COGENERATION IN NSW

REVIEW AND ANALYSIS OF OPPORTUNITIES

Prepared by

Institute for Sustainable Futures

For

NSW Department of Planning

Institute for Sustainable Futures
University of Technology, Sydney
PO Box 123
Broadway, NSW, 2007

COGENERATION IN NSW

Review and Analysis of Opportunities

FINAL

For NSW Department of Planning

Authors:

Josh Usher, Chris Riedy, Jane Daly and Kumi Abeysuriya

Institute for Sustainable Futures

Disclaimer

Please cite this report as: Usher, J, Riedy, C, Daly, J and Abeysuriya, K 2008, *Cogeneration in NSW: Review and Analysis of Opportunities*, prepared by the Institute for Sustainable Futures, University of Technology, Sydney for the NSW Department of Planning, March 2008.

Acknowledgements

The authors would like to thank all of the stakeholders that gave up their time to be interviewed for this report. For reasons of confidentiality, interview participants have not been identified by name in this report. We would also like to thank Blair Healy of Cogent Energy and Joe Zannino of Stockland for contributing case studies on cogeneration for use in the report. Finally, we would like to thank Chris Tully from the NSW Department of Planning's Demand Management and Planning Project for initiating this report and providing the data analysed in the report.

Executive Summary

The Demand Management and Planning Project (DMPP) under the NSW Department of Planning engaged the Institute for Sustainable Futures (ISF) at the University of Technology, Sydney (UTS) to prepare this report on the status of cogeneration in NSW. Cogeneration is the simultaneous production of two forms of energy, generally electrical and thermal, also referred to as combined heat and power (CHP). Cogeneration makes productive use of the heat that is normally rejected as waste in conventional generators, resulting in higher overall efficiency.

Over the past five years, the DMPP has investigated 81 opportunities for cogeneration in a range of commercial, industrial and other applications. The investigations by the DMPP team covered the inner metropolitan region of Sydney and involved inspection of all facilities that generally have demand greater than 500kVA. Net cost savings and payback periods were calculated for each opportunity. Analysis of these data forms the core of this report and helps to demonstrate the viability of cogeneration to regulators and the marketplace.

The DMPP has also provided funding support for the following activities:

- Significant funding was provided to the market place to reduce the hurdle rate for the installation of large cogeneration systems within commercial buildings, resulting in cogeneration projects at 101 Miller Street, North Sydney and 133 Castlereagh Street, Sydney
- Two cogeneration pilot programs were totally funded in the multi unit residential sector, at Chatswood and Rouse Hill
- Large cogeneration feasibility studies were undertaken at industrial sites owned by Lion Nathan and AMCOR.

Background

While the capital cost of cogeneration exceeds alternatives such as grid connection and natural gas heating, it delivers operating cost savings that can make it commercially attractive in the right circumstances, particularly when there is a significant thermal load alongside an electrical load. In addition, cogeneration can deliver substantial greenhouse gas reductions over grid electricity. When using natural gas for cogeneration in NSW, these savings can exceed 50%.

Installed cogeneration capacity in NSW by the end of 2006 was about 307MW, with natural gas and waste gas being the dominant fuels and most plants located in industrial facilities. Recently, there has been growing interest in non-industrial applications of cogeneration, particularly in commercial and residential high-rise developments. By delivering greenhouse gas reductions, cogeneration can help organisations to meet regulatory requirements and corporate objectives by improving BASIX scores and increasing ratings under the Australian Building Greenhouse Rating (ABGR) scheme and Green Star.

Cogeneration technology

Cogeneration can use a range of different fuels in the main electricity generation unit, including coal, natural gas, petroleum-based products (diesel and fuel oils), solid biomass (e.g. bagasse), biofuels and biogas. Natural gas is the most commonly used fuel, due to its relatively low cost, ease of transport (via pipeline), wide availability and low greenhouse intensity. Biomass and biogas are environmentally preferable fuels that are increasingly being used for cogeneration.

Cogeneration is possible with a range of technologies, including reciprocating gas engines, combustion gas turbines, microturbines and fuel cells. Gas engines are the most commonly used technology in smaller installations, while gas turbines are preferred for larger installations. Both of these technologies emit pollutants, of which NOx is the pollutant of most concern. Lean burning gas engines and gas turbines will usually meet regulatory requirements relating to air emissions, however additional treatment of emissions may be necessary in some circumstances.

Cogeneration plants can deliver various outputs in addition to electricity, including hot water, space heating, hot air/steam for industrial processes, space cooling (using an absorption chiller) and dry air (with the use of a desiccant). Their flexibility can be improved using on-site backup and energy storage.

Economic analysis

Table ES1 summarises the characteristics of the 81 sites investigated by the DMPP. If all opportunities were taken up, they would deliver a reduction in peak demand of 70.6MVA and a reduction in greenhouse gas emissions of 331 kilotonnes CO_2-e per year.

Site Type	*Number of Sites*	*Peak MVA Reduction*	*Peak MVA Reduction per Site*	*MWh / year Reduction*	*Tonnes CO_2e / year Reduction*
Commercial	2	0.8	0.4	8,986	6,131
Education	4	7.3	1.8	44,006	30,024
Entertainment / Sporting / Leisure	6	1.7	0.3	14,060	9,592
Food	3	7.6	2.5	45,256	30,877
Health	17	10.7	0.6	65,378	44,605
Hospitality	9	3.1	0.3	24,303	16,581
Industrial	31	31.3	1.0	245,744	167,663
Infrastructure	1	0.4	0.4	1,693	1,155
Manufacturing	3	4.4	1.5	16,000	10,916
Media	1	0.4	0.4	2,824	1,927
Printing and Publishing	1	0.4	0.4	1,314	896
Retail	1	0.2	0.2	1,209	825
Water Utility	2	2.3	1.2	14,934	10,189
Total	**81**	**70.6**	**0.9**	**485,707**	**331,382**

Table ES1: DMPP site investigation summary.

At each of the sites investigated, the organisation provided its investment criteria for adopting cogeneration. The criteria varied from a simple payback period of 1 to 6 years with an average of 2.8 years for the 81 case studies. The DMPP then calculated the government subsidy required to ensure that a cogeneration plant at each site would meet these investment criteria. The results are presented in Figure ES1 and in Table ES2. To capture the full technical potential at the payback periods provided by the customers, a subsidy of $3,221/kVA would be required. The overall average subsidy required was $1,350/kVA.

As an alternative to providing subsidies, uptake of these opportunities could be improved by:

- Encouraging customers to lower their internal rate of return requirements for cogeneration. The effect of a fixed IRR of 12% on cogeneration uptake is shown in Figure ES2. More than 20MVA of cogeneration would be implemented without a subsidy and a subsidy of $400/kVA would deliver the full technical potential across the sites investigated.

- Providing access to network deferral payments. Figure ES3 shows how the subsidies required at the 81 sites investigated by the DMPP would decrease if a network payment of $400/kVA or $800/kVA was provided.

- Ensuring that cogeneration is benefited by a future emissions trading regime. Figure ES4 shows the impact of various carbon prices on uptake of cogeneration opportunities investigated by the DMPP.

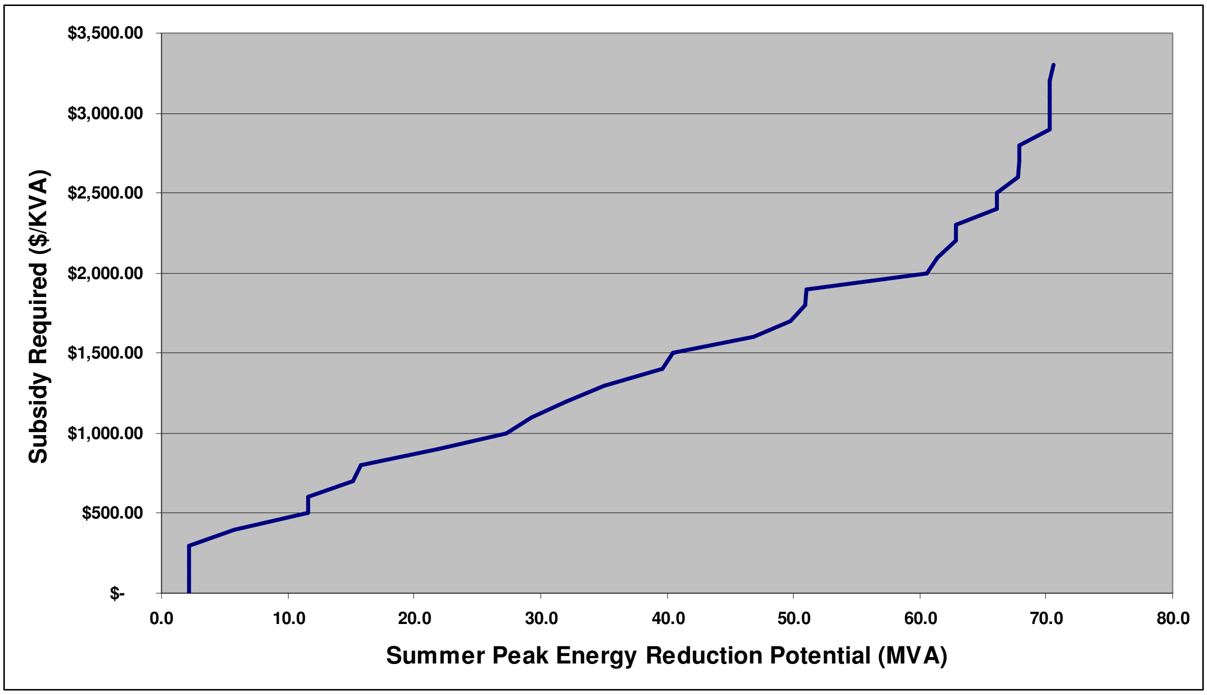

Figure ES1: Level of subsidy required to capture potential peak demand reductions at investigated sites.

Subsidy ($/kVA)	*Peak Demand Reduction (MVA)*
0	2.2
200	2.2
400	5.8
500	11.7
1000	27.3
2000	60.6
3221 (Full Technical Potential)	70.6

Table ES2: Subsidy required for peak demand reduction.

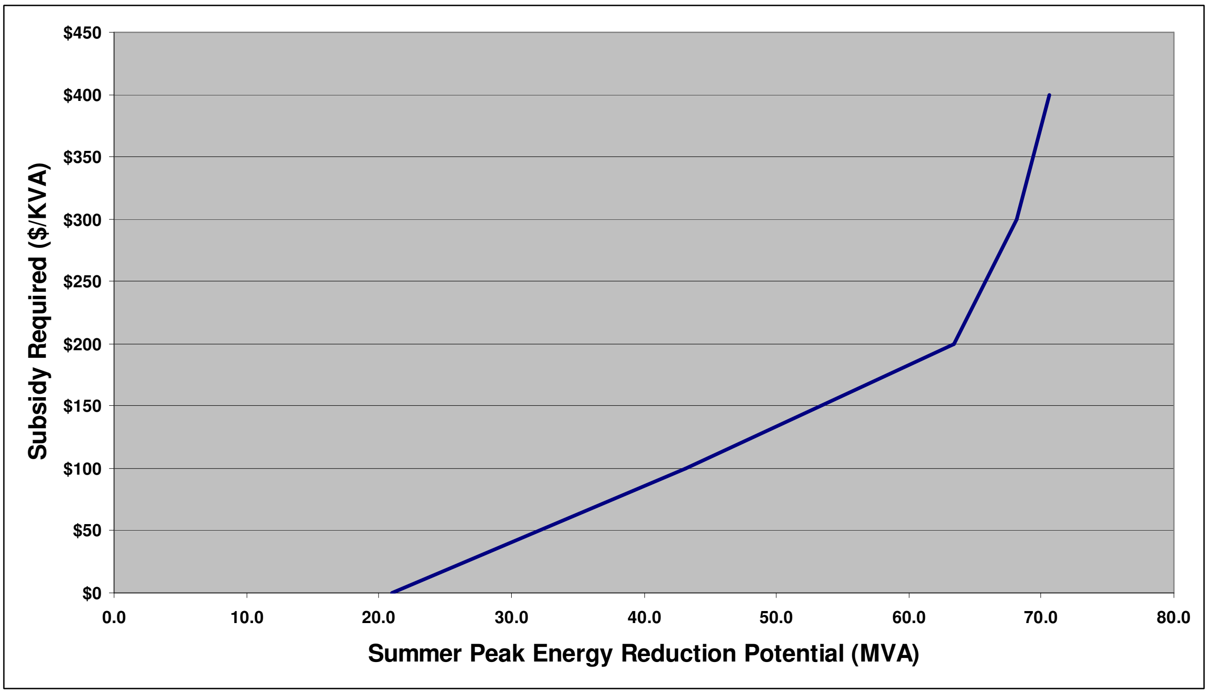

Figure ES2: Cumulative summer peak energy reduction potential with increased subsidies for a fixed customer IRR requirement of 12%.

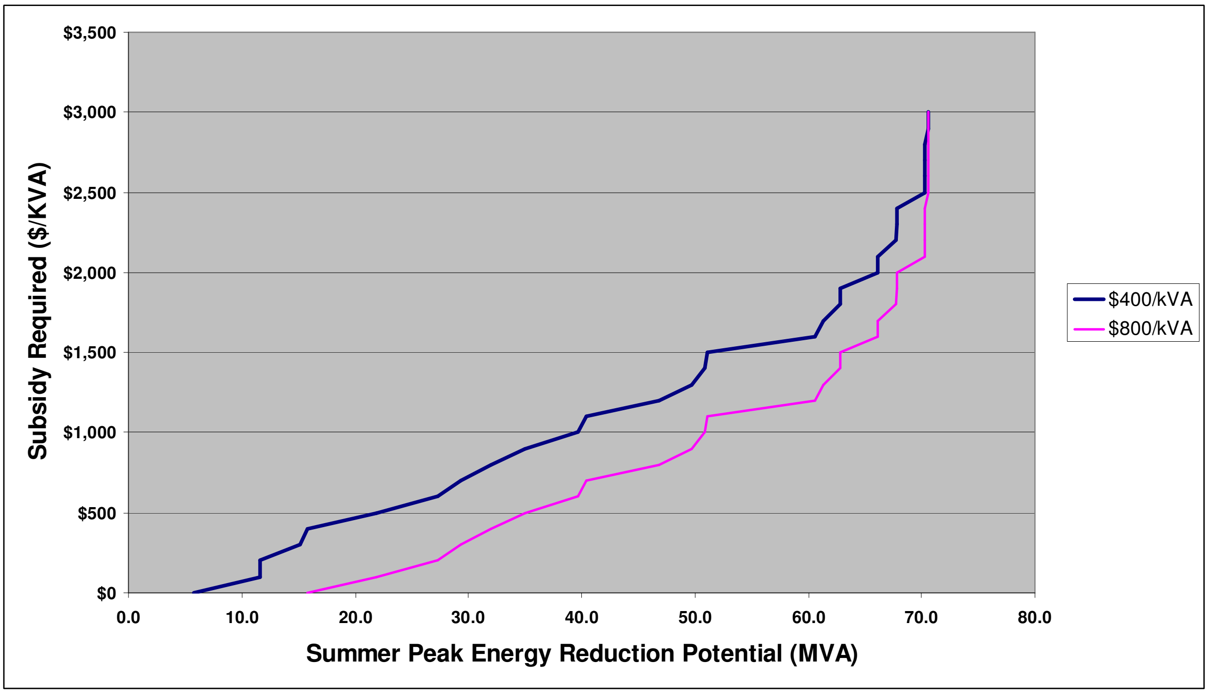

Figure ES3: Cumulative summer peak energy reduction potential with network payment and government subsidy.

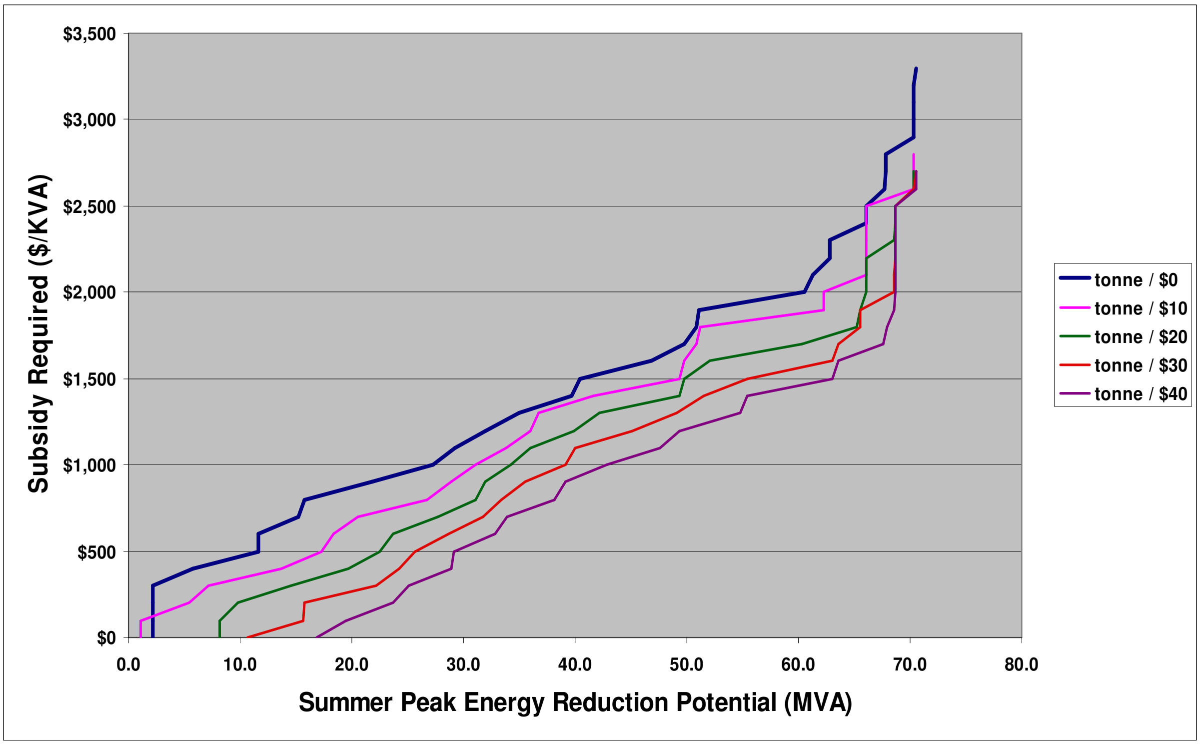

Figure ES4: Effect of carbon pricing on required government subsidy versus summer peak reduction potential.

The role of government

Governments have an important role to play in improving the uptake of cogeneration in NSW. The regulatory framework within which cogeneration operates can facilitate or inhibit implementation of cogeneration. In NSW, cogeneration proposals must comply with:

- Planning laws and instruments. In general, cogeneration would require a Development Application to the local Council, unless it is part of a larger development.
- Environmental laws, of which requirements relating to air emissions are particularly important for cogeneration facilities
- The requirement to hold an electricity retail licence if selling electricity to customers
- Requirements under the National Electricity Law and Rules relating to registration as a generator or distributor, connection to the electricity network and export of electricity
- Any requirements established by the distribution network service providers (DNSPs) regarding connection to the electricity distribution network. The three main DNSPs in NSW are Energy Australia, Integral Energy and Country Energy.
- If using natural gas, the requirements established by gas network operators for access to the gas network
- Accreditation requirements under the NSW Greenhouse Gas Reduction Scheme if seeking to generate NSW Greenhouse Gas Abatement Certificates (NGACs).

In some circumstances, these regulatory requirements create barriers to cogeneration that are discussed below.

Governments also provide a range of support mechanisms for cogeneration, including:

- The NSW Greenhouse Gas Reduction Scheme, which allows accredited cogeneration facilities to create NGACs for low-emission generation of electricity and for the supply of heat that results in a reduction of electricity use. NGACs have a market value that can improve the commercial viability of cogeneration
- Grant funding available through the NSW Green Business Program or the Public Facilities Program under the NSW Climate Change Fund
- The use of licence conditions to require DNSPs to conduct and publish investigations on the cost effectiveness of implementing demand management strategies that may permit distribution network augmentations to be deferred or avoided. This allows cogeneration proponents to potentially benefit from payments for network deferral.

Barriers to cogeneration and potential solutions

Despite its environmental and network benefits, the economic analysis in this report indicates that cogeneration remains a marginal commercial proposition in many applications, requiring government subsidisation to proceed. Where there is a significant thermal load alongside an electrical load, or there are significant network constraints, cogeneration may make commercial sense. In the absence of these conditions, the margin between grid electricity and natural gas prices is rarely sufficient to drive investment in cogeneration. Cogeneration is also seen as a risky venture, as a result of current uncertainty about future carbon prices, relative trends in electricity and gas prices and lack of familiarity with the technology.

To improve the commercial viability of cogeneration, the following strategies are required:

- Introduction of an emissions trading scheme that puts a value on greenhouse gas emission reductions and does not unfairly disadvantage cogeneration
- Improvements to network planning processes to ensure that cogeneration providers are compensated for any network benefits they provide
- Reduction of transaction costs and risk through experience and government support.

Emissions trading

The low carbon price that currently exists under the NSW Greenhouse Gas Reduction Scheme is a barrier to cogeneration. The introduction of emissions trading is highly likely to improve the commercial viability of cogeneration, although much depends on the final structure of the trading scheme and the carbon price. Additional support measures, such as feed-in tariffs or low interest loans for cogeneration facilities, may need to be considered.

Network planning and connection

According to the IEA (2007), 'energy regulators and their regulated entities continue to plan for the future using models that rely heavily on major, centralised investments in large power plants and new transmission/distribution capacity'. Cogeneration is a different approach that avoids or defers these investments and is not always well represented in network planning processes.

Similarly, the MCE (2006) notes that network 'connection requirements for non-conventional technologies can be inconsistent, complex, inappropriate to technology and impose relatively high transaction costs'. For small-scale cogeneration, network connection regulations and technical standards can be unnecessarily onerous, or non-existent.

Although the national framework for network regulation is being revised, it remains unclear how the revisions will impact cogeneration. Cogeneration would clearly benefit from revisions to the National Electricity Rules to provide greater incentives for demand management. ISF and RAP (2008) provides detailed recommendations on how to improve treatment of demand management in the National Electricity Rules and these recommendations are endorsed here.

Government support

Several of the cogeneration opportunities that have been taken up in NSW have benefited from active facilitation and support from the NSW Government, first through SEDA and more recently through the DMPP. While funding support through the Climate Change Fund is critical to alleviate initial capital costs and provide more experience with cogeneration, funding alone is not sufficient. At this stage in the development of the cogeneration market, the level of expertise to investigate, analyse and design successful cogeneration projects is limited. Without active government facilitation and support for cogeneration projects, opportunities like those identified in this report will be lost.

The NSW Government should establish a dedicated team within an appropriate department to provide active facilitation and support of cogeneration projects. One of the first tasks of this team should be to take forward the cogeneration opportunities already identified by the DMPP. Another should be to prepare a comprehensive cogeneration guide for potential adopters of cogeneration. This current report provides a starting point, but the focus of the guide would be more on the practical issues and processes that an organisation needs to go through to make a decision on whether to invest in cogeneration. The guide would cover NSW regulatory requirements and approval processes as well as processes for conducting feasibility studies and obtaining information. As well as reducing transaction costs, a guide of this sort would help cogeneration proponents to manage risk.

Conclusion

Cogeneration is a proven technology that is building market momentum and, with the right thermal demand and economic and regulatory environment, can be expected to provide sizeable demand management opportunities. Cogeneration offers substantial environmental benefits and can have commercial benefits in the right circumstances. When fuelled by natural gas or renewable fuels, cogeneration can deliver electricity with much lower emissions intensity than the grid. Further, the use of waste heat means that overall efficiency of energy conversion is greatly increased. Cogeneration also offers the potential to reduce peak electrical demand, thereby reducing the need for network augmentation. As climate change response becomes more urgent, cogeneration has great potential to contribute to greenhouse gas emission reduction.

Cogeneration technologies have matured to the extent that they are now being seriously considered as a way of reducing costs and achieving environmental benefits in a range of applications. Improvements to absorption chillers have also improved the viability of trigeneration, which is an attractive option for sites with significant cooling loads. However, there is still relatively little experience with cogeneration in NSW and this is reflected in the lack of streamlined processes for approval and connection of cogeneration plants and the shortage of reliable information on feasibility of cogeneration.

Nevertheless, several businesses have emerged recently with a focus on cogeneration provision and recent applications of cogeneration in high-rise commercial and residential buildings in Sydney are adding impetus to the market. These pioneering efforts are helping to pave the way for further applications of cogeneration in the future.

The investigations undertaken by the DMPP identified two cogeneration opportunities as commercially viable according to the customers' own investment criteria. One of the opportunities is already being undertaken and thus no assistance was required from the DMPP. The second opportunity is a simplified cogeneration opportunity in the health sector. It would be unlikely however that this opportunity would be implemented without significant funding. The remaining cogeneration opportunities required funding assistance of up to $3,221/kVA. These opportunities would deliver total peak demand reductions of 70.6MVA, energy savings of 407 GWh per year and greenhouse gas savings of 277 kilotonnes CO_2-e per year for an average subsidy of $1,350/kVA.

The hurdle rates established by organisations for investments in cogeneration are high, reflecting perceptions that the technology is risky and concerns about the size of capital investment. It needs to be recognised that asking a business to change from its current mode of operation to an alternative is difficult. The capital cost to purchase a boiler to generate hot water or steam is far less than to install a cogeneration plant.

In general cogeneration opportunities are likely to become much more attractive, and many will become financially viable, as electricity prices rise relative to gas prices. A higher cost on greenhouse emissions than presently created by the penalty cap under the NSW Greenhouse Gas Abatement Scheme may be required to see large numbers of cogeneration investments. However, even the present value of NGACs significantly improves the economics of cogeneration compared to other technologies. A higher carbon price and more attention to the ways in which cogeneration can provide network benefits and be paid for these benefits is needed to further improve the viability of cogeneration.

Table of Contents

List of Tables

List of Figures

Abbreviations

ABGR	Australian Building Greenhouse Rating
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AMEIF	Australian Municipal Energy Improvement Facility
CEC	California Energy Commission
CHCP	Combined heat, cooling and power
CHP	Combined heat and power
COAG	Council of Australian Governments
DA	Development Application
DEC	Department of Environment and Conservation
DECC	Department of Environment and Climate Change
DMPP	Demand Management and Planning Project
DNSP	Distribution Network Service Provider
DUOS	Distribution use of system
DWE	Department of Water and Energy
EA	EnergyAustralia
EPA	Environment Protection Authority
EPI	Environmental Planning Instrument
GGAS	NSW Greenhouse Gas Reduction Scheme
IPART	Independent Pricing and Regulatory Tribunal of NSW
ISF	Institute for Sustainable Futures
IRR	Internal rate of return
LEP	Local Environmental Plan
MCE	Ministerial Council on Energy
MCFC	Molten carbonate fuel cell
NCC	Newcastle City Council
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company

NER	National Electricity Rules
NETS	National Emissions Trading Scheme
NGAC	New South Wales Greenhouse Abatement Certificate
NOx	Nitrogen oxides
NSP	Network service provider
PAFC	Phosphoric acid fuel cell
PEMFC	Proton exchange membrane fuel cell
RDGWG	Renewable and Distributed Generation Working Group
REP	Regional Environmental Plan
RFP	Request for proposals
SCR	Selective catalytic reduction
SEPP	State Environmental Planning Policy
SKM	Sinclair Knight Merz
SOFC	Solid oxide fuel cell
TUOS	Transmission use of system
UTS	University of Technology, Sydney
VOCs	Volatile organic compounds

1 Introduction

The Demand Management and Planning Project (DMPP) under the NSW Department of Planning engaged the Institute for Sustainable Futures (ISF) at the University of Technology, Sydney (UTS) to prepare this report on the status of cogeneration in NSW. Cogeneration has significant environmental benefits and this report seeks to identify ways in which uptake of cogeneration might be improved in NSW. Section 1 of this report provides an introduction to cogeneration technology and the work undertaken by the DMPP to investigate the feasibility of cogeneration in NSW.

1.1 Background

Cogeneration is the simultaneous production of two forms of energy, generally electrical and thermal, also referred to as combined heat and power (CHP). Cogeneration makes productive use of the heat that is normally rejected as waste in conventional generators, resulting in higher overall efficiency. In addition, cogeneration facilities are typically located at the point of energy demand, so losses associated with transport of electricity are largely avoided. As a result, cogeneration facilities can achieve overall energy efficiency of 70-90% compared to only 35% on average for conventional supply of electricity from the grid.

Cogeneration is most attractive at sites with a large heating load (such as hotels, hospitals, manufacturing facilities, or precinct scale developments). The heat can also be used to create "coolth" through the use of an absorption chiller to meet large scale air conditioning requirements. An absorption chiller is like a refrigerator, except it uses heat as its energy source instead of electricity. It creates chilled water that can be used for cooling. The combination of cogeneration and an absorption chiller is known as trigeneration or combined heat, cooling and power (CHCP). An example of a typical trigeneration system is shown in Figure 1.

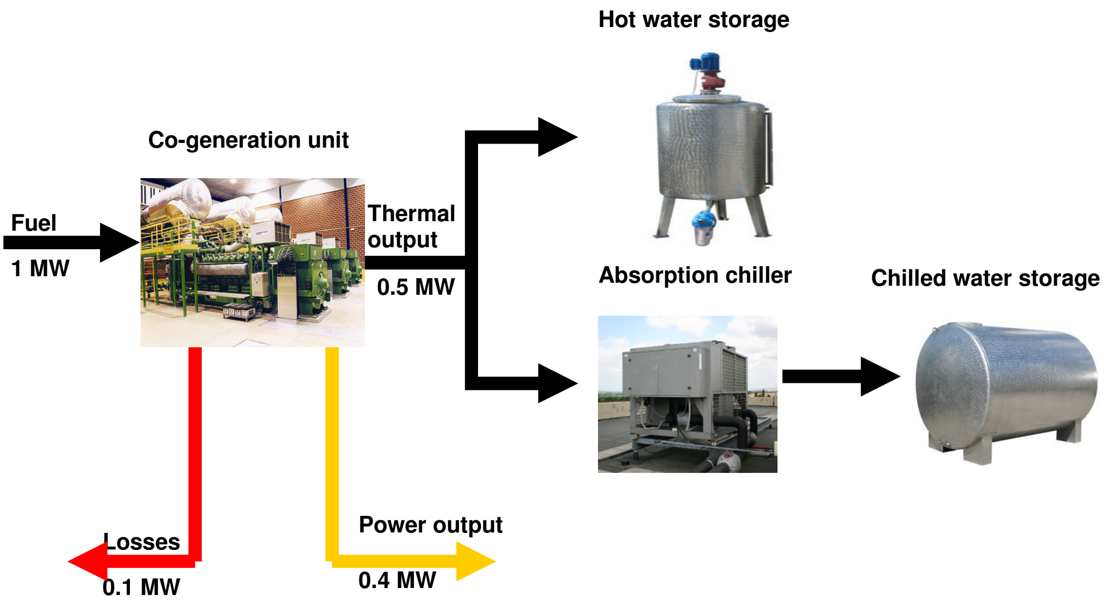

Figure 1: Typical trigeneration flow diagram.

Cogeneration can use various fuels, including coal, petroleum products, natural gas, biomass and biogas. The majority of cogeneration facilities installed recently in NSW use natural gas and most facilities under investigation intend to use natural gas. The popularity of natural gas reflects its availability, cost and greenhouse intensity.

1.2 Costs and benefits

Cogeneration has upfront capital costs associated with construction or installation of the generating and heat recovery equipment, as well as ongoing operating, fuel and maintenance costs. In assessing the commercial viability of a cogeneration facility, the capital and recurring costs need to be compared to the capital and recurring cost of alternatives. At many sites with existing connections to the electricity grid, this becomes a simple question of whether the recurring costs of cogeneration are less than the recurring costs of electricity supply and, if so, how long it will take for the reduction in recurring costs to pay for the capital cost of the cogeneration facility.

Estimated electricity generating costs for cogeneration plants range from $40-50/MWh for large gas turbines to $60-70/MWh for small reciprocating gas engines (RDGWG 2006). Although these estimates will compare favourably with the cost of electricity for many organisations, cogeneration payback periods in comparison to an existing grid connection are unlikely to be attractive unless there is a significant thermal load alongside the electrical load. However, as markets continue to develop for greenhouse gas emission reductions, cogeneration is becoming more attractive at existing sites. A carbon price increases the cost of grid electricity relative to cogeneration (for most commonly used fuels), which decreases payback periods. Overseas, where electricity prices and thermal demand both tend to be higher, cogeneration is much more common than in Australia (IEA 2007).

In NSW, the greenhouse gas intensity of electricity from the grid is 1.068 tonnes per MWh. A typical reciprocating engine generator running off gas in NSW would have a generation intensity of approximately 0.713 tonnes per MWh. However, the generator is also creating useful heat that can reduce electricity demand by up to 50%. When these two factors are combined, greenhouse gas reductions of between one half and two thirds are possible. As emissions trading markets continue to develop, the potential for cogeneration to capture additional value through emission reductions will increase.

Other factors can also improve the viability of cogeneration. When there is a capital cost associated with connection to the electricity grid, then it is only the marginal capital cost of a cogeneration facility that needs to be paid off. New developments, or existing developments that are increasing their load, will usually be required to pay a contribution to the cost of any electricity network augmentation required to serve the development. In areas where there are electricity network capacity constraints, these costs can be significant. For large developments, they may even exceed the capital cost of cogeneration and will certainly reduce payback periods substantially. In constrained parts of the electricity network, the network utility may also pay for firm demand reductions provided by cogeneration.

An additional benefit of cogeneration that may be of value to some organisations is improved reliability. With gas supply reliability higher than electricity reliability in many of Sydney's suburbs, sites using cogeneration plants often have less time without power. The value placed on this higher reliability will vary from case to case.

The potential economic, environmental and reliability benefits of cogeneration are driving a significant increase in interest in the technology in NSW.

1.3 Cogeneration in NSW

The first cogeneration installation in Australia was in 1928 at the Port Kembla Steelworks. Cogeneration is now a proven and reliable technology with 151 projects greater than 100kW in size installed across Australia (BCSE 2007). Total installed cogeneration power plant capacity in Australia by the end of 2006 was 2,667MW, mainly in heavy industries such as metal, paper and chemicals (Clean Energy Council 2007) but also in the sugar industry and health services (BCSE 2007).

Table 1 shows the installed cogeneration capacity in NSW at the end of 2006, by fuel type. NSW accounts for 11.5 per cent of installed cogeneration capacity in NSW, with natural gas and waste gas being the dominant fuels. Most of these plants are in industrial facilities.

Fuel	*Installed Capacity (MW)*
Bagasse	15.5
Black liquor	20.0
Sewage gas	3.5
Coal	11.0
LPG	0.1
Natural gas	176.4
Waste gas	80.4
Total	**306.9**

Table 1: Installed cogeneration capacity in NSW by fuel type. Sources: BCSE (2007).

Recently, there has been growing interest in non-industrial applications of cogeneration, particularly in commercial and residential high-rise developments. By delivering greenhouse gas reductions, cogeneration can help organisations to meet regulatory requirements and corporate objectives by improving BASIX scores and increasing ratings under the Australian Building Greenhouse Rating (ABGR) scheme and Green Star.

In 2006, the NSW Department of Planning commissioned a report on the potential application of cogeneration in residential apartment buildings in NSW as a way of achieving BASIX energy targets (Invenergy 2006). Subsequently, the NSW Department of Planning initiated demonstrations of cogeneration at two multi-unit residential sites in Chatswood and Rouse Hill.

Trigeneration is also being investigated for several major mixed-use developments in Sydney, at Barangaroo, Frasers Broadway and North Eveleigh. In addition, GridX has installed a trigeneration system at Mirvac's Glenfield Vision Estate, which is the first residential estate in the world to use trigeneration.

There appears to be great potential for growth of cogeneration in NSW and Australia. The current installed cogeneration potential in Australia amounts to about 5.6 per cent of total installed generating capacity in Australia (IEA 2007). The International Energy Agency examined a selection of countries accounting for 80 per cent of global electricity generation and found that cogeneration made up 10.3 per cent of installed capacity on average (IEA 2007). This gives some indication of the short-term growth potential for cogeneration.

1.4 Feasibility studies

Over the past five years, the NSW Demand Management and Planning Project (DMPP) have investigated 81 opportunities for cogeneration in a range of commercial, industrial and other applications. Net cost savings and payback periods were calculated for each opportunity. Analysis of these data forms the core of this report and helps to demonstrate the viability of cogeneration to regulators and the marketplace.

The investigations by the DMPP team covered the inner metropolitan region of Sydney and involved inspection of all facilities that generally have demand greater than 500kVA. The following categories of potential cogeneration users were identified:

- Hospitals and health facilities
- Hotels, cinemas, clubs and hospitality venues
- Industrial / manufacturing facilities
- Government offices of local, state and federal agencies
- Multi dwelling residential
- Educational facilities, universities and TAFE
- Commercial, multi retail and mixed use commercial
- Public utilities such as RailCorp and Sydney Water.

Table 2 provides a summary of the sites studied, their associated summer peak demand reduction potential and potential annual energy savings. Food, education, and manufacturing sites offer the highest average peak demand reduction potential per site while industrial, health, food, and education offer the highest peak demand reduction potential in total.

Site Type	*Number of Sites*	*Peak MVA Reduction*	*Peak MVA Reduction per Site*	*MWh / year Reduction*	*Tonnes CO_2e / year Reduction*
Commercial	2	0.8	0.4	8,986	6,131
Education	4	7.3	1.8	44,006	30,024
Entertainment / Sporting / Leisure	6	1.7	0.3	14,060	9,592
Food	3	7.6	2.5	45,256	30,877
Health	17	10.7	0.6	65,378	44,605
Hospitality	9	3.1	0.3	24,303	16,581
Industrial	31	31.3	1.0	245,744	167,663
Infrastructure	1	0.4	0.4	1,693	1,155
Manufacturing	3	4.4	1.5	16,000	10,916
Media	1	0.4	0.4	2,824	1,927
Printing and Publishing	1	0.4	0.4	1,314	896
Retail	1	0.2	0.2	1,209	825
Water Utility	2	2.3	1.2	14,934	10,189
Total	**81**	**70.6**	**0.9**	**485,707**	**331,382**

Table 2: DMPP site investigation summary.

1.5 Scope

While there have been some efforts to collect case studies on successful cogeneration applications (e.g. by the former Department of Energy, Utilities and Sustainability) and some reports on the potential of cogeneration in particular applications (e.g. the BASIX Cogeneration Report) there is not yet a comprehensive resource on the status of cogeneration in NSW.

This report will:

1. Analyse the economics of cogeneration in NSW, based on investigations by the Demand Management and Planning Project
2. Present case studies of successful applications of cogeneration
3. Discuss the approval process for cogeneration and any regulatory barriers that currently exist
4. Provide recommendations on how to increase the penetration of cogeneration and similar distributed generation technologies.

1.6 Report structure

This report is structured as follows:

- Section 2 provides an overview of cogeneration technology
- Section 3 presents economic analysis of the cogeneration opportunities identified by the DMPP
- Section 4 summarises several case studies of the application of cogeneration in NSW
- Section 5 reports on stakeholder consultation undertaken during preparation of this report
- Section 6 reviews the role of government in regulating and providing support for cogeneration in NSW
- Section 7 discusses barriers to further adoption of cogeneration in NSW
- Section 8 provides conclusions and recommendations on how to increase the uptake of cogeneration in NSW to capture its environmental and economic benefits.

2 Cogeneration technology

This section provides a brief summary of cogeneration technology, covering fuel types, generation equipment, energy outputs that can be delivered, control of air emissions and other infrastructure requirements.

2.1 Fuel

Cogeneration can use a range of different fuels in the main electricity generation unit, including coal, natural gas, petroleum-based products (diesel and fuel oils), solid biomass (e.g. bagasse), biofuels and biogas.

Natural gas is the most commonly used fuel, due to its relatively low cost, ease of transport (via pipeline), wide availability and low greenhouse intensity. Coal is cheaper than natural gas but has significantly higher greenhouse intensity and is less convenient to transport in the quantities required for cogeneration. Petroleum products are also less convenient to transport and more greenhouse intensive than natural gas, but are often used as a backup fuel due to their ease of storage.

Biomass is an environmentally preferable fuel source, as it can have zero greenhouse gas emissions if sourced as part of a sustainable agricultural or forestry cycle. However, biomass is expensive to transport and not economically viable unless the source is nearby. When there is a nearby source of biomass, it can be an attractive option. For example, the Rocky Point Sugar Mill in Queensland installed a 30MW biomass cogeneration plant in 2002, fuelled by bagasse from the sugar mill and green waste and wood waste from the surrounding area.

Internationally, biomass cogeneration has been implemented in urban contexts. For example, the Dockside Green redevelopment in Victoria, Canada is implementing a cogeneration facility that uses waste wood biomass to produce a clean gas that converts to heat for heating and domestic hot water needs on site. Again, proximity to fuel sources is critical to make biomass cogeneration viable.

The full fuel cycle emission factors for a variety of fuels used in cogeneration are compared below in Table 3. While these emission factors are based on the quantity of fuel combusted, the actual greenhouse gas emission reduction for the transition from conventional grid electricity to cogeneration will depend on the efficiency of the engine, the efficiency of the waste heat use, and the energy source that the generated heat is displacing.

Fuel Source	*Full Fuel Cycle Emission Factors (kg CO_2e/GJ)*
Black coal (NSW)	97.6
Diesel	77.2
Natural gas (NSW)	68.0 – 71.3
Biogas methane (from landfill and wastewater)	5.0
Bagasse and wood waste	1.4-1.5

Table 3: Full fuel cycle emission factors for various fuel sources. Source: Australian Greenhouse Office, AGO Factors and Methods Workbook, Department of the Environment and Heritage, December 2006.

2.2 Generation equipment

The California Energy Commission (CEC 2007) provides a useful guide to distributed energy technologies that can be used in cogeneration applications, including reciprocating engines, microturbines, combustion turbines and fuel cells. Each technology is considered in more detail below, drawing on CEC (2007).

2.2.1 Reciprocating engines

Reciprocating engines are one of the most commonly used cogeneration technologies and one of the most technically mature. They are available in a wide range of sizes, from 5 kW to 7 MW or more. They convert the energy contained in a fuel into mechanical power, which is used to turn a shaft in the engine. A generator is attached to the engine to convert the rotational motion into power. Reciprocating engines use commonly available fuels such as gasoline, natural gas, biogas and diesel fuel.

Reciprocating engines have electrical efficiencies ranging from 25% to 45%. Their total installed cost is in the order of $1,250/kW. Their strengths include low capital cost, good electrical efficiencies, quick start up, fuel flexibility, high reliability and low natural gas pressure requirements. Their weaknesses include high atmospheric emissions (of NOx), noise and frequent maintenance requirements. Despite these weaknesses, reciprocating gas engines are currently the preferred technology in most cogeneration applications being installed or under consideration in NSW. For example, the demonstration projects developed by the NSW Department of Planning for multi-residential apartment buildings in Rouse Hill and Chatswood use gas engines provided by Tedom.

2.2.2 Combustion turbines

Combustion turbine generators are a mature technology, with a size range from about 500 kW up to 25 MW for distributed applications. They can be fuelled by natural gas, oil, or a combination of fuels (dual fuel). The fuel is burnt in a combustion chamber with pressurised air to produce a high-pressure, high-velocity gas. This gas is then used to generate electricity in a turbine.

Electrical efficiencies range from 25-40% and installed costs tend to be a little higher than for reciprocating gas engines. The advantages of combustion turbines are high efficiency and low cost (particularly in large systems), availability over a wide range of power output, ability to produce high-temperature steam using exhaust heat, well-established marketing and customer service channels, high power-to-weight ratio and proven reliability and availability. Disadvantages include reduced efficiencies at part load, sensitivity to ambient conditions (temperature, altitude) and lower cost and efficiency for smaller systems. Combustion turbines are most attractive for larger sites with demand for high-temperature steam. For example, AGL has installed a gas turbine cogeneration facility at the Coopers Brewery in Adelaide to supply electrical and steam requirements.

2.2.3 Microturbines

Microturbines are small combustion turbines that produce between 25 kW and 500 kW of power. They were derived from turbocharger technologies found in large trucks or the turbines in aircraft auxiliary power units. Microturbines are nearing commercial status, however many microturbine installations are still undergoing field tests or are part of large-scale demonstrations. The CSIRO Energy Centre in Newcastle and Newcastle University have installed gas-fired microturbine cogeneration plants.

Microturbines can use natural gas, hydrogen, propane or diesel as fuel. They have electrical efficiencies of 20-30% and low NOx emissions. The advantages of microturbines are their small number of moving parts, compact size, light weight, low emissions, ability to utilize waste fuels and long maintenance intervals. Disadvantages include their low fuel to electricity efficiencies and loss of power output and efficiency with higher ambient temperatures and elevation. Microturbines have strong potential as a small-scale cogeneration technology but are generally not commercially viable at present.

2.2.4 Fuel cells

Fuel cells use an electro-chemical reaction to create electric current. Fuel cells are similar to batteries, except that batteries carry a limited supply of fuel internally, whereas fuel cells use fuel that is continually replenished. Fuel cells can use various fuels, including natural gas, biogas and petroleum products. However, these fuels need to be converted into hydrogen for use in the fuel cell. The conversion takes place either in a dedicated fuel reformer or as a consequence of high temperatures in the fuel cell. The chemical reaction that creates electricity in a fuel cell generates heat, which can be captured in a cogeneration system.

Fuel cells come in different varieties, based on the type of electrolyte and materials used:

- Phosphoric acid fuel cells (PAFC)
- Molten carbonate fuel cells (MCFC)
- Solid oxide fuel cells (SOFC)
- Proton exchange membrane fuel cells (PEMFC).

MCFCs and SOFCs are larger units that operate at high temperatures and do not require a separate fuel reformer. PAFCs and PEMFCs operate at lower temperatures and require a separate fuel reformer.

Fuel cells range in capacity from 1kW to 10MW and have electrical efficiencies from 25-60%. Fuel cells are currently much more expensive than other cogeneration technologies, however costs are projected to fall to levels that are competitive with existing technologies. Different types of fuel cell have different strengths and weaknesses. All are quiet, with zero NOx emissions and high electrical efficiency, but applications are currently limited by their high cost.

The first commercial fuel cell installed in Australia is located at the Australian Technology Park in Sydney. The 200kW phosphoric acid fuel cell was fuelled by natural gas passed through a steam gas reformer and used to generate electricity and hot water. Fuel cells are likely to become increasingly attractive cogeneration options in the future; an Australian organisation, Ceramic Fuel Cells Limited, is seeking to commercialise its fuel cell technology by 2009.

2.3 Outputs

Cogeneration plants can deliver various outputs in addition to electricity, including:

- Hot water production
- Space heating
- Hot air/steam for industrial process heat
- Space cooling (using an absorption chiller)
- Dry air generation (with the use of a desiccant).

The specific outputs depend on the power generation technology and its configuration. Reciprocating engines and combustion turbines can be configured to deliver any of the outputs above. Other technologies that operate at lower temperatures, such as microturbines, PAFCs and PEMFCs are unable to deliver steam at the pressures required for industrial applications.

Given the high demand for air conditioning in Australia, there is increasing interest in the use of trigeneration to deliver space cooling. The absorption chiller is a key component in a trigeneration system, using waste heat to generate chilled water. It works like a refrigerator, but uses waste heat as its energy source instead of electricity. Absorption chillers provide a way to use excess heat from a cogeneration facility that can significantly improve feasibility at sites with significant cooling loads. However, absorption chillers need to shed large quantities of excess heat and typically require larger cooling towers than conventional air conditioning systems. Larger cooling towers use more water, so the increase in water use needs to be weighed against the reduction in use of grid electricity. Alternative cooling systems, such as geothermal heat exchange, are a possible option to avoid the use of larger cooling towers.

2.4 Emission controls

2.4.1 Air emissions

Cogeneration can result in local air emissions, which are subject to regulatory requirements. Typical air pollutants associated with cogeneration include:

- Oxides of nitrogen
- Carbon monoxide
- Oxides of sulphur
- Unburnt hydrocarbons

- Particulate matter.

The pollutants of most concern are oxides of nitrogen, carbon monoxide and unburnt hydrocarbons.

Concentration limits at point of emission

Cogeneration facilities need to comply with the requirements of the *Protection of the Environment Operations (Clean Air) Regulation 2002*. This regulation establishes concentration limits for emissions from equipment and activities. For example, new gas-fired cogeneration would be subject to the concentration limits in Table 4.

Pollutant	*Reciprocating Engine*	*Gas Turbine*
Solid particles (total)	50 mg/m^3	50 mg/m^3
NO_2 and NO (NOx)	450 mg/m^3 = 220ppm	70 mg/m^3 = 34ppm
Volatile organic compounds (VOCs)	40 mg/m^3 VOCs or 125 mg/m^3 CO	40 mg/m^3 VOCs or 125 mg/m^3 CO
Smoke	Ringelmann 1 or 20% opacity	Ringelmann 1 or 20% opacity

Table 4: Concentration limits for air emissions from trigeneration.

Ground level concentrations

During the approval process, the consent authority may also require demonstration that the ground level concentration criteria contained in Section 7 of the Approved Methods for the Modelling and Assessment of Air Pollutants in NSW (DEC 2005) can be met. The criteria of most concern for cogeneration facilities are those for NOx, which require that ground level concentrations are below 0.246 mg/m^3 on an hourly basis and 0.062 mg/m^3 on an average annual basis. The combined impact of existing background levels of NOx and any new emissions from cogeneration must be below these limits.

Design implications

Without control technologies, a combustion gas turbine would not meet the concentration limits for NOx specified in Table 4. Typical NOx emission concentrations are 150-300 ppmv. Therefore, a combustion gas turbine would require additional emission controls to achieve compliance. The most suitable control technology is likely to be dry low NOx control, which would add approximately $1/MWh to the cost of the turbine (SKM 2004).

Reciprocating gas engines may comply without the need for emissions control technology, depending on the specific engine chosen. A lean-burn engine should be able to deliver emission concentrations of about 250 mg/m^3 which are well below the emission limit at the point of emission (SKM 2004).

The ability of either technology to meet ground-level concentration requirements will depend heavily on site conditions. SKM (2004) reports on some example modelling for a 2MW gas reciprocating engine with NOx emissions of 250 mg/m^3 and a stack height of 10m, assuming a background concentration of 0.1 mg/m^3. The maximum modelled concentration was about 0.165 mg/m^3, which is below the criteria of 0.246 mg/m^3. The maximum concentration occurred at a distance of about 50-60m from the stack. Similar modelling for a gas turbine resulted in even lower concentrations.

These results indicate that, in a typical application, additional treatment of NOx emissions is not required to comply with regulatory requirements. However, there may be particular conditions where additional treatment is required, such as when the background concentrations of NOx at a particular site are high due to traffic emissions or there are nearby buildings that might be in the path of the exhaust. If there is a risk that ground-level concentration limits will be exceeded, additional emission controls may be required.

One option is to increase the stack height to improve dispersion of NOx emissions. Another option is to use additional air emission control technologies to reduce the concentration of emissions from the stack. To date in Australia, the use of lean burn gas engines or gas turbines with dry low NOx control has generally been sufficient to meet regulatory requirements. However, at sites in close proximity to high-rise residential buildings, the addition of a technology such as Selective Catalytic Reduction (SCR) may be necessary. According to SKM (2004), SCR is likely to be the next emission reduction technology implemented in Australia as regulatory requirements tighten. SCR is a process where NOx is stripped from the exhaust gases following combustion. SCR operates by injecting a reagent into the exhaust gas stream. Additional equipment is needed, including a reagent storage tank. Very low levels of NOx emissions are possible, with NOx removal efficiencies above 90%.

SCR adds a substantial cost of around $6/MWh to generation costs due to higher capital and operating costs. In approximate terms, about half of the additional cost is capital cost ($3/MWh) and half is operating cost ($3/MWh) (SKM 2004).

2.5 Other infrastructure

2.5.1 Backup

While most cogeneration equipment has high reliability, shutdown for planned maintenance is required at regular intervals. There is also a risk of unplanned shutdown due to equipment failure. The installation of multiple generators is an excellent way to manage planned and unplanned maintenance requirements.

However, even with multiple generators, there remains a risk of interruption to the fuel supply. Backup options are therefore required to address this risk. The simplest option is to provide electricity grid connection so that electricity can be imported to cover any shortfall from on-site cogeneration. While this is an excellent backup option, there is a cost associated with grid connection and allocation of standby capacity. As a result, other backup options, or a combination of grid connection and on-site backup options may be more cost-effective in particular applications.

Backup options that reduce reliance the electricity network include:

- Emergency load shedding: Using smart metering, an immediate response to loss of fuel supply could be to shut down non-essential loads to reduce total demand.
- Dual-fuel generators: Dual-fuel generators can run on multiple fuels, so interruption of one fuel supply would not prevent the generator from running.
- Fuel storage: Storage of the generator fuel for emergency use allows continued operation in the event of fuel supply interruption.
- Hot and chilled water storage: Storage of hot and chilled water can be used to reduce heating and cooling loads in the event of interruption of fuel supply.

- Backup generator: A separate generator (e.g. a diesel generator) can be installed to provide backup in the event of interruption of fuel supply to the main generator.

2.5.2 Energy storage

Electrical and thermal demand varies with time, and a cogeneration facility sized to meet peak demand will not operate at its full capacity much of the time. A cogeneration facility can follow electrical and thermal load to some extent. A single plant can often be operated down to 70% of its rated capacity to provide some load following capability. A facility containing multiple plants provides greater flexibility, as plants can be switched on or off to follow load.

However, another option is to use energy storage to increase the capability to follow electrical and thermal loads. This allows the total size of a cogeneration facility to be reduced below the size required to meet peak demand. Energy generated during off-peak periods can be used to meet the excess demand during peak periods. While storage of electricity in batteries is expensive, storage of thermal energy in the form of hot or chilled water can be a cost-effective option.

3 Economic analysis

This section uses data from cogeneration feasibility studies conducted by the DMPP at 81 sites around Sydney to examine the economics of cogeneration. Table 2 summarises the characteristics of the 81 sites, including potential peak demand, energy and greenhouse gas savings. As noted in Section 1.4, the focus of the investigations was on the inner metropolitan area of Sydney and on sites with demand greater than 500kVA. There may be many other opportunities for cogeneration outside the area of investigation.

A variety of plant types and configurations were considered in the DMPP studies, based on what was best suited to the site in question. These included different generator types (e.g. gas turbines and reciprocating engines), different fuel sources (e.g. natural gas and biogas), and a variety of configurations (e.g. heating used for industrial purposes, cooling in conjunction with an absorption chiller, and direct heating of residences or swimming pools).

The focus of the DMPP investigations was on the level of subsidy required to encourage organisations to implement cogeneration, based on the payback periods that each organisation was willing to accept for cogeneration. We have undertaken additional analysis to understand the impact of payments for deferral of network augmentation and greenhouse gas emission reduction on the commercial viability of cogeneration. All analysis is based on raw data provided by the DMPP, which included location, type of plant, summer and winter peak demand reduction, total energy reduction, cost savings, capital cost, internal rate of return (IRR), customer investment criteria and the subsidy required to meet the customer investment criteria.

3.1 Government subsidisation

At each of the sites investigated, the organisation provided its investment criteria for adopting cogeneration. The criteria varied from a simple payback period of 1 to 6 years with an average of 2.8 years for the 81 case studies. The DMPP then calculated the government subsidy required to ensure that a cogeneration plant at each site would meet these investment criteria. The results are presented in Figure 2 and in Table 5.

Across the 81 sites, the DMPP found technical potential for cogeneration of 70.6MVA, an average of 0.87MVA per site. To capture the full technical potential at the payback periods provided by the customers, a subsidy of $3,221/kVA would be required. Table 5 shows the capacity that would become commercially viable at different subsidy levels.

As shown in Table 6, the required subsidy varied across the different sectors studied. The lowest average required subsidies were in the food industry while the highest were in education. The overall average subsidy required was $1,350/kVA.

It is important to note that the subsidy values are based on the customer's own investment criteria. It is unlikely that any distributed energy technology could meet the investment criteria for the four customers requiring payback within one year. However, there are often demand management solutions such as load reduction through education or simple modifications that have payback periods shorter than 1 year. Section 3.3 considers the internal rate of return in more detail.

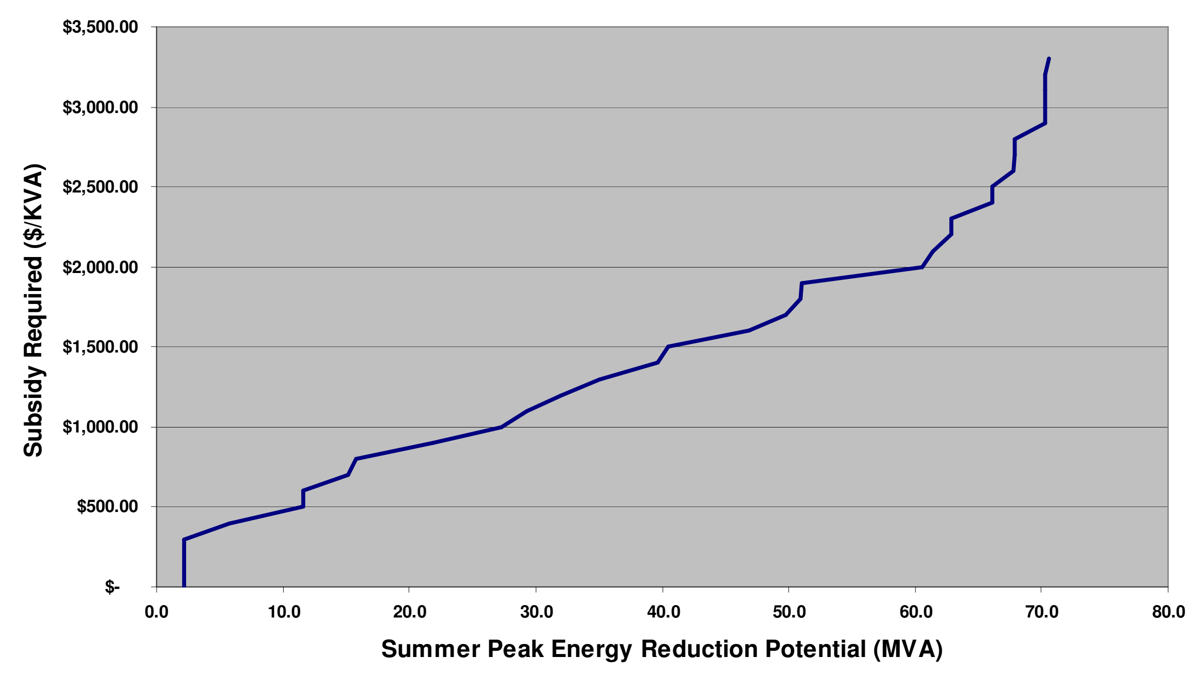

Figure 2: Level of subsidy required to capture potential peak demand reductions at investigated sites.

Subsidy ($/kVA)	*Peak Demand Reduction (MVA)*
0	2.2
200	2.2
400	5.8
500	11.7
1000	27.3
2000	60.6
3221 (Full Technical Potential)	70.6

Table 5: Subsidy required for peak demand reduction.

Site Type	Average Subsidy Required (per kVA)
Commercial	$1,219
Education	$2,248
Entertainment / Sporting / Leisure	$1,198
Food	$430
Health	$1,230
Hospitality	$1,651
Industrial	$1,364
Infrastructure	$1,315
Manufacturing	$1,442
Media	$1,554
Printing and Publishing	$1,219
Retail	$2,024
Water Utility	$489
Overall Average	**$1,350**

Table 6: Average required subsidy by site type.

3.2 Effect of cogeneration scale

We investigated the impact of cogeneration scale, measured as the value of the capital investment, on simple payback periods. The results are shown in Figure 3 for the 67 sites with payback periods of less than 20 years. It is evident that simple payback periods increase as capital costs increase.

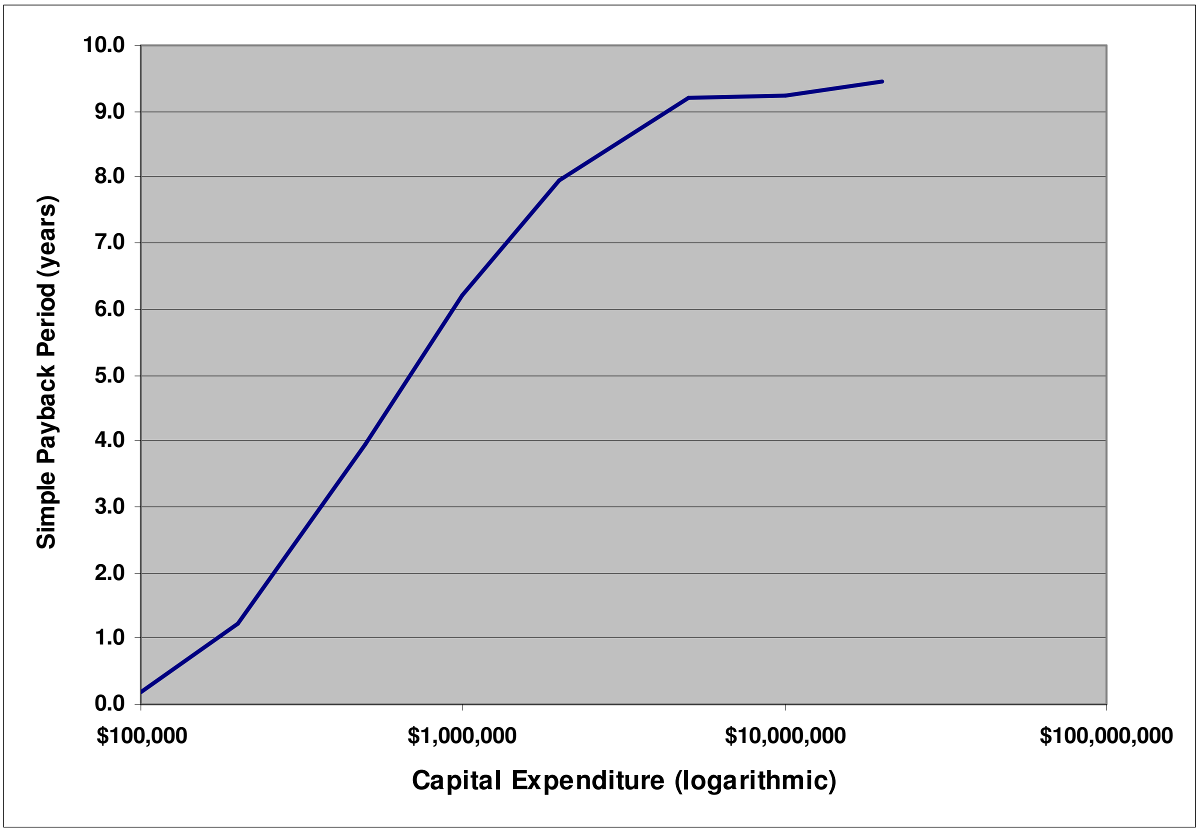

Figure 3: Effect of scale on simple payback.

3.3 Customer internal rate of return

Further analysis of the DMPP data from the 81 sites was undertaken to examine the effect of customer IRR on uptake of cogeneration opportunities. While only two sites or 2.5% of sites analysed required no subsidy based on their required simple payback period, 20 of the sites or 25% of sites analysed would implement cogeneration without a subsidy if they only required an IRR of 12%. This information can be seen below in Figure 4.

Figure 5 shows the required subsidy to achieve specified peak demand reductions assuming all customers were willing to accept a more reasonable IRR of 12%. More than 20MVA of cogeneration would be implemented without a subsidy and a subsidy of $400/kVA would deliver the full technical potential across the sites investigated.

It is clear that the high hurdle rates established by customers for cogeneration are a significant barrier to uptake. These high hurdle rates may be a consequence of lack of familiarity with the technology and the perception that it constitutes a high-risk investment. Customers may also have overstated their IRR to increase their potential to receive a subsidy from the DMPP.

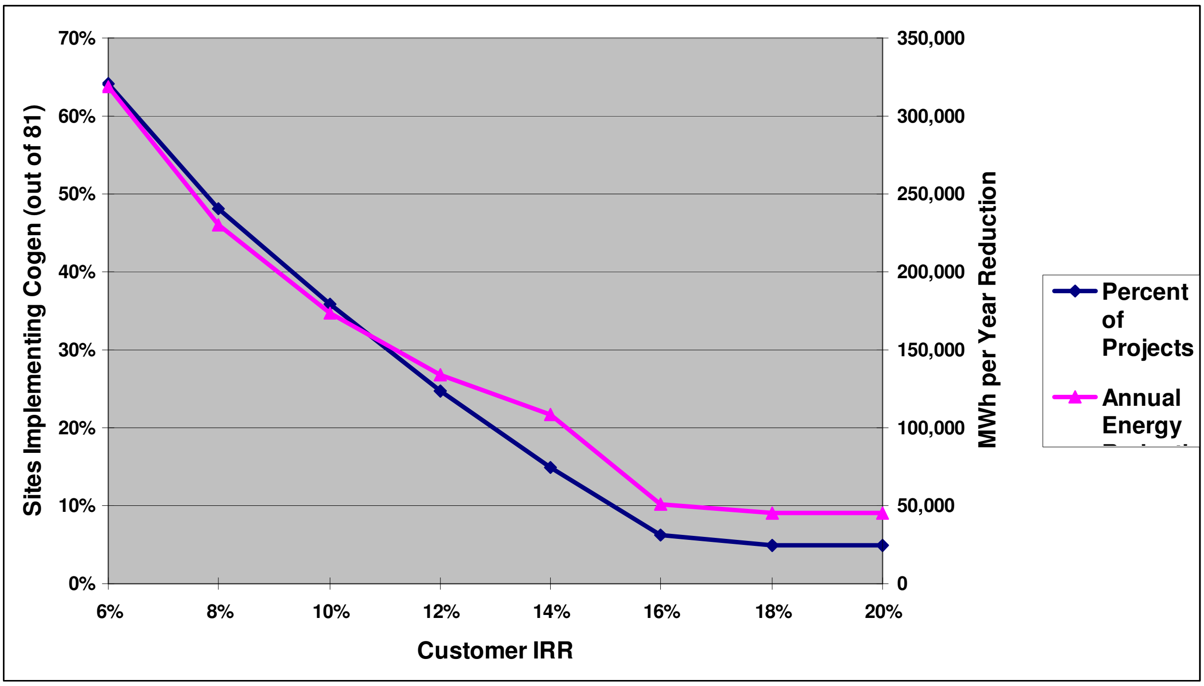

Figure 4: Uptake and energy savings as a function of IRR.

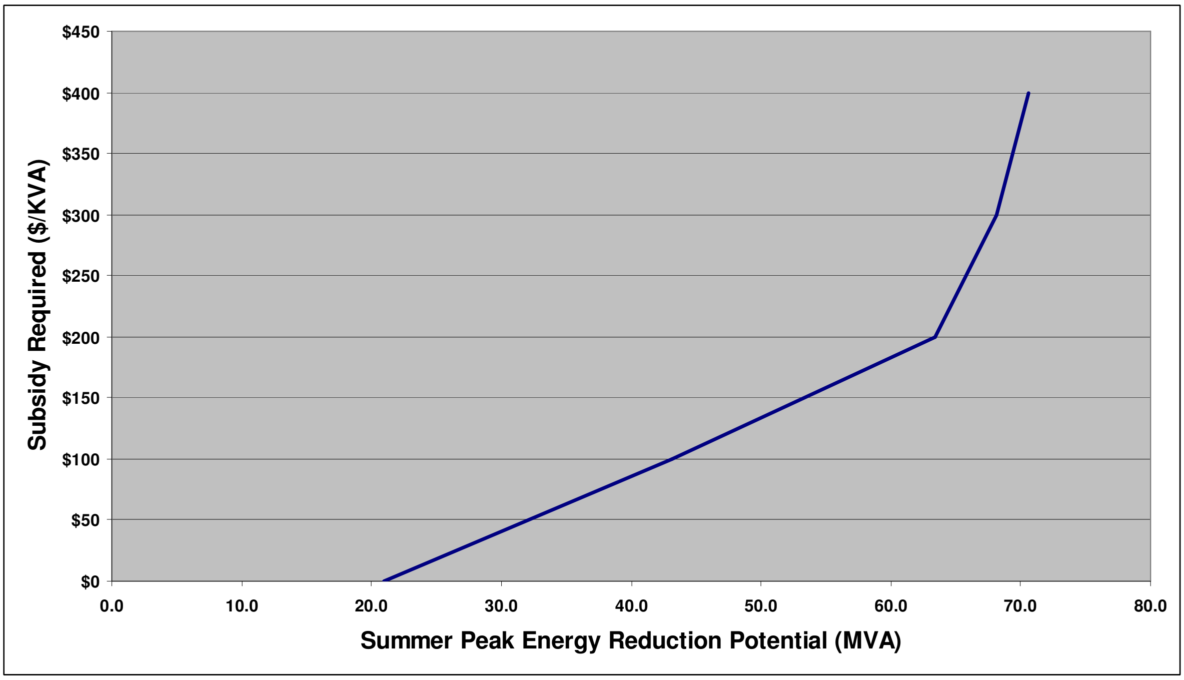

Figure 5: Cumulative summer peak energy reduction potential with increased subsidies for a fixed customer IRR requirement of 12%.

3.4 Network deferral payments

The analysis so far does not consider the value associated with the potential for cogeneration to reduce peak demand and contribute to deferral of electricity network augmentation. As mentioned earlier, network deferral savings can often be significant and can be used to subsidise the costs of projects. An example of this is the network constraint in the Willoughby STS Supply Area where EnergyAustralia (EA) is accepting submissions to reduce demand. EA will potentially pay up to $550 per kVA to reduce network demand by 4.5MVA. To the extent that cogeneration can deliver firm demand reductions, this effectively reduces the subsidy required to implement cogeneration projects in that area.

Sinclair Knight Merz (2003) estimate that the marginal distribution cost for the NSW distribution networks ranges from $400/kVA to $800/kVA. Figure 6 shows how the subsidies required at the 81 sites investigated by the DMPP would decrease if a network payment of $400/kVA or $800/kVA was provided.

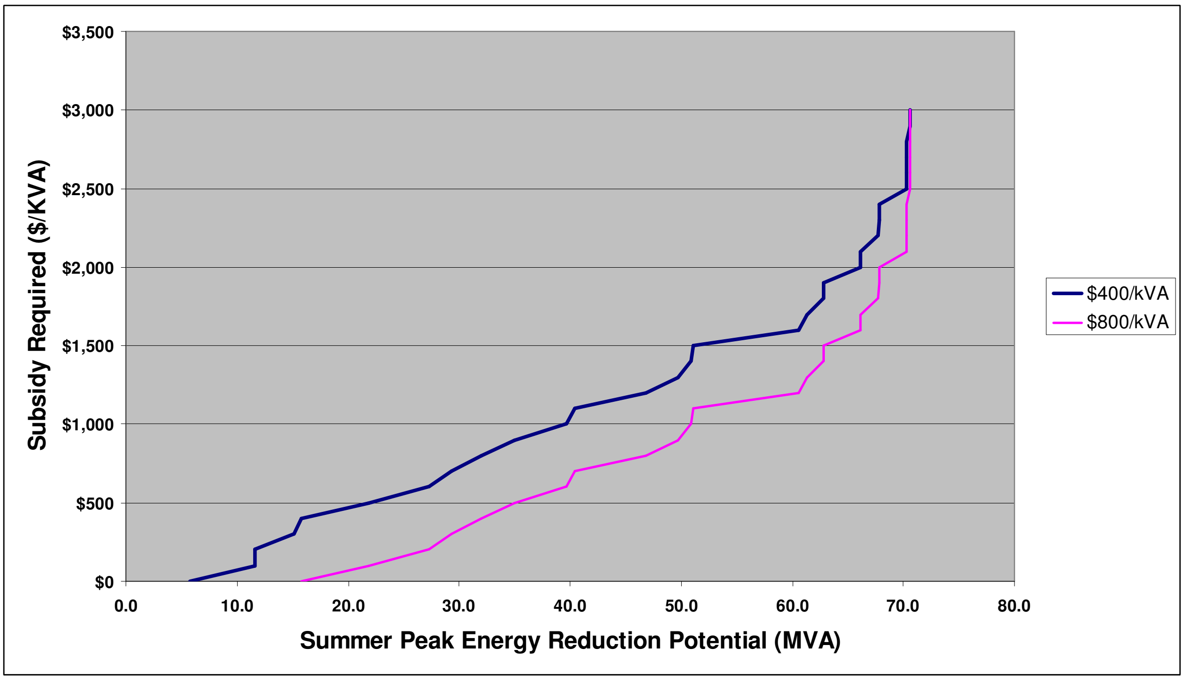

Figure 6: Cumulative summer peak energy reduction potential with network payment and government subsidy.

The following is an excerpt from the EA demand management options consulting paper and is typical of offerings of this type:

> EnergyAustralia invites submissions from interested companies, organisations and individuals regarding opportunities and ideas to reduce the peak electrical demand in Willoughby STS supply area.
>
> Growth in electricity demand in this area means that peak demands are forecast to approach the capacity of the local electricity supply network. EnergyAustralia is investigating initiatives to reduce this demand ("demand management" or DM) as part of a solution that will maintain reliability and levels of service more cost effectively than installing additional network infrastructure alone.
>
> Energy Australia has completed a DM Screening Test and is of the opinion that cost effective DM options might be found, if explored further. On this basis it is conducting an investigation to identify and evaluate the available options (EA 2007).

The key requirement to access these network payments is that cogeneration delivers a permanent reduction in demand. If the site still requires grid connection for backup purposes and would draw its full peak demand in the event of failure of the cogeneration plant, then there are no network benefits as the network still needs to be built to accommodate the backup demand. Therefore, these network payments are only likely to be available where a site is either willing to accept the risk of interruption of power due to loss of gas supply or provides on-site backup to reduce the need for grid backup. In practice, this may mean that a network payment would be used to cover the cost of on-site backup and the overall economics of cogeneration would remain as shown in Figure 2. A payment in the order of $400-800/kVA would be sufficient to buy a backup diesel generator as standby at most sites.

3.5 Greenhouse gas reduction payments

An additional benefit of cogeneration that needs to be considered is greenhouse gas reduction. With the implementation of emissions trading in Australia, cogeneration should become more economically attractive, as it provides energy with lower greenhouse intensity than grid electricity. Cogeneration facilities are currently eligible to generate NSW Greenhouse Abatement Certificates (NGACs) for generation of electricity with lower greenhouse intensity than the NSW pool coefficient and for supply of waste heat. At present, any accredited abatement certificate provider that develops a cogeneration facility can receive and trade NGACs generated by that facility.

As of April 2008, the price of NGACs had fallen to $6.70 (per tonne of CO_2-e). This carbon price provides little additional incentive for organisations considering cogeneration. Attention is now turning to Australia's proposed National Emissions Trading Scheme (NETS), which is due to commence in 2010. Cogeneration is likely to benefit under the current emissions trading proposals, however the size of the benefit depends on several factors.

Under current proposals (National Emissions Trading Taskforce 2007), the coverage of NETS in 2010 will cover all six Kyoto gases and include stationary energy, transport, industrial processes and fugitives. Direct emitters above 25,000 tonnes of CO_2-e per year will be required to hold emissions permits. A cogeneration facility with an electrical capacity of 4MW would generate approximately this amount of greenhouse gas if it was running constantly. This raises several issues for cogeneration.

First, most cogeneration facilities will generate less than 25,000 tonnes of CO_2-e per year and will not be considered liable parties under NETS. This means that they will not be required to hold emissions permits for their greenhouse gas emissions. As a result, most organisations installing cogeneration facilities will be able to benefit from carbon prices by reducing their import of grid electricity or selling excess electricity into the grid at higher prices. The magnitude of the benefit will depend on the quantity of grid electricity avoided, its greenhouse intensity and the carbon price. Is should be noted that the National Emissions Trading Taskforce (Dec 2007) recommended that "point of liability for sub-threshold (<25 kt CO_2-e) natural gas use be placed upon natural gas retailers" (pp. 14).

Second, larger cogeneration facilities will be disadvantaged by emissions trading, relative to smaller facilities. By 2010, cogeneration facilities over 4MW in size will be required to hold sufficient emission permits at the end of each year to cover the greenhouse gas emissions from the facility. This represents an extra cost for larger cogeneration facilities. Larger facilities will still benefit from the carbon price component of avoided electricity prices but the magnitude of the benefit will depend on the difference between the greenhouse intensity of electricity from cogeneration and electricity from the grid.

Under present proposals, cogeneration operators will not be able to generate offset credits that they can trade in the market. This is to avoid double counting of emission reductions by liable parties and cogeneration operators. However, given that many cogeneration proposals are close to commercial viability now, the above analysis indicates that a carbon price will make many more proposals viable.

Figure 7 shows the effect of carbon pricing on the annual greenhouse gas emission reductions achieved at the 81 DMPP sites, assuming different IRRs. At a customer IRR of 12%, a carbon price of $20 per tonne would result in enough projects being implemented to reduce CO_2-e by over 200,000 tonnes annually or the equivalent of taking 50,000 cars of the road from the sample of 81 sites analysed in the DMPP study. This is based on the plant operating at an electrical efficiency of 40% and the assumption that heat was being created from gas before the installation. It should be noted that this is a conservative estimate, as gas combustion is one of the least carbon intensive methods of creating heat.

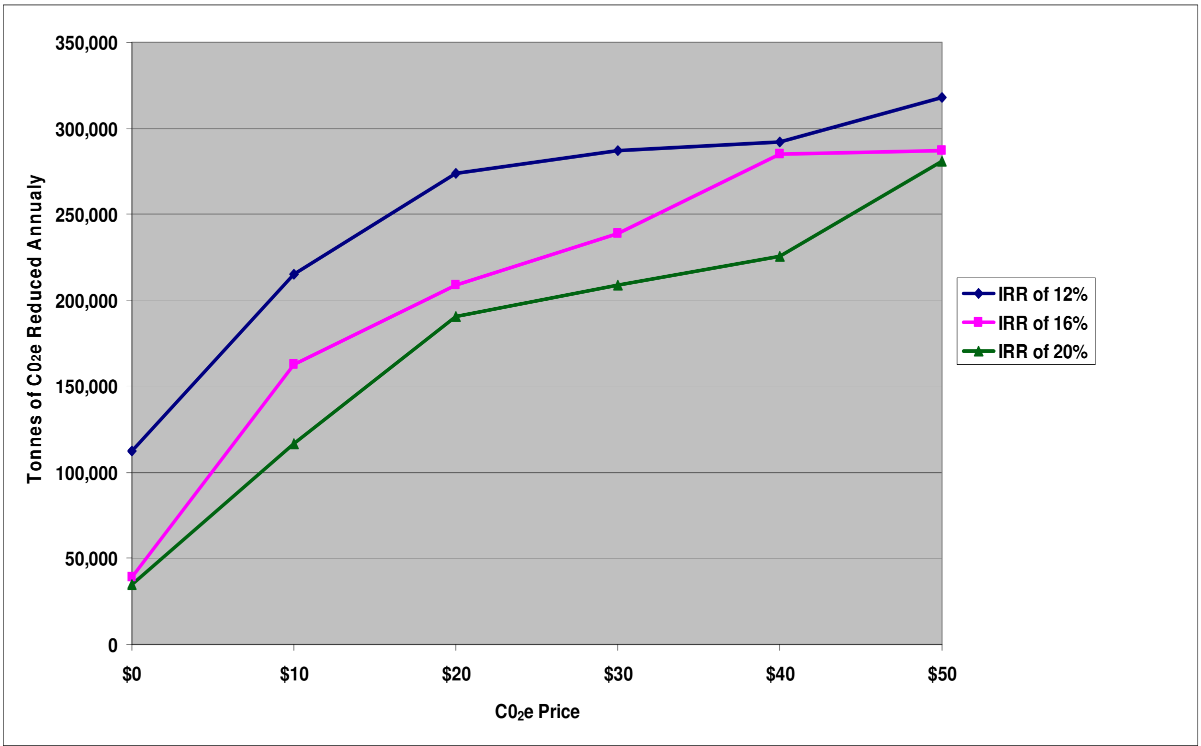

Figure 7: Effect of carbon pricing on annual greenhouse gas emission reduction at different IRRs.

It is also useful to look at the effect of carbon pricing on subsidy requirements, as in Figure 8 below. As would be expected, the cogeneration capacity that would be implemented without a subsidy increases with carbon price.

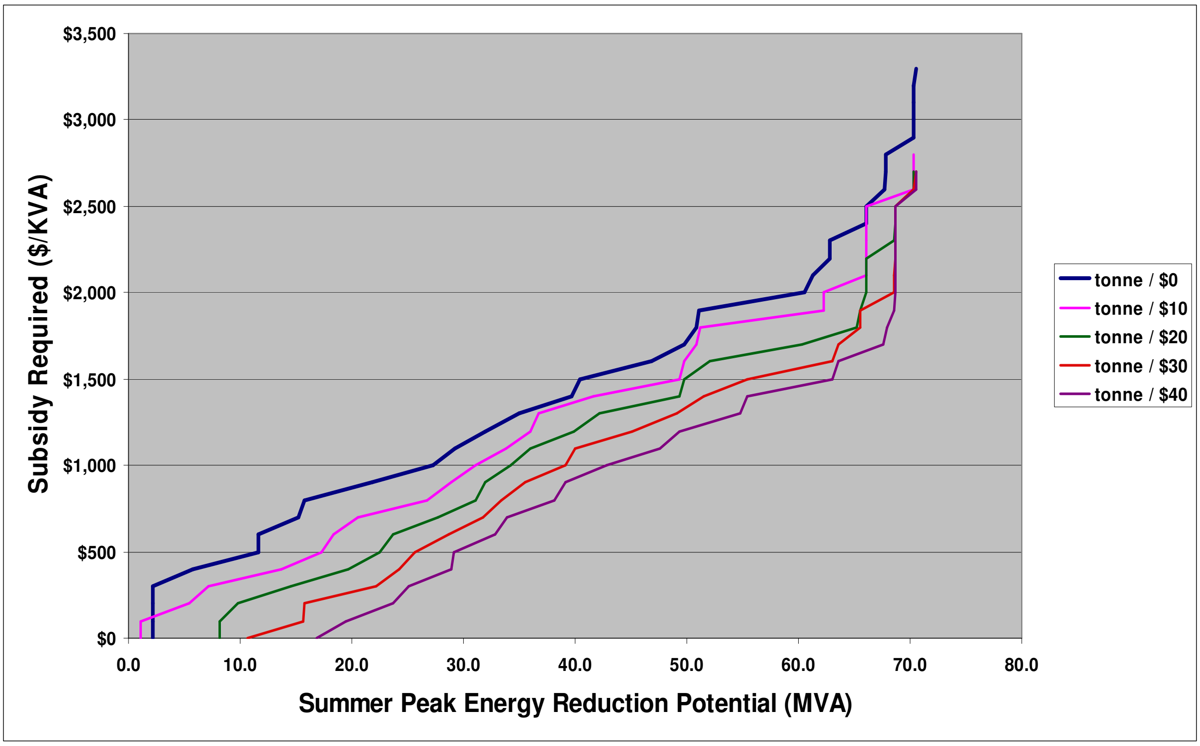

Figure 8: Effect of carbon pricing on required government subsidy versus summer peak reduction potential.

3.6 Combined Factors

By combining some of the factors discussed above, it is possible to more clearly see the business case for cogeneration.

The first scenario to examine is the potential to use the network reduction charge to cover the cost of on-site backup. If we then assume a carbon price of $30 per tonne of CO_2-e and accepted a minimum IRR of 12%, then over 75% of the peak reduction potential would be realised with annual CO_2-e savings of over 285,000 tonnes (87% of potential of all sites).

The second scenario to examine is when the network payment is used to reduce the capital cost of the cogeneration plant. If all the sites were able to receive a $400 per kVA network reduction charge and were able to take advantage of a carbon price of $10 per tonne of CO_2-end accepted a minimum IRR of 15%, then all of the cogeneration plants in the study would be built with a combined peak summer power reduction of 70.6 MVA and annual CO_2-e savings of over 330,000 tonnes.

4 Case studies

This section presents several case studies on cogeneration systems that have been examined in detail or implemented in NSW recently with support from the DMPP. The DMPP has provided funding support for the following activities:

- Significant funding was provided to the market place to reduce the hurdle rate for the installation of large cogeneration systems within commercial buildings. Section 4.1 presents case studies from two commercial buildings where this funding was taken up.
- Two cogeneration pilot programs were totally funded in the multi unit residential sector, at Chatswood and Rouse Hill. These pilot programs are discussed in Section 0
- Large cogeneration feasibility studies were undertaken at industrial sites owned by Lion Nathan and AMCOR. The results of the feasibility studies are discussed in Section 4.3.

4.1 Commercial buildings

4.1.1 101 Miller Street

Mirvac have commenced installation of a trigeneration unit at 101 Miller Street in North Sydney with partner Cogent Energy. This project was primarily motivated by three factors: cost savings, greenhouse gas emission reductions, and improved reliability. The trigeneration plant will be set up to operate in parallel with the grid but is not expected to return electricity to the grid. It will be the first existing large high-rise office building in Australia to use trigeneration. The building also contains a retail plaza in addition to the office space. The Managing Director of Cogent Energy, Mr Blair Healy said, "Cogent delivers less costly, more efficient and more reliable energy with an improved environmental footprint".

According to Mirvac (2007), the trigeneration plant will deliver the following benefits:

- A reduction of CO_2 emissions by approximately 45 per cent, which is some 6,500 tonnes per annum - the equivalent of taking 1,600 cars off the road
- A reduction in electricity costs to the building and tenants when compared to current market prices for grid power
- The ability to provide the building and the tenants with 100 per cent back up power supplies for continuity of business
- The technology has an efficiency of 75 – 80 per cent compared to grid power which is approximately 30 per cent
- More reliable source of energy during peak demand periods.

The plant will comprise two 1,116 kW engines operating at 0.8 power factor with each engine coupled to a 750 kW absorption chiller. These chillers will then be integrated into the building condenser and chilled water systems to provide a peak cooling capacity of 1,500 kW. The entire system will be set up to automatically run during peak and shoulder electricity demand periods. This site is a good candidate for cogeneration as the existing plant room has enough spare capacity for the entire plant.

Cogent has found the NSW Government, Councils and commercial building owners to be supportive of cogeneration projects. They have also had positive experiences working with IPART and EnergyAustralia (the Demand Management Group and Network Engineering in particular).

Cogent and Mirvac are, however, facing some significant challenges with the project. A key barrier has been EPA approval of emissions to air from the site, due to concerns about NOx. If a catalytic converter is required to treat exhaust emissions, it will significantly increase capital costs in the order of 20%. Another issue is the reluctance of EA to allow the facility to export energy back to the grid, making it more difficult to justify the economics of the project.

A final significant challenge is to get the NSW Department of Environment and Climate Change (DECC) to agree to another form of energy and associated CO_2 emission content. Currently DECC recognize only grid energy (940 kg of CO_2 per MWh) and GreenPower (0 kg of CO_2 per MWh). Cogent are currently lobbying DECC to recognize CogenPower (about 480 kg of CO_2 per MWh depending on engine efficiency). This would have a significant impact on the uptake and viability of cogeneration as a company such as Cogent could size their plants to export into the grid economically with the addition of this greenhouse related premium.

4.1.2 133 Castlereagh Street

Stockland is currently investigating the implementation of an approximate 1MVA trigeneration plant at their head office at 133 Castlereagh Street, Sydney. This building was first acquired in October of 2000, and Stockland have made the decision to examine trigeneration. The primary driver for this decision was the positive environmental impact expected from the installation – a reduction by 20% of greenhouse gases that Stockland contributes as a tenant in the building. It will also likely provide 3 Green Star points from the Green Building Council of Australia, potentially lifting the Stockland tenancy from 5 to 6 Green Stars. This would be the first 6 Green Star tenancy rating in a refurbished commercial building in NSW.

The plant will likely be located on the rooftop, which will help Stockland to minimise some cost issues related to lack of available underground space. The system is designed to operate at 85% net efficiency with the approximate 1MVA gas fired generator linked to a 1MW absorption chiller. The site includes both retail and commercial space, which provides a better overall load profile to justify trigeneration.

There have been some significant challenges during the course of the investigation. The first significant hurdle that Stockland is facing is the high capital costs involved in the system. Even though there will be cost savings on electricity, the payback period may be quite long. The second issue they are facing is technical hurdles put up by EnergyAustralia. These make it difficult to run in parallel with the grid and even more difficult to be able to feed back excess power into the grid. Stockland have also found dealing with cogeneration service providers challenging as the small number of completed projects in NSW demonstrates the relative lack of experience that many of these providers currently have. Overall, Stockland has found the experience a significant challenge and they flagged excessive energy supply authority constraints as a major barrier.

Stockland has benefited greatly from their involvement in the DMPP and will be continuing with their investigation of trigeneration for their head office and would like to see it operational by the end of 2008.

4.2 Multi unit residential pilot program

In May 2007, the NSW Premier and the Minister for Planning announced $400,000 in funding for two demonstration cogeneration projects in residential multi-unit buildings at Chatswood and Rouse Hill (NSW Department of Planning 2007). The Multi-unit Residential Cogeneration Demonstration Project is an initiative of the NSW Department of Planning. It involves partnership with residential development companies Lend Lease GPT and Mirvac (NSW Department of Planning).

Reciprocating gas engines will be installed at Lend Lease GPT's seven storey residential development at Rouse Hill and Mirvac's 25 storey Cambridge Lane apartment building in Chatswood. Each engine will deliver 25kW of electricity to supply common area demands, including lighting and ventilation. The engines will also provide 47kW of heat, which will supply approximately 65% of total hot water demand at each site. The engines will be fuelled by natural gas and will have an overall fuel efficiency of approximately 87%. They will save about 80 tonnes of greenhouse gas emissions per year (NSW Department of Planning 2007).

4.3 Industrial sites

4.3.1 Lion Nathan feasibility study

The Lion Nathan brewery at Lidcombe relies on heat for their processes. At the time of DMPP's involvement, the site was upgrading their process and the investigation was timely and identified cogeneration as a viable option. The DMPP then, in partnership with Lion Nathan, carried out a feasibility study to look at the best way to maximise the heat for the process and reduce electricity.

The existing facility has a peak demand of 6,930 kVA and an annual electricity consumption of 30,904 MWh with summer peaks in November and January. The site is an ideal candidate for trigeneration as refrigeration accounts for 45% of the peak demand and 35% of total electricity consumption. Therefore, a power plant combined with an absorption chiller would be capable of significant load reductions.

The DMPP examined two options. The first option was an $840,000 cogeneration plant that would operate for 16 hours per day and reduce peak demand and base load requirements in the order of 600kVA. The IRR for this plant was 22%, which did not meet Lion Nathan's required IRR for a cogeneration facility of 33%. A subsidy of $465/kVA would be required to meet the customer investment criteria.

The second option was a $5.5 million cogeneration unit combined with an absorption chiller that would reduce peak demand by nearly 4MVA and would require only a marginally higher subsidy of $481 per kVA. The IRR for this plant was 22% and it would pay for itself in 4.6 years. Despite this, the feasibility study revealed that the initial up front capital cost was a hurdle and the project is now on hold. DMPP have advised Lion Nathan to apply for assistance through the Climate Change Fund. This approach seems entirely logical given both the network load reduction and greenhouse gas savings that could be achieved through the project.

4.3.2 AMCOR feasibility study

The DMPP is currently working with AMCOR in the development of a potential large scale cogeneration feasibility study. This study is examining the potential to provide power and steam to a new paper machine at the Botany Site. Two options were considered with a total plant size of either 25MW or 58MW. The larger plant was considered the most economical option and would supply the steam and electrical demands with additional generating capacity to export up to 30MW of electricity back to the network. This is enough power to significantly alleviate network infrastructure upgrade requirements and may qualify for subsidisation under EA's task force on the Sydney Supply Area Demand Management Options.

Greenhouse gas emission reduction is another significant driver for this project. Each $10 increment in carbon price corresponds to an approximate increase in internal rate of return of 1%. In the modelling used for the pre-feasibility analysis, a carbon price of $10 per tonne was assumed. This price was chosen because of its correspondence to the average price available under the NSW Greenhouse Gas Abatement program. However, it is likely that the national emissions trading scheme introduced in 2010 will have average carbon credit prices ramping up to $30 per tonne by 2030 based on preliminary modelling (McLennan Magasanik 2006). This would increase the IRR on the project from approximately 11% to 14.5% using preliminary estimates.

However, even without incentives such as carbon credits and network demand reductions, the project appears to be economical taking into account the current and predicted prices of gas and electricity. There are a few remaining hurdles to get over before project approval is given. These include the following considerations:

- Confirmation of gas supply and pricing for the site
- Independent owner and operation versus third party operators
- Timing of the project to coincide with the development of the new paper machine
- Assessing potential benefits of local area electricity demand reduction

Work is continuing on this project and it is another example of a potential opportunity that would have been missed if DMPP was not involved.

5 Stakeholder consultation

As part of the investigations into the status and potential of cogeneration in NSW, ISF interviewed key stakeholders, including cogeneration service providers, organisations that have implemented or are considering cogeneration, government departments and network utilities. Stakeholder input is summarised in the sections below and helps to inform the discussion on barriers to adoption of cogeneration in Section 7.

5.1 Cogeneration service providers

Three cogeneration service providers were interviewed. Their responses are summarised in Table 7, Table 8 and Table 9.

Question	*Response*
Can you explain your business model?	Our focus is on commercial buildings in the CBD, with about 30 active projects at various stages of development. We finance the capital and own the equipment we install, and enter into long-term contracts (~12 years) to provide energy services to the building. We use natural gas for trigeneration, and run in grid parallel import mode. Our systems are not designed to export electricity to the grid initially, because interconnection becomes more complex if exporting, and requires more complex negotiations with the network operator. Once the company has been in operation longer and proved their performance they would explore the potential to export power. The facilities are designed to deliver less than the demand of the building so their equipment can operate at around 95% capacity, leading to better asset utilisation. They would run the trigeneration plant during peak and shoulder periods, and purchase grid power during non-peak periods, which is cheaper than what they would generate at these times.
What are the main drivers/motivations for customers to invest in cogeneration?	Raising environmental credentials is definitely the main driver. Cogeneration gives an additional 1.5 stars in the ABGR scheme, and 1 star in the Green Star rating scheme.
Who are the regulatory agencies you have had to deal with and what has been your experience with them?	EPA [DECC] – for approvals relating to emissions and noise; IPART – for retail licence [retailing electricity is part of their business strategy]. There has been no problem dealing with these regulators, it has been quite straightforward and they are very supportive. They have received a grant from DMPP for one of their projects, and have applied for DECC Green Business Program funds.
What do you see as the barriers?	Dealing with electricity and gas networks has been quite challenging. They take a short term view with connection charges, network charges, access and capacity charges, and see the cogeneration provider as an ordinary customer rather than recognising the potential for their [utility] businesses to benefit. For example the gas network services provider wants the costs of a new gas pipeline for one of their greenfield projects to be borne entirely by them. Also the usual gamut of commercial barriers that face a start-up company –the target customers are often unfamiliar with cogeneration, new business idea etc.
Do you see anything changing in the future?	Expect that emissions trading and MRET will increase demand for cogeneration.

Table 7: Summary of responses from first cogeneration provider.

Question	*Response*
Can you explain your business model?	We provide a full range of cogeneration services - feasibility, design, construction, operation and maintenance – but do not act as an external provider of energy due to market structure and electricity contestability rules.
What are the main drivers/motivations for customers to invest in cogeneration?	They don't invest in cogeneration! The driver of *interest* depends on customer type. Commercial buildings are interested in improving environmental ratings, or have commercial pressure from tenants. Industrial actors are interested in improving economics of their processes.
Who are the regulatory agencies you have had to deal with and what has been your experience with them?	Network suppliers (sic) and local councils. There has been no problem with them at all.
What are the obstacles?	The structure of the electricity market and contestability regime is the major obstacle. Potential cogeneration customers want an external agent to supply the services, but an external agent is not permitted to supply energy to customers under the electricity market structure [without an electricity retailer licence]. That makes it very difficult to implement a viable project. A successful project from the cogeneration service provider's perspective is where the customer has made the capital investment and self-generated, and given the technical operation and maintenance contract to them. Dealing with the networks has not been a problem at all. Others complain about difficulties because they don't understand the connection procedures. Another barrier is the very low price of electricity. Some commercial buildings have electricity supply contracts at 6 cents per kWh [making it difficult for cogeneration to compete].
What changes have you seen in the operating landscape over the period of your operation?	The landscape has become more complex. There is more interest in cogeneration.
Do you see anything changing in the future?	No. We anticipate no significant impact from emissions trading because cogeneration currently creates NGACs and we would expect emissions trading to provide an equivalent incentive.

Table 8: Summary of responses from second cogeneration provider.

Question	*Response*
Can you explain your business model?	We are a utility business that provides a full service to customers rather than just building plant and departing. We build plant and provide operation and maintenance services. In some cases the developer may wish to own the equipment; in other cases the developer may choose not to carry the capital burden, and have us own the equipment.
What is your perception of the overall experience of providing cogeneration services in NSW?	It has not been an easy road. It is getting easier but it is still not easy. Cogeneration is being promoted mainly by Planning [government departments and policy], not through electricity networks. It is not easy negotiating with the networks; they don't have standard connection policies It is essential that cogeneration is planned early-on in a project, right from the initiation stage, rather than tacked on midway through.
What are the drivers for customers to consider cogeneration?	There are two main drivers. (a) The development may be taking place in a power constrained area, where there are high costs to get grid power, requiring extension/augmentation of the network that would have lead times of 5+ years. This is common in some of the new high growth areas in former agricultural and dairy land. If reticulated gas supply happens to be available then it is possible to consider cogeneration and do a 'fuel swap' as a cost effective solution. This is probably the driver for 40% of our business. (b) Sustainability drivers such as meeting BASIX, ABGR and Green Star drive about 60% of our business. Cogeneration provides a very cost effective way to achieve the desired ratings, especially if we put in the capital so there is no additional capital burden on the customer.
What do you see as the barriers?	[Negotiating with the electricity networks]. Gaining gas supply access is often difficult. The gas market is not competitive enough. Efforts to make gas competitive have lagged efforts for creating competition in electricity. The entry of Alinta, AGL and most recently SPAusnet (merger) has led to staff reductions so that these service suppliers lack adequate resources. It is very slow to get a new service. In the past, there have been issues with the Councils. Local governments were not familiar with a private sector service provider. Now there is greater awareness and the interactions are improving.
What changes do you anticipate in the future?	Our business is based on the 'spark gap' between the price of gas and electricity. We anticipate that carbon pricing will increase the gap over the 10-15 year time horizon. We expect greater fuel swap for electricity generation from black coal to gas, raising gas prices, but electricity prices will also rise so the gap would remain. The projects would not attract finance if they did not have a strong economic case including assessment of such risks.

Table 9: Summary of responses from third cogeneration provider.

5.2 Organisations that have implemented cogeneration

5.2.1 Bluescope Steel (Port Kembla)

The steel making process creates waste methane, and Bluescope Steel has been using this to produce steam essential to their process. Co-generation of electricity has been included almost from inception of the facility. The cogeneration units are nearing the end of their lives (60 years and 25-40 years old) and planning for their replacement has been ongoing for almost 10 years. Delays have mainly been due to the size of the project investment and internal processes for getting the economics right.

The project is at feasibility stage and will be presented to the Board for decision in mid-2008. The project investment is almost $1 billion, and would generate 200 MW of electricity (or 275 MVA). The steel-making plant has high electricity demand (typically 140 MW) and the new cogeneration facility will make Bluescope Steel largely self sufficient in electricity. It will also produce all of the process steam required, and utilise all of the waste methane (the previous configuration generated 20 MW using some of the gas with surplus waste gas being flared). Table 10 summarises interview responses provided by Bluescope Steel.

Question	*Response*
What have been the drivers for choosing cogeneration?	The main driver is operational security. The plant is dependant on the cogeneration plant (for steam) - if it fails the whole process has to shut down. The upgrade will significantly improve security. Other drivers are to reduce carbon footprint, utilise waste gas, be self sufficient in electricity (may need to import a little at times, and be able to export at times).
Who are the regulatory agencies you have had to deal with and what has been your experience with them?	DECC and the Department of Planning are key parties for obtaining consents. The regulators have been extremely supportive and excited by the project. The project is running to a very tight timeframe and delays by regulators have at times been a source of some frustration.
What incentives are being used to support cogeneration at the site?	Currently set up to create NSW Greenhouse Abatement Certificates. The NGACs and avoided electricity purchase costs greatly improve the business case. The up-coming emissions trading scheme creates some uncertainty as it is unclear what impacts it will have on revenue. However, Bluescope Steel is optimistic that they would be no worse off.

Table 10: Summary of interview responses by Bluescope Steel.

5.2.2 Newcastle City Council – Australian Municipal Energy Improvement Facility

The Australian Municipal Energy Improvement Facility (AMEIF's) goal is to support market transformation and the uptake of new technology in line with its vision to *profitably* reduce greenhouse gas emissions. It works with local governments and the community, and offers consultancy services to other organisations.

Newcastle City Council (NCC) approached the University of Newcastle to develop a cogeneration project for the university. A 30kW natural gas fuelled microturbine was installed in early 2003. The electricity is used for the air conditioning system and waste heat for hot water services to the Medical Sciences building. Table 11 summarises interview responses provided by Newcastle City Council.

Question	*Response*
What have been the drivers for Newcastle City Council to pursue cogeneration?	Primarily to fulfil its vision for a 'greener' Newcastle, support market transformation and encourage a new technology.
Who are the regulatory agencies you have had to deal with and what has been your experience with them?	EnergyAustralia is a collaborator. There were no problems with connection since they were in a partnership arrangement for project. SEDA provided a significant capital grant. Development approval was not needed. There was no increase in emissions since turbine flue gas was replacing earlier boiler emissions.
What difficulties have you encountered?	As early adopters, it was very difficult to get information about prices for hardware, to assess what reasonable capital costs for the project were. Initially the project was earmarked for the university aquatic centre, which is leased and managed by a third party. There were complications negotiating an agreement, particularly in relation to assigning liability for any damages. So the project was abandoned and revived for the medical sciences facility.
What would you do differently?	The project has been running for 5 years now, there haven't been any issues with the technology and it is a great success! The collaboration between NCC, the university, SEDA and EnergyAustralia was good.

Table 11: Summary of interview responses by Newcastle City Council.

5.3 Developers considering cogeneration

We interviewed one developer that is considering cogeneration. Their responses are summarised in Table 12.

Question	*Response*
What are the drivers for considering cogeneration in the development?	The company's aspirational environmental sustainability targets. Improving environmental ratings – residential BASIX, ABGR, Green Star rating. Future proofing the development in anticipation of customers requiring better environmental performance in future. Economic drivers. The network constrained location requires the developer to fund network upgrades for grid supply of electricity, and the economics of trigeneration is being explored as an alternative option of comparable capital cost. Options to capture network support payments for providing grid support at constrained peak periods may make trigeneration the more economically effective option. Furthermore, the kWh cost of electricity from trigeneration plant is less than the average commercial retail price.
What are your concerns about cogeneration?	Aesthetics and the size of the required plant. Source of point-source emissions. Developer's aspiration for higher-than-required environmental performance means that post-combustion scrubbers would need to be installed to meet higher air quality standard. Water use and aesthetics of cooling towers needed to dissipate surplus heat.
What barriers or challenges have you encountered?	Negotiating potential connection arrangements with the electricity network has been difficult for the various options considered, including grid export and/or partial grid back up. Negotiating with gas supplier for gas of required pressure and volume has been complex and time consuming. The developer anticipates that customers would perceive onsite cogeneration (relatively new technology) as being less reliable than grid supply. To achieve equivalent reliability requires investment in back up and standby facilities. There is a lack of readily available information and tools to make feasibility assessments. This meant the developer has had to outsource the feasibility assessment despite in-house capability.
What would make cogeneration easier to consider as an option?	Greater availability of information on energy use for energy efficient buildings. Information on energy consumption in different uses is available for "average building", which has been inadequate for estimating energy requirements for an energy efficient development. More standard procedures for negotiations with networks.

Table 12: Summary of interview responses by developer.

5.4 Government authorities

5.4.1 Department of Water and Energy

Table 13 summarises interview responses provided by the Department of Water and Energy.

Question	*Response*
What is DWE's role or interest in cogeneration?	DWE is the policy agency for the NSW Greenhouse Gas Abatement Scheme (GGAS) [implementation agency is IPART] and are interested in opportunities to improve the effectiveness of the scheme. Cogeneration can make an important contribution to GGAS. In the transition to an emissions trading scheme, DWE wants to make sure that existing benefits to cogeneration are not lost.
What do you see as the successes, opportunities and challenges for cogeneration?	Very relevant for NSW energy efficiency strategy, especially for "improving the Government's energy efficiency performance through energy savings projects across government buildings, hospitals and schools". Hospitals in particular can benefit from cogeneration. Cogeneration may get a boost from the price for carbon. Higher electricity prices and a bigger carbon market (relative to NGAC market size and the low price of NGACs) will benefit cogeneration. It is possible that smaller cogeneration units as in apartment buildings may not benefit due to high transaction costs. But they may fall below threshold for an emissions liability.

Table 13: Summary of interview responses by Department of Water and Energy.

5.5 Network utilities

5.5.1 EnergyAustralia

There are three 'layers' at which EnergyAustralia considers connection of cogeneration facilities, based on size:

- Large industrial scale cogeneration (>100 MW): These are no different to other market generators in the electricity system. They are well understood and pose no problematic issues from a network perspective. Usually the planning processes are longer than 5 years, and from the proponent's perspective the economic case is difficult, there are various risks relating to security of energy contracts, security of business prospects over these time frames, etc. So these are in practice difficult for customers to implement – in fact there are none of this scale in the EA network area [all existing industrial scale cogeneration is in Integral Energy's network].

- Commercial scale cogeneration (100 kw – 5 MW range): Many of these are going ahead, driven by environmental objectives. This market is maturing, with proponents considering business issues, risks and opportunities rather than simply technical issues. These can operate in non-export mode, grid-parallel non-export mode, or grid parallel export mode, which have different levels of simplicity and cost for the customer to connect to the grid, but there are no material differences between them for the network. The larger systems are easier – they connect to the 415V network. There are fault issues that may require transformer/substation upgrades costing around $100,000 which is not much for a project costing a million or so.

There are no policy obstacles at this scale.

Connection costs depend on individual contexts. There can be two circumstances where connection costs can escalate. "Fault duty problems" arise in a CBD or high density area (does not affect suburbs), and these risks are exacerbated by adding a generator to the area. The solution in this case is to replace all the switchboards, adding another $million or so to the costs. The other circumstance is where an existing substation may require additional switchgear, but because the building is old there is no space to accommodate the additional hardware. The only way to connect the generator is to demolish and rebuild the entire substation – all in order to add some switchgear!

- Very small scale (few kW): These generators generally come with inverters that are very simple as long as they comply with specific inverter standards, so they can connect without any issues. A bidirectional meter for exporting to the grid costs around $200. Other generators like microturbines and fuel cells need to have inverters added. This can make small generators uneconomic from the customer perspective. Again, there are no obstacles from the network perspective.

Table 14 summarises interview responses provided by EnergyAustralia.

Question	*Response*
What causes many cogeneration proponents to see the network utility as a significant barrier?	Unfamiliarity on both sides. There is lack of experience for both the network and the developer. Often developers want to use the network for back-up but not in the course of normal use, and do not want to pay connection charges. But the network has no processes for reserving capacity that is not being used. So this is outside normal business processes. Network costs depend on individual specifications. Developers generally want to know "how much would it cost to connect?" without having the specifics of what they want to connect because that would depend on overall cost including connection cost. An iterative process is needed. The network specialists have to work out designs and changes to the system to connect distributed generators. Most of them end up not being implemented, so it is seen as a wasted time and effort. There are standard generator connection contracts and standards; these are very general to cover every type of configuration. The policy and guidelines exist. But real projects are needed to make the interfaces less clumsy. Projects are relatively few and therefore it has not become part of regular business operations, so experience is lacking. Experience and lessons do not get shared through the organisation so the next person faced with similar issues doesn't have the knowledge.
What can be done to overcome the barriers?	EA is looking at improving their processes because they see distributed generators as a positive development that can support their network operations.

Table 14: Summary of interview responses by EnergyAustralia.

5.5.2 Alinta AGN

Alinta manages the network of gas pipes and ensures capacity is available to deliver gas at the required pressures and volumes. The gas commodity is sold by retailers. Network costs are regulated and relatively stable. The commodity cost is much more volatile.

In the past 12 months there has been an exponential increase in the number of inquiries and requests for gas to supply cogeneration. Reciprocating engines use low pressure and can be supplied by the standard gas supply network. Gas turbines require high pressures, and need augmentation of the network or the addition of compressors. From the network perspective the investigations are tying up resources, because a majority of the projects don't take off.

Alinta identified the following potential barriers to cogeneration:

- Electricity prices are rising, but so are gas commodity prices so the economic balance is shifting [for customers].

- Cogeneration customers want long term contracts for their economic risk management. This is not such an issue with the network, as the access arrangements have standard 2 year reference contracts with the option to renew. Network prices are regulated with price reviews every 5 years. However, arrangements may not always suit the customer.

6 The role of government

This section discusses the current role of government in regulating and supporting cogeneration. Section 6.1 describes the regulatory framework affecting cogeneration and Section 6.2 outlines current incentives, assistance and government support for cogeneration in NSW.

6.1 Regulatory framework

The regulatory framework affecting cogeneration is complex and involves multiple jurisdictions, government agencies, regulators and utility businesses. This section outlines regulatory and approval requirements established by the main regulatory stakeholders.

6.1.1 Jurisdictional requirements – New South Wales

Planning approval

The *Environmental Planning and Assessment Act 1979* is the principal law regulating the assessment and determination of development proposals in New South Wales, including proposals for cogeneration. The Act is administered by the Minister for Planning. The Act divides development into three broad categories:

- Development that does not require consent or exempt development
- Development that requires consent
- Development that is prohibited.

The *Environmental Planning and Assessment Act 1979* establishes three types of Environmental Planning Instruments: Local Environmental Plans (LEPs), Regional Environmental Plans (REPs) and State Environmental Planning Policies (SEPPs). Any party proposing a development must refer to all relevant Environmental Planning Instruments (EPIs) to determine whether development consent is required. All Environmental Planning Instruments (EPIs) are available online at www.legislation.nsw.gov.au. Any of these EPIs could contain specific provisions relating to cogeneration.

A Local Environmental Plan divides the Local Government Area into zones such as rural, residential, recreational, environmental protection and business zones. Each zone will have a list of the types of development that are allowed without consent, allowed with consent or that are prohibited. Most LEPs are available on Council websites.

Regional Environmental Plans apply to nominated regions which may be smaller or larger than a single Local Government Area. These Plans can regulate any matter which the Minister believes is of environmental planning significance for that region.

State Environmental Planning Policies cover matters that the Minister considers of environmental planning significance for the State. For example Schedule 6 of the *State Environmental Planning Policy (Major Projects) 2005* requires that development under $5 million within the area of Sydney Olympic Park, Redfern-Waterloo Authority Sites, Circular Quay, Luna Park, Rocks to Dawes Point, East Darling Harbour, Darling Harbour and parts of the Rocks, Walsh Bay, Sydney Casino Switching station and the Fish Market requires the Minister for Planning's consent.

Under *State Environmental Planning Policy (Major Projects) 2005*, 'development for the purpose of a facility for the generation of electricity or heat or their co-generation (using any energy source, including gas, coal, bio-fuel, distillate and waste and hydro, wave, solar or wind power)' must be approved by the NSW Minister for Planning if it:

- Has a capital investment value of more than $30 million, or
- Has a capital investment value of more than $5 million and is located in an environmentally sensitive area of State significance.

None of the 81 cogeneration opportunities investigated by the DMPP had a capital investment value of more than $30 million. However, four had a capital value of more than $5 million and may have required Ministerial approval.

Most proposed cogeneration developments would need to submit a development application (DA) to the local council in order to obtain development consent. They would not usually require Ministerial approval unless part of a larger development that requires Ministerial approval. Application forms and instructions for lodging a DA can be obtained by contacting the local council. Most DAs will also need to be submitted with some form of Environmental Impact Assessment or Statement of Environmental Effects.

EPA licensing requirements

The *Protection of the Environment Operations Act 1997* requires an EPA licence for any electricity generating works that:

- Supply or are capable of supplying more than 30 megawatts of electrical power from energy sources (including coal, gas, bio-material or hydro-electric stations), but not including from solar powered generators, or
- Are within the metropolitan area of Sydney, Newcastle and Wollongong (being the area bounded by and including the local government areas of Newcastle, Maitland, Singleton, Hawkesbury, Blue Mountains, Wollondilly, Wollongong, Shellharbour and Kiama) and incorporate electricity generating plant (other than emergency standby plant that operates for less than 200 hours per year) and are based on or use:
    a. Gas turbines, which burn or are capable of burning, in the aggregate, fuel at a rate of more than 20 megawatts on a net thermal energy basis, or
    b. Internal combustion piston engines, which burn or are capable of burning, in the aggregate, fuel at a rate of more than 3 megawatts on a net thermal energy basis.

Only three of the 81 cogeneration opportunities investigated by the DMPP exceeded 3MW in size; these would have required an EPA licence if they used gas engines, but not if they used gas turbines.

A cogeneration facility could also be subject to load-based licensing requirements. For cogeneration using gas, nitrogen oxide is an assessable pollutant for which load fees may be payable under the NSW load-based licensing system. However, based on the EPA's online calculators, load fees only apply to electricity generation facilities that have the capacity to generate more than 250 GWh per annum, which corresponds to a 28MW plant operating continuously. An administrative fee would still be charged.

Whether or not they need an EPA licence, cogeneration facilities need to comply with regulations relating to air emissions as discussed in Section 2.4

Electricity retail licensing requirements

Licensing requirements for retailers and generators of electricity are managed at the jurisdictional level. In New South Wales the principle regulatory bodies are the Independent Pricing and Regulatory Tribunal (IPART) and the Department of Water and Energy (DWE). The relevant legislation covering licensing requirements in the electricity market is the *NSW Electricity Supply Act 1995*. The Act does not require issuance of a licence for generators however distribution network service providers will require a generator to meet certain standards for connection to the network. The Act does require retailers to obtain a licence.

If a cogeneration owner only supplies its own electricity needs or exports to the grid through arrangements with the network utility and a retailer, it will not require a retail licence. However, if a cogeneration owner wishes to supply external customers with electricity it becomes an electricity retailer and will require a retail licence.

In NSW, the Minister for Utilities has the power to issue licences to allow entities to supply or distribute electricity. IPART is responsible for administering the licensing process. Licences are issued subject to conditions relating to matters such as effective retail competition, consumer protection, greenhouse gas abatement, reliability and safety (IPART 2007).

The process for applying for an electricity retailer supplier's licence is by submitting the Energy Retail Supplier's Licence Application Form. IPART provides a guide to assist prospective applicants. Following submission along with an application fee of $1,500, the Tribunal would undertake public consultation on the application (IPART 2007). The application is assessed by the Tribunal in accordance with the Protection of the Environment Administration Act 1991 (electricity licence applications only) and a recommendation is made to the Minister. The Minister will then make a decision on the application. Once the licence has been granted, the licence holder will be required to meet obligations such as ongoing compliance reporting and possibly occasional audits (IPART 2007).

As a general rule, the retail licensing process is fairly straightforward if the cogeneration owner wishes to sell electricity to customers via a standard grid connection. Applications become more complex if the cogeneration owner wishes to develop an isolated grid that is not connected to the rest of the electricity network, as this raises issues of monopoly provision and lack of customer choice. GridX has applied for a retail licence for off-grid supply of electricity from cogeneration that is still under consideration. No other licences of this type have been granted to date in NSW.

More information on the licensing process can be found on IPARTs website at: http://www.ipart.nsw.gov.au/welcome.asp, or by consulting the *Guide for prospective NSW Electricity and Natural Gas Retail Suppliers*, also available on IPART's website.

The current licensing arrangements are expected to continue in the short term however all non-economic distribution and retail functions of the NEM are scheduled to transfer to the AER after legislation is introduced into South Australian Parliament in September 2009. It is likely that retail licensing or 'Energy Business Authorisation' function will be carried out by the AER after that time (AAR 2007).

6.1.2 The National Electricity Law and Rules

The National Electricity Law and rules govern the operation of the National Electricity Market (NEM). The Rules have the force of law, and are made under the National Electricity Law.

Currently, work is underway through the Ministerial Council on Energy (MCE), the national policy and governance body for the Australian energy market established by the Council of Australian Governments (COAG), to develop a national framework for energy and to amend the National Electricity Law and Rules to this end. As part of this effort, the Australian Energy Regulator (AER) and the Australian Energy Market Commission (AEMC) were formed to provide a consistent national approach for energy market regulation. The AER will assume responsibility for the economic regulation of the energy sector in a staged process.

In 2007, the NEM Rules were amended with changes to the economic regulation of distribution services. From January 1 2008, economic regulation of distribution networks in NSW passes from IPART to the AER.

There are a number of aspects of the Rules that are of relevance to cogeneration proponents. Some proposed changes to the Rules as part of the national reforms may also be relevant to cogeneration proponents.

Registration

The National Electricity Rules (the Rules) require that any person wishing to participate in the National Electricity Market must register with the National Electricity Market Management Company (NEMMCO) as a market participant. The categories of participants include: customers, generators, network service providers, special participants, intending participants and traders. Depending on the plant size and intended use, a cogeneration facility may need to be registered with NEMMCO under the generator category.

Generating Systems

Under the Rules, any person who owns, controls or operates a generating system connected to a transmission or distribution network must register as a generator. The generator must classify their unit as either market scheduled, market non-scheduled, non-market scheduled or non-market non-scheduled. A generating unit with an aggregate nameplate rating of 30MW or greater will be classified as scheduled. Generating systems less than 30MW are classified as non-scheduled. Under Clause 2.2.3(b) of the Rules, large generating systems may be classified as non-scheduled with NEMMCO's approval only where the primary purpose of the generating unit is local use and sent out generation rarely exceeds 30MW, the physical and technical characteristics of the unit are such that it is not practicable for it to participate in central dispatch, or the output of the unit is intermittent (NEMMCO 2007).

Under Clause 2.2.1(c) of the Rules, certain generators may be considered exempt and are not required to register with NEMMCO. Currently, generators below 5MW are exempted from registration. In addition, generating systems with an aggregate nameplate rating less than 30MW may also be exempted by NEMMCO if it exports less than 20GWh into the grid in a year. Even if an exemption may apply, an application for exemption must be made to NEMMCO in order for it to be granted. It is likely that all of the 81 cogeneration opportunities investigated by the DMPP would be exempt from the need to register as generators, as all but one is less than 5MW in size and the larger one is unlikely to export more than 20GWh into the grid.

Information about the registration process for market participants is easily accessible through the NEMMCO website or through a dedicated information centre which is available for preliminary discussions on registration applications.

Distribution Systems

Under section 11(2) of the National Electricity Law (NEL) and Clause 2.5.1 of the National Electricity Rules, a person must not own, control or operate a distribution system that forms part of the interconnected transmission and distribution system, unless that person is registered or has gained an exemption from the AER from the requirement to register (AER 2007). There may be situations where a cogeneration proponent wishes to develop its own grid that is connected to the rest of the electricity network. In this situation, the proponent would need to register as a Network Service Provider (NSP) or gain an exemption from the AER.

The AER can grant an exemption from the obligation to register as a NSP, which by definition would also exempt a person from compliance with the obligations in chapter 5 of the NER. Alternatively, the AER may grant a more limited exemption from the operation of chapter 5 of the NER, so that the person must still register, but need not comply with the obligations in chapter 5 that would otherwise apply (AER 2007). The following case study is an example of such a situation.

Case Study - GridX Power Pty Ltd Network Service Provider Application for Exemption

In April 2006, GridX Power Pty Ltd applied to the AER seeking an exemption from the requirement to register as a NSP under the NEL and the NER. The application sought 'an in-principle indication from the AER that if a GridX model network were constructed, GridX would be entitled to be granted exemption from registration in respect of its interest in that network' (AER 2007, p. 4). The GridX proposal is to operate a combined generation, distribution and electricity retail operation.

GridX Power Pty Ltd is seeking to develop innovative energy solutions for new residential housing estates by generating electricity from small, natural gas-fired generating units connected to the domestic gas reticulation system and embedded with the electricity network. Under this model, electricity and waste heat produced by the generating units would supply electricity and hot water to the residences on these estates and the system also includes the option of provision for cooling via reticulated chilled water (AER 2007).

GridX also proposes to export excess energy generated within each embedded network to the NEM, but proposes that its network be configured so that the import of electricity from the NEM into a GridX network is not possible (AER 2007).

The AER concluded that it is not appropriate to grant a general exemption for the GridX model. However the AER considered it more appropriate to grant GridX a specific exemption from the requirement to register as a network service provider under the NER, and exemption from compliance with certain, but not all, obligations applicable to NSPs under chapter 5 of the NER.

The AER found that there would be a good case for granting a specific exemption from the obligation to register as a NSP for networks operated by GridX in specified locations subject to the following conditions:

(a) GridX would need to obtain and hold a retail and/or distribution licence in the relevant jurisdiction that provided for:

> (i) a shadow pricing arrangement to be developed independently and to be subject to regulatory oversight under the retail licence;
>
> (ii) appropriate dispute resolution arrangements.

(b) GridX would need to comply with the provisions of chapter 5 of the NER requiring it to:

> (i) maintain and operate its network in accordance with good electricity industry practice and applicable Australian Standards;
>
> (ii) comply with applicable regulatory instruments; and
>
> (iii) comply with applicable technical and safety standards (AER 2007, p. 36).

The exact terms of any conditions would be determined at the time of granting an exemption (AER 2007).

Source: Australian Energy Regulator 2007, Decision – GridX Power Pty Ltd Network Service Provider Application for Exemption, May.

Connecting and exporting to the network

A co-generator may wish to connect to the grid to export surplus power. As discussed above, generators may or may not need to be registered NEM participants under Chapter 2 of the Rules. If the generator is required to be registered as a participant under the rules, at all times the connection process must ensure compliance with the National Electricity Rules (NER). The NER outlines the obligations for both the connection applicant and the Network Service Provider (NSP) which include:

- Connection Enquiry by the Connection Applicant contained in section 5.3.2
- Connection Enquiry Response by the NSP contained in section 5.3.3
- Connection Application contained in section 5.3.4
- Preparation of an Offer to Connect by the NSP contained in section 5.3.5
- Offer to Connect by the NSP contained in section 5.3.6 (NER).

The process is outlined in the NEMMCO document Connecting New Generation – A Process Overview and can be found at: http://www.nemmco.com.au/registration/110-0543.pdf.

Figure 9 illustrates the process, highlighting the documents available from NEMMCO in orange and the documents required by NEMMCO in red.

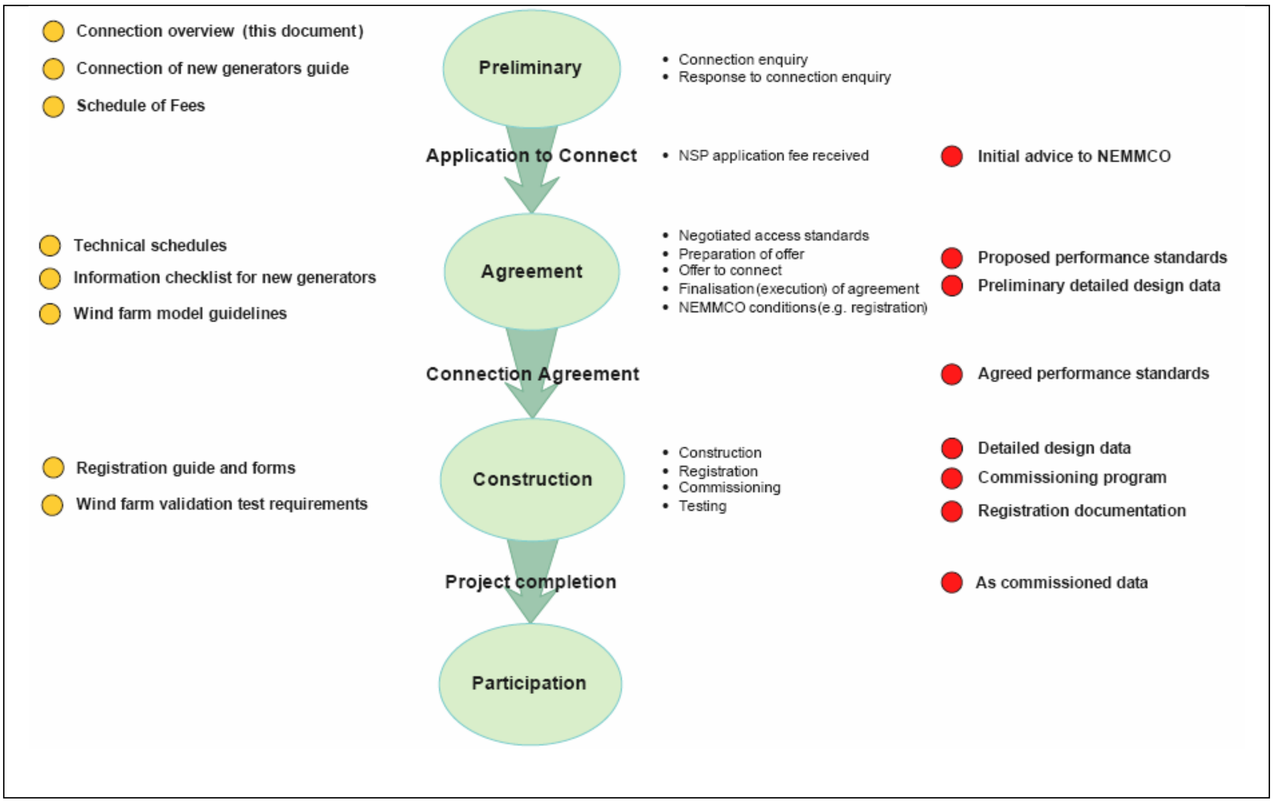

Figure 9: NEMMCO grid connection process. Source: NEMMCO (2006), *Connecting New Generation – A Process Overview*.

A new national framework for distribution network planning and connection arrangements is currently being developed. The proposed changes to the Rules are outlined in the independent consultants report by NERA/ACG which will be used as the basis to develop the new national arrangements for electricity distribution network planning and connection arrangements.

The report builds on other MCE work streams, such as the previous work of the Renewable and Distributed Generation Working Group (RDGWG) (for example, their report 'Impediments to the Uptake of Renewable and Distributed Generation'), and a draft code of practice for Embedded Generation prepared for the Utility Regulators Forum (MCE SCO 2007).

It is likely that a number of amendments will be made to Chapter 5 of the Rules related to network connection arrangements. Details of the proposed changes can be found in the NERA/ACG report on the MCE website at: http://www.mce.gov.au/index.cfm?event=object.showContent&objectID=872DC4B0-F5C1-48FB-B002E70E10C8D70E

Distribution Use of System Charges

Under the amended rules for economic regulation of distribution services, Clause 6.1.4 prohibits Distribution Use of System (DUOS) charges for the export of energy. This means that a DNSP must not charge a distribution network user distribution use of system charges for the export of electricity generated by the user into the distribution network.

Avoided Transmission Use of System costs

Transmission Use of System (TUOS) costs are charged to a Distribution Network Service Provider (DNSP) as payment for the use of the transmission infrastructure that delivers electricity to their distribution network. If generating electricity within the distribution network that is also used in that network, embedded generation systems such as cogeneration would reduce the amount of electricity transmitted through the transmission network. This may reduce TUOS costs for the DNSP.

Under Section 5.5 of the National Electricity Rules, DNSPs are required to pass through to an embedded generator the amount of customer TUOS charges the DNSP would otherwise have had to pay to a transmission network service provider had the embedded generator not been connected to the DNSP's network (AER 2003). This is so-called avoided TUOS.

The requirement to pay embedded generators, avoided TUOS charges was implemented in lieu of embedded generators negotiating network support payments with TNSPs and in recognition of the poorer relative bargaining position of embedded generators (NERA 2007).

As part of the development of a national regulatory framework for electricity distribution networks, the MCE and COAG have made commitments to reduce barriers and establish effective mechanisms for distributed generation and demand side response. To this end, the MCE has made efforts to consider incentives and impacts on DG and DSR through the process of developing a national distribution framework. As part of this effort, the MCE engaged NERA Economic Consulting (NERA) to prepare a report 'Part One: Distribution Rules Review – Network Incentives for Demand Side Response and Distributed Generation'. The report recommended that the Rules should remove the requirement for DNSPs for make avoided TUOS payments to embedded generators (NERA 2007). It is yet to be seen whether this recommendation will be adopted under the new national framework.

6.1.3 Network service provider requirements

To connect generation equipment to the electricity network, approval must be sought from the relevant Distribution Network Service Provider (DNSP). The three main DNSPs in NSW are Energy Australia, Integral Energy and Country Energy.

There appears to be no standard process for connecting a cogeneration plant to the electricity grid. Each DNSP has their own requirements for connection of cogeneration equipment to their network. As each network connection is unique, network connections are managed on a case by case basis; the equipment type and generation capacity generally determine the process. The process can be complex and expensive. Cogeneration proponents need to reach agreement with the DNSP on the technical terms of connection, contractual matters, the allocation of costs for feasibility studies and any grid reinforcements or line extensions that may be required. Most DNSPs are skilled at modelling loads but may have less experience in modelling the effect of embedded generation on the system.

The Australian Standard AS 4777 'Grid Connection of Energy Systems via Inverters' must also be complied with if the cogeneration system uses inverters to provide power output up to 10kVA per phase. Individual assessment will likely be required for inverters with an output greater than 10kVA per phase. Generators need to ensure that specifications for equipment are acceptable to the DNSP prior to installation as the DNSP may require installation of particular equipment in the distribution network to accommodate increased fault levels or additional protection requirements to maintain system stability. Stability modelling is likely to be required to determine the connection's potential effect on the system.

The lack of a streamlined process for cogeneration is largely a reflection of the small number of applications received by DNSPs each year. Conversely, DNSPs have generally set in place stringent guidelines for the connection of solar PV to the grid which is a reflection of the higher number of applications for this type of embedded generation. The complex processes that exist at present add substantially to the transaction costs for organisations considering cogeneration.

If a cogeneration owner wants to export electricity to the grid through its grid connection, it will also need to negotiate an energy purchase agreement with the retailer.

6.1.4 Gas network connections

Regulation of access to the gas network is subject to the provisions of the National Third Party Access Code for Natural gas Pipelines Systems (the Code). Gas retailers have access to the network and gas connection and supply can be arranged through a retailer. Obtaining a connection to the gas distribution network for the supply of gas to a cogeneration facility will depend on the location in the state. Different utilities supply different regions:

- Alinta AGN Ltd transports natural gas to the Greater Sydney region and over 45 regional areas across NSW including coastal centres between Newcastle and the Hunter Region north of Sydney and Wollongong and Shellharbour south of Sydney. The Network also extends to the Riverina, Blue Mountains and the major centres of the Central Tablelands.
- Country Energy operates the Wagga Wagga Gas Distribution Network, supplying gas to more than 20,000 customers in southern NSW towns
- Central Ranges Pipeline Pty Ltd is a natural gas transportation and distribution company bringing natural gas to the Central Ranges around Tamworth.

Each gas network operator has its own access arrangements. However, the following information is generally required when applying for connection for a cogeneration facility:

- Location of the nearest gas path valve
- Required metering pressure
- Load summary consisting of the equipment's average and maximum hourly gas consumption rate (MJ/h)
- Usage pattern (Invenergy 2006).

As with connection to the electricity network, a cogeneration developer may be required to pay the cost of any augmentation of the gas network required to supply gas to the site. The cogeneration owner will also need to negotiate a supply contract with a gas retailer.

6.1.5 NSW Greenhouse Gas Reduction Scheme

The NSW Greenhouse Gas Reduction Scheme (GGAS) allows parties to produce Abatement Certificates (NGACs) for eligible activities resulting in abatement of greenhouse gas emissions. Cogeneration projects are able to apply to become registered abatement certificate providers based on the project's associated emissions reductions.

Under the Scheme, the Independent Pricing and Regulatory Tribunal (IPART) accredits abatement projects and administers the scheme for NSW and the ACT. Parties must apply to IPART for accreditation. Information about the application process is available in the Guide to Applying to become an Accredited Abatement Certificate Provider. An application will generally entail a completed application form, supporting documentation relating to any calculations and an application fee of $500.

IPART will assess the application and may request an investigation or audit. The investigation would seek to substantiate any information, calculations and other items in the application. Based on the information provided and the investigation/audit, IPART would then determine whether the applicant should receive accreditation as an abatement certificate provider. A successful applicant would be notified and added to the GGAS Registry. They would then be able to generate NGACs for sale to offset the cost of cogeneration.

6.2 Incentives, assistance and opportunities for cogeneration

This section discusses support schemes that are available for cogeneration.

6.2.1 NSW Greenhouse Gas Reduction Scheme

The GGAS scheme aims to reduce greenhouse gas emissions associated with the production and use of electricity and to develop and encourage activities to offset the production of greenhouse gas emissions (GGAS 2007). Accredited abatement certificate providers can create NGACs for carrying out abatement activities under one or more of the scheme rules. The Scheme has five Greenhouse Gas Benchmark Rules addressing Compliance (Rule 1), Generation (Rule 2), Demand Side Abatement (Rule 3), Large User Abatement Certificates (Rule 4) and Carbon Sequestration (Rule 5) (GGAS 2004). Providers are able to sell the NGACs to benchmark participants each year, or use them to meet their own benchmark if they are also benchmark participants. The creation of NGACs significantly improves the economics of cogeneration.

The main rules that apply to cogeneration projects are the Generation Rule 2, and the Demand Side Abatement Rule 3. The Generation rule allows creation of NGACs for low-emission generation of electricity, which is calculated as the emissions intensity of generation as compared to the pool intensity. The Demand Side Abatement rule allows creation of NGACs for activities which result in reduced consumption of electricity. Cogeneration facilities may be able to generate NGACs for low emission electricity and for the supply of heat that results in a reduction of electricity use.

6.2.2 Energy Savings Fund and Public Facilities Program

The NSW Government's Energy Savings Fund was to provide $200 million over five years for projects that save energy and reduce peak electricity demand. The objective of the Fund was to reduce electricity consumption and greenhouse gas emissions in the state, reduce peak electricity demand, stimulate investment in innovative measures and increase public awareness about saving energy (DEUS 2006a).

The Energy Savings Fund provided funding to several cogeneration projects, including:

- $200,000 in funding to the Willoughby City Council Cogeneration at Willoughby Leisure Centre
- $1,960,000 in funding to the GPT group for the Retailer Shopping Centre Embedded Cogeneration program
- $137,999 in funding to Gosford City Council for Biogas Cogeneration at the Kincumber Sewage Treatment Plant.

In addition, the NSW government provided $461,000 funding to the Powerhouse Museum through the Public Facilities Program. The Powerhouse cogeneration project provides electricity for lighting and air-conditioning at the museum as well as thermal energy to heat the water at the new Ian Thorpe Aquatic centre across the road (DEUS 2006b).

The Energy Savings Fund and Public Facilities Program have now been incorporated into the NSW Climate Change Fund, discussed below.

6.2.3 The Climate Change Fund

The NSW Climate Change Fund was established in July 2007 under the *Energy and Utilities Administration Act 1987*. It incorporates the Water and Energy Savings Funds and is currently being developed.

Under the Climate Change Fund, cogeneration projects may be eligible for funding through the NSW Green Business Program or the Public Facilities Program. The NSW Green Business Program provides $30 million over five years for projects that will save water and energy in business operations in NSW (DECC 2007a). The Public Facilities Program provides $30 million for water and energy saving projects in public facilities such as schools, community buildings, sporting facilities, museums and art galleries (DECC 2007b). Activities which are eligible under the two programs are similar and include, but are not limited to:

- Education and technology trial activities which increase the adoption of efficient technologies and practices
- Projects which improve the efficiency of buildings, appliances and industrial processes
- Projects which reduce peak electricity demand
- Projects which reduce the demand for electricity or water supplied from electricity or water supply networks – e.g. cogeneration, fuel switching, water recycling, stormwater harvesting (DECC 2007a).

More information on the programs including the eligibility criteria can be found on the website of the Department of Environment and Climate Change currently at: http://www.epa.nsw.gov.au/grants/ccfund.htm.

6.2.4 Building rating tools

There are several voluntary building rating tools, including the Australian Building Greenhouse Rating (ABGR) and Green Star. The ABGR provides a consistent approach to assessing the greenhouse performance of commercial office buildings. Its star rating system allows differentiation within the building industry. The Green Star rating scheme, operated by the Green Building Council of Australia, provides a comprehensive sustainability rating for buildings. The ABGR rating is one component of the overall Green Star rating. Installation of a cogeneration system can help to increase ratings under both tools.

One of the methodologies under the GGAS DSA Rule refers to the ABGR and the templates used by ABGR assessors are integrated with the NGAC calculation methodology.

6.2.5 Demand management for DNSPs

Currently, the Electricity Supply Act 1995 requires the NSW government to impose licence conditions on the DNSPs to conduct and publish investigations on the cost effectiveness of implementing demand management strategies that may permit distribution network augmentations to be deferred or avoided (DEUS 2004).

The Demand Management Code of Practice provides guidance to DNSPs about how to meet this licence obligation. The code of practice requires DNSPs to keep a register of interested parties that wish to be informed in relation to each supply constraint forecast to occur within five years (ACG/NERA 2007). The code of practice also requires that DNSPs issue a formal Request for Proposals (RFP), calling for non-network solutions in relation to a specific constraint. Before issuing a RFP, the DNSP must consult with interested parties to raise awareness of an upcoming constraint and explore possible non-network solutions. The

DNSP can invite parties to prepare an investigation of potential demand management options. However it must issue a formal RFP calling for formal submissions before it can go ahead with a network augmentation (ACG/NERA 2007).

The code of practice outlines in detail what needs to be in a RFP such as the level and timing of the system support required; the results of any investigations with customers; data regarding customer types and the loads of any large existing customers; as well as all relevant assumptions to be used in the evaluation of proposals (ACG/NERA 2007). The RFP must allow for at least eight months before the forecast date that the system support investment decisions must be made and at least eight weeks for the submission of proposals (ACG/NERA 2007).

The code of practice also specifies what needs to be included in proposals. Proponents may submit draft proposals to the DNSP for comment prior to the final submission date (ACG/NERA 2007).

There may be opportunities for cogeneration proponents to respond to DNSP requests to undertake investigations and explore possible solutions to provide demand reduction in those areas in the network identified by DNSPs. However, distributed generation such as cogeneration would normally only be considered to provide a demand management function if the distributor can rely upon it to be available whenever required (DEUS 2004).

Proposed national arrangements

With the shift to national regulation, the regulatory requirement for DNSPs is expected to remain. Specifically, the NERA/ACG report recommended that:

> For any project to alleviate a network constraint for which the network solution could require an estimated capitalised expenditure of $2m or more, DNSPs should be required to perform an economic cost-benefit assessment of that project. As part of this assessment, the DNSP should be required to consult publicly and be required to issue an RFP from potential providers of non-network solutions to the network constraint (NERA/ACG 2007, p. 157).

In addition, the NERA/ACG report recommends that the AER issue a statement of specific requirements for the contents of the RFP for non-network solutions to address an emerging network constraint. The report recommended that the RFP include, at a minimum:

- the technical requirements that the non-network solution would need to meet;
- the estimated range of costs for network solutions and an indication of the resulting annual cost that a non-network solution would need to better in order to be selected; and
- an indication of whether the DNSP considers non-network alternatives to be a feasible solution for the project (NERA/ACG 2007, p. 158).

The report also recommended that the RFP process should 'provide sufficient time for proponents of non-network solutions to prepare their cases while allowing the DNSP, in the absence of a committed non-network project, to implement a network solution after a cut-off date' (NERA/ACG 2007, p. 158). It also recommended that the RFP process 'be capable of being brought to closure, with the non-network solution either committed (and bound) to deliver in a reasonable period of time, or the DNSP free to select an alternative option' (NERA/ACG 2007, p. 158).

While MCE processes are still underway, it can be expected that a requirement for DNSPs to consider non-network solutions will carry forward under the national regulator. Until the final legislative package is prepared it is unknown whether this regulatory requirement on DNSPs will bring any benefits to embedded generation such as cogeneration.

7 Barriers to uptake of cogeneration

Further uptake of cogeneration in NSW faces several barriers. This section identifies the main barriers, drawing on the analysis in this report, stakeholder interviews, the discussion of the regulatory framework in Sections 6.1 and 6.2, and previous work (e.g. MCE 2006; IEA 2007).

7.1.1 Commercial viability

Despite its environmental and network benefits, the economic analysis in Section 3 indicates that cogeneration remains a marginal commercial proposition in many applications, requiring government subsidisation to proceed. Where there is a significant thermal load alongside an electrical load, or there are significant network constraints, cogeneration may make commercial sense. In the absence of these conditions, the margin between grid electricity and natural gas prices is rarely sufficient to drive investment in cogeneration.

Emissions trading should increase the price of electricity relative to natural gas in the short to medium term, due to the higher greenhouse intensity of current grid electricity. Under current proposals, there may be a window between 2010 and 2015 where the relative increase is even greater due to exclusion of natural gas production from emissions trading. However, cogeneration investment decisions need to consider long term electricity and gas prices. While it appears very likely that emissions trading will make many more cogeneration facilities commercially viable, much will depend on the future carbon price. Meanwhile, the lack of certainty about a carbon price acts as a barrier to cogeneration investment.

It is difficult for proponents to capture the network benefits of cogeneration. Information about network constraints can be difficult to obtain and network pricing does not reflect constraints at particular locations (MCE 2006). Where cogeneration can provide a firm demand reduction, it should be paid appropriately for this network deferral. This will increase commercial viability.

Even where cogeneration is commercially feasible, the high upfront capital costs can deter investors. High transaction costs are also a problem. Experience with cogeneration is still fairly limited, making it difficult and expensive for potential investors to obtain good information about the feasibility of a particular proposal. Network connection negotiations and licensing can be difficult and time consuming processes that add to the cost of a cogeneration facility.

7.1.2 Regulatory requirements

Cogeneration facilities must meet a range of regulatory requirements in NSW. While it is important that cogeneration facilities are subject to regulation, the nature of the regulatory requirements can act as a barrier. Lack of familiarity and experience with cogeneration amongst regulators can lead to complex and time-consuming approval processes and delays.

Some cogeneration suppliers have argued that the requirement to obtain a retail licence for small-scale cogeneration acts as a barrier to uptake. While some have opted to go through the process of obtaining a retail licence, others have chosen to avoid acting as retailers and instead to follow a model where the customer makes the capital investment for self-generation but gives the technical operation and maintenance contract to an external provider. There appear to be few significant barriers here.

Obtaining a licence for air emissions is another potential barrier for cogeneration facilities, particularly in built-up areas, or where there are high background levels of NOx. Some facilities in these areas will need to add air emission control technologies, which add significantly to the cost of a facility. Alternatively, there may be a shift from gas engines to low-emission gas turbines in some cases.

Energy market rules are another potential barrier to cogeneration. Full retail contestability was established in NSW from 1 January 2002. Electricity customers are able to choose their own retailer. This may present a barrier for cogeneration in commercial and residential buildings because the residents or tenants must be able to choose their supplier and will not necessarily wish for their electricity to be supplied by the cogeneration plant. This situation can mean that electricity from cogeneration plants will only be used to power common areas such as building lighting, ventilation and lifts, unless the developer is convinced that the cogeneration facility can deliver electricity at a price that is more attractive than those available through the retail market.

Further, as identified by the MCE (2006), there is an underdeveloped market framework for the sale of power outside of the wholesale market, which may limit opportunities for cogeneration and result in relatively higher transaction costs.

7.1.3 Network planning

According to the IEA (2007), 'energy regulators and their regulated entities continue to plan for the future using models that rely heavily on major, centralised investments in large power plants and new transmission/distribution capacity'. Cogeneration is a different approach that avoids or defers these investments and is not always well represented in network planning processes.

Currently, under the demand management code of practice, proposals submitted to DNSPs are evaluated and ranked on the basis of the total annualised cost of providing the system support. The total cost must be based on not only the cost incurred by the DNSP, but also must consider any changes to the level of transmission or distribution losses. The total annualised cost is then adjusted to account for the relative risk profile of the various options.

The risk adjustment that is carried out in evaluating proposals could act as a barrier for cogeneration if the risk profile of a cogeneration solution is perceived to be higher due to the DNSP's lack of familiarity with the technology or with a lack of familiarity with demand side response in general. As there is no dispute resolution mechanism if a proponent disagrees with the option selected by the DNSP, there is little that a cogeneration proponent could do if it suspects that the risk evaluation could be a determining factor for their solution being rejected.

According to the MCE (2006), a 'lack of transparent information on network planning and current and prospective network constraints (e.g. substation fault levels) reduces developers' ability to identify prospective projects and accurately assess feasibility'.

It is yet to be seen how the revised national framework for network regulation will impact cogeneration. Submissions from stakeholders have raised a number of issues with the proposed rules. Firstly, that the RFP process often depends on the commitment of the DNSP to a project and DNSPs require a regulatory incentive to undertake network solutions. Secondly, requirements around timeframes for the RFP process can potentially limit or impede the development of economically efficient non-network solutions to network constraints (CUAC 2007).

The NERA/ACG report recommended that a dispute resolution regime be established for challenges in relation to cost benefit analyses completed by DNSPs. The report recommended that RFPs are to be held for projects valued over $2m. However it also recommends that only projects over $10m be open to a dispute resolution process, leaving smaller project proponents with no dispute resolution mechanism.

7.1.4 Network connection

Electricity grid connection for sent out energy from cogeneration is proving to be complex and expensive. Cost allocation for the various studies and equipment that may be required for a connection is unclear. DNSPs have little experience in connecting cogeneration plants to the distribution network and project developers argue that DNSPs impose excessive constraints and lack standard connection policies. At the same time, project developers can become a source of frustration for DNSPs as a lot of work is required to analyse the impact of the connection but many of the connections do not end up being implemented. DNSPs can see this as a waste of time. Further, many developers do not understand the impact of cogeneration on the network and what this means for connection costs.

While part of the problem is lack of experience on both sides with connection of cogeneration and its impacts on the network, the MCE (2006) notes that network 'connection requirements for non-conventional technologies can be inconsistent, complex, inappropriate to technology and impose relatively high transaction costs'. For small scale cogeneration, network connection regulations and technical standards can be unnecessarily onerous, or non-existent. More streamlined connection processes for cogeneration could improve the viability of projects.

NERA (2007) argues that the need to pass on avoided TUOS payments can distort DNSP incentives for the connection of cogeneration to the network, particularly where DNSPs are not able to pass these payments through to other users. As a result, DNSPs may not see it as being in their best interest to facilitate connection of cogeneration.

Project developers also argue that gas connection can be prohibitively expensive. Some gas suppliers may require the cost of new gas pipelines to be borne by the gas customer. Negotiations with gas suppliers for required pressure and volume of gas can prove complex and time consuming which is acting as a barrier for cogeneration proponents.

7.1.5 Risk management

Many potential cogeneration developers see cogeneration as a risky venture, which causes them to impose high hurdle rates for cogeneration investment. There are several sources of uncertainty that contribute to this perception of risk. First, the technology remains unfamiliar and can be seen as complex. Potential investors are generally not already in the business of energy generation and can be daunted by the technical and regulatory requirements. Objective, reliable information about cogeneration can be difficult to obtain and there may be a lack of financing options and skilled labour. All of these factors contribute to the sense of uncertainty about investing in cogeneration.

Second, there remains considerable uncertainty about future carbon pricing arrangements. The current GGAS arrangements in NSW will remain in place until a national emissions trading scheme is introduced in 2010. However, it remains unclear how GGAS participants will be treated under a national emissions trading scheme. The NSW government is in the process of assessing how GGAS will transition to a national scheme. At the very least, a national scheme should seek to not disadvantage those that have already made an investment under GGAS. For future investors, the viability of cogeneration is sensitive to the final rules for emissions trading and the eventual carbon price. While these remain uncertain, investing in cogeneration remains risky.

Third, there is uncertainty over the relative movement of future gas and electricity prices. While emissions trading should drive up the price of electricity relative to natural gas, increasing demand for natural gas may also increase prices. Reliable information on current prices can be difficult to obtain and future prices are even less certain.As cogeneration is very sensitive to the difference between electricity and gas prices, uncertainty about these prices poses an additional risk to potential investors.

7.1.6 Government support

While there have been some good examples of government assistance for cogeneration in the form of funding, demonstration plants and other programs, there remain a number of additional options that governments could pursue to support cogeneration more actively. There appears to be a general lack of leadership from government, a lack of knowledge of the benefits of cogeneration and a lack of knowledge about the processes, barriers and other issues faced by cogeneration developers.

A large part of the potential cogeneration market (potential customers) is in the area of public facilities such as hospitals and schools. A lack of knowledge of cogeneration options for these facilities is acting as a barrier for cogeneration developers.

Another barrier is the lack of ongoing commitment from the NSW Government. This lack of commitment is epitomised by the abolition of the Sustainable Energy Development Authority (SEDA) in 2004. Prior to its abolition, SEDA provided grants and interest free loans to organisations implementing cogeneration systems. A number of developers of cogeneration projects benefited from the support provided by SEDA. While the DMPP has recently played a similar role, there does not appear to be any mechanism to provide ongoing facilitation of cogeneration projects after completion of the DMPP.

While cogeneration proponents have access to GGAS, the effort required for the GGAS application process and the fees may exceed the benefit for smaller projects. As the value of NGACs can significantly improve the economics of a cogeneration project, missing out on NGACs due to prohibitively high transaction costs could act as a barrier. However, this may present an opportunity for an external organisation to offer services to aggregate a number of small generators and undertake their applications on commission.

7.1.7 Other issues

There are a range of other issues that can act as barriers in particular circumstances, including space constraints, the aesthetics of cogeneration facilities and associated infrastructure and perceptions that the technology is less reliable than grid electricity.

8 Conclusions and recommendations

Although the purpose of this report is primarily to provide an update on the status of cogeneration in NSW and the work done by the DMPP to facilitate implementation of cogeneration, we have included some recommendations on how to improve the uptake of cogeneration. There are several existing processes that are seeking to reduce the barriers to cogeneration and we have sought to focus on recommendations that may not be adequately picked up under these existing processes.

8.1 Discussion

Cogeneration is a proven technology that is building market momentum and, with the right thermal demand and economic and regulatory environment, can be expected to provide sizeable demand management opportunities. Cogeneration offers substantial environmental benefits and can have commercial benefits in the right circumstances. When fuelled by natural gas or renewable fuels, cogeneration can deliver electricity with much lower emissions intensity than the grid. Further, the use of waste heat means that overall efficiency of energy conversion is greatly increased. Cogeneration also offers the potential to reduce peak electrical demand, thereby reducing the need for network augmentation. As climate change response becomes more urgent, cogeneration has great potential to contribute to greenhouse gas emission reduction.

Cogeneration technologies have matured to the extent that they are now being seriously considered as a way of reducing costs and achieving environmental benefits in a range of applications. Improvements to absorption chillers have also improved the viability of trigeneration, which is an attractive option for sites with significant cooling loads. However, there is still relatively little experience with cogeneration in NSW and this is reflected in the lack of streamlined processes for approval and connection of cogeneration plants and the shortage of reliable information on feasibility of cogeneration.

Nevertheless, several businesses have emerged recently with a focus on cogeneration provision and recent applications of cogeneration in high-rise commercial and residential buildings in Sydney are adding impetus to the market. These pioneering efforts are helping to pave the way for further applications of cogeneration in the future.

The investigations undertaken by the DMPP identified two cogeneration opportunities as commercially viable according to the customers' own investment criteria. One of the opportunities is already being undertaken and thus no assistance was required from the DMPP. The second opportunity is a simplified cogeneration opportunity in the health sector. It would be unlikely however that this opportunity would be implemented without significant funding. The remaining cogeneration opportunities required funding assistance of up to $3,221/kVA. These opportunities would deliver total peak demand reductions of 70.6MVA, energy savings of 407 GWh per year and greenhouse gas savings of 277 kilotonnes CO_2-e per year for an average subsidy of $1,350/kVA.

The hurdle rates established by organisations for investments in cogeneration are high, reflecting perceptions that the technology is risky and concerns about the size of capital investment. It needs to be recognised that asking a business to change from its current mode of operation to an alternative is difficult. The capital cost to purchase a boiler to generate hot water or steam is far less than to install a cogeneration plant.

In general cogeneration opportunities are likely to become much more attractive, and many will become financially viable, as electricity prices rise relative to gas prices. A higher cost on greenhouse emissions than presently created by the penalty cap under the NSW Greenhouse Gas Abatement Scheme may be required to see large numbers of cogeneration investments. However, even the present value of NGACs significantly improves the economics of cogeneration compared to other technologies. A higher carbon price and more attention to the ways in which cogeneration can provide network benefits and be paid for these benefits is needed to further improve the viability of cogeneration.

8.2 High priority opportunities

In the Botany area, there are many large industrial sites that are adjacent to each other that use steam as part of their process. There are also two coal fired boilers reaching the end of their life in this location. As a result significant capital will be required to be committed to replace them in the near future.

This co-incidence of closely located thermal demand and aging boiler equipment represents a significant opportunity to install a large gas fired cogeneration plant to service the needs of all of the customers on the site and, as a result, to provide a sizeable generating capacity to feed electricity into the grid. The DMPP has investigated two separate opportunities in the Botany area, one with a potential capacity of 100MW and the other with a capacity of up to 60MW. For these opportunities to become a reality would require a great deal of facilitation and time to manage the process and the interests of all stakeholders.

This could only occur with leadership from the NSW Government driving this opportunity. Any significant delay in pulling the stakeholders in this project together will almost certainly result in the opportunity being lost for another 15 or 20 years.

8.3 Recommendations

8.3.1 Commercial viability

To improve the commercial viability of cogeneration, the following strategies are required:

- Introduction of an emissions trading scheme that puts a value on greenhouse gas emission reductions and does not unfairly disadvantage cogeneration
- Improvements to network planning processes to ensure that cogeneration providers are compensated for any network benefits they provide
- Reduction of transaction costs through experience and government support.

The first strategy is being pursued through the Garnaut Review and the development of an emissions trading scheme. The second is being pursued by the MCE as part of energy market reform and the transfer of distribution network regulation to the Australian Energy Regulator. However, the third is receiving relatively little attention and recommendations in this regard are provided in Section 8.3.6.

8.3.2 Regulatory requirements

Cogeneration proposals would benefit from consolidated information on NSW regulatory requirements relating to cogeneration and approval processes. This could be published in the form of a guide for potential cogeneration proponents. In compiling the guide, it is likely that opportunities to streamline approval processes would also become apparent. One current area of uncertainty is the regulatory requirements for islanded networks, within the framework of retail contestability. If a cogeneration plant serves multiple customers at a location that is not connected to the grid, then those customers will not have the option to choose another supplier and regulation is needed to prevent monopoly exploitation of this situation. Regulatory arrangements in this situation need to be clarified.

8.3.3 Network planning

Cogeneration would also benefit from revisions to the National Electricity Rules to provide greater incentives for demand management. ISF and RAP (2008) provides detailed recommendations on how to improve treatment of demand management in the National Electricity Rules and these recommendations are endorsed here.

8.3.4 Network connection

A streamlined process for connection to the grid could be formulated and followed by DNSPs however this will not reduce the complexity involved in assessing each connection. The connection process would remain a case by case arrangement based on the equipment type and generation capacity.

Cost allocation rules could be developed to determine which party would bear the costs related to the connection. For example, fault issues may require transformer or substation upgrades. At the moment the cost is borne by the cogenerator however other models of cost allocation may be more appropriate. For example, in Denmark any grid extensions for connection of off-shore wind generators are considered a public good and therefore the cost is borne by the grid operator (and ultimately by customers). Alternative types of cost allocation models such as this need to be explored further.

Negotiating and obtaining an energy purchase agreement with a retailer for the sale of surplus power is another barrier to cogeneration. Standardised contracts could be used for cogeneration as are currently available for residential solar photovoltaics.

8.3.5 Risk management

Investment in cogeneration will always carry a degree of risk. The risk will be greatly reduced once details of NETS become clearer and experience with cogeneration continues to grow. The emergence of cogeneration service providers that can manage risk for potential investors is an important step in the development of the market for cogeneration.

The provision of better information is an important way to reduce risk and this is an area where government can play a greater role, as discussed below.

8.3.6 Government support

Several of the cogeneration opportunities that have been taken up in NSW have benefited from active facilitation and support from the NSW Government, first through SEDA and more recently through the DMPP. At this stage in the development of the cogeneration market, the level of expertise to investigate, analyse and design successful cogeneration projects is limited. Without active government facilitation and support for cogeneration projects, opportunities like those identified in this report will be lost.

While funding support through the Climate Change Fund is critical to alleviate initial capital costs and provide more experience with cogeneration, funding alone is not sufficient. There is a clear need for government to provide technical support and facilitation for identified cogeneration opportunities. There is a real risk that this market transformation role will be lost upon completion of the DMPP, at a time when the market for cogeneration has the potential to rapidly increase with further support.

The NSW Government should establish a dedicated team within an appropriate department to provide active facilitation and support of cogeneration projects. One of the first tasks of this team should be to take forward the cogeneration opportunities already identified by the DMPP. Another should be to prepare a comprehensive cogeneration guide for potential adopters of cogeneration. This current report provides a starting point, but the focus of the guide would be more on the practical issues and process that an organisations needs to go through to make a decision on whether to invest in cogeneration.

While emissions trading is likely to provide sufficient incentive to encourage greater uptake of cogeneration in NSW, the NSW Government should also consider additional support mechanisms to ensure that cogeneration is not unfairly disadvantaged relative to larger scale technologies. Feed in tariffs that provide premium payments for cogeneration electricity are one option. Low interest loans to reduce upfront capital cost are another option.

9 References

ACG/NERA 2007, Network Planning and Connection Arrangements – National Frameworks for Distribution Networks, A joint report prepared by the Allen Consulting Group and NERA Economic Consulting for the Ministerial Council on Energy Market Reform Working Group, August.

AER 2003, Sithe and Integral–Avoided transmission use of system payments, Dispute Resolution Panel Decision, Australian Energy Regulator, January http://www.aer.gov.au/content/index.phtml/itemId/672138/fromItemId/672130

AER 2007, Decision – GridX Power Pty Ltd Network Service Provider Application for Exemption, Australian Energy Regulator, May 2007.

BCSE 2007, Clean Energy Report 2007, Australian Business Council for Sustainable Energy, May 2007.

California Energy Commission 2007, California Distributed Energy Resource Guide, viewed 19 December 2007, http://www.energy.ca.gov/distgen/index.html.

Clean Energy Council 2007, Clean Energy Fact Sheets: All About Cogeneration, www.cleanenergycouncil.org.au.

DEC 2005, Approved Methods for the Modelling and Assessment of Air Pollutants in New South Wales, Department of Environment and Conservation (NSW), August 2005.

DECC 2007a, NSW Green Business Program, NSW Department of Environment and Climate Change, website http://www.environment.nsw.gov.au/grants/ccfgbp.htm

DECC 2007b, Public Facilities Program, NSW Department of Environment and Climate Change, website http://www.environment.nsw.gov.au/grants/ccfpfp.htm

DEUS 2004, Demand Management for Electricity Distributors NSW Code of Practice, Department of Energy, Utilities and Sustainability, September http://www.deus.nsw.gov.au/publications/NSW%20Code%20of%20Practice%20Demand%20Management%20for%20Electricity%20Distributors%202004.pdf

DEUS 2006a, Energy Savings Fund, NSW Department of Energy Utilities and Sustainability, website, http://www.deus.nsw.gov.au/energy/Energy%20Savings%20Fund/Energy%20Savings%20Fund.asp

DEUS 2006b, Public Facilities Program, NSW Department of Energy Utilities and Sustainability, website http://www.deus.nsw.gov.au/Energy/Energy%20Savings%20Fund/Energy%20Savings%20Fund%20Projects/Public%20Facilities%20Program%20Funded%20Projects.asp#TopOfPage

EA 2007, Demand Management Options for the Willoughby STS Supply Area, Energy Australia, October 2007.

EDO 2007, Planning and Development Fact Sheets, Environmental Defenders Office New South Wales, http://www.edo.org.au/edonsw/site/factsh/fs02_overview.php

EUROPA 2007, Cogeneration, http://europa.eu/scadplus/leg/en/lvb/l27021.htm.

GGAS 2004, Fact Sheet Accreditation Process for Abatement Certificate Providers, Greenhouse Gas Reduction Scheme, July, http://www.greenhousegas.nsw.gov.au/documents/syn77.asp

GGAS 2007, Compliance and Operation of the NSW Greenhouse Gas Reduction Scheme during 2006 Report to Minister, Greenhouse Gas Reduction Scheme, Independent Pricing and Regulatory Tribunal, July.

International Energy Agency 2007, The International CHP/DHC Collaborative website, http://www.iea.org/G8/CHP/chp.asp

Invenergy 2006, BASIX Cogeneration Report: Cogeneration for Residential Apartment Buildings in NSW – Challenges and Opportunities, NSW Department of Planning, July.

IPART 2007, Guide for prospective NSW Electricity and Natural Gas Retail Suppliers, Independent Pricing and Regulatory Tribunal, pp1-11.

ISF and RAP 2008, Win, Win, Win: Regulating Electricity Distribution Networks for Reliability, Consumers and the Environment, Review of the NSW D-Factor and Alternative Mechanisms to Encourage Demand Management, Institute for Sustainable Futures and Regulatory Assistance Project for Total Environment Centre.

McLennan Magasanik Associates 2006, Impacts of a National Emissions Trading Scheme on Australia's Electricity Markets, National Emissions Trading Taskforce, July.

Ministerial Council on Energy 2006, Impediments to the Uptake of Renewable and Distributed Energy, Discussion Paper, Ministerial Council on Energy Standing Committee of Officials, Renewable and Distributed Generation Working Group, http://www.mce.gov.au/assets/documents/mceinternet/DiscussionPaperImpedimentstoUptakeRDG20060222140112.pdf

MCE SCO 2007, Introductory note, National Frameworks for Electricity Distribution Networks Network Planning and Connection Arrangements, August 2007

NEMMCO 2007, Registration Information, http://www.nemmco.com.au/registration/registration.htm#GuidesForms

National Emissions Trading Taskforce, 2006. *Possible Design for a National Greenhouse Gas Emissions Trading Scheme*.

National Emissions Trading Taskforce, Possible design for a national greenhouse gas emissions trading scheme: Final framework report on scheme design, December 2007

NSW Department of Planning 2007, BASIX Multi-Unit Residential Cogeneration Demonstration Project: Fact Sheet.

NERA 2007, Part One: Distribution Rules Review – Network Incentives for Demand Side Response and Distributed Generation, NERA Economic Consulting, April 2007.

RDGWG 2006, Impediments to the Uptake of Renewable and Distributed Energy, Discussion Paper, Renewable and Distributed Generation Working Group, Ministerial Council on Energy Standing Committee of Officials, Canberra.

SEDA 2003, SEDA Case Study: Macquarie University Saves with Cogeneration, http://www.deus.nsw.gov.au/Publications/2_2%20macquarie_uni.cs.pdf

SKM 2003, Reducing Regulatory Barriers to Demand Management, for the Independent Pricing and Regulatory Tribunal of NSW, November.

SKM 2004, Small Scale Cogeneration: Emission Regulations and Control Technologies, Sinclair Knight Merz for the Sustainable Energy Development Authority (NSW), Sustainable Energy Authority Victoria and Sustainable Energy Development Office (Western Australia), April 2004.