picking winners" in a complex and dynamic technology and pricing environment be solved by government demonstration programs, or does the LETDF demonstrate that government intervention of this form only exacerbates the dilemma?

- Would the market not benefit from readily available status updates on publicly co-funded projects in order to make more informed decisions about different investment options in relation to emerging technologies?

- Finally, should program transparency in relation to selection criteria, evaluation process, contractual progress, project monitoring and assessment be a primary objective in order to ensure accountability of Government, administering departments and funding recipients?

> Or, would the risk of disclosing commercially sensitive information deter potential demonstration project funding applicants and severely restrict the range of solutions available to the market? At what point, does the scale tip in favour of loosening concerns about commercial confidentiality in order to secure attractive funding support? And, surely, would the market as a whole not benefit more from Government expenditure on demonstration projects if more information about the projects economics, technology successes and failure and operational status were made publicly available?

Implementation of public policy interventions is complex and rarely fully achieves its desired objectives. Of course, an obvious pre-requisite is a clear and transparent set of policy objectives combined with robust and credible ex ante and ex post estimates of these objectives be they technological, commercial or industry transformational. Often, however, even this simple thesis appears to be overlooked in programme design in Australia.

Demonstration project objectives are to prove the viability of a new technology together with its possible economic advantages under realistic conditions. Some criteria against which project success could be characterised include novelty (technology or application); pre-existence of necessary knowledge; execution on a realistic scale of operations; participation of both technology producers and users; pre-competitive; demonstrate technical superiority or ability to comply with regulations or standards; or prove its economic advantages.

As if determining the success of *projects* is not problematic enough, assessing the efficiency and effectiveness of *programs* seems almost insurmountable. Demonstration programs are designed to "shorten the time within which a specific technology makes its way from development and prototype to widespread availability and adoption by industrial and commercial users" (Lefevre, 1984) or provide certainty to commercial actors by underpinning demand and thereby reducing investors' commercial deployment risks and enhancing prospects for private investment in these technologies.

Public funding of such programs should enhance the ability to access capital which may otherwise not be forthcoming from private sources due to the perceived risk of the project. A further reason is the need to access shared industry infrastructure or publicly owned infrastructure. Often the outcomes of demonstration projects are expected to be shared among a range of industry actors and access to infrastructure by just one competitor may not be well regarded by others in the sector. The balance between corporate intellectual property creation and the public good is often difficult to achieve. Publicly funded demonstration projects provide some rationale for sharing operational learning's resulting from demonstration projects since the risks of failure are shared between the public and private purse.

Opponents of publicly funded demonstration programs argue that in the absence of a clearly identified strategic need, government sponsorship should be confined to exploratory and diversified research to resolve technical uncertainties. The Center for Science and Technology Policy at NYU (Lefevre, 1984) has concluded that "the record is bleak when the federal government attempts to develop particular technologies when it has no direct procurement interest in the innovation itself" Similarly, Michaelis (Michaelis, 1968), nearly 50 years ago and before the phenomenal growth of innovative privately funded start-up technology companies, argued that technological innovation is pulled into the marketplace not pushed by government.

Another complexity in designing demonstration programs is that, typically, technical unknowns are overshadowed by a variety of economic and environmental considerations. Program objectives are important since technical goals play a major role in program definition while a host of non-technical factors inhibit commercialisation. These technical and non-technical program goals compete with each other for priority.

A further complexity is the appropriate division of administrative responsibility between private and government stakeholders. Government policy often revolves around accountability of public funds while commercial objectives include market positioning, prestige and profits. Government oversight may hinder commercialisation yet address good governance requirements. Project failure (such as the US Solara debt guarantee loss) may provide an inducement for a more hands-off approach once the funding decisions are committed.

Harborne (Harborne et al., 2007) argues that an effective technology demonstration program must "(a) foster diversity for technology innovation, (b) create legitimacy for the technology; and (c) create powerful, persistent and predictable incentives that generate a self-reinforcing process of market creation and adoption." Baer (Baer, 1976) sought to identify the major factors associated with successful project outcomes and formulate guidelines for Government to improve the execution of demonstration programs. Karlstrom (Karlström and Sandén, 2004) explored criteria for ex ante selection of projects and ex post determination of success.

Despite the public data describing demonstration projects in specific areas, there is a paucity of information on the economic efficiency of demonstration projects as a tool of public policy or as an aid to technology commercialisation. This is especially so when considered alongside other policy tools such as business subsidies (which are often applied in countries within Europe for example in the German PV sector), investment tax allowances, or direct publicly funded development.

"It is surprising that the role of demonstration projects ... has not received more explicit and systematic attention, especially as they involve substantial commitments of public funds" according to Harborne (Harborne et al., 2009),a sentiment confirmed by Lefevre (Lefevre, 1984) who commented that "surprisingly little is known about energy demonstrations and whether the sceptics of technology forcing are correct". Hendry (Hendry et al., 2010) states "the role of public demonstration projects ...remains imperfectly conceptualised and researched. Notable in this is the absence of substantial evidence on what companies actually gain as distinct from what advocates suggest they should and what policy makers believe sponsored (demonstration) can achieve". Meanwhile, demonstration projects "if undertaken together with the private sector, can be a strong contributor to the introduction of new and promising technologies in the marketplace" but should "be made only when there is likely to be a sustained market" to avoid being wasteful and ineffective (Bañales-López and Norberg-Bohm, 2002).

Indicators of success of publicly funded demonstration programs include institutional learning that can be shared among industry participants to yield on-going cost improvements and enhanced technological choices; dissemination of information to market participants thus opening up markets and eliminating institutional barriers; creation of coalitions of participants and stakeholders who will underpin market development, and; transference of market benefits and risk from the government sector to the private sector.

Learning results in lower cost, enhanced operational proficiency, improved safety and skills development which enables introduction and diffusion of technology. Learning rates are highest at the initial phases of technology development and plateau as technology matures. The incentive to share learning-by-doing among industry participants in order to build commercial success is often at odds with industrial stakeholders' desires to retain proprietary knowledge.

Technical and market information generation and dissemination to potential adopters is vital to building commercial momentum and, yet, again, industrial often see the data developed during demonstration as proprietary and important to profitable growth. Demonstration program design may encourage or impede collaboration among stakeholders. Program design may induce competition amongst participants for funds (thereby eliminating the potential for broad collaboration of stakeholders) or may induce competition across technologies (and may ultimately result in the failure of complementary technological solutions). Thus, program design is a key determinant of program success in creating appropriate stakeholder coalitions.

Almost by definition, commercial success demands that the private sector assumes most of the risk and benefits of the products or technology. During program inception the proportion of public sector versus private sector risk assumption is a key indicator of the prospects of successful commercialisation. The greater the prospect of success and the greater the reward for success, the larger proportion of risk the private sector will assume. The willingness of a private sector participant to assume a larger share of risk is regarded as the most useful gauge of the likely success of a demonstration project and value creation potential. However, demands within a program for substantial private sector commitments may only permit well capitalised industrial partners to participate and may result in actually exclude smaller firms to penetrate markets (which may ultimately have been addressable without government support in any case).

Strengthening demonstration demands supplementation with other diffusion-oriented programs such as accelerated depreciation schedules, exemption from corporate or sales taxes, government purchase guarantees and grants. In the energy sector, in particular, government regulation regarding carbon emissions and energy efficiency can be imposed to provide economic incentives for industry participants to explore emerging technological solutions.

However, oftentimes, demonstration programs (among other Government interventions) are flawed. Three key areas demand close attention if programs are to actually accelerate commercialisation of technology:

1. Additionality

In order to ensure program outcomes, policy makers must consider the incremental impact of policy versus the counter-factual alternative (which can only be estimated). In the case of emission reduction policies, the mechanisms must apply to influence emissions above "business as usual" baselines. Measuring baselines is complex and hence it is not trivial to determine the true abatement that can be attributed to a particular program or activity. For example, closure of a coal fired power station may not result in emissions reductions since other coal fired stations may increase output to meet demand. Similarly, incentives that enhance the efficiency or abatement potential of existing plant may not displace higher emissions generation since lower cost higher emission intensive plants may be able to compete more successfully to supply a competitive and oversupplied electricity market. Additionality has been extensively analysed in designing policy and the Clean Development Mechanism, for example, has been subject to much review in this respect.

2. Perverse incentives

Some policy measures have been noted as producing effects counter to the policy design. For example, compensation payments to generators for early closure are likely to create expectations that Government's will pay participants upon exit, thus creating incentives to remain in operation until payment is offered and thereby increase barriers to exit.

3. Project delivery risk

Policies which incentivise the development of projects by promising the award of grants or subsidies create risk through failed project delivery and crowding out of other worthwhile alternative projects. Where projects are valued partially for their scale, these risks are magnified. Failure to proceed with projects is not the desired outcome for project developers or their sponsors, however, without suitable performance guarantees, developers do benefit from the 'option value' of winning a public support for a planned project and the option to defer, cancel or on-sell a project is not without value. Meanwhile, other project proponents are excluded from the market for months to many years. Governments do not achieve planned abatement and communities do not achieve lower cost and more flexible outcomes. Simple program design rules such as portfolio risk management which spread incentives across sectors and participants can assist in overcoming these weaknesses, albeit at a higher cost of program administration.

6.5 Assessment of Policy Interventions

In order to assess the success of demonstration programs and similar policy interventions, a suitable framework for evaluation is required. The following framework, developed by the author, is proposed.

Table 7 Framework for Assessing Policy Interventions

Program Objectives	Indicators of Success
Sharing of institutional learning, intellectual property & fact-finding	- Published technical information - Published market information - Published case studies - Patent filings - Declining costs of production and implementation

Shortens time to widespread availability and adoption	- Adoption and availability targets are disclosed at program initiation and continually assessed during program implementation and at conclusion
Enables access to private capital	- Growth of private capital applied to the target sector and underlying projects
Assists in overcoming barriers to market development such as access to infrastructure, permits or regulatory impediments	- Barriers to market development are identified and disclosed - Program design incorporates elements that assist in overcoming identified barriers
Provides appropriate administrative responsibility and accountability	- Results from appropriate industry consultation - Clear guidelines for project delivery and accountability
Results in diversity of technology innovation	- Emergence of multiple technological approaches
Provides parallel implementation of reinforcing incentives for market creation	- Integrates well with other government research, development and deployment policies and initiatives
Is economically efficient (compared to alternative programs)	- Economic analysis framework is developed and assessed prior to program launch
Details explicit project selection criteria	- Criteria are relevant, objective and transparent
Is subject to post-implementation determination of success	- Review and audit are thorough, independent and transparent
Creates stakeholder coalitions for industry development	- Strong collaboration between industry participants - Competition for funds does not crowd out smaller competitors
Results in the transfer of risk from the government sector to the private sector	- High proportion of private vs public funding - Low proportion of contractual, investment and market risk adopted by the government

A large range of policy instruments is available to Governments to assist in overcoming the impediments to adoption of important low-carbon and distributed energy technologies. Among these, demonstration programs have consumed substantial public investment and, as evidenced by the failure of several such programs including the LETDF and Solar Flagships, reform is required in order to advance future program objectives. Program design as well as execution has been flawed while program objectives have been unclear and a new framework must be adopted to ensure past mistakes are not repeated. The underlying thesis that major public expenditure on highly centralised and largely unproven technology deployment will attract future private capital for deployment has not been proven. On the other hand, a range of initiatives, such as SRET, FIT's, reverse auctions and direct grants has demonstrated that increasingly mature and distributed technologies (such as rooftop solar PV and cogeneration) respond much more rapidly to appropriate policy instruments and are much more rapidly *deployed with lower risk. The following chapter considers the factors that private investors DO value when evaluating investments in new sustainable technologies.*

Chapter 7 Private Investment in New Energy Technologies

This chapter explores the rate of growth in investment in new energy technologies and the drivers of such investment and presents a framework for evaluating investment opportunities in this sector.

7.1 Growth and Scale of Investment

New energy technologies have gained significantly increased investment over recent years within Australia and internationally. Despite constrained access to capital due to the global financial crisis and international climate policy uncertainty, a range of drivers including volatile fossil-fuel energy production costs, a growing number of national clean energy policies and inflows of private investment have resulted in continued research, development and commercial deployment of clean energy technologies. Overall expenditure on such technologies grew some sixteen-fold from 2001 to 2008 before falling in 2009 (International Energy Agency, 2010b). Even with this decline, the world saw greater investment in clean electricity generation technologies than fossil fuel generation in both 2008 and 2009. Despite this growth in investment in low carbon sources of energy, fossil fuels remain dominant in the global energy mix, supported by subsidies that have been estimated to $523 billion in 2011, up almost 30% on 2010 and six times more than subsidies to renewables (International Energy Agency, 2012). In 2014, investment in clean energy technologies reached US$310 billion, the second highest annual investment in history.

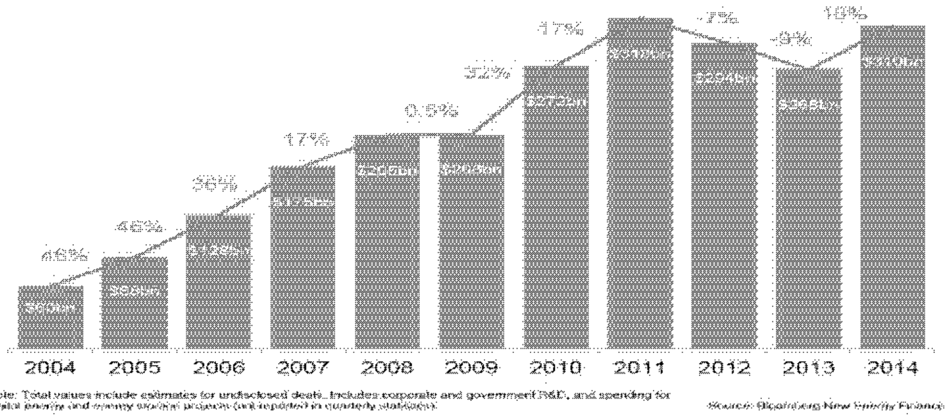


Figure 42 New Investment in Clean Energy

Source: (Luke Mills, 2015)

The largest component of this investment was renewable energy asset finance, followed by expenditure on deployment of small scale distributed energy capacity. The next largest investment component was the public and private investments research and development. This seems to support the suggestion that successful research requires substantially more expenditure on development and demonstration, and perhaps an order of magnitude larger investment in commercialisation and widespread deployment.

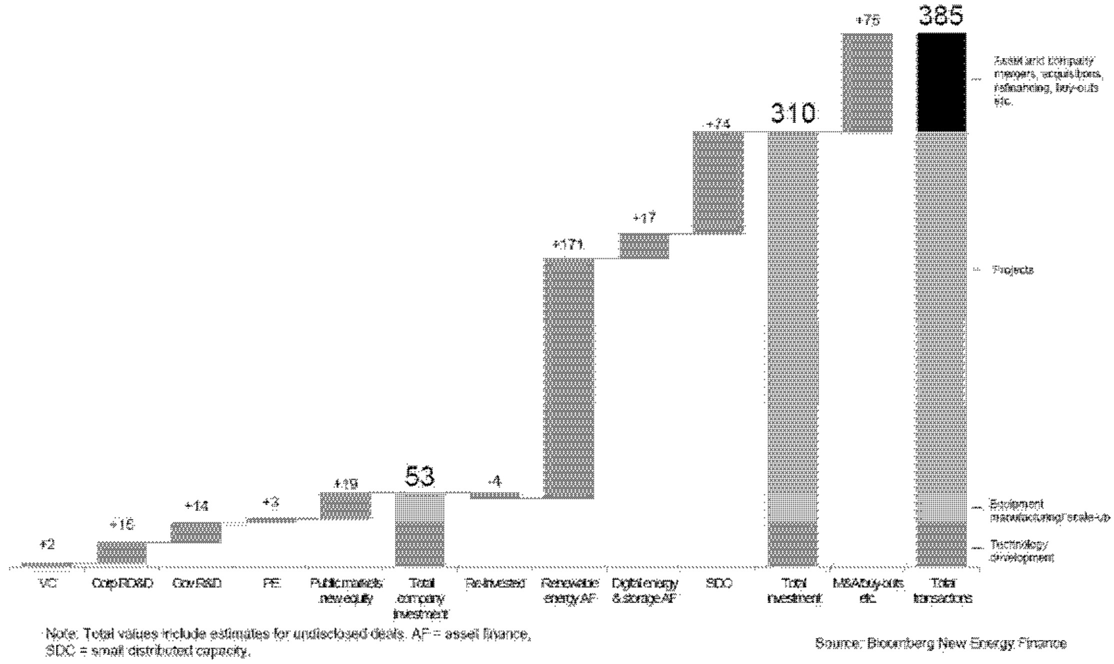


Figure 43 Clean Energy Investment Types and Flows

Source: Mills, 2015 #261}

Innovation can fail at any point in this chain. Governments have a key role in R&D and demonstration, yet the scale of investment that appears to be required to address our climate and energy security concerns will almost certainly require major private investment (at least, in market-based economies). Such private investment will be driven by direct corporate (strategic) expenditure as well as participation by financial investors such as mutual funds, banks, venture funds, infrastructure funds and the like.

7.2 Drivers of Investment

Commercialisation of innovative technologies is a challenging exercise, demanding competitive intellectual property, market access, organisational expertise and access to capital. Furthermore, the clean energy technology sector faces some unique challenges. Unlike other highly innovative areas of the economy such as IT and pharmaceuticals, clean energy technologies must demonstrate technical, operational and economic viability in the face of well established, relatively inexpensive and proven alternatives. The only real disadvantages of these incumbents are future supply constraints and consequent uncertainties on future pricing, and a range of adverse environmental impacts, which remain unpriced externalities in our energy markets. As a result, the great majority of current clean energy asset investment is presently driven by supportive policy incentives such as feed-in tariffs, renewable energy targets and other publicly funded support.

There are two key contexts for driving complementary private investment – the policy and wider institutional frameworks put in place by national governments to support clean energy, on the one hand; and firms' internal processes of financial investment decision-making, on the other. There is ample evidence of the challenges in getting such contexts right. For example, some countries have had very limited success in delivering renewable energy deployment targets due to inadequate policy frameworks. Similarly, the decision-making processes of the financial investment community are frequently bought into question, most recently due to the evident misallocation of capital that contributed to the global financial crisis.

For a relatively small economy like Australia with considerable fossil-fuel energy reserves and relatively low energy costs, channelling clean energy investment appropriately will be vital if commercial exploitation is to generate both environmental dividends and investment returns.

Technology innovation is an enormously challenging process involving R&D, demonstration, deployment and commercialisation. Private investors are generally unwilling to risk capital in such endeavours without commitments regarding commercialisation. In the clean energy space where new technologies must compete against well entrenched fossil fuel incumbents, commercialisation will be highly dependent on government policy support. In some countries, high energy prices, significant government policy support and large energy industry participants ensure there is significant private sector R&D and demonstration. In many others, including Australia, investment in research and development, leading to larger scale exploitation, is generally derived primarily from the public sector – research by universities and other largely publicly funded research institutions such as the CSIRO. Demonstration of promising technologies may be publicly funded, or undertaken by joint public-private investment such as the Renewable Energy Commercialisation Program (RECP) or Low Emission Technology Demonstration Fund (LETDF) (Wilkins, 2008a).

However, none of these mechanisms are suitable vehicles to promote large scale private investment. Major investment will only flow when success in research, development and early stage commercialisation are demonstrated. In particular, adequate risk-weighted investment returns must be demonstrated for such deployments to be widespread and economically viable. Appropriate selection of technology and investment opportunity is critical to ensure that scarce resources are not wasted and that the most prospective investment opportunities receive funding.

Commercialisation takes on a variety of forms including licensing, company formation and growth, joint venture, in-house adoption, deployment or use (replacing or supplementing incumbent products, technologies or companies). The global market for alternative energy sources is estimated (Day and Shoemaker, 2011) to reach US$315bn by 2018 and the number of significant investments in the sector has grown by more than 30% over the past few years (Bennett, 2010). As the IPCC (Allen, 2014) has stated "Substantial reductions in emissions would require large changes in investment patterns .... investments in low carbon electricity supply and energy efficiency in key sectors (transport, industry and buildings) are projected in the scenarios to rise by several hundred billion dollars per year before 2030. Within appropriate enabling environments, the private sector, along with the public sector, can play important roles in financing mitigation and adaptation".

Given the large potential market and the increasing amounts of investment directed towards capturing a part of it, it appears that inadequate focus is applied to improving the success of such investments.

Benchmarks for determining commercial benefit include the breadth of diffusion and adoption, market penetration, funding of local research and development, growth of local manufacture, or broader industry spin-offs that lead to industry development which generate jobs. Benchmarks for societal benefit may include lowering of emissions and greater access to, and reliable availability of, lower cost energy.

Investment success is easier to measure. Internal rate of return, cash on cash return on investment, project net present value, total revenue or contribution to profit are the success measures of financial and corporate investors globally. In determining a framework for investment in sustainable energy initiatives, it is important to focus on the constituents of the relevant investment community. These constituents include corporations (large and small, sector specific such as power utilities or resource companies, and transnational vs local), the public sector (state owned enterprises, universities and research institutions, and governments themselves), and financial institutions (mutual funds, banks, venture funds, infrastructure funds and the like).

Corporate and public investors consider investment decisions very differently to financial investors. Whereas a financial investor would assess an investment in terms of size, risk, return and liquidity, a corporate investor may consider these factors alongside the strategic coherence of the investment, whether it is a core business investment or a peripheral one whose objective is to provide competitive information, create future investment or acquisition options, or to satisfy corporate social responsibility obligations or expectations. A public sector player would heavily weight social benefit and indicators of commercial success such as industry creation, job creation, value added, reduction in emissions, and political and public popularity, among other factors. Corporate investment far outweighs pure financial investment on a direct dollars invested basis notwithstanding the fact that the financial backing for corporations to undertake investment activities ultimately derives from the investments in equity and debt by individuals, pension funds, insurance companies, banks and other financial institutions.

While there is a strong body of prior research on investment decision processes and financial theory – much of this applied to publicly traded stocks where fundamental investment analysis is differentiated from technical analysis through an increased focus on underlying economy, industry and company factors.

In emerging industries with relatively immature actors and unclear market developments, even basic fundamental analytical approaches are inadequate. Investment theory research which is relevant includes aspects related to portfolio and capital market theory, security valuation approaches, market efficiency analysis and derivative valuation (Farrell, 1993). Research related to investment under conditions of uncertainty, the application of behavioural theory, connection to environmental factors through socially responsible investing (De Graaf and Slager, 2006), and debates regarding fundamental versus quantitative analysis (Gregory-Allen et al., 2009) , is applicable to investment decisions in mature industrial and resource markets. However, none satisfactorily address the circumstances of the emerging clean energy sector where there is both an environment of almost infinite combinations of source and nature of technology, stage of development, technological risk, geographic location and political risk, organisational capabilities, prospective growth, public sector support, competing technology, market adoption issues and more; yet also an equally confusing set of choices in funding sources, risk preferences, proximity and availability of funds, investment expertise, vehicle structure, tax regime and competing investment products.

Investors' funds are broadly fungible – they can easily transcend different investment choices and geographic boundaries. In practice, however, funds directed at complex and emerging investment themes (such as infrastructure, exploration, research and development) tend to be locally managed and often locally sourced. Proximity to an investment is presumed to imbue a greater understanding of the risks and potential rewards of an underlying investment. Energy is a global commodity but its use mix is a function of local availability (compared with competing local resources); local cost; availability of energy distribution infrastructure; economic and social costs of changing the fuel source mix; population and market size, growth and profitability; sovereign and political risk, etc. Thus, one must consider the target geography as a key dimension to consider when evaluating the preferences of investors. Analysts such as Ernst and Young (Ernst&Young, 2014b),recognising the importance of country-by-country reviews, conduct on-going analyses of country attractiveness for some aspects of renewable energy – focussing on infrastructure (including market, planning and access to finance) and technology which can provide valuable inputs into an investment decision-making process.

Public policy within a country can play a vital role in attracting private investment. A key government role is to create a coherent and comprehensive policy and institutional framework to support private investment. Public policy initiatives that, firstly, informs prospective investors about prevailing local technology costs and characteristics; secondly, provides 'demand pull' (including government intervention and incentives for sustainable energy, as well as other efforts that demonstrate and enhance social and political will); and finally, delivers 'supply push' support (including availability of some publicly funded capital, appropriate planning and energy market frameworks and skills development) would all enhance an economy's ability to attract investment to the sustainable energy sector.

A great deal of investment takes place based on ad-hoc or flawed investment criteria or no established investment criteria at all. Much of this investment is lost as a result of technology, market and company failure and a substantial proportion delivers below market average returns. These difficulties are amplified by the complexity of the clean-energy sector – with inadequate performance history, massive choices in technology and operational platforms, uncertain regulatory environments and challenges from cheaper well-established substitutes. Government assistance (particularly in Australia) has failed to attenuate these problems.

Improved investment outcomes in the renewable and sustainable energy sectors will lead to a greater volume of capital available for investment and, consequently, better commercial outcomes for technology developers and those who deploy new energy initiatives. Therefore, a thematic approach to investment in the sustainable energy sector is required. This should be informed by a deep evaluation of critical investment parameters according to a structured process, in order to improve investment returns and therefore enhance outcomes in terms of deployment of new energy sources, with the consequent benefits of improved environmental and societal outcomes. The investment community must improve its performance and use of information in order to avoid misallocation of resources and poor early investment outcomes which might cause delays in exploiting emerging technologies and benefiting from better environmental outcomes.

Policy makers should support external investment in commercialisation and deployment without creating distorting market-based incentives resulting from ideological or vested-interest support for particular technologies or companies. Policy should facilitate a coherent and comprehensive institutional framework that will encourage financial investors to successfully generate returns here in Australia. It's a global competition and investment will flow to those places that have the most coherent, secure and prospective investment environments.

7.3 Evaluating Financial Investment Opportunities

An investor in sustainable energy projects would survey the relevant landscape to identify the universe of opportunities that firstly, best align with its world view of technology and market trends and secondly, take a regional view of key adoption factors. A corporate manager would focus upon the requirements of his or her business and identify strategic (such as competitive advantage, market positioning, risk reduction) and operational benefits (such as lower cost and greater reliability) of investing in particular technologies or capital assets.

The universe of potential investments would then be assessed against four key factors (a) scale of investment, (b) liquidity, (c) return potential and (d) risk. These factors, and their underlying criteria, will determine the attractiveness of an investment. These factors may be dissected into more detailed criteria in order to discern the characteristics of individual investment opportunities.

An investment process such as this is relatively standard fare. Modelling of public stock investments utilise approaches which are similar in order to make improved asset allocation decisions (Hoyland et al., 2003). Structured approaches to investing in the property mortgage sector have also been postulated (Matsakh et al., 2008). The challenge in optimising investment in the sustainable energy sector is in determining, firstly, what are the macro trends and factors dictating attention to certain technologies, sectors or geographic regions (i.e. what factors define a potentially attractive universe of opportunities); secondly, what factors comprise the detailed criteria; and, thirdly, what weightings should be applied to these detailed criteria.

Ideally, a mutually exclusive and comprehensively exhaustive set of factors could be constructed against which an investor's preferences could be applied in order to select the most attractive investments for consideration. Ideally, this could be regression tested against real-world examples to refine the commercial framework and use it as a predictive tool. These stochastic techniques are unfortunately not able to be applied to this "real-world" problem since the data for such historical testing and assessment are often absent. The challenges in predicting commercial performance of this immature industry is illustrated by the different correlations between large publicly traded stocks and the S&P 500 index (measured to be as high as 97%) whereas a blend of small capitalisation stocks (with characteristics similar to those emerging sustainable energy sector) demonstrates a correlation to the S&P 500 index of only 78% (Coaker, 2007).

In dealing with technological innovation, in companies that often do not possess scale, robustness or diversity, it is unreasonable to expect significant correlation to financial metrics alone, even if the data did exist. In dealing with established industries such as property or manufacturing or even technology based sectors such as IT or healthcare, an established history of success and failure exists to guide future investment decisions. This is not the case in sustainable energy investment. So, any commercial framework that an investor might apply to the universe of potential investments in the emerging, technology rich, field of sustainable energy innovation must rely on highly qualitative assessments against the selected criteria.

This superimposes analytical risks (for example, imperfect information, information asymmetry, deception or lack of full disclosure by management) and biases (for example, does the assessor have a hidden agenda, a conflict of interest, inadequate knowledge of the subject matter, a non-statistically relevant historical bad or good experience) that are difficult to account for and that may skew the investment outcomes. Being aware of such deficiencies could enable operational processes or counterbalances to be developed to improve investment assessment and resulting outcomes through objective data gathering, assessment and analysis.

7.4 Frameworks for Improving Investment Outcomes

A framework for assessing and managing financial investments in the sustainable energy sector must involve a stepwise process of determining macro investment themes on a sectoral and geographical basis followed by the determination of detailed investment parameters which can be objectively assessed and recorded. These parameters are then weighted based on the investor's preference for risk, exposure and return expectations and assessments made in line with the investor's portfolio requirements. Recognition of the imprecision of the review process, available data and potential assessment errors would then be factored into the decision process. Review of investment performance – both actual investments and broader market performance must be tracked and evaluated in order to gauge success.

Numerous studies (e.g. (Fleten et al., 2007), (Maribu et al., 2008), (Wickart et al., 2007)) have focussed on the outcomes of investment in distributed generation assets. Some explore real options theory and conclude that investment in distributed generation is warranted when demand growth is low and uncertainty is high as a result of smaller unit size and shorter lead times. Other studies have focused "on critical parameters (e.g. electricity demand per household, household density, the cost of battery replacement, policy intervention) in the cost competitiveness and therefore uptake of a particular DG technology." (Lilley et al., 2012).

The World Alliance for Decentralized Energy (WADE) has developed models to determine investments in electricity generation, transmission and distribution capacity and compare future alternative energy systems. These models could be used to assess the investments, benefits and costs of alternative energy assets.

Most analyses focus on the benefit from single energy investments and model these using tools such Distributed Energy Resources Customer Adoption Model (DER-CAM) (Maribu et al., 2007), HOMER (Lilienthal, 2005) and Balmorel (original developed in 2001 by the Danish Energy Research Program).

However, while such models are of critical importance, they may not enhance the quality or likelihood that rational investment decisions will be made absent a more comprehensive framework for investment identification and evaluation. Unless investment objectives are determined, the size of the total investment pool is known and the impact of each subsequent investment decision on a prior investment thesis is understood, having better knowledge about a particular investment's merits is unhelpful. Thus, an investment process model is required.

The author has developed the following investment process model to assist in identifying, prioritising and allocating capital to competing investment opportunities in the clean technology sector.

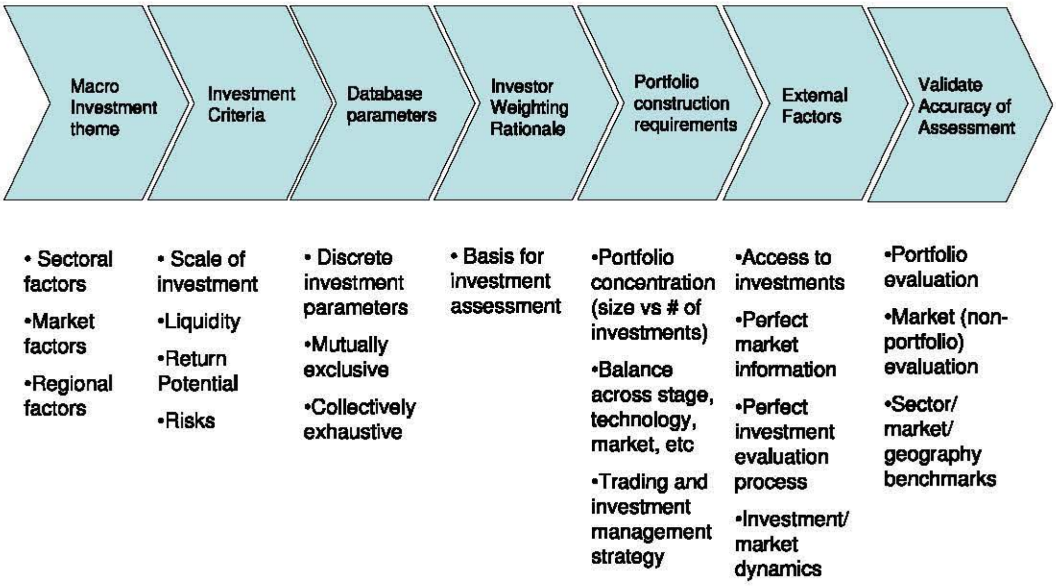


Figure 44 Investment Process Model

The underlying factors underpinning each part of such a process are described below.

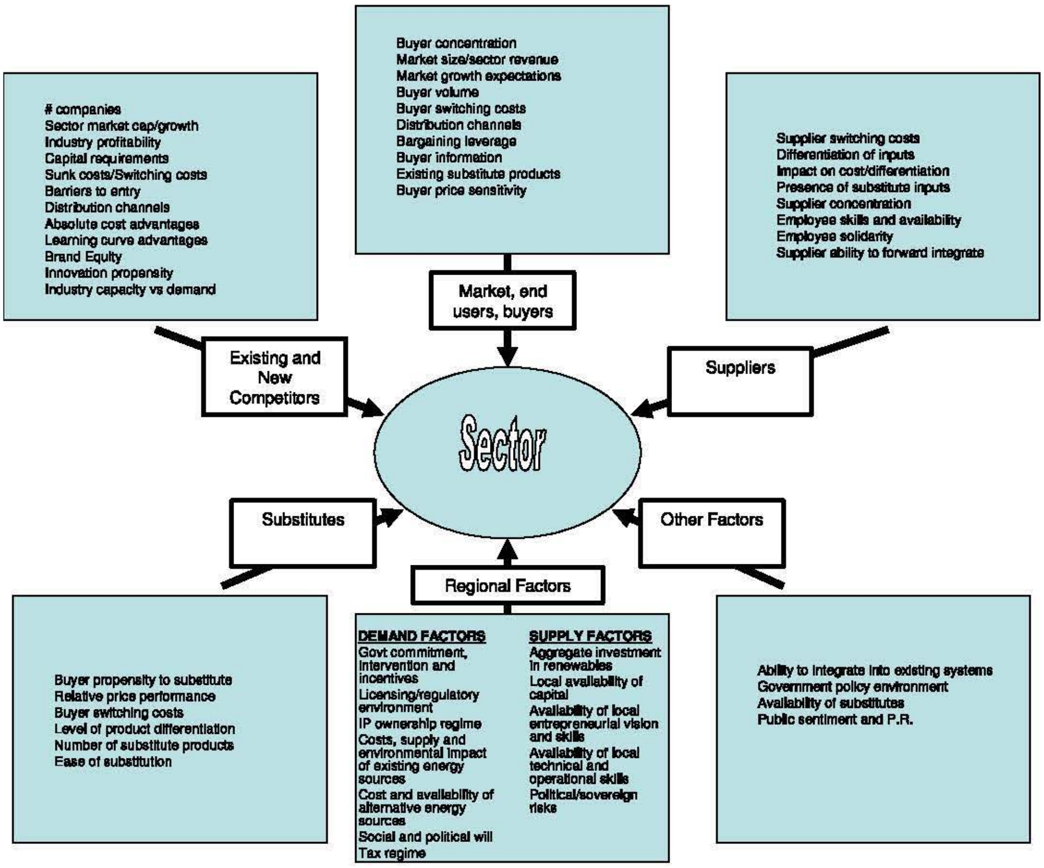


Figure 45 Macro Investment Themes

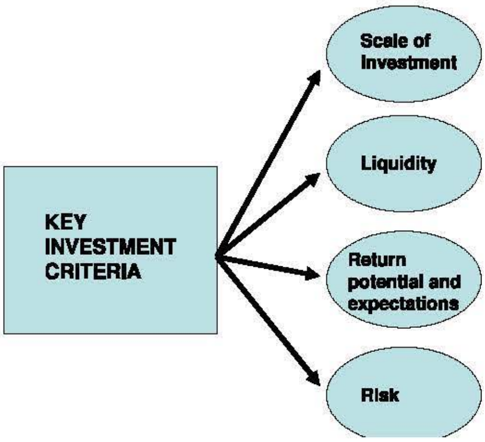


Figure 46 Investment Criteria

Table 8 Assessment Parameters for Investment Criteria

Scale of investment	Liquidity	Return Potential	Risk
Total expected investment Timing of expected investment Equity/debt mix Availability of non-dilutive capital Application of funds	Volume and value of equity (if traded) Number and likely interest of counterparties (if not traded) Time to maturity and stable cashflow Likely liquidity profile when mature Time to liquidity (operational or technological maturity, market)	Anticipated strategic value Value to acquirer Value of assets Market positioning Ability to deliver future value Market value (NPV) Value creation potential Organisational capital	Likelihood and impact of: - external risks (competition, market preferences, etc) -internal risks (management, product failure) -technological limitations -financial market events -funding limitations

Different investor groups will have different preferences in making capital asset investment decisions. Traditional planning for investment in electricity generation assets (based on least cost optimisation) may not place sufficient priority on a portfolio management approach to asset evaluation. Such an approach assesses how an incremental investment may affect the returns of a portfolio relative to its economic risk. Having established the requirements of portfolio construction (Brands et al., 2005), portfolio analyses shows that the addition of renewables to a portfolio of conventional generation assets reduces the overall portfolio cost and risk, even if the stand-alone generating cost of some assets could be higher (Awerbuch and Berger, 2003)

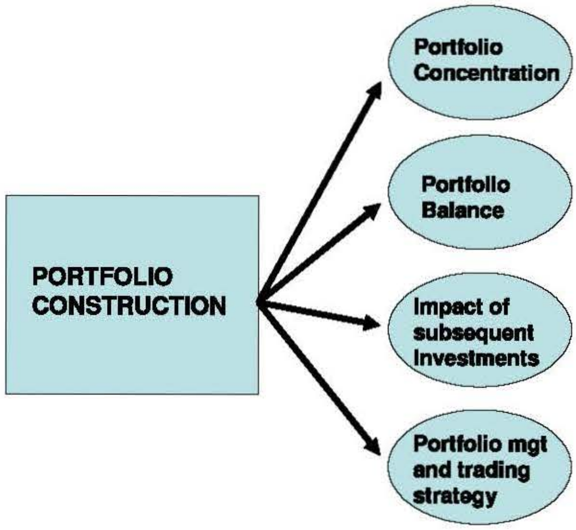


Figure 47 Portfolio Construction

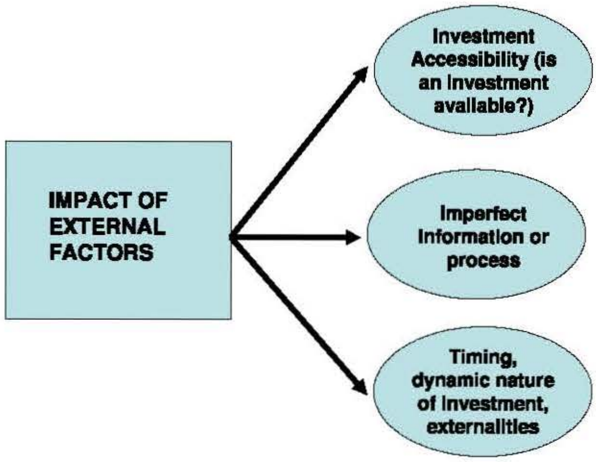


Figure 48 Impact of external factors

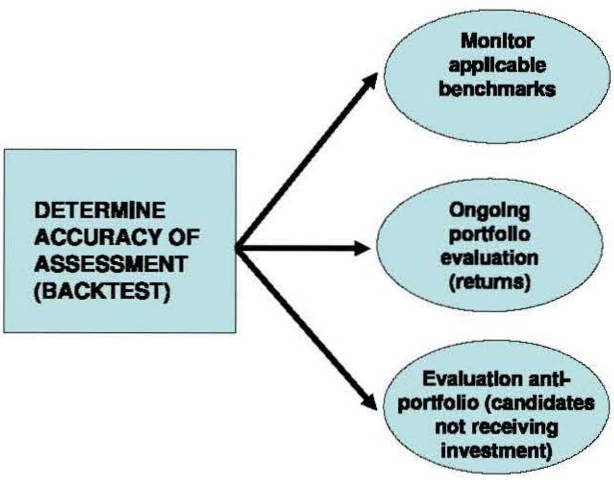


Figure 49 Accuracy of Assessment

Chapter 8 Cogeneration and Trigeneration in Commercial and Industrial Applications

This chapter presents a tool that has been developed to assist in evaluating the emissions reductions and economic returns on investment in cogeneration and trigeneration in industrial applications and presents an analysis of 86 potential cogeneration and trigeneration applications.

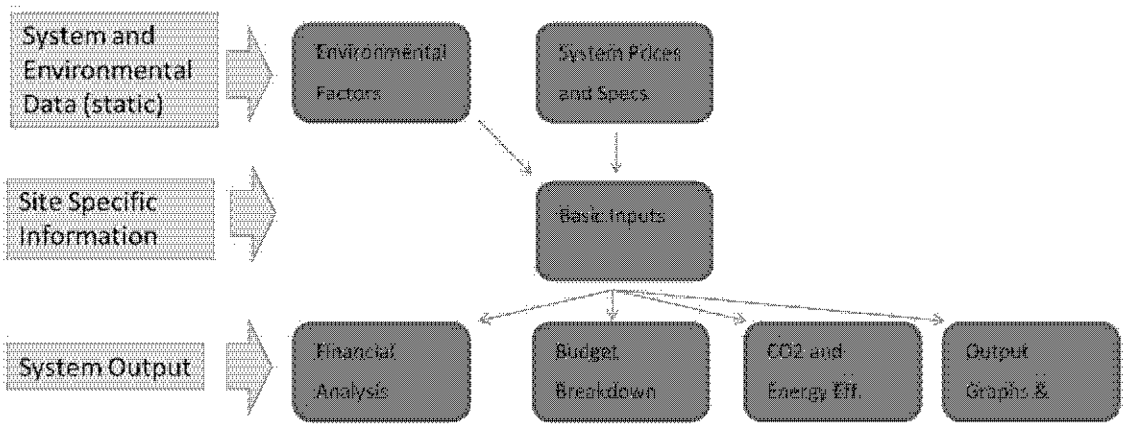
8.1 Modelling Cogeneration and Trigeneration

In order to analyse energy usage, efficiency, and emissions, an (excel) model was developed by the author in collaboration with Mr Jake Thodey (of Simons Green Energy Pty Ltd). This model is the property of Simons Green Energy Pty Ltd and does not form part of the original contribution of this thesis. The model is able to be tailored to suit a site's heating and cooling requirements, with system size, operating hours, and HVAC equipment combinations able to be modified according to user's preferences. Similar models, such as RETScreen (Natural Resources Canada, 2013) and the NSW Office of Environment and Heritage's Cogeneration Feasibility Tool (2013) have been developed by others.

The model co-developed by the author is designed to be applicable to a wide range of industrial and commercial applications. It is differentiated from the models referenced above in several ways:

- It can accommodate multiple generating elements. Presently, it can accommodate two cogeneration systems
- It can accommodate trigeneration system design by incorporating an absorption chiller in the analysis with a variable proportion of waste heat being allocated to heating purposes versus cooling via the absorption chiller
- It can compare financial, energy efficiency and emissions performance with existing BAU systems of a various equipment configurations (eg. boilers, heat-pumps, etc)
- It utilised actual vendor prices for estimated capital costs of deployment and uses heuristic rules for estimating costs of installation, maintenance and operation.

The structure of the model is presented below.



The model uses contains several worksheets that link together to provide financial, budgeting, energy efficiency and carbon emissions data related to the implementation of a cogeneration or trigeneration system. These outputs are represented in tabular form and graphically.

Inputs to the model are broadly of two forms - relatively static data and site specific data. Static environmental data includes information such as grid-based emissions factors and relevant gas/electricity conversion factors. System data includes information about typical systems such as performance specifications, system efficiency, electrical and thermal output, fuel consumption, pricing data based on actual system costs, installation cost data, etc).

The model demands inputs regarding system size, thermal utilisation, installation complexity, operating hours, external tariffs, equipment being replaced or supplemented, how much thermal energy is applied to heading vs cooling and how much is unable to be utilised. Many of these items are assumed based on the nature of the implementation, the specified equipment and specific site data or external analysis. These items include:

<u>Grid Electricity and Gas Prices</u> - Fuel costs are based on operators' historical fuel and electricity accounts and detailed NMI data are analysed to confirm appropriate size matching of the cogeneration unit with the site demands. Uncertainty prevails when estimating future gas and electricity prices over a 15-20 year period and hence both sensitivity analyses and analysts forecasts are used in the projections.

<u>Capacity Factors and Utilisation</u> - Assumptions are made about the capacity factors and utilisation factors of the equipment that is being compared. For cogeneration and trigeneration, it is assumed that the systems are sized for base (not peak) loads and have a

fairly flat load profile. Utilisation and capacity factors of between 90-95% allow for failure and scheduled maintenance.

Operating Hours - Cogeneration systems may operate during hours of business activity which often coincide with times that sites are subject to peak and shoulder electricity rates – typically, between 7 am and 10 pm either 5 or 7 days per week. However, some sites (mainly manufacturers) operate their plants 24 x 7 while others, such as schools or commercial buildings will only operate 15 x 5 or even less. Given the absolute reduction in emissions that derives from the operation of more efficient equipment, obviously, operating lower emissions plant for fewer hours will adversely impact the capital per tonne of emission abatement. However, in order to obtain greater emissions abatement, the equipment might have to operate uneconomically during off-peak periods.

Useful life - Experience in the UK suggests that most cogeneration system operators will not rebuild their cogeneration units after the second life major overhaul which, on average, is assumed to occur at around the 80,000 hours operating life and which will extend the operating life to around 120,000 hours. Operating a unit 24x7x365 will translate this into a life of around 14 years. By comparison, if the engine were the prime mover in a vehicle traveling at 50km/h, 120,000 hours of operation would be equivalent to travelling approximately 6 million kilometres or around 8 round trips from the earth to the moon

Capital costs – Equipment costs are based on actual prices published by overseas manufacturers of cogeneration and trigeneration equipment, along with estimated or actual installation costs of equipment and integration with existing site services (gas, water, electricity).

Financial factors - The discount rate applied to the investment applied to the analysis has a substantial impact on the Net Present Value (NPV) of the investment. The discount rate is based on the assumed weighted average cost of capita for the firm making the investment decision. The rate is generally estimated based on the debt and equity mix of the firm. Generally, the life of the cogeneration equipment is assumed to range between 15 and 20 years dependent upon the run-time assumptions made (24 x 7 vs 15 x 5 or some other scenario).

The model outputs a financial analysis of project returns and an analysis of emissions and energy efficiency as well as a range of financial parameters and metrics to guide decision makers. Key financial metrics include Payback Period, Net Present Value (NPV) and Internal Rate of Return (IRR).

In an environment of uncertain future gas and electricity prices, payback period, the speed with which one will recover the investment, is a measure of the risk of the investment – the earlier capital is recovered, the lower the risk. However, since a 20 year investment may result in a 4 year payback, a focus on this parameter alone is misleading. So NPV (overall value and impact of the investment) and IRR (equivalent to the annual return on the investment) must be compared. Each metric is relevant to an investment decision.

While the primary rationale for a cogeneration investment is generally economic, organisations also derive non-tangible "corporate good citizenship" benefits from promoting the reduced CO2 emissions that these systems generate. Carbon and other emissions reductions such as NOx are benefits of distributed generation. The centralised grid is responsible for over 36% of Australia's total greenhouse gas emissions and a similar proportion of total NOx emissions. The model produces estimates of total carbon abated (compared with relevant emissions intensity of the grid in the jurisdiction where the proposed installation will take place). This information can then be assessed to determine the cost of abatement for an investment in distributed generation.

Similarly, energy efficiency improvement for the energy generated on site compared with that consumed from the grid (which in NSW is reported (Kinesis, 2012) to have an overall energy efficiency of 32.6%) is estimated. The overall site efficiency improvement (for that portion of energy that is replaced or supplemented by distributed generation) is straightforward to assess when the total site use of grid electricity is known.

8.2 Cogeneration and Trigeneration in Commercial and Industrial Projects

Over the period January 2012 – September 2013, 86 commercial and industrial sites were analysed[13] using the model discussed above. Approximately 65% of the 86 sites were in NSW and 12% were in Victoria. Some of the data and conclusions from this analysis are presented below.

Energy Prices

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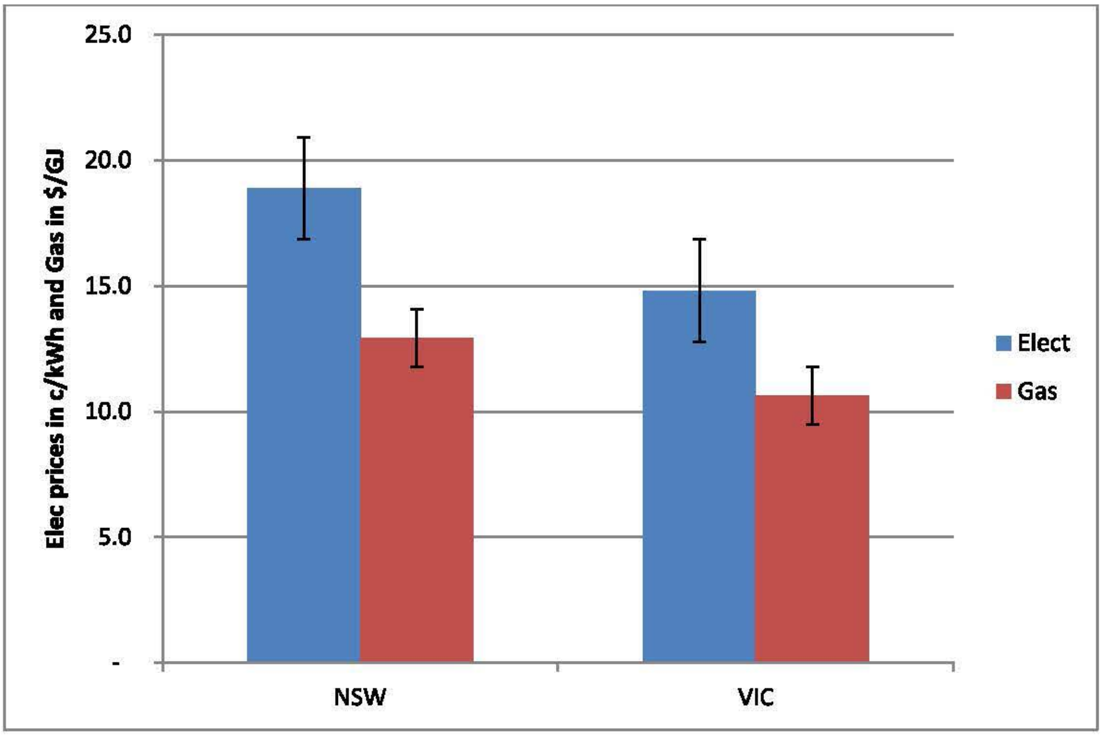
[13] Internal SGE analysis

Actual gas and electricity prices at the time of the analyses were used in the model. Victorian sites benefited from substantially lower general electricity and gas prices. This is consistent with generalised energy price information.



Spark Spread

The 86 sites analysed used different assumptions regarding the projected spark spread (the price difference between electricity and gas) derived from assumptions about future gas and electricity price rises. In analyses conducted during 2012, the forecast electricity prices for the five years to 2017 were projected to increase at 18% annually followed by subsequent rises of 9% per annum while gas prices were assumed to grow at just 5% per annum into the foreseeable future. In analyses conducted during 2013, a much higher risk of gas price increases and more constrained electricity price rises were assumed with the potential installations modelled with identical 7% per annum increases for both energy sources.

To normalise the assumptions about spark spread, three categories were created with approximately, one-third of the proposals falling into each category:

- "large" where the initial 5 year electricity price rises at more than 2.5x the increase in gas prices,
- "moderate" where the initial 5 year electricity price rises at between 1.5x the gas price increase but less than 2.5x, and
- "small", where the electricity price rise is less than 1.5x the gas price rise increase.

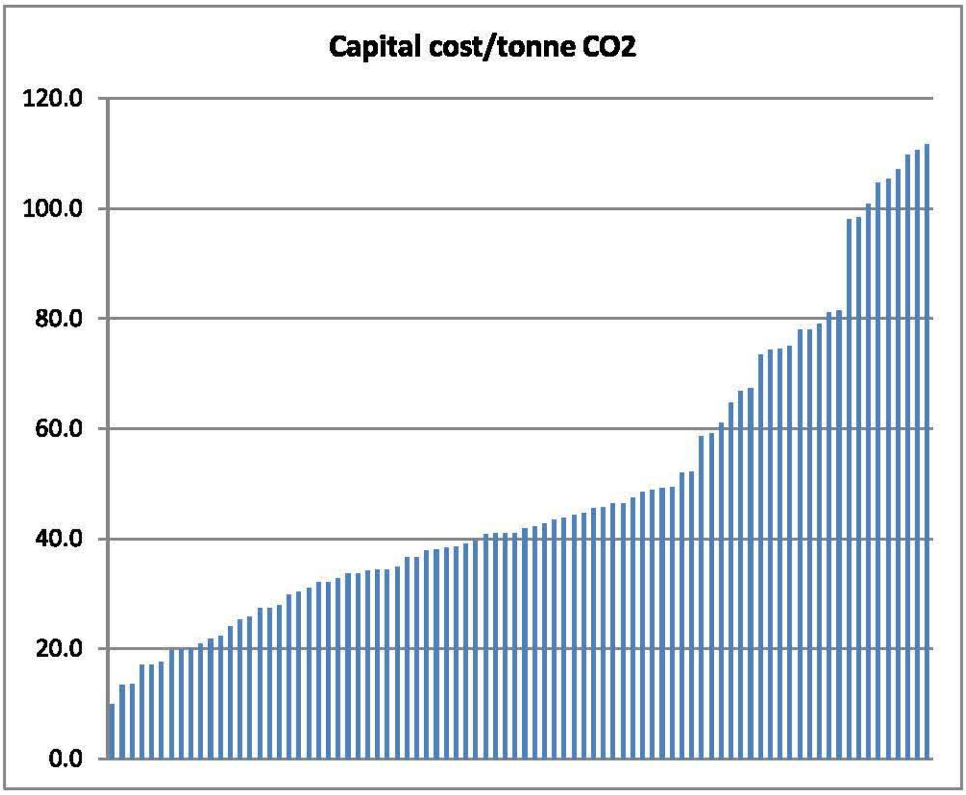
Based on present forecasts for near-term natural gas prices even "moderate" assumptions might now be seen as optimistic for a fuel switch to gas.

Cogeneration vs trigeneration

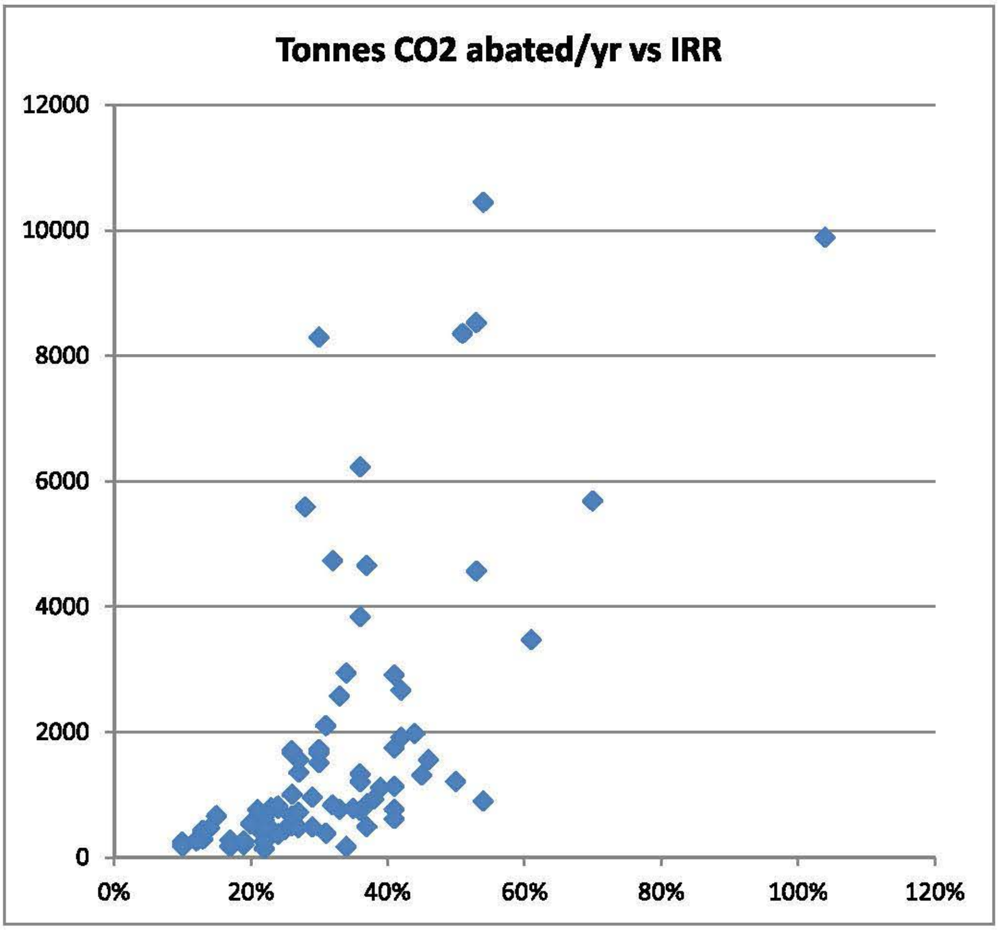
Thirty-three trigeneration proposals were evaluated along with 53 cogeneration proposals. The average capital cost for a trigeneration implementation was $1.35m and the average cogeneration system was less than $850,000.

The results of the analysis suggest that:

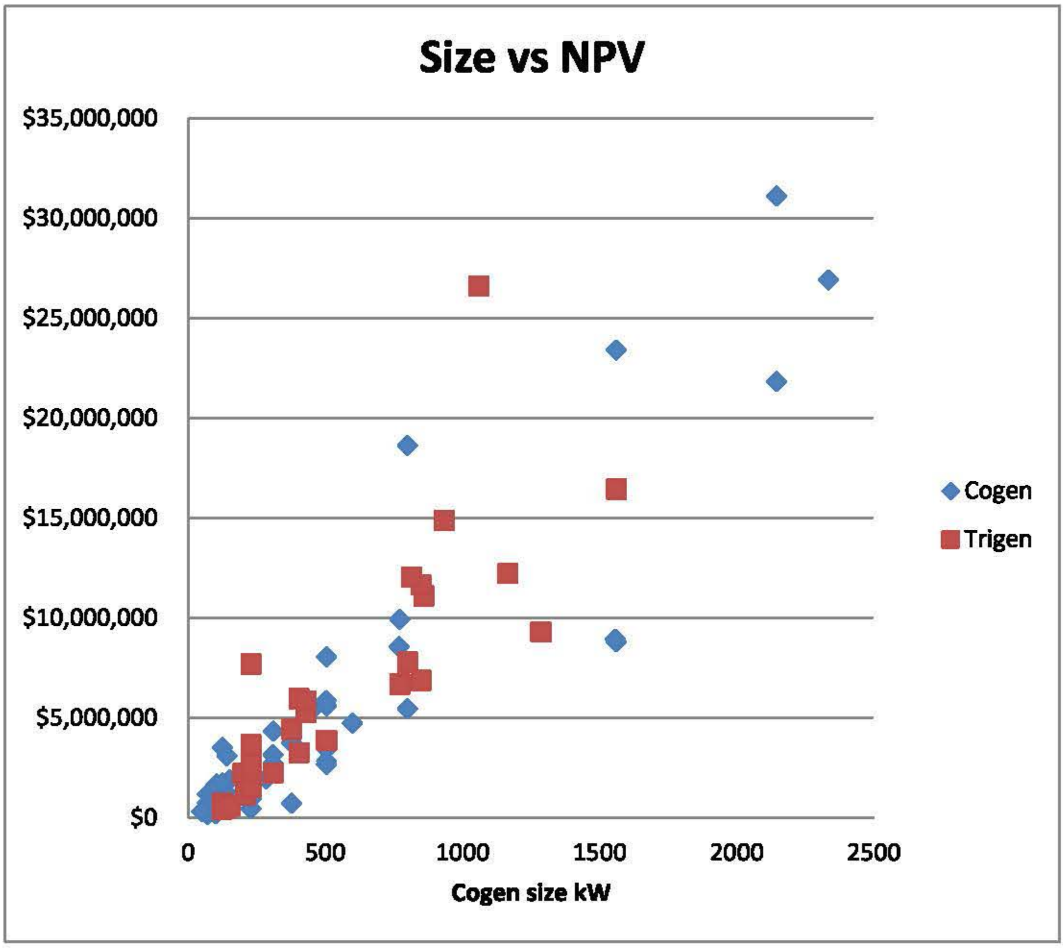
- The average capital cost per tonne of CO2 abated over an assumed 20 year life of equipment is $29.27.



- The average IRR is positive at around 32% per annum and the cost of carbon abatement is negative, that is, a net benefit (saving money while reducing carbon emissions).



- Larger systems are generally more financially attractive, at least below around 500kW. Further, projects that generate greater returns also abate more carbon.
- Cogeneration is a more attractive financial investment than trigeneration. This is because of the additional capital cost for trigeneration.



There is a strong opportunity to efficiently and economically combine distributed technologies with existing motive equipment and thermal plant for process or comfort heating and cooling in industrial settings. The financial metrics (internal rate of return, net present value and payback period) along with sustainability outcomes (emissions and energy efficiency) and risk preference (including energy supply and pricing risks) determine the merits of alternative combinations.

Opportunities to replace or upgrade various energy conversion systems (such as electric in-duct heating or older electric chillers) and source electricity from distributed generation may generate significant returns.

Heating ventilation and air conditioning (HVAC) represents about half the energy consumption for domestic buildings (more than double that for domestic hot water) while for commercial and industrial buildings, Perez-Lombard (Pérez-Lombard et al., 2008) estimated that HVAC energy consumption in developed countries was around 50 % of total building energy consumption and around 20% of total energy use. In the USA it was estimated to be around 57% of building energy consumption. This level of demand creates serious peak load management issues. Consequently, financial, environmental or risk mitigation improvements resulting from combining available technologies and sources of energy such as electricity, gas or biofuels and solar with their uses can be substantial.

Typical technologies applied to these sources and their applications include:

- Grid supplied electricity – Coal fired thermal, CCGT, OCGT, Wind, Hydro, Utility PV
- Natural gas fired cogeneration (reciprocating and turbine) supplying electricity
- Natural gas fired cogeneration (reciprocating and turbine) supplying hot water
- Waste heat steam generators supplying steam
- Hot water or exhaust fired absorption chillers supplying chilled water
- Electric chillers supplying chilled water
- Natural gas fired boiler – fire-tube and condensing style supplying hot water or steam
- Electric heat pumps [14] supplying hot water

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[14] Heat pumps use a refrigerant as an intermediate fluid to absorb heat where it vaporizes, in the evaporator, and then to release heat where the refrigerant condenses, in the condenser. The refrigerant flows through insulated pipes between the evaporator and the condenser, allowing for efficient thermal energy transfer at relatively long distances. These are air-source heat pumps but might also be geo-thermal systems.

- Gas heat pumps[15] supplying hot water

Table 9 Comparison of HVAC Technologies

Thermal Equipment	Technology	Efficiency (COP[16])	Comments
Cooling	Air Cooled Electric Chilling	COP 2.8-3.1	Relatively high efficiency
	Water Cooled Electric (reciprocating/ centrifugal)	Recip COP 4.2-5.5 Centrif COP 5 - 6.1	Very high efficiency which increases with size
	Absorption (waste heat/exhaust)	COP 0.6 – 1.2	Low efficiency, but heat source is "free". Single & double effect
	Electric heat pump (Air Conditioning)	???	
Heating	Boiler (conventional)	80% thermal efficiency	
	Boiler (condensing)	90% thermal efficiency	
	Gas heat pump	???	
	Electric heat pump (air source)	COP 3-4	Theoretical potential for COP to increase to Carnot Limit (12)
	Electric heat pump (geothermal)	COP 2.5 – 5	

Analysing the interaction between these technologies is important. For example, where a trigeneration system consisting of a cogeneration system and an absorption chiller is combined

[15] Sometimes referred to as absorption pumps, gas heat pumps work similarly to any other air-source heat pump, except instead of using electricity to fuel their operation they rely on natural gas. Gas heat pumps have an engine operated by natural gas and utilize natural refrigerants, such as ammonia and water.

[16] useful heat/work input

with electrical chillers, the absorption chiller (with a COP of, say, 1) is typically used to boost the electrical chiller (which may have a COP of, say, 6). The cogeneration system may have an electrical efficiency of around 42%[17] and usable waste heat of around 48% and so would create 0.42 kW of electrical energy plus 0.48 kW of cooling work for each kW of fuel energy. However, to create an identical amount of cooling work from the electrical chiller would require just 0.08 kW of additional electricity (or around 19% more electricity). Therefore, a trigeneration system would be equivalent to a generator with just 50% electrical efficiency at its point of use. By comparison, centralised power generation energy efficiency in Australia is closer to 30% so an increase in efficiency to 50% still represents a substantial benefit. In addition, system flexibility (i.e. timing of electrical and cooling needs), economics and emissions reduction are also major drivers.

In order to assess the benefits of distributed generation's interaction with other equipment, one must determine (or make assumptions about) grid efficiency and emissions (which vary in each state depending upon the generation mix) and equipment that uses the energy within the boundary of the site (e.g. boilers, electric heat pumps, and direct gas air heating for cogeneration systems; or boilers, electric chillers and electric heat pumps for trigeneration systems).

Based on the analysis of the 86 examples referenced above, key combinations of equipment were categorised and their financial, abatement and energy efficiency improvements tabulated below.

Table 10 Analysis of HVAC Technology Combinations

Combination (% of sites)	Average IRR	Avg capital cost/tonne CO2	Avg Efficiency Increase
Cogen Gas Air (1%)	61%	$17.02	88%
Cogen Boiler (56%)	34%	$26.87	67%
Cogen EHP (3%)	23%	$38.59	43%
Trigen/AC (7%)	41%	$20.31	66%
Trigen/Boiler-AC (33%)	26%	$44.16	63%

[17] ENERG technical documentation

In one project, the use of cogeneration to augment gas/air heating generated an IRR of over 60%. This particular company was a manufacturer with several plants in Australia and more than 600 manufacturing plants worldwide. This standout project also had the lowest cost per tonne of carbon abated (i.e. highest saving per tonne) and an excellent efficiency improvement. While gas direct air heating is very efficient, the capital cost of the cogeneration systems is low as a result of very simple integration.

Cogeneration, supplementing traditional gas boilers provides strong returns, relatively low cost abatement and strong increases in efficiency. On the other hand, the simple augmentation of electric heat pumps with cogenerated thermal energy has the lowest investment return, relatively low increase in efficiency and relatively poorer cost per tonne abated.

Trigeneration systems which supplement electric chillers with all thermal energy able to be used in both summer and winter also provides strong returns, very low cost abatement and strong efficiency improvements. These sites are predominately industrial where chilled water is used in the manufacturing processes.

A number of sites were assessed for possible installation of trigeneration but where not all of the thermal energy is required. These sites were observed to deliver relatively lower investment returns and relatively higher cost of abatement, while still offering strong improvement in energy efficiency compared with the centralised grid. Gas fired generator sets which were not combined with thermal equipment to utilise waste heat did not exhibit substantial energy efficiency benefits. However, depending on their applicable gas and grid-based electricity pricing, some made acceptable investment cases while delivering carbon abatement at attractive costs since the capital costs are relatively low given few integration issues and costs.

Replacement of grid-based electricity and aging electrical chillers with trigeneration generated strong energy efficiency outcomes. In one case in Sydney, replacement of two aging 700 kW electric chillers (with COP's of around 3) with a trigeneration solution and a single new 800kW electric chiller with a COP of 6 would deliver an IRR of 26% and a capital cost per tonne of CO2 abated of $41.90. However, due to the improvement in COP of the chillers, there was a significant (86%) improvement in energy efficiency. Sites which could utilise all of the waste heat 24 x 7 produce the strongest results with one outstanding site showing an IRR of above

50% with a capital cost per tonne of abatement of $19.90 and an efficiency improvement of 69%.

The analysis of a large number of real-world cases reveals that certain combinations of technology (such as cogeneration plus absorption chillers which can be used year round to supplement electric heat pumps and cogeneration systems replacing gas-fired direct air heating) generate outstanding investment returns, very attractive emissions abatement and significant energy efficiency improvement. Larger systems tend to offer greater investment returns and cogeneration, as a rule, also offers better returns.

Interesting emerging combinations to consider include industrial trigeneration and solar PV (without storage) augmenting grid electricity and electric chillers and also integrating gas fuel cells with absorption chillers.

It is clear from the analysis that there is clear potential for the application of cogeneration, in particular, and trigeneration under a more restructure set of circumstances. The suitability of cogeneration and trigeneration is dictated by the cost of installation, the relative prices of gas and electricity and availability of favourable thermal and electrical loads. In some cases, the financial outcomes and emissions reduction are compelling and capital expenditure by site owners is easily justified. In many other cases, the economics are sufficiently strong to enable third-party investment (debt or equity) in deployment while delivering suitable risk-weighted returns to investors and ongoing cost-reductions to site owners. Nonetheless, take-up of cogeneration is lower than might be anticipated and direct incentives for deployment in industrial and commercial settings, along with deployment in wider-scale applications may be required to accelerate the rate of diffusion.

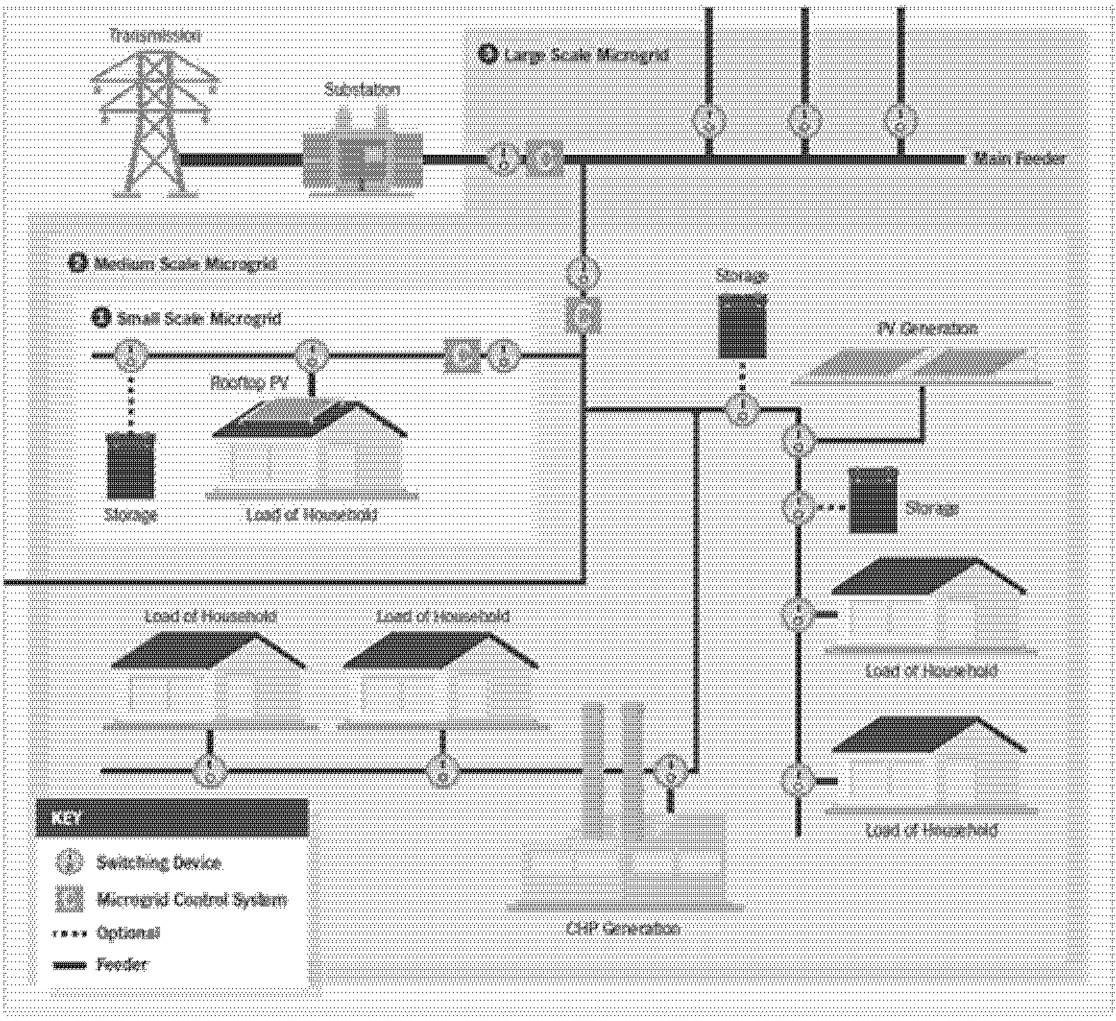
Chapter 9 Cogeneration and Trigeneration in Precinct and Micro-grid Applications

This chapter presents a case study on the application of cogeneration and trigeneration to precinct and micro-grid developments. The results of the analysis are extrapolated to estimate the potential impact of wide-scale deployment of these technologies.

Forward thinking town developers are increasingly investigating the potential for new town and precinct developments to become models for sustainable development incorporating initiatives in relation to water use, waste management and biomass, advanced communications as well as energy. Recognising that buildings in Australia consume around 40% of stationary energy production and are responsible for one-quarter of the Country's greenhouse gas emissions, the opportunities for improved building efficiency combined with decentralised energy production offers the promise of reduced energy intensity and lower greenhouse gas emissions. These benefits can be maximised when the implementation of these solutions is at the green-field stage with the cost of building electrical and thermal networks at their lowest.

A micro-grid may be either an entirely off the grid-based electricity network or may rely on a network connection for emergency backup. This can be determined by economics without being constrained by technology, since acceptable reliability and availability can be guaranteed with an appropriate micro-grid design. To enhance the economics, a micro-grid will provide a distributed electrical and thermal network to residents and occupants of the community. The thermal network will offset traditional individual heating and cooling devices while designing highly energy-efficient housing and commercial premises will reduce overall electricity demands. Development of micro-grids also offers the potential for the community to take responsibility for meetings its own energy demands through community owned energy services companies which may generate sufficient returns to ensure continued investment in the energy network and system and whereby customers can share in the benefits of ownership

A micro-grid mirrors the traditional power grid's structure at micro-scale, typically ranging from between several kilowatts (residential) up to megawatt scale in size. They enlarge features such as distributed generation while compressing others, such as transmission and wide-area balancing. The defining characteristic of a micro-grid is the co-location of power generation and load.



SOURCE: GTM RESEARCH, DOE

Figure 50 Microgrid Topology

The US dominates micro-grid deployments with 44% of known implementations (Asmus, 2010) and 1,500 MW of micro-grid capacity operational. In 2013 alone, there were seven announcements of new micro-grid projects in the USA. In the UK, cogeneration base-load electrical and thermal micro-grids have been established for over a decade. In Aberdeen, the micro-grid utility operates as a not-for-profit entity at arm's length from the local Council. In Woking Borough, a company was incorporated in 1999 to own and operate plant for the production and supply of electricity, heat and chilled water to customers. The Woking micro-grid supplies heat, electricity and chilled water to town centre buildings (hotels, conference centre, civic offices, multi storey car parks) and residential customers using a mix of gas-fired reciprocating engines, absorption chillers and a fuel cell along with solar PV across 80 island energy sites connected by a dedicated "private wire" distribution network. European micro-grids account for 16% of worldwide deployments, while Australia accounts, disproportionately, for 12% of deployments.

In Australia, the large number of micro-grids is a consequence of the number of isolated residential, tourism and mining communities. Most of these micro-grids rely on diesel combined with wind and solar PV. In Kings Canyon, a micro-grid consisting of three diesel generators (total capacity 1.1MW) and 225kW of solar PV supplies the resort and residences. With an area of around 500 square km and 2000 residents King Island is implementing a diesel, wind, solar and battery storage micro-grid, operated by Hydro-Tasmania. The King Island micro-grid incorporates 1.6 MWh (@3 MW) of battery storage, with the capacity to power the entire island for up to 45 minutes. This is reportedly the largest battery storage installed to date in Australia.

Micro-grids have progressed from the demonstration phase to the deployment phase. Along the way, these systems have demonstrated (Shahidehpour, 2011) up to 50% reduction in peak load consumption. In developing countries, village-level micro-grids are a feature of rural electrification. Within the next few years, analysts suggest (Barton, 2013) that over 3.1GW of new micro-grid capacity will come on line representing a total investment of $7.8bn and providing power to one-million homes.

IEEE's standard 1547 is the major guideline for distributed resource integration and focuses specifically on micro-grid issues.

FIGURE 3-15: MICROGRID AUTONOMY SCENARIOS

	HIGH AUTONOMY SCENARIO: MANY ISLANDED MICROGRIDS	MEDIUM AUTONOMY SCENARIO: ONE MACROGRID COMPRISED OF MANY GRID-CONNECTED MICROGRIDS	HIGH DEPENDENCE SCENARIO: WIDE-AREA CONNECTIVITY WITH FEW MICROGRIDS
Advantages	High cybersecurity of "sealed islands"; high local energy efficiency; ability to optimize local solutions for specific targets, such as emissions reduction or deferring local network upgrades	Efficient wide-area balancing (DG systems become controllable, virtual power plants); reduced transmission losses; peak demand reduction at distribution feeder	Wide-area balancing allows leveraging advantages of specific geographies
Disadvantages	High cost of stability management; utility resistance due to complete customer loss in traditional markets; limited balancing capabilities; potential technical difficulties for transient state control of many parallel microgrids	Sunk investment when islanding capabilities are not used most of the time	High fragility of transmission lines; high susceptibility to cyber-attacks; transmission losses
Drivers	High electricity prices that encourage "going offline"; density of critical loads; cost reductions based on fast development of standardized microgrid building blocks	Regulatory and legal standards for microgrid implementation and value stream recovery; limited progress in islanding control	Slow regulatory progress; large-scale transmission system investments
Grid-Edge Relevance	Medium	High	Low

SOURCE: GTM RESEARCH

Figure 51 Microgrid Autonomy Scenarios

Some features of micro-grids are:

- They can effectively utilise diverse but complementary distributed energy resources by matching of supply and demand resources. The micro-grid can be designed to provide a closer fit between desired network performance and specific operating or environmental requirements. A micro-grid can be designed for an acceptable level of efficiency, a specific level of reliability, a specified level of power quality, an environmental emissions profile, or for minimum cost or maximum economic value. That is, a micro-grid can make traditional commoditised electricity customisable to meet the needs of its consumers, a feat difficult to match by traditional centralised grids.
- They can empower the consumer and create choices for how to manage risk while optimising costs. While traditional electricity consumers are price takers, a micro-grid's customers have greater flexibility to make investments in efficiency and distributed generation (rooftop PV and storage) while receiving more rational compensation from their provider.
- They can promote infusion of private capital with investors making choices between continued investment of large amounts of capital to replace and maintain ageing infrastructure while complying with environmental standards, micro-grids provide alternative investment options which have the added benefit of easing demands on utilities and while simultaneously modernising the grid. It has been estimated (Asmus, 2013) that the global micro-grid market is expected to grow to as much as US$40 billion by 2020.
- They improve energy efficiency by generating electricity at sites that are located close to the customers served. The 7–10 percent losses typical in transmission and distribution are eliminated saving energy costs, reducing emissions and preserving resources.

Thus, micro-grids offer the potential to deliver substantial carbon emissions reductions, improved overall energy efficiency and lower long term operating costs and energy prices to energy consumers. In order to deliver these benefits, the proposed energy system must optimise demand (demand management) on the one hand and supply on the other, in a cost efficient manner both in relation to capital costs (deployment) as well as operating costs.

The key design issues surrounding the growth of micro-grids are cost, availability and reliability.

- Cost is a function of capital investment in generation and distribution plus the operating costs of the infrastructure.
- Availability is determined by the design of the system to ensure it provides sufficient energy to meet the variable loads imposed on it, at all times. Peak load events (often weather induced) demands sufficient reserve capacity be made available while demand management capabilities can reduce the absolute requirements of these peak events.
- Reliability will be derived by examining the robustness of the distribution network and an analysis of the reliability of each item of generation equipment. Diversification of generation sources, fault prediction and identification along with ease of rectification improve reliability.

Cogeneration-based micro-grids (with gas fired reciprocating or turbine powered electrical generators) combined with renewable generation and storage are anticipated to provide the requisite reliability, availability and economics to compare favourably with the traditional centralised electricity grid. As indicated in the charts below, cogeneration compares favourably with a range of low-carbon generation technologies when new generation capacity is required.

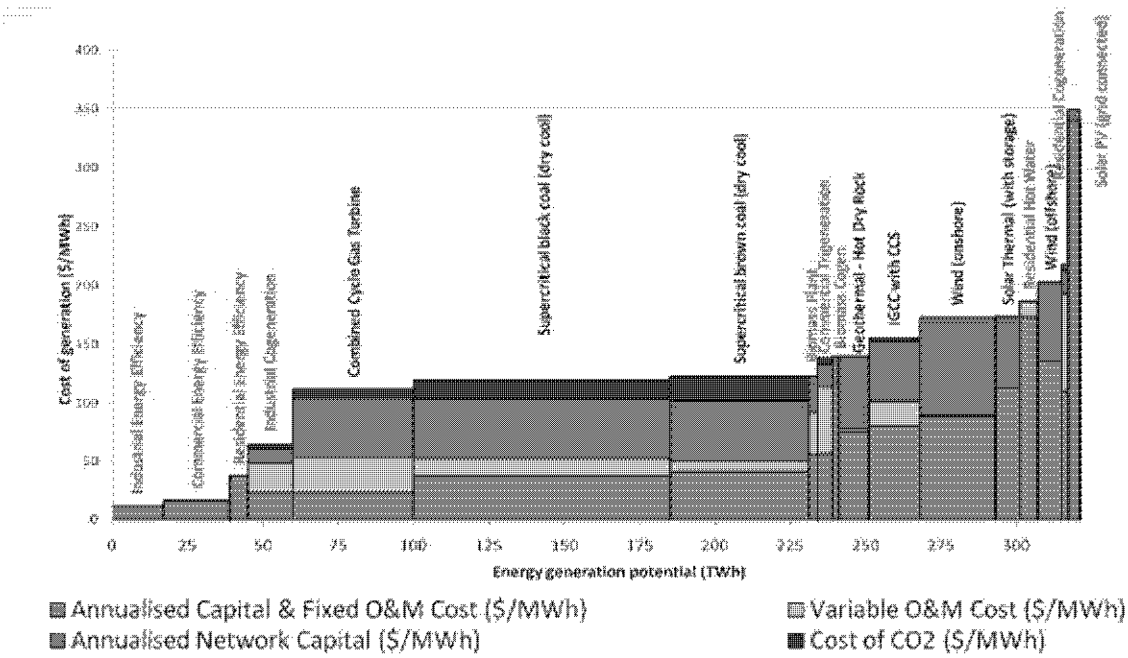


Figure 52 Levelised Cost and Potential of Supplying New Energy Demand

Source: (Dunstan et al., 2011)

9.1 Design Issues

In 2013, a micro-grid design providing both electrical and thermal energy for a new town development located in NSW north of Sydney was developed. This design had to address the following technical parameters:

- Reliability and availability. The system designed would be able to reliably produce power and be constantly available, notwithstanding mechanical or electrical breakdowns, maintenance, weather events, or control system failures. Failure in supplying electricity for even short periods each year can result in high financial losses and is especially required for applications such as data centres and hospital operating theatres. Target availability in developed countries is at least 99.99% which implies around 53 minutes of non-availability each year.

  In order to achieve these levels of reliability, a diversity of generation methods was important. The micro-grid would contain sufficient generation capacity and type that could supply adequate amounts of energy with sufficient reliability. As the diversity of the generation methods in any system is reduced, availability and reliability is compromised. The micro-grid would employ more than one method of generation as well as energy storage. In addition, increasing reliability would result from a mix of duty/standby systems of critical components, with the benefit of increasing the peak available capacity of the system.

  Monitoring of critical generating components, functions and timely maintenance is factored into system reliability. Each component's availability (the amount of time between planned maintenance actions divided by the amount of time between maintenance actions plus the time to complete maintenance actions) is defined and a reliability factor (the amount of time based on the scheduled operating time less the unscheduled outage time divided by the scheduled operating time) determined. Cogeneration systems based on gas fired reciprocating engines have a reliability of around 97% and typical availability of around 95%. The product of these two values suggests a proportion of unavailability of less than 7% per unit. A single unit, operating on a 24x7 basis would be unavailable around 600 hours every year which would be unacceptable. Multiple smaller units would be implemented to cover the periods when some are unavailable.

Power system reliability analysis based on interaction of multiple components is complex and cannot be summarised in this thesis. However, applying some simplifying assumptions to a scenario with multiple cogeneration units in a micro-grid reveals that the probability (P) that exactly (m) units will be available out of a fleet of (n) units at any time can be estimated by a binomial probability distribution with (n) units available to run, each with a reliability of (R) per unit. This probability can be expressed as follows:

$$P(m \text{ out of } n \text{ units}) = n!/\{m! \times (n-m)!\} \times R^m \times (1-R)^{(n-m)}$$

For example, in the case of one unit being installed to meet the total load with a reliability of 97%, the probability that that unit will run at any point of time is simply 97%. However, if there were three units installed, and the demand could be met by just two of the three units, then the probability that exactly three would run at any point of time is 91.26% and the probability that exactly two would run is 8.47%. Adding these two probabilities together suggests that system reliability (excluding single points of failure such as electrical interconnections or gas/fuel supply) would be 99.74% (or broadly, 23 hours of unavailability over a year). By extension, if 10 units were installed but only 7 were required to produce the desired energy supply, the sum of probabilities yields an overall probability of 99.985% that there would be sufficient units available to produce the desired output and only 1.2 hours where the desired capacity would not be available.

This analysis, while simplistic and ignoring complex failure modes and strategies to increase availability, suggests that distributed generation in an off-grid micro-grid, backed up with diverse energy sources (e.g. diesel, solar PV and battery) can deliver acceptable availability and reliability without substantial investment in overcapacity or capacity reserves.

- Capacity. The capacity of the generation system must exceed the peak demand imposed by the micro-grid at any time. It must have the capacity to deal with expected and unexpected peak loads. Estimating these peak loads can be difficult so therefore a reserve capacity factor must be applied. The NEM holds between 15% and 32% reserve capacity. As outlined above, the reserve capacity required in a micro-grid will be determined by the number and diversity of generating units and the number and diversity of loads.

Energy balance is important in a micro-grid which contains a high proportion of intermittent energy (PV) since the micro-grid cannot rely on additional capacity becoming available on demand. The energy available to the system is finite and depends on matters that cannot usually be controlled or even predicted with any certainty. Thus, a system relying on PV requires energy storage.

- Robustness. The system must be robust enough to recover from unexpectedly large loads or other challenges that may affect either the capacity or the reliability of any system.

- Efficiency. Generators have to produce electricity at the lowest possible cost, with maximum reliability and using sustainable, low emissions fuel sources. Low electricity rates are not simply a matter of equity, but access to power drives economic activity and increases competitiveness. While emissions reduction is a genuine compelling objective, higher electricity prices than may be supplied by incumbent generators will make all activities within the micro-grid more expensive and lead to a reduction in support and, ultimately, failure of the micro-grid supplied community.

- Quality (frequency, voltage and power quality). Power balance (matching power generation with consumption) is essential for frequency stability. There are a number of techniques used to maintain power balance and hence frequency - load shedding, increase primary generation and recovery of stored energy. All of these are available within the micro-grid, but because the system is small, variations are harder to manage.

  Short-term storage of energy is needed to cope with the fluctuations in power demand or accommodate the sudden loss of some generation. A micro-grid with small generators will not have a lot of "inertia" (unlike a national grid) with small generators neither storing significant energy in their mechanical inertia nor able to respond quickly to sudden changes of load. Battery storage and inverters permit load following to follow rapidly changing demand while giving time for the generators to respond. This same storage is used to help accommodate the diurnal variation of demand. Small power imbalances can produce large frequency excursions and they may happen more quickly than in the grid. This means that stored energy recovery must be fast and precise - battery / inverter systems are quite fast enough to ensure adequate frequency control.

The Australian power system operates at 50 Hz and compatibility of the micro-grid, whether or not a grid connection is required, is desirable. However, unlike the grid where frequency variations are tightly set, this may not mandatory in a non-connected micro-grid. Frequency control is the result of managing the rotational speed of the generators - the fewer the generators, the more volatile the frequency variations. Compounding this issue, the generators need to respond quickly to load variations in order to preserve power balance which requires both rapid detection of frequency change and fast, accurate control of load generation. Inverters can be used to control frequency since the inverter frequency can be controlled independently of load. System voltage is controlled by the voltage of the generators and the reactive flow. Reactive balance is more critical in a micro-grid since all reactive demand may be supplied from just one generator at certain times. If reactive loads are high, then the micro-grid may need to apply additional units of generating capacity. Voltages at the consumer's home are specified by law in the national grid but reasonable tolerances are accepted and micro-grids may, again, be more tolerant of variations.

Power quality may be a significant design issue for a micro-grid. Voltage dips, flickers, interruptions, harmonics, dc levels, are more critical in a small system. With electrical storage, power quality can be maintained by electronic inverters not only supplying power at the fundamental frequency, but also generating reactive power to supply the needs of reactive loads, cope with unbalanced loads and generate the harmonic currents needed to supply non-linear loads.

9.1.1 Design Elements

The proposed system incorporated the following design elements:

- It would be built out progressively to match the development demands of the community. A minimum base load capacity and number of system components (generating units, distribution, and centralised control) would be implemented at the initial construction phase in order to provide adequate reliability. The micro-grid would incorporate a number of distributed energy centres which would house relevant system components and these would ideally be located close to the proposed loads (residences and community centres/town centre) to provide economic transport of available heat for future heating and cooling demands.

- Electricity generation via gas fired reciprocating[18] engines would supply base load for the micro-grid. While these generators do not have good load following capabilities, they operate very efficiently at high loads (above 70% of design maximum) and adequately, down to 50% of design maximum and provide cost effective base-load electricity. Cost effectiveness is a trade-off between total demand satisfaction (i.e. how much of the total electrical output in MWh over a period the cogeneration system can satisfy) and utilisation (planned operating duration of the system). These factors determine the economics of investing in capital.
- The base load cogeneration system would be supplemented by solar PV technology located on each household roof and feeding energy into the micro-grid via a suitable inverter. During peak summer periods when solar insolation is most valuable, PV will be predominately used to (a) provide incremental energy for in-home air conditioning (b) recharging the battery storage system and (c) minimising gas/fuel costs by reducing the load on the cogeneration system. Solar PV has the advantage of generally being available when demand is highest – generally at peak times of the day when temperatures are greatest and air-conditioning demands are high. However, it is intermittent (due to cloud cover) and cannot be relied upon to provide continuity of supply during prolonged period of adverse weather conditions.
- The base-load cogeneration system would be supplemented to provide sufficient energy to satisfy demand peaks. The supplementary technologies would include (a) diesel generator(s) that can be brought on line quickly with good load following characteristics, and (b) centralised battery banks. In addition, the diesel generator set would provide back-up power in the event of a gas interruption or equipment malfunction with the cogeneration system. The difference between the generating elements' capacity and the peak demand would be met by the battery energy storage system. Battery storage is integral to a micro-grid solution. While expensive, batteries can deliver energy during peak periods and recharge during less than base-load demand periods. In addition, storage can be designed to deliver nominal night time loads where demand is below the minimum operating capacity of the cogeneration systems. However, batteries cannot provide indefinite emergency provisioning. Where required due to cogeneration maintenance or failure or extreme loads, the diesel generator would supply additional power. Diesel generation has relatively low

[18] Reciprocating technology has higher electrical efficiency in small scale generation than gas turbine technology

capital costs but high operating costs. Diesel can operate on a variety of diesel blends including bio-diesel and re-cycled oil wastes. Fuel is easy and relatively safe to store. While prolonged running is uneconomic due to fuel costs, use of diesel for bridging peak loads and for emergency backup is viable.

- Gas-fired, centralised boilers would be used to supplement the heat provided by the cogeneration systems and provide sufficient hot water in the event of a cogeneration system failure.
- An 11 kV volt electrical distribution network would connect the micro-grid's precincts and energy centres incorporating suitable high-efficiency transformers to step down to 415V and 240V to each household. The 11kV distribution network would allow for load balancing and redundancy. Underground distribution is relatively expensive but cost effective during the construction phase. It is inherently robust since it is not exposed to the elements, however it is relatively expensive to repair.
- Thermal networks would be implemented using insulated buried pipes forming a closed loop network (incorporating a gas-boiler backed up) with centralised hot water storage tanks and individual plate heat exchangers for domestic hot water and hot water loop convection heaters for space heating. Flow pipes would transport >65 degree hot water and return pipes would deliver 50 degree water.
- Demand management would be implemented in order to reduce peak demands on the network. This would require utilisation of a communications network to monitor usage, apply predictive tools (based on heuristics, weather, and other external factors), and exercise control over key pieces of equipment sitting on the network that drive demand (and, obviously, supply). The demand management system would consist of (a) centralised server/software which monitors and controls loads and production (b) Smart sensors which transmit usage, power and temperature information (c) Smart meters in each household which monitor and transmit load and consumption data, and (d) Smart controllers in each household which can exercise control over certain loads within the household
- Each household within a micro-grid would have a solar PV array (and inverter), a smart meter and controller along with a heat exchanger for delivering domestic hot water to each residence, a controllable diverter to a household AC system to provide heating (or a dedicated hot water loop convection heater in each household) and smart-meter controlled appliances (specifically, refrigerators and A/C system).

The first stage in assessing and sizing the proposed precinct micro-grid was to determine the energy demand characteristics. Demand for electricity changes continuously depending upon the time of day, day of the week and the season with variations based on (a) growth in demand over time and changes in long term weather patterns (temporal changes) (b) seasonality and (c) daily variations (diurnal) patterns.

Night time demand is lowest due to reduced human activity. In the morning, when people wake up and appliances are switched on, electric transport systems ramp up, offices are lit, shops start trading and factories commence production a morning peak is usually experienced. During the day as temperatures warm, air conditioning use drives substantial electrical demand. Afternoon peaks, with workers commuting and arriving home represent a further peak. In many countries, demand spikes late in the evening as peak tariffs turn to off-peak and electric storage water heaters and pool pumps automatically switch on. Diurnal variation may be estimated based on Ausgrid data[19].

In Australia, demand patterns vary substantially with ambient temperature and with disparities between summer and winter demand. Seasonal variations are estimated based on weather data which influences temperature, hours of daylight, and seasonal activities. In the latitudes under consideration, summer peaks represents planned peak design electrical loads and will be used as the basis for the electrical system design.

Long term planners must also consider temporal changes in weather (in particular warming) that would affect demand.

Accepted average household electrical demand is 6,500kWh per year or around 17.8 kWh per day. IPART (IPART, 2010) provides indications of demand based on number of dwelling occupants. Homes with 1-2 occupants consume an average of 5000 kWh per year (13.7kWh per day), those with 3-4 occupants consume 7,700 kWh per year (21.1kWh per day) while those with 5+ occupants consume 10,200kWh per year (27.95 kWh per day). In a greenfield town development, using energy efficient design and materials, materially lower average household demand (perhaps up to 40% lower) is realistic. This would translate to around 8.5 kWh per day, 13 kWh per day and 17.3 kWh per day respectively. Obviously, the aggregate demand will depend on the mix of housing and the size of the development, however, an average demand per household of 11kWh per day is reasonable.

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[19] Residential average summer day loads obtained from Ausgrid data for average of 26,651 customers

Most new Australian homes are fitted with air-conditioning. Peak summer electrical loads are generally driven by thermal demands which are in turn influenced by the thermal efficiency of a household and the use of thermal comfort equipment. Residential air-conditioning drives planned and unplanned peak events. Peak winter loads are also driven by thermal demands often served by reverse cycle air conditioning.

Following changes to the National Construction Code in 2010, state governments introduced mandatory six-star efficiency ratings for new houses. Ratings are determined based on building materials, glazing and sealing of the building. The choice of domestic services - hot water, insulation and artificial lighting - are also considered. A house built to the 6-star standard will use roughly 20 to 25 per cent less energy on heating and cooling compared to a 5-star rated house of equivalent size.

New homes are assumed to be built to a high standard of thermal insulation – equivalent to at least 3-star thermal rating. As noted above, most new-build homes will incorporate a 3-5kW air conditioning systems (which are highly efficient heat pumps) for thermal comfort. All modern air conditioning systems have the ability to operate in reverse cycle mode (heating as well as cooling) which increases their functionality.

Estimating thermal demand for a household requires relevant historical detailed weather data and accurate information about each household's thermal mass and thermal equipment. Based on the location within NSW of the subject precinct, houses will require heat during the 5 coldest months of the year. Assuming the average thermal demand over these months will be approximately 16kWh/day for space heating plus approximately 4.6kWh/day per household of hot water demand it was assumed that 20.6kWh/day would be required during winter and only 4.6kWh/day per household would be required for water heating during the summer months.

In new-build communities, the incremental cost of installing a thermal network of pre-insulated pipes underground is reasonable. Distribution of stored hot water according to the demands of residents can be provided by a cogeneration system backed up by a centralised gas boiler. Water can be made available at a temperature of 65 degrees which is sufficiently high for the avoidance of bacteria, for use as domestic hot water and for diversion through the fan coil of the air-conditioning system for space heating. A district heating network would supply cogeneration suppled heat first with any requirement over and above that provided by a centralised gas boiler system. Water would be stored in tanks to retain the heat generated by the Cogeneration system. A suitable hot water network will reduce gas consumption required for hot water generation at each household and reduce electricity consumption that would have been required for space heating via the reverse cycle air conditioning system.

To reduce peak demands, the demand management system would limit the time of use for air conditioning and heating systems at certain peak periods or when residents are not at home.

Based on the above analysis, a typical household thermal demand profile was derived. Peak air conditioning demand in summer was assumed to be 15kWh per day (January, no rain) and peak heating demand in winter being 27kWh/day (July, rain).

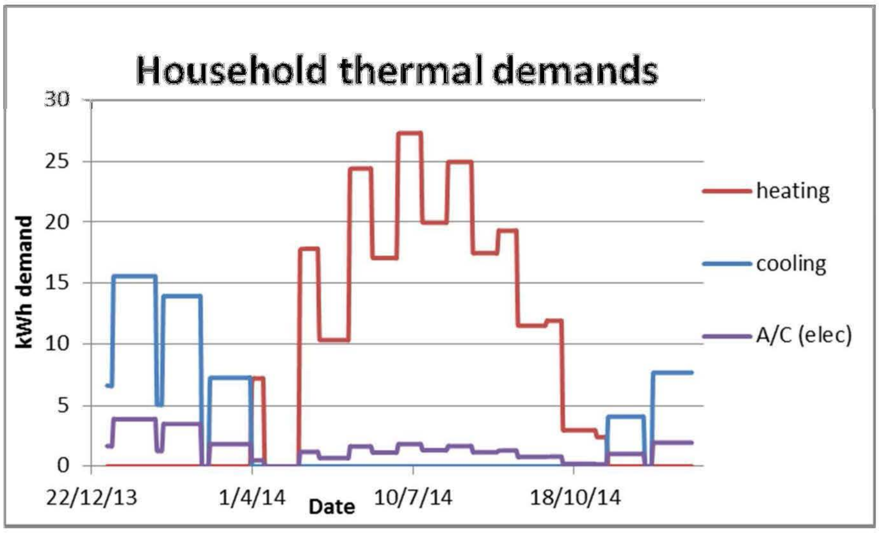


Figure 53 Household Thermal Demand

Assuming a small reverse cycle air conditioning split system has a cooling COP of 3.5 and a heating COP of 4.5, the summer cooling electrical requirement would be approximately 4.3kWh/day and the winter heating electrical requirement would be approximately 6kWh/day (assuming the air conditioning system generates its own heating). However, if the thermal energy from the circulating hot water is utilised in winter, the winter heating electrical demand will reduce to just 1.5kWh which is sufficient to run the system's fan only.

In a hybrid cogeneration/solar PV/battery storage micro-grid, on hot summer days when the air conditioning cooling demand is likely to impose the greatest loads on the electrical network adequate solar insolation should be made available (when buffered through the battery storage system) to satisfy demand. During winter (and especially on rainy days) with reduced solar insolation, an adequate supply of heat should be made available from the gas cogeneration units to satisfy demand.

Having established average demands, daily demand profiling (over a 24 hour period) was estimated by analysing distinct user loads (excluding air conditioning, centralised heating and solar PV gains).

Table 11 Typical Residential Loads

Load Period	Load Appliance or Activity
Base Load	refrigerator, appliance standby mode, charging devices
Morning Peak	breakfast preparation appliances, washing machine, television
Midday peak	loads for stay at home parents & retirees, washing, television, lunch preparation appliances
Night peak	dinner preparation appliances, washing machine, television, kettle, battery charging, electric heating

These loads were estimated to develop an average daily demand profile for an average day in the year.

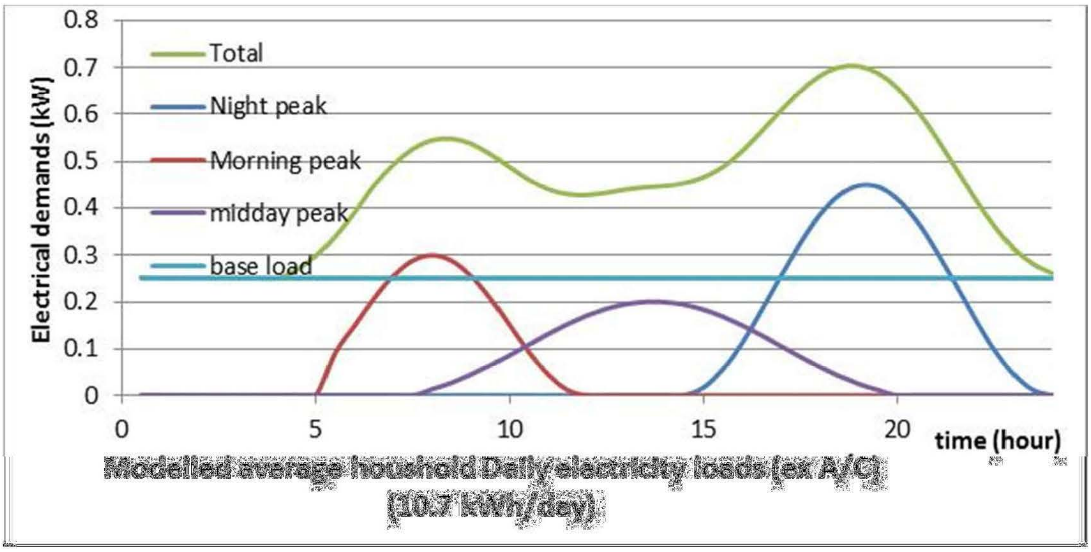


Figure 54 Average Daily Electrical Loads

The daily average load profile was overlaid with thermal comfort loads (driven by air conditioning use) utilising daily temperature profiles derived using seasonal and daily weather variation date sourced from the Bureau of Meteorology. Outside temperature has an effect on inside temperature of the building based on the insulating properties of the walls, windows and roof; the difference in temperature between the outside and the inside; and the thermal mass (ability to store heat) of the household. User behaviour was assumed– for example, heating would be turned on when the building temperature drops below 20 degrees (and turned off at 21 degrees). Cooling would be turned on at 24 degrees (and turned off at 23 degrees). The electricity required to provide this heating or cooling was calculated and added to the total building electricity requirement.

With each household assumed to have a 2 kW solar PV system generating energy that is fed into the micro-grid, the energy generated was overlayed on the demand profile of each household. Solar insolation estimates are available to describe how much power may be attributed per KW of installed capacity varying by season and location.

Based on the precinct location, an average 17.4% capacity factor was assumed, equivalent to 4.2 kWh/kW of solar PV. Thus, based on the assumed daily energy requirement of each house (including air conditioning) of approximately 12.5kWh per day, a 2kW solar system could supply, on average 8.3kWh per day.

The three factors required to estimate average demand were therefore:

(a) home appliance demand,

(b) air conditioning loads to satisfy thermal comfort requirements, and

(c) solar production

These were added to produce a "Per Home Profile" of consumption (demand) and production (output) over the year.

For the site analysed, the average daily load in ½- hourly intervals per home for each months of the year is illustrated in the graph below. This graph shows the kWh demand and output from each of home with the energy generated being the area between the zero axis and the plotted point.

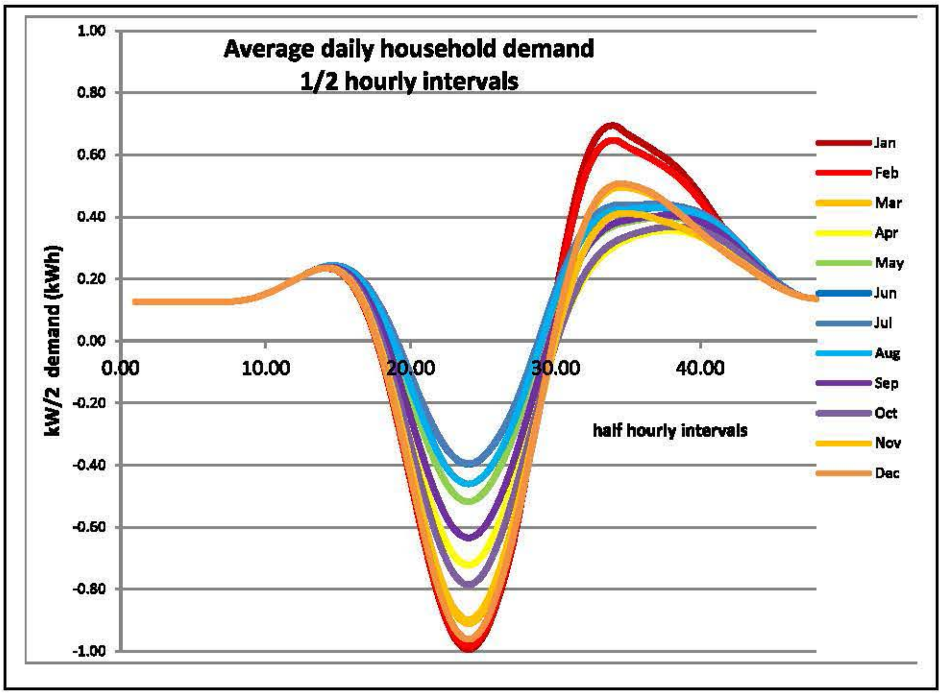


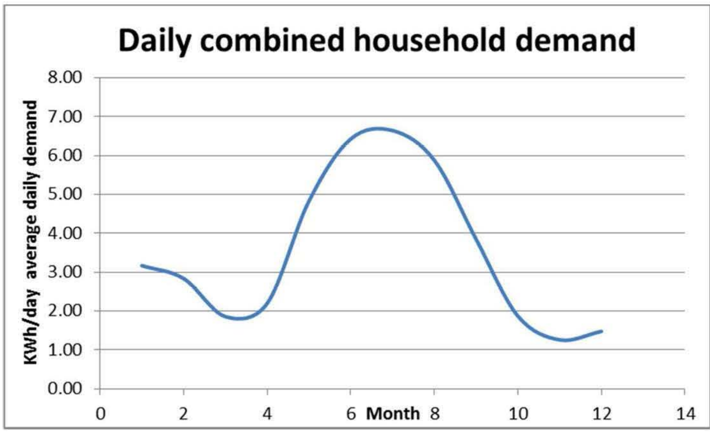
Figure 55 Average Daily Household Electricity Demand

9.1.2 Micro-grid Sizing and Efficiency

The micro-grid energy system was sized based on the individual demands of each user. A residential-only development was assumed. The modelling took account of the distribution losses within the micro-grid from distributing electrical energy to households via step-up transformers (415V to 11kV), reticulation via underground cabling at 11kV, and stepping-down to 415V for supply to households, with typical transformer efficiency of around 95%-98%.

Battery storage of remote household generated power (from the rooftop PV) would travel through the micro-grid (or via a proximate connection to the cogeneration system) to the centralised battery bank for charging and then through the micro-grid again for discharging. Battery efficiency (ratio of charge in vs usable capacity out) was assumed to be between 85% and 95% depending on technology.

Taking account of these losses, system efficiency of between 69% and 87% was assumed. The demand profiles based on the Per Home Profiles were re-evaluated and led to the boundaries for sizing equipment to produce cogenerated electricity.



month	Daily kWh
Jan	3.17
Feb	2.84
Mar	1.86
Apr	2.20
May	4.83
Jun	6.43
Jul	6.65
Aug	5.88
Sep	3.85
Oct	1.87
Nov	1.26
Dec	1.48
Average	3.53

Figure 56 Daily Combined Household Demand

Peak demand (in summer) determined the peak capacity requirement of the base-load generation. For a 400 home precinct, at a peak summer load of around 0.65 kWh per half hour, the peak capacity required would be around 0.65 x 2 x 400 or around 520 KW with the average daily demand of around 3.53 kwh/day/household or around 3.53 x 365 x 400 (515,380 kWh) of cogenerated electricity.

These outcomes were compared with alternative cases for precincts without thermal networks or solar PV. If there was no thermal network and all thermal comfort requirements were satisfied by air-conditioning, the peak cogeneration electrical capacity would increase to 552 kW and the aggregate annual cogenerated electricity demand would rise to 678,000 kWh for the 400 households. If there were no solar PV installed, the peak capacity requirement (in summer) would remain at around 500 kW (0.62 x 2 x 400) but the aggregate annual cogeneration demand would increase three-fold to 1,825,000 kWh for the 400 households, substantially increasing operating costs.

A micro-grid design was developed consisting of the following components for an initial deployment across 400 households:

- 2 x 500 kW cogeneration units,
- 400 x 2 kw solar PC arrays,
- A centralised storage battery with a capacity of 2500kW and a discharge/charge rate of 1000kWh,
- A 1.2 MW of diesel backup capacity, and
- A 1.2 MW gas fired backup boiler

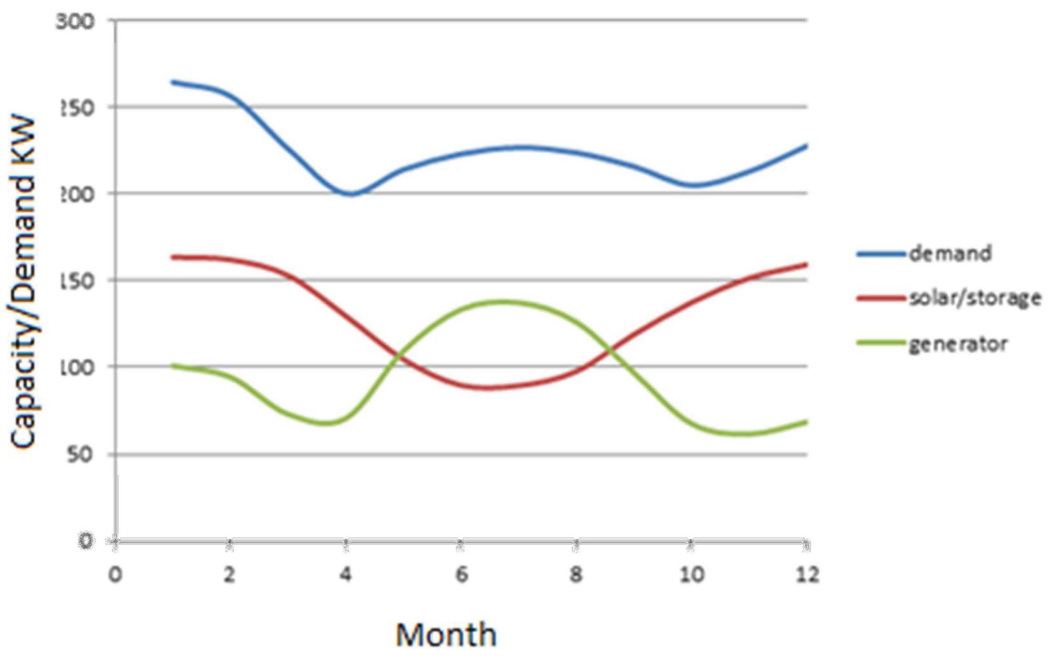


Figure 57 Monthly Demand and Capacity

The proposed energy system was determined to be capable of supplying the varying average summer and winter loads with just one of the two cogeneration systems able to cater for at least 3 times the predicted average power requirements for the town. A single 500kW unit operating at 100% capacity would be required to run for approximately 6.5 hours per day in winter and 4.5 hours per day in summer. This was equivalent to approximately 1,980 hours per year in total or 990 hours per year per unit (around 22.6% utilisation for one system or 11.3% utilisation for both systems). During this period, the cogeneration system would deliver approximately 42% of the total energy requirement. Peak demand on the cogeneration units was be around 500kW (or 50% of installed capacity), however, average demand varied between 62kW to 137kw which is less than 15% of the available capacity

The heat generated from cogeneration is a by-product of electricity generation. More electrical power was required in winter than in summer, and heat generation correlated with the average thermal demand for most of the year. However, at the peak of winter, more heating capacity was determined to be required than the cogeneration units would be able to deliver and at these times, the gas-fired condensing boiler would be employed to deliver heat to the centralised thermal tank and into the thermal network. The design capacity of the boiler was 1200kW, or approximately 3 times greater than the average heating demand to provide for abnormally cold conditions. On average over the year, the cogeneration units supply approximately 50% of the heating required by the precinct and the other 50% comes from the boiler system.

To ensure redundancy in particularly cold periods or if the gas supply is disrupted, thermal heating remains available by utilising the home air conditioners in reverse cycle mode. Further, the back-up diesel generator can supply the entire peak load requirement for extended periods in the event of prolonged low temperatures and rain (no solar) or gas supply interruptions.

9.1.3 Micro-grid Cost Analysis

The capital requirements and long run economics of the proposed off-grid micro-grid were estimated with the key assumptions outlined below:

Capital Costs

Cogeneration - Average capital costs for containerised cogeneration equipment (excluding ancillaries and installation) was assumed to be 60c - 80c per watt of capacity at the 1 – 2 MW per unit scale. Average capital costs for non-containerised cogeneration equipment (excluding ancillaries and installation) was assumed to be 50c-70c per watt of capacity at the 1 – 2 MW per unit scale.

Photo-voltaic - According to GTM Research, production costs for Chinese crystalline-silicon (c-Si) PV module manufacturers are expected to fall from US50 cents per watt in the fourth quarter of 2012 to 36 cents per watt by the end of 2017. For a typical 2 kW rooftop solar PV installation, including inverter, regulator, racking and installation, a cost per watt of A$1.20 (after rebates) is reasonable.

Battery Storage - Suitable large scale battery storage systems are available from a small number of vendors. Key technologies include lead-acid, lead-acid combined battery and capacitor (ultra-battery) and lithium-Iron-Polymer. To obtain the requisite energy charge/discharge rates, LI-Fe-PO is preferred, despite relatively high capital costs. For a typical 500kWh battery storage system, a cost of between $0.80 and $1.40 per watt was assumed.

Backup Diesel - Average capital costs for containerised diesel backup generation equipment and the associated diesel storage tanks (but excluding installation) is approximately $0.60 per watt of capacity at the 1MW per unit scale.

Transformers - The number of transformers and associated voltage stabilising equipment required depends on the complexity and size of the micro-grid. Transformers range from $30,000 to $150,000 per unit.

Absorption Chilling - The average cost of absorption chilling is around $0.20 per watt of thermal cooling output for absorption chillers above 500kW.

Hot Water Storage Tanks - The average cost of hot water storage is around $0.50/L for storage volumes around 200,000L

Hot Water Boilers - The average cost of gas fired hot water boilers is around $0.09/W for boilers at the 1MW scale.

Consumer Premises Equipment (CPE) - CPE relevant to a proposed micro-grid energy system would include a smart meter costing around $300 (Cook, 2013a) plus in-residence controls and sensors at around $200 per household controlling air conditioning and refrigeration; hot water loop convectors or condenser diverters for reverse cycle air-conditioning, estimated to cost an incremental $1000 per household; domestic water heating Plate Heat Exchangers (PHX) estimated to cost around $500 per household.

Monitoring and Control Equipment - It was estimated that the minimum cost to establish centralised hardware and services to manage energy generation, distribution and smart metering would be around $250,000 for a central energy centre plus a further $100,000 at each distributed generating site. The software component of managing energy generation, distribution and demand management would cost a minimum of $500,000 initially plus $100 per household connected to the network.

Plant Room and Centralised Civil Costs - Each energy centre would require a plant room facility. It is proposed to house small units below 1MW in acoustic enclosures (75db at one meter) in indoor plant-rooms and larger 1MW generators in a containerised arrangement. Containerised cogeneration systems are environmentally secure and don't require any additional weather protection or sound attenuation (75db at one metre). Battery storage is also available in containerised packages. Appropriate physical security is required for cogeneration units, energy storage, back-up diesel generation along with controls, pumps, hot water storage and other requirements. It was assumed that each energy centre will cost $250,000 to construct.

Installation Costs

Generating Equipment - The estimated installation costs for cogeneration at the 1MWe scale is around $1 per watt.

Trenching – the estimated cost of trenching was $70/m with all services (electrical distribution, gas and thermal) located within a single trench.

Electrical Distribution - The size of the micro-grid will determine the voltage and costs of the distribution system with cable sizes (and hence cost) dictated by the transmission/distribution voltages. Underground cabling imposes higher initial construction costs taking account of the cost of trenching, poles, labour, cabling and materials. High voltage underground distribution has been estimated to cost up to $1,500 per meter with the cost of trenching being the largest single proportion. Underground cabling may offer advantages in terms of amenity and reduced maintenance due to better protection against weather events. On the other hand, the cost of finding a fault, trenching, cable splicing, and re-embedment is more expensive than repairing a fault in an overhead line and extended line outages can cause service interruptions to consumers. Assuming that cables can be laid in existing trenching at incremental marginal costs, then the cost of the distribution network will reduce by around 75% to $375 per meter. This compares with around $300 per meter for overhead cabling.

Pipe-works - Thermally insulated piping network with storage was specified with a 2-pipe system reticulating hot water among the residential sites and a 4-pipe system reticulating both hot and chilled water through the commercial and mixed use developments. Thermal hot water pipe-works using pre-insulated 80mm pipe is estimated at $100/m resulting in flow and return costs of piping of $200/m. Thermal chilled water pipe-work will depend on the use for the chilled water – typically only supplied to mixed use and commercial premises located relatively close to a trigeneration energy centre. Chilled water piping will be run underground and the installed cost of suitable flow and return pipe was estimated at $200 per metre. Gas pipe-works would be required to provide sufficient quantities of natural gas to each energy centre within the development, as well as gas to all homes and commercial premises. Gas reticulation was estimated to cost between $50 and $75 per metre.

Based on these cost estiamtes, capital and installation costs were estimated for a 400 household off-grid micro-grid, making assumptions about the size of the development, avoidance of certain expenditures (such as individual instantaneous gas hot water heating systems), and incorporation of costs for distributed electrical distribution system that would otherwise be required for a grid-connected electricity distribution system.

The total estimated capital costs derived ranged between $13.7 million and $16.5 million or around $34,000 to $41,000 per household.

<u>Operating Costs</u>

Operating costs included fuel for natural gas fired cogeneration systems and backup diesel and hot water boiler systems, maintenance and management and operations.

Fuel (Natural Gas) - Cogeneration units and boilers require natural gas (and/or biogas) for their operation. Specific natural gas consumption for cogeneration at the 0.5 MW scale is approximately 266m3/hour per MW and approximately 240m3/hour per MW at the 2 MW scale. Natural gas prices were assumed at prevailing rates, with assumed price escalators based analysts forecasts.

Fuel (Diesel) - Standby and peak load diesel generators require diesel (and/or biodiesel) for their operation. Specific fuel consumption for diesel generators at the 1MW scale is approximately 257 litres/hour per MW. Diesel fuel prices are relatively stable and were assessed at prevailing rates.

Maintenance - Cogeneration units require periodic maintenance. Maintenance costs include consumables (coolant, oil, filters, etc.), allowance for overhaul, and labour. In total, these costs equate to approximately 1c per kWh of electricity produced. Absorption chillers also require periodic maintenance including regular checks of the equipment, periodic cleaning of the unit and some consumables, an allowance for periodic overhaul, and labour. In total, these costs equate to approximately 0.2c per kW of thermal energy capacity. Hence, for a 1MW absorption chiller, the annual maintenance cost would be approximately $20,000 per year. Diesel generators require periodic maintenance. Maintenance costs include consumables (coolant, oil, filters, etc.), allowance for overhaul, and labour. Assuming intermittent operation only (approximately 20 hours per month) for a 1MW engine, the maintenance cost would be approximately $20,000 per year.

Management and Operations - A micro-grid will require continuous real time monitoring. System components provide on-line 24x7 monitoring and alarms which detect and alert operators of outages, adverse trends and periodic or identified maintenance requirements. The cost of system-based monitoring is built into the maintenance costs for these components. On-site management and operations staff would be required with dedicated operations staff. An annual cost of $150,000 to $300,000 per energy centre was assumed.

With natural gas costs of between $10 and $13 per GJ and cogeneration providing between 28% and 44% of the total annual electricity requirements and 50% of the thermal energy (heating) requirements, operating the equivalent of between 630 hours per year and 990 hours per year at 80% of their rated output, the direct cost of generating electricity were estimated to range between 14.5c/kWh and 21.3c/kWh for the total energy produced by the cogeneration/diesel system (between 511,000kWh and 784,750 kWh per year) or between 4.1c/kWh and 9.3c/kWh for the total electricity consumed by the 400 households of approximately 1,825,000 kWh per year.

With total average household demand estimated at 12.5kWh/household/day or 4,563 kWh/household/year, the direct cost (fuel and maintenance) of generating this amount of electricity is between $186 and $418 per household per year.

Battery storage produced by the Chinese manufacturer, BYD, has a claimed 4000 cycle life. Assuming a cycle broadly equates to a day's charge/discharge, the cost per annum per household of battery storage is $456 to $798 per household per year.

Making reasonable assumptions about the amortisation of other capital equipment (10 years for CPE, 25 years for PV, 25 years for generating equipment and 40 years for distribution system and installation), the annual cost per household of amortised capital and installation ranges between $1,222 and $1,308.

The total cost per kWh of electricity generated in the micro-grid was estimated to be between 41c and 55c.

Table 12 Relative Costs of Electricity Produced in Micro-grid

Component	Cents per kWh of electrical[20] energy produced
Direct cost	4.1 – 9.3
Battery cost	10 – 18
Amortisation of capital and installation	27 – 29
TOTAL COST PER KWH	41 – 55 c per kWh

By contrast, Country Energy's 2013 (class 5700) electricity tariff indicates a per kwh charge of 31.11 cents plus an annual fixed charge of $1.248 per day (or $455 per year).

The fully amortised cost of electricity and thermal heating per household, per year would range between $1,864 and $2,524 per annum which is competitive with grid-supplied electricity (plus an allowance for gas for thermal heating) especially considering the small scale of system modelled. This suggests that a larger, more mature off-grid micro-grid will be capable of presenting even more attractive economics.

9.1.4 Environmental benefits

The NSW electricity grid produces 1.05kg CO2e for each kWh of delivered electricity (Department of Industry, 2013b). A 500kW natural gas generator produces approximately 0.705kg of CO2e for each kWh of electricity produced. By utilising 100% of the high grade heat from this cogeneration system, the carbon dioxide output is equivalent to 0.381 kg CO2e per kWh.

Based on household thermal modelling, the average thermal demand over the coldest 5 months of the year is approximately 16kWh/day of heating which can be combined with a hot water requirement of approximately 4.6kWh/ day. Analysis of the monthly requirement for heat and the availability of heat from the cogeneration system reveals that almost all of the generated heat will be utilised with less than 5% wasted.

[20] However, the comparison assumes that the thermal energy provided to each household is free to each household whereas the value of thermal energy to a householder will depend on the alternative costs of space heating electricity and gas heated domestic water.

Table 13 Micro-grid Thermal Supply and Demand

Month	Space Heating	Dom Hot Water	Total	CHP electrical supply (kWh)	CHP thermal output (kWh)	CHP heat utilised (kWh)	Boiler heat utilised (kWh)	CHP heat wasted (kWh)
Jan	0.0	4.6	4.6	6	6.7	4.6	0.0	2.1
Feb	0.0	4.6	4.6	6	6.2	4.6	0.0	1.6
Mar	0.0	4.6	4.6	4	4.8	4.6	0.0	0.2
Apr	1.9	4.6	6.5	4	4.7	4.7	1.8	0.0
May	13.2	4.6	17.8	7	7.2	7.2	10.6	0.0
Jun	20.2	4.6	24.8	8	8.8	8.8	16.0	0.0
Jul	23.5	4.6	28.1	8	9.1	9.1	19.0	0.0
Aug	21.1	4.6	25.7	8	8.3	8.3	17.4	0.0
Sep	14.7	4.6	19.3	6	6.4	6.4	12.9	0.0
Oct	5.8	4.6	10.4	4	4.5	4.5	6.0	0.0
Nov	0.6	4.6	5.2	4	4.1	4.1	1.2	0.0
Dec	0.0	4.6	4.6	4	4.5	4.5	0.1	0.0
Average	8.4	4.6	13.0	5.7	6.3	5.9	7.1	0.3

The cogeneration units can satisfy 5.7kWh per day of electrical demand for each household with the balance provided by the rooftop solar PV. At an emissions intensity of 0.397kg/kWh of electricity generated, the daily output of CO2 per household will be 2.26kg CO2/day. By contrast, if these households were on the NSW grid, the 13.5kWh of power that is required per household per day would emit 14.18kg of CO2. Obviously, substitution of power from the grid may not come from an "average" emitting generator. If this substitution comes from a natural gas fired generator, the emissions outcomes will not be as attractive. However, if it comes from a coal fired generators, the emissions benefits will be understated.

Taking account of typical household electrical, heating, hot water and cooking requirements, an average house connected to the off grid micro-grid would emit 7kg of CO2 per day. This would be a 32% reduction compared with a solar PV-only, grid-connected NSW household with similar energy efficiency ratings and a 64% reduction compared with a grid-only NSW household with similar energy efficiency ratings. When compared with an average home in NSW that is not especially energy efficient and predominately uses electricity, the micro-grid connected home would produce a 77% reduction. That is, a stand-alone micro-grid connected home could produce as little as 23% of the emissions produced by a standard home while using just 27% of the (generated) energy required by a standard household.

Mancarella (Mancarella, 2009) concurs that "distributed cogeneration technologies represent a key resource to increase generation efficiency and reduce greenhouse gas emissions". He noted, however, that "the diffusion of distributed cogeneration within urban areas, where air quality standards are quite stringent, brings about environmental concerns on a local level" and cautioned against considering the relatively higher emissions from generators operating frequently at partial load. For some who have argued that distributed generation's emissions benefits are overstated due to localised and possibly overstated emissions reductions, Heath (Heath and Nazaroff, 2007) argued that the consequences of these emissions are mitigated by a "high level of utilization" of distributed generation while Akorede (Akorede et al., 2010) added that further reductions in emissions from distributed generation are possible through the use of "renewable energy sources, in the generation of electric power" such as biogas, for example.

9.2 Risks and obstacles

The key challenges posed in developing a micro-grid are:

- Attracting investment to fund the up-front capital that will be amortised over a long period (upwards of 25 years)
- Managing the build-out of the micro-grid in line with progressive development of planned housing and commercial precincts which demands innovative deployment and business models
- Ensuring that delivered energy prices are affordable to the community which requires good base data and forecasting methodologies for internally developed power and external (grid-based) electricity and gas prices
- Matching the community's electrical demands with available supply as well as matching the community's thermal demands (water and space heating and space cooling) with the micro-grid's ability to supply thermal energy which requires good base data and use models
- Designing the micro-grid to meet predictable and unpredictable loads. In a traditional electricity network, diversified loads combine to produce relatively predictable aggregate demand characterised by a limited number of peak events. A limited scale micro-grid has a less predictable load profile since the aggregated loads suffer from lack of diversity and specific loads may dominate the aggregate. Should an extreme weather event occur and all households on the grid respond by turning on their air conditioners this would generate a peak event at a specific point in time that could overwhelm the generating capacity of the micro-grid. In a more geographically diverse grid, the extreme event would be less likely to affect all users on the grid at the same

time. In a grid with more diverse users, the peak events would not affect all users (e.g. commercial users would have a different load profile to residential users).

- Overcoming regulatory and technical constraints, particularly in relation to the supply and sale of electricity which demands a thorough understanding of retailing rules (in particular regarding consumer choice) and technical standards.

Micro-grid deployment will involve the development of electrical, thermal and IT networks. This infrastructure will involve certain risks – including design unknowns and approvals that may result in delays in deployment or incur additional expenses. There are risks associated with the operation of the micro-grid. One of the high-impact risks is the safety of electrical equipment due to possible frequency/voltage mismatches when paralleling several distributed energy resources. There may be failures in the operation of micro-grid components, including the micro-grid master controller. To mitigate these risks, operational readiness testing of individual equipment and the whole system should be thorough to ensure that the micro-grid can deliver the expected performance. The size of generation resources is critical and risks associated with incorrect sizing (both under and oversizing) should be carefully considered during the planning phase. Regular testing and maintenance should be conducted to minimise the risk of any unreliable operation. Communication system failures and delays between the micro-grid master controller and each micro-grid component may have a significant impact on operation. High-speed and secure communication channel must be selected to provide communications among micro-grid components and devices – wireless or unreliable means of communications are not considered to be viable. The micro-grid may be vulnerable to cyber risks or physical attack and must be appropriately secured. In addition, the local network can be brought down accidentally with a severe impact. Extensive physical and information security is required.

Obstacles to deployment of micro-grids in Australia include:

- An unfavourable regulatory environment that prevents the micro-grid owners from selling electricity to residents and consumers within the town. Presently, retail regulations impose certain requirements on network service providers to choice to consumers. A singe generator and distribution network service provider may not be capable of providing consumer choice.
- Problematic and expensive technical compliance requirements. While connection standards of CPE and generating assets are well established, the technical compliance

standards of a micro-grid at scale are unclear and may be onerous and expensive to comply with.

- Need for continuity of capital and performance guarantees for delivery. The evolution of a micro-grid will require ongoing capital investment to ensure sufficient generating and distribution capacity is available to satisfy energy consumers. Lead-times may be problematic. While it is relatively straightforward to secure a grid connection and future capacity from the national network, planning for deployment of a micro-grid will have to take account of equipment supply, construction and commissioning lead times. Equipment of the nature proposed can have supply lead times of up to 12 months.

These obstacles will generally have the effect of delaying the implementation of micro-grids and increasing the perceived cost of capital of their deployment. The risk factors will vary by location and the nature of the surrounding urban environment and its connectivity to broader population bases, generating assets and network infrastructure. The relative popularity of remote micro-grids is more a function of the absence of cost effective alternatives as opposed to efforts to overcome the broader issues associated with micro-grid deployments in areas with established and available network and generating assets.

Chapter 10 Impact of Widespread Deployment of Distributed Generation

The importance of energy, and particularly electricity, to global economic, industrial and social development is unarguable. Few industries are as large with more than 17 billion tonnes of oil equivalent energy anticipated (World Energy Council, 2013) to be produced in 2020 or as connected with US$3.375 trillion of fuel resources traded internationally (World Trade Organization, 2013) – the largest single sector. Yet, nearly 1.3 billion people remain without access to electricity and 2.6 billion do not have access to clean cooking facilities. With US$1 trillion in investment required to achieve universal energy access by 20130, the IEA projects that nearly one billion people will still be without electricity in 15 years.

Dislocations caused by:

- burgeoning energy demands of developing countries;
- changing national energy mix due to the emergence of renewables and fears about nuclear power;
- emerging exports of oil from Africa and natural gas from Australia;
- a renewed sense of energy security in the USA as a result of economic exploitation of shale oil and gas;
- technologies that enable international trade in LNG;
- inconsistent international pricing mechanisms for gas and the disparity between gas prices in different regions of the world;
- the growth of non-conventional gas (along with related commercial and environmental concerns); and
- the need for substantial investments in energy infrastructure to ensure availability and reliability of the electricity networks,

have created an unpredictable and demanding planning environment.

Overshadowing these short-term issues, is the spectre of potentially catastrophic climate change which could adversely impact the poorest nations and affect the economies and social well-being of all the earth's inhabitants. With electricity related green-house gas emissions responsible for 42% (International Energy Agency, 2014) of all global emissions, a solution to curbing the impact of climate change is vexed and has eluded international planners. As a result, there is a non-uniform mix of individual country policies (sometimes within a regional framework) which seek to balance domestic economic security with global well-being – issues which are frequently seen as conflicting and incompatible.

Within Australia, the energy sector has an important place. Central issues related to energy in Australia include:

- uncertainty regarding future domestic energy prices in the context of dramatic historical increases in electricity prices and concerns about the supply and international pricing of East Coast natural gas;
- environmental and community concerns regarding extraction of non-conventional gas which may further exacerbate these looming gas supply issues on the East Coast;
- continued dependence on emissions intensive energy sources, particularly, black and brown coal;
- integration of low emissions and renewable energy sources into the energy mix;
- high concentration of energy demand among industrial users and their dependence on relatively low cost energy in order to maintain their international competitiveness, along with the continual restructuring of the Australian economy and movement away from its industrial and manufacturing base;
- the ownership structure and motivations of electricity industry incumbents which contributes to constraints in introducing innovation and new technology, while rewarding over-investment in inflexible and expensive network infrastructure;
- increased investment in Australia's massive transmission and distribution network, without commensurate growth in output. This has led to declining electricity productivity and unproductive investment suggesting inefficiency due to a combination of inaccurate forecasting and less than ideal strategies for dealing with infrequent peak events;
- a regulatory environment which is slow to recognise change and implement policy recommendations.

In Australia, climate change was hotly debated and was identified as "*the greatest moral, economic and social challenge of our time*" by former Prime Minister, Kevin Rudd, prior to his election in 2007. More recently, it retreated from the headlines as the economy faltered and a new Government took control in 2013. Nonetheless, the environment continues to occupy the attention of the populous and the present government's "Direct Action" policy has been developed to address greenhouse gas emissions in order to meet the Country's 2020 emission reduction target of 5%.

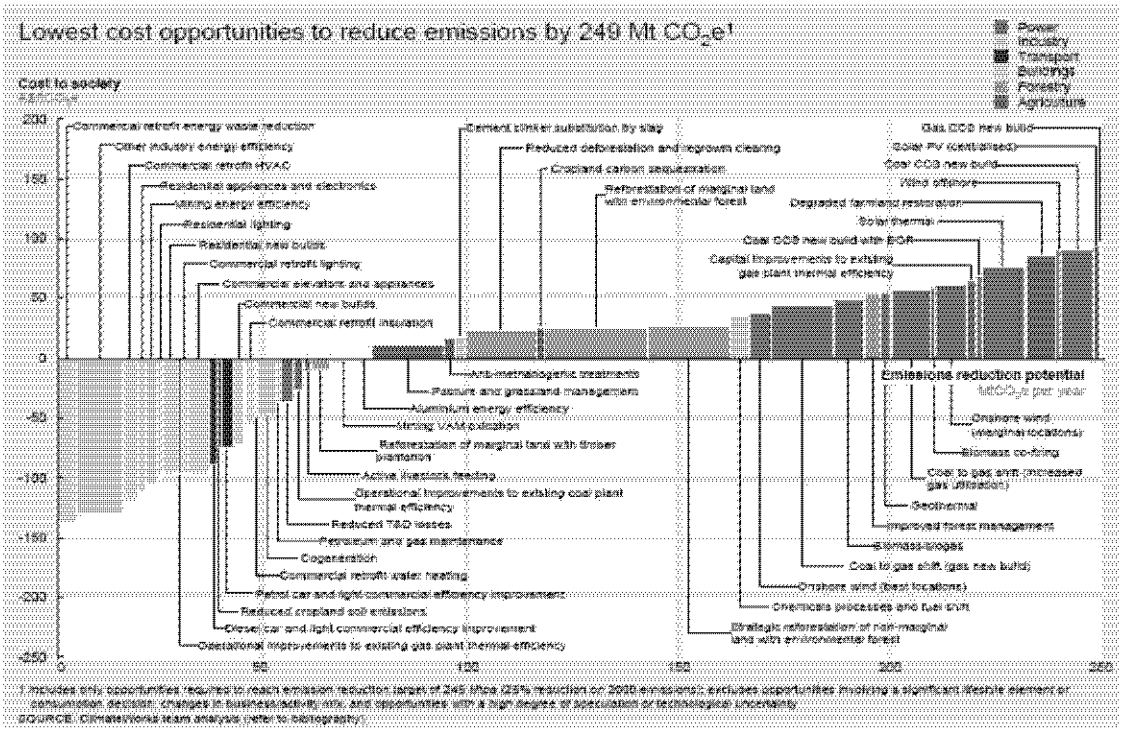
10.1 Benefits of Distributed Generation

With centralised electrification in Australia now more than a century old and little change to either our sources of generation or the configuration of our network, it is imperative that Australian industry, policy makers and the community, plan for a better long-term sustainable stationary energy system that will reduce costs, improve competitiveness, improve flexibility and reduce emissions intensity. Regulators and incumbents have made poor forecasting decisions for the growth in demand, growth in peak demand and reliability requirements of the centralised grid and consumers are now paying dearly for these mistakes. Migration towards a more distributed generation environment can deliver these benefits through a mix of smaller, on-site generation sources, improved energy efficiency and intelligent management of consumers' energy demand. The technologies exist today to deliver better investment and environmental outcomes, requiring a framework of suitable investment incentives and a favourable industry and regulatory environment to move towards a more favourable energy system.

Based on the analysis of distributed generation's potential penetration in, and benefits for, commercial and industrial applications and micro-grid (and precinct) applications, the financial and environmental benefits are compelling.

If all of the potential for adoption of distributed energy identified by the Institute of Sustainable Futures was achieved, up to 73 megatonnes of emissions would be avoided within electricity sector. This would be a 35% reduction on 2009 levels or around 15% of total Australian emissions. Given the negative abatement costs associated with energy efficiency and the low capital costs per tonne of abatement associated with distributed generation, the overall cost of abatement from aggressive adoption of distributed energy could be neutral (factoring in the cost of redundant centralised generation and networking assets).

Figure 22: Greenhouse gas emission reduction potential



Source: ClimateWorks 2010, p.10

Figure 58 Australian Greenhouse Gas Reduction Potential

As highlighted by McKinsey (McKinsey, 2007), cogeneration alone can provide around 13% of all identified negative cost CO2 emission reductions (70 megatons) for buildings by 2030 and 53% of all negative cost reductions (80 megatons) for industry by 2030.

According to the International Energy Agency, cogeneration could reduce global greenhouse emissions by at least 4% in 2015 and by 10% in 2030 which translates to 950 MT/year. This is equivalent to one-and-a-half times India's total annual CO2 emissions from power generation and would "therefore make a meaningful contribution towards the achievement of emissions stabilisation necessary to avoid major climate disruption." Unlike other technologies, the potential for reduced CO2 can be realised very quickly, thus providing an opportunity for low or no cost GHG emissions reductions. IEA further noted that this would result in a 7% overall reduction (or around $795 billion) in the power sector investments over the next 20 years through reduced transmission and distribution network investment and displacement of higher-cost generation plants. The energy saving and capital cost benefits is projected to "slightly reduce the delivered costs of electricity to end consumers". Expanded use of cogeneration would reduce the need for investment in new centralised power plants and transmission infrastructure, and integrate with future renewable fuel sources from biomass gas, landfill gas, wood waste, and anaerobic digester gas. The USA alone could expand its cogeneration capacity to displace 11,600 PJ of fuel a year - about 11% percent of total U.S. energy consumption or double Australia's total energy consumption.

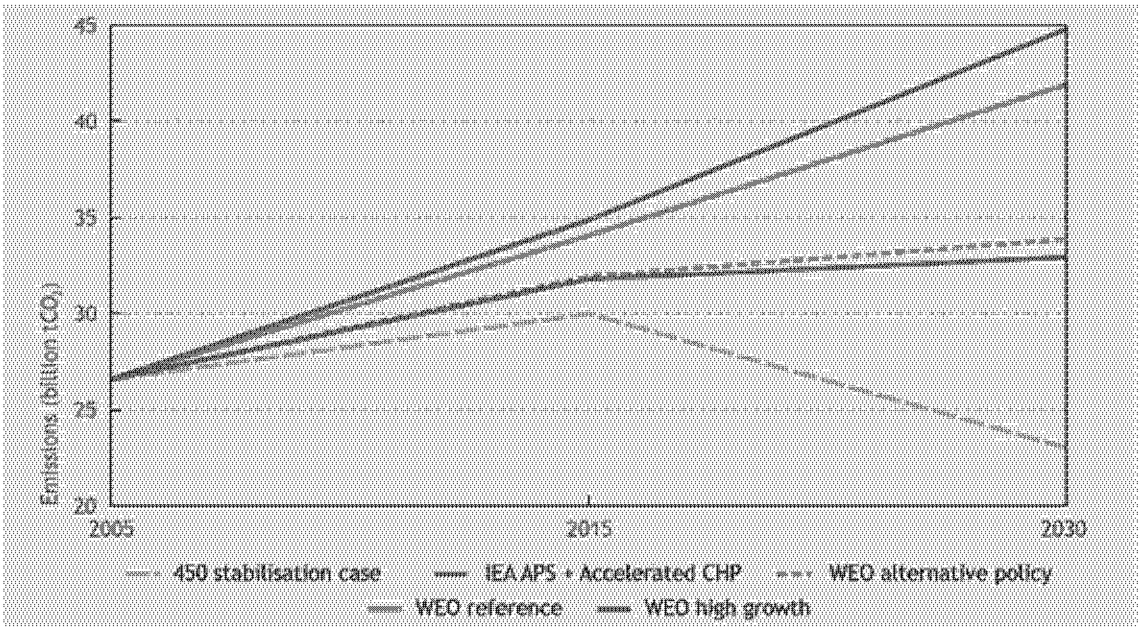


Figure 59 Contribution of CHP to a 450 ppm Stabilisation Scenario

Source: (International Energy Agency, 2008)

In a study (Boonekamp and Sijm, 2004) undertaken to assess the cost of carbon abatement policies in the Netherlands, cogeneration was identified as one of the least-cost solutions at EUR25 / tonne CO2, lower than building insulation, condensing boilers and wind power. A further study (Netherlands Environment Assessment Agency, 2008) identified that cogeneration had delivered 15% of total GHG emissions reductions between 1990 and 2005.

The Institute of Sustainable Futures suggested in 2011 that modest targets for decentralised energy should be aimed at saving $1 billion p.a. in energy costs through avoided network investment and customer energy savings; reducing peak demand by 3000 MW and avoiding the emission of 10 million tonnes of carbon dioxide. These targets would require financial incentives which were estimated to cost between 30-40% of the anticipated saving in network investment and which could be removed once barriers to deployment are overcome. The financial incentives could take the form of capital grants or long term investment support for deploying new, cost effective, generating assets.

10.2 Obstacles to Distributed Generation

With these compelling benefits, it is surprising that distributed generation is not being more aggressively adopted. There are numerous market failures and institutional barriers preventing the rapid uptake. These include:

- Incumbents using inefficient methodologies to price distributed generation and increasing use of network based prices versus volume based prices
- Regulatory barriers in favour of incumbents and technical barriers to connection
- Cultural barriers that favour business as usual approaches
- Lack of accurate information about alternatives
- Split incentives, where costs and benefits do not accrue to the parties creating them
- Unrealistic investment criteria which investors demand to be met before implementing new energy projects which are not reflective of the risk and economic life of the assets

Policy responses to these obstacles might include a mix of regulatory and pricing reform, information provision, incentives, facilitation, coordination and target setting. Setting targets for implementation of distributed generation with quantified potential benefits can focus investments for identifiable outcomes.

Chapter 11 Conclusions and Future Work

11.1 Deployment Frameworks

Researchers have declared that "development and diffusion of low carbon technologies will be central to stabilizing the climate over the 21st Century" hence understanding the influencers that impact the rate of technology diffusion is important. Diffusion research entered the mainstream in the 1970's as models for diffusion processes were adopted. In particular, Bass and Rogers created models that incorporated individual decision makers and communication channels as key factors. The rate of adoption of technologies has, in turn, been since characterised in familiar adoption curves or S-curves, evolving over shorter or longer timeframes depending on the nature of the industry and technology in question. Learning effects, resulting from volume increases that deliver lower costs to manufacture or implement technology appear to be critical to the rate of take up of technology.

While the applicability of diffusion frameworks to low carbon energy technologies is not yet mature, more recently, researchers have focussed on particular technologies in order to understand the impact of regulatory frameworks that can accelerate learning effects and take-up. Researchers have determined that technology adoption is influenced by a range of market forces and actors, technical innovation, improved price performance and cost reductions as well access to capital and public policy support.

11.2 Adoption of Sustainable Energy Technologies

The penetration of low-carbon centralised and distributed technologies in the Australian energy mix is increasing and a more varied combination of electricity generators is likely to evolve over coming years. In particular wind, solar (centralised and rooftop), combined cycle gas turbines and other centralised technologies (such as carbon capture and sequestration) and distributed technologies (such as cogeneration) will play a part, influenced by a mix of government policy and cost reductions over time (subject to technology innovation and adoption volume).

In the case of wind, the reduction in cost for each doubling of production is estimated at around 14%, reducing the capital cost of deployment and resulting in rapid take up of the technology. In Australia, the Government's Renewable Energy Targets have resulted in total investments of more than $5bn in wind farm development and around 3.1GW of generating capacity.

Large-scale and Rooftop Solar has grown even more rapidly, with rapid global expansion in deployment of solar PV resulted from, and in, significant manufacturing cost reductions. It is estimated that the learning effect in solar PV is around a 20% cost reduction for every doubling of production capacity. In Australia, a range of grant schemes and RET support as well as FiT's for rooftop installations have driven the growth of solar power with the penetration of PV now estimated at around 14% of households and the capacity to generate around 3GW of energy.

Combined Cycle Gas Turbines (CCGT) have also shown rapid penetration of the energy system. Cost reductions due to innovation and volume growth from the transport and aircraft industry combined State Government incentive programs have driven capacity increases in Australia to around 4 GW.

On the other hand, cogeneration, which has existed for more than 120 years, has been relatively slow to gain widespread adoption. Technology innovation in the form of natural gas fired reciprocating (and microturbine) engines and control systems over the past 2-3 decades has improved commercial viability. In Australia, however, penetration of cogeneration is estimated to be at less than 10% of its technical potential with around 3.3 GW of installed capacity (or around 6% of total generating capacity). Globally, around 8% of world electricity generating capacity is cogeneration in industrial, commercial and precinct settings. Yet, in some countries penetration is much higher (52% in Denmark, 19% in Eastern Europe, 13% in Germany and China). According to Climateworks (Climate Works Australia, 2011), "Despite its significant potential to meet power demand challenges, cogeneration remains underutilised". With a large number of potential sites and compelling financial and environmental benefits, the capacity to double the penetration of cogeneration in Australia to levels comparable with world averages is high.

Analysts have projected that the potential for distributed energy in Australia could provide up to 40% of total energy demand by 2020 assuming favourable market and policy conditions, with energy efficiency and cogeneration/trigeneration contributing the most. This would have avoided up to $14.9billion (2010) in network expenditure.

When mapped against the familiar diffusion frameworks, S-curves for Wind, CCGT and Solar PV indicate that penetration relevant technologies can occur over decades (as is the case for centralised technologies such as wind and CCGT) or years (as has been the case for rooftop PV). However, the rate of diffusion of these low-emission technologies Australia depends on ongoing energy and climate policy as well as market developments including gas availability and price, and future electricity demand projections.

11.3 Challenges to Deployment

The challenges and impediments preventing broader adoption of new technologies in the energy sector include technical integration issues; risks associated with early adoption and the requirement to demonstrate the viability of technologies prior to wide scale adoption; incumbent interests which delay or prevent new entrants and technologies from effectively competing with their established and, often, exclusive system infrastructure; and market and pricing issues which make emerging technologies financially less competitive that established and mature technologies.

Technical impediments in relation to distributed generation may include difficulty in forecasting output with resulting variability of voltages and frequencies, prevention of back-flow of electricity into the distribution network which can result in voltage rises and variable output power and voltages of distributed elements that can cause instability and accelerate wear. It is apparent, however, that these impediments can be overcome based on experience on other jurisdictions.

Incentives for early adoption may be required to provide greater certainty in pricing, reduce investor risk, inform producers and consumers and attract investment. These incentives may be in the form of demonstration or procurement-based funding and their absence may retard adoption rates of emerging technologies.

Incumbents often present barriers to adoption of new technology. This may require the establishment of more pro-technology policy regimes with the removal of regulatory, financial and informational barriers and introduction of targeted incentives to overcome incumbent resistance. Obstructive technical regulations; laws and financial incentives that favour established technologies and incumbent generators; and lack of awareness about technology all act to embed incumbents and reduce technological innovation.

Finally, relative prices of conventional grid-based electricity and competing fuel prices or capital costs for alternative technologies are a key determinant of the rate of adoption of alternative technologies. Market forces driven by transparent and liquid trading markets alongside pricing regimes for externalities such as carbon emissions can be influenced by relevant government policy tools.

11.4 Government Program Effectiveness

Public policy measures related to energy are diverse. The Productivity Commission (Productivity Commission, 2011) identified 1096 policy measures across nine countries with 237 different policy measures in Australia alone. The potential for overlapping policies with high administration and compliance costs is apparent.

Carbon price mechanisms have an economy wide impact and, in theory, produce least-cost abatement via market mechanisms. Carbon prices work directly on the largest emitters while their impact is felt across all consumers, particularly of energy intensive products and services. Large scale grant and demonstration programs, such as the Low Emissions Technology Demonstration Fund ($500m), Solar Flagships Program ($750m) and ($2bn) Carbon Capture and Storage Flagships Program, are also focussed on large, relatively high risk projects with promoters usually associated with industry incumbents whose motivations are not necessarily well aligned to the programs' objectives. Failure of projects funded under such programs to progress or to deliver is common and, given the lengthy timeframes between program design and initiation and project determination, such failures generally fizzle rather than bang, with little media, community, industry or government attention to outcomes as a result of changing political focus and personalities. Yet, the opportunity cost of such failures is immense. Appropriate program design rules can improve outcomes, however, such programs carry inherent risk due to poor portfolio diversification which can only be ameliorated by supporting a wider range of smaller projects with diverse risk profiles and projected outcomes.

At the other end of the spectrum, subsidies in the form of Feed-in-Tariffs have been demonstrated to be effective in securing rapid take-up of innovative technologies but are often expensive burdens on the economy. This form of subsidy impacts on smaller consumers and generators – households and small commercial enterprises. By contrast, the Renewable Energy Target, has been demonstrated to be a robust and financially responsible mechanism for encouraging the deployment of both large scale and small scale renewable energy sources.

Two key gaps are apparent in Australia's energy policy mix and the emerging "Direct Action" policy framework has the potential to address one of these weaknesses.

Firstly, while the largest emitters are subject to carbon prices, or will benefit from direct subsidies and grants for emissions reductions, and small consumers and generators benefit from subsidies in the form of Feed-in-Tariffs, intermediate consumers of electricity – large commercial enterprises and sites and medium industrial sites (diverse manufacturers and processors) have no incentive to reduce emissions while suffering high and increasing electricity and gas costs. Australia has seen the decline of local manufacture and this trend is likely to continue notwithstanding small reductions in energy prices as carbon prices are withdrawn. Meanwhile, such intermediate enterprises have little incentive to innovate, invest in securing their own energy sources, or reduce emissions. A more innovative electricity network, utilising a mix of distributed generation technologies, promises lower cost, lower emissions, greater reliability and resilience and little "regulated" capital investment.

However, realising this objective demands a suitable energy policy framework, a regulatory regime that demands the cooperation of incumbents and a suite of supporting financial incentives and funding mechanisms. Procurement mechanisms have been demonstrated to be able to deliver low cost adoption of low emissions technologies both overseas (for example, in California, South Africa and India) and domestically (such as the ACT's solar PV Auction). It would seem that such mechanisms are compatible with the Federal Government's Direct Action policy framework that seeks to obtain lowest cost emissions through a reverse auction mechanism.

Secondly, regulated emissions standards for greenhouse gases have received little attention in the Australian context compared with similar standards imposed by the EPA in the USA and under the Clean Air Act in the UK and similar policies in China. Regulating emissions intensity of older technology coal fired power stations could see them ultimately replaced by lower emissions generation from sources such as natural gas or wind. The alternative means of achieving the same objectives (abandonment of inefficient and polluting generation) through policies such as "contracts for closure" is likely to encourage gaming by incumbents to extract rents for future investment and divestment decisions.

The analysis has revealed that program design in Australia, as well as execution, has been flawed. Program objectives have been unclear and a new framework must be adopted to ensure past mistakes are not repeated.

Substantial public expenditure on highly centralised and largely unproven technology deployment does not appear to attract private capital for future deployment. On the other hand, a range of initiatives, such as SRET, FIT's, reverse auctions and direct grants has demonstrated that increasingly mature and distributed technologies (such as rooftop solar PV and cogeneration) respond much more rapidly to appropriate policy instruments and are much more rapidly deployed with lower risk.

11.5 Private Investment Frameworks

In order to frame appropriate public policy and share the burden for new investment in energy infrastructure, a proper understanding of private sector investment theory is imperative. The mix of behavioural, financial and risk management criteria that private sector investors apply to expenditure decisions relating to the introduction of new capital assets or investment in long-term but risky technologies is complex. The role of public policy is to guide desired community outcomes while demanding investment from the private sector that does not erode (and possibly improves) competitiveness.

Investment in energy by private sector financial and corporate entities is large and rapidly increasing. Funds will flow where returns are highest, risks are identifiable, information is available and decision processes are transparent. At times, limited government incentives and the introduction of complementary regulations can produce substantial changes in investment behaviour by corporations and individuals (for example, the banning of incandescent lamps alongside incentives for energy efficiency). Government co-funded capital grants and tax incentives have been used to encourage investment by both improving project economics and triggering investments that may otherwise not have been considered.

Thus, program design should be cognizant of the potential leverage of relatively limited incentives and subsidies that trigger rational but much larger investment outcomes by commercial and industrial energy users.

11.6 Cogeneration & Trigeneration in Commercial, Industrial and Micro-grid Applications

Analysis of the potential financial and environmental benefits of distributed generation in the form of industrial and commercial cogeneration and trigeneration and broad distributed generation technologies (solar PV, battery storage and trigeneration) has been assessed.

The outcomes of a specially developed modelling tool has been applied to 86 potential cogeneration and trigeneration applications to determine key financial metrics such as payback period, Net Present Value (NPV) and Internal Rate of Return (IRR) and environmental benefits associated with energy efficiency and displacement of grid-provided electricity generated in predominately coal-fired thermal plants.

The analysis suggests that the average capital cost per tonne of CO_2 abated over an assumed 20 year life of equipment is approximately $30 and a negative overall cost of carbon abatement with projects yielding an average IRR of around 32% per annum. Larger systems proved more financially attractive and cogeneration is a more attractive financial investment than trigeneration. Opportunities to replace or upgrade various energy conversion systems (such as electric in-duct heating or older electric chillers) and source electricity from distributed generation may generate significant returns while combining alternative HVAC technologies may also deliver greater efficiency as well as flexibility. On the other hand, sites which didn't utilise the waste heat from the generator did not exhibit substantial energy efficiency benefits (but depending on relative gas/electricity prices may have made acceptable investment cases).

The application of cogeneration and trigeneration to precinct and micro-grid developments is both feasible and may be environmentally and financially attractive. A micro-grid may be either an entirely off the grid-based electricity network or may rely on a network connection for emergency backup. This can be determined by economics without being constrained by technology, since acceptable reliability and availability can be guaranteed with an appropriate micro-grid design. A micro-grid mirrors the traditional power grid's structure at micro-scale, typically ranging from between several kilowatts (residential) up to megawatt scale in size. They enlarge features such as distributed generation while compressing others, such as transmission and wide-area balancing. The defining characteristic of a micro-grid is the co-location of power generation and load.

As a result of its numerous remote communities, Australia is disproportionally represented in micro-grid deployment. Many micro-grids have demonstrated up to 50% reduction in peak load consumption and can utilise diverse but complementary distributed energy resources. Micro-grids also empower the consumer and create choices for how to manage risk while optimising costs and can promote private capital with smaller, more tangible investment rewards and risks. Investment in micro grids is expected to grow rapidly as a result. Micro-grids improve energy efficiency by generating electricity at sites that are located close to the customers served and therefore offer the potential to deliver substantial carbon emissions reductions, improved overall energy efficiency and lower long term operating costs and energy prices to energy consumers.

Cost, availability and reliability of micro-grids are able to be estimated and guaranteed providing certainty to investors, operators and customers. Technical advances ensure that service quality and future investments can be optimised as the micro-grid develops. For example, today's micro-grid might incorporate solar PV, battery storage for smoothing and backup, cogeneration for base load power and thermal energy and diesel backup for reliability and robustness. In the future, other generating elements such as waste-to-power, distributed fuel cells, and other forms of chemical storage will emerge that provides stronger economics and greater efficiency.

The analysis of the design of a micro-grid has demonstrated that capital costs can be justified by competitive energy tariffs with energy provided at competitive rates compared with traditional grid-supplied energy.

Nonetheless, a number of risks and challenges exist that contribute to the relatively slow take-up of distributed generation micro-grids. These include generally unfavourable regulatory restrictions imposed on micro-grid owners, onerous technical compliance requirements and the need for continuity of capital and performance guarantees for delivery.

11.7 Wide-spread Potential for Distributed Generation

The importance of energy, and particularly electricity, to global economic, industrial and social development is unarguable, while the dynamic changes in supply and demand have created an unpredictable and demanding planning environment. With the consequences of potentially catastrophic climate change looming, substantially driven by electricity related green-house gas emissions, meaningful solutions based on innovative approaches to future energy systems are necessary. In Australia, energy policy is complicated by a range of domestic issues (gas prices, extraction of non-conventional gas, availability of low cost coal resources, changing structure of the economy, ownership and motivation of electricity industry incumbents, unique scale of transmission and distribution infrastructure and a ponderous and partisan regulatory and policy environment).

Distributed generation in Australia has the potential to make substantial inroads into the traditional energy system with financial and environmental benefits in commercial and industrial applications as well as micro-grid (and precinct) applications. It has been estimated that up to 73 megatonnes of emissions would be avoided within electricity sector should this potential be realised, accounting for around 15% of total Australian emissions. At a global scale, cogeneration alone could reduce global greenhouse emissions by at least 4% in 2015 and by 10% in 2030 which translates to 950 MT/year which would contribute a meaningful reduction to emissions and assist in avoiding climate disruption.

Further, since cogeneration offers negative cost abatement, it would save consumers money while reducing power industry investment requirements (globally, by around US$795 billion through reduced transmission and distribution network investment and displacement of higher-cost generation plants) while in Australia, a saving of around $1 billion per annum could be made by avoiding network investment, and reducing peak energy demands.

To achieve these benefits, is has been estimated that financial incentives estimated to cost between 30-40% of the anticipated saving in network investment may be required but these could be removed once barriers to deployment are overcome. The financial incentives could take the form of capital grants or long term investment support for deploying new, cost effective, generating assets.

Despite these compelling benefits distributed generation has not been adopted aggressively as a result of numerous market failures and institutional barriers.

11.8 Future work

The following questions surfaced as a result of the author's research work that resulted in this thesis:

1. How can the economic and societal benefits of adoption of sustainable energy technologies by simply and clearly articulated in order to educate and inform the general public, and, in turn, its political leadership? ?
2. What forms of persuasion are most effective in engaging and convincing political leadership and key influencers that deployment of such technologies is necessary, provides financial and social benefits and is both realistic and achievable?
3. What public policy instruments can be promoted and created to drive the widespread adoption of these technologies, and how can these instruments be made more effective than previous failed or flawed policies and programs?

Often, the ability to absorb complex messages of great importance is limited by both the complexity (and sometimes lack of clarity or ambiguity) of the message (and its underlying analysis) as well the difficulty in altering the belief system of the receiver of the message.

Academics and task-forces such as the IPCC have done a relatively poor job in describing the impact of, and solutions to, ongoing climate change and, particularly, the availability of technical options such as a move to distributed generation that can influence climate outcomes. While there is widespread peer acceptance of the theory, there has been limited public pressure applied to the political leadership to drive satisfactory outcomes. Hence, these influencers have, hitherto, failed to action their concerns in a meaningful manner.

At the same time, there is very little research on the belief systems of those in positions of influence in relation to engaging on the issue of climate change and optimising the environmental and economic benefits of transitioning to a low carbon sustainable energy system. This issue, in particular, is one that the author will seek to research and better understand.

Appendix A: Publications arising from this thesis

Conference Papers and Presentations

"Combining Technologies for Energy Efficiency", The Australian Institute of Refrigeration, Air Conditioning and Heating (AIRAH) Annual Conference September, 2013

"Cogeneration – A Solution to Your Problems and to Our Problems", Clean Energy Council Annual Conference, 2012

"Case Study of a Successful Cogeneration Installation", The Australian Institute of Refrigeration, Air Conditioning and Heating (AIRAH) Annual Conference September, 2012

"Do Sustainable Energy Demonstration Programs Work?", Australian Solar Council (AuSES) Annual Conference, 2011

" Improving Investment Outcomes in the Development and Commercialisation of 'Clean' Energy Technologies Within Australia", Australian Solar Council (AuSES) Annual Conference, 2010

Panels and Committees

"Clean Technology and Renewable/Alternative Energy", Panel Member - Melbourne International Venture Capital Conference, March 2011

"Joint Science and Technology Cooperation Committee", Delegate representing Australia as part of a scientific delegation led by the Chief Scientist to the EU, October 2012

Papers

AARON, A. & MCGILL, I. 2010. Improving Investment Outcomes in the Commercialisation of Cean Energy Technologies Within Australia. Sydney: Unversity of New South Wales, Unpublished Paper

AARON, A. & MCGILL, I. 2011. Do Demonstration Projects Close the Gap Between Technology Risk and Commercial Backing? Sydney: Unversity of New South Wales, Unpublished Paper

AARON, A. & MCGILL, I. 2012. A Comparative Review of Australian technology demonstration and commercialisation initiatives in sustainable energy. Sydney: Unversity of New South Wales, Unpublished Paper

FLORAN, N., MCGILL, I. & AARON, A. 2014. Stocktake of Low-carbon Power Generation in Australia. Sydney: University of New South Wales.

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