Submission
No 31

COGENERATION AND TRIGENERATION IN NEW SOUTH WALES

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4 September 2013

Dear Mr Miller,

Thank you for the opportunity to make a submissions on the NSW Parliamentary Inquiry into Cogeneration and Trigeneration.

If you require any further information or clarification, please do not hesitate to contact Jonathan Prendergast on [redacted]

Yours sincerely

[redacted]

Jonathan Prendergast
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Submission to:

Inquiry into Cogeneration and Trigeneration in NSW

By NSW Parliament Legislative Assembly Public Accounts Committee

Prepared by:

PRENDERGAST PROJECTS

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Revision 0

Introduction

1. Buildings use 40% of the nation's energy and produce 23% of the nations Greenhouse Gas (GHG) emissions. In recent years, investment in electricity networks has seen electricity costs increase 70%. Precinct Cogeneration and Trigeneration (Cogeneration) can assist in reducing the impact of both of these issues.
2. Our energy systems are crucial to our way of life, impacts on our environment and support of economic development. As we move further to a technology and electricity based economy, using less manual labor, the cost of energy will be a key factor for companies considering investment in NSW. Cogeneration energy technologies have great potential in NSW to reduce energy costs to the community and businesses, improve energy efficiency and reduce Greenhouse Gas (GHG) emissions.
3. Prendergast Projects provides advice to clients on Precinct Cogeneration and District Energy projects. These projects see low emission generation and distribution of electricity, heating and cooling, on a multi-building basis, rather than each building considering it's heating and cooling (and sometimes embedded low emission generation) requirements.
4. Precinct Cogeneration, and District Energy more broadly, has been or is being investigated for numerous projects in Australia, including:
    a. In NSW: The City of Sydney (including Green Square), Frasers Central Park, Parramatta, UTS, Macquarie University, University of Western Sydney
    b. Around Australia: Bowden, Tonsley Park (SA) Townsville, Brisbane (QLD), Docklands, Dandenong, Arden-Macaulay, Officer, Melbourne, RMIT, Manningham, Southbank (VIC), Perth, Parliament House (ACT), Brindabella and Madura Business Parks (ACT), and many more.
5. District Energy, cogeneration and embedded generation is prevalent overseas, including over 400 systems in Denmark, New York District Heating, Chicago Thermal (District Cooling), Gothenburg, Malmo, Woking, Birmingham, Southampton, Woking, Seoul and Singapore.
6. While there are numerous barriers and challenges to precinct cogeneration, this submission primarily concentrates on network charges applicable to embedded generation using the local electricity grid. For other issues relating to Precinct Cogeneration, we refer you to other submission by the Energy Efficiency Council and City of Sydney and also excellent work done by the Institute of Sustainable Futures (ISF), Total Environment Centre, and Climate Works' proposed rule change to AEMO.
7. Network charges include Distribution Use of System (DUOS) and Transmission (TUOS) charges and are paid by the electricity retailer to the local distribution and transmission network service providers. Network charges are 'passed-through' by the retailer to the electricity customer.

Key Recommendations

8. The cost of network charges applied to electricity sold using the local grid by embedded generation is the key issue to the economics and greater development of precinct cogeneration. We propose a system that more fairly reflects the cost of use of the electricity network. Such regulation change would enable precinct cogeneration, as other precinct energy measures to be more fairly judged for feasibility, and developed in suitable locations.

In the long term, such policy would see additional benefits of delayed future electricity grid augmentation, reduction in energy costs, more energy efficiency and reduced GHG emissions

Benefits of Cogeneration for Precincts and Districts

9. The benefits of Cogeneration and advantages compared to other technologies include:
    a. When installed close to energy demands, and waste heat can be utilised to provde thermal energy, it is highly efficient, compared to other combustion energy generation technologies
    b. It can significantly reduce GHG emissions due to this efficiency and use of natural gas, compared to grid delivered electricity.
    c. The engines can also use biogas, when it becomes more available and cost competitive in the future, particularly if it becomes available via the gas grid
    d. It can reduce the need for electricity network augmentation, including installation of new transmission lines from remote power generation systems
    e. It is compact, and while there are challenges, is suitable for installation in existing buildings in dense urban environments or in new precincts.
    f. In the right circumstances, due to the low comparative cost of grid delivered gas compared to grid delivered electricity, investment in a Cogeneration system can see paybacks of 4-7 years.
    g. It can be turned on and off on demand to generate during times of high demand or high pricing.

Benefits of Precinct Cogeneration

10. The benefits of Cogeneration for Precincts, compared to single buildings, include:
    a. A more aggregated Heating and cooling demand between several buildings which have peaks at different times, resulting in greater use of waste heat and resultant higher efficiency of the Cogeneration system.
    b. Better economics due to greater use of waste heat and less investment in pipework to connect several buildings.
    c. Heating and cooling demand is more consistent throughout the year and throughout the day which means heat recovery and the absorption chiller can operate consistently rather than having to adjust for demand.
    d. Technical and management capability is centralised rather required independently on each project
    e. Projects that start as precincts can over time connect more and more customers. Further aggregation of thermal load can lead to other energy efficiency and GHG reduction initiatives such as waste to energy, thermal storage, heat recovered from industry, ice storage, free cooling from ocean, lakes and rivers and use of renewable fuels such as biogas and biomass.

Limitations of Cogeneration

11. Cogeneration is a plug in technology as part of a broader energy approach. It is best used and most suitable when there is nearby large and consistent electrical and thermal energy demand.
12. Typically overseas, Cogeneration is used for large utility scale generation where a district heating or cooling system exists, so the waste heat can feed into the system. Such systems are supplemented by other heat sources such as gas boilers, waste to energy, thermal storage, heat recovered from industry and other means. This seasons heating supply able to meet varying heating demand.
13. Cogeneration is not suitable to following energy demand loads. Cogeneration systems greatly lose their benefit of efficiency once they are operating at under 70% utilisation. For these reasons, they are not suitable as a stand-alone technology to service a building, factory or precinct. Cogeneration is a complementary technology that should be coupled with other sources of electricity and thermal energy, such as the electricity grid and other thermal sources.
14. Cogeneration is generally not suitable to commercial or residential buildings. Electrical and thermal demands of such buildings vary over the year, during the week and during the day. NSW experiences a very temperate climate by world standards, and for much of the year thermal demand is low. Even on a cold winter day, heating is required in the mornings after which point the occupants and equipment in the building often provide enough heat to maintain a suitable temperature.
15. Cogeneration is generally not suitable for new developments. Cogeneration is a plug-in technology that optimally services known and existing loads. It is difficult to estimate electrical and thermal loads of new buildings. Such estimations are normally done to assess the worst-case scenario, and ensure enough plant capacity exists. This does not suit cogeneration as if demand is lower than expected, it can only operate at limited times through the year. There are many examples where cogeneration has been installed in new commercial buildings and has not been able to operate as the building is found to use less energy than expected or full tenancy does not occur until months or years after cogeneration installation.
16. Electricity is highly regulated in Australia to protect consumers and providers. Cogeneration is typically installed to provide electricity to the host building or nearby customers. Due to contestability regulation, customers are able to choose their electricity supplier. This creates uncertainty for cogeneration projects, as building typically include several customers (base building owner, several commercial tenants, many retail tenants) and such customers are not incentivized to use the cogeneration electricity. Careful consideration must be made of this prior to sizing and investment of Cogeneration.

Applicability of Technology in NSW

17. Cogeneration is off the shelf technology, and experience is growing in Australia in terms of design, development, installation and operation.
18. In overseas projects, the more efficient use of gas or other fuels by using cogeneration has been driven by energy security or high-energy prices, particularly gas. NSW may suffer similar circumstances in the near future.

19. Cogeneration is suitable as part of NSW's future energy mix to provide energy during peak and shoulder periods to meet demand, and reduce the need for further network investment. While NSW has seen over $7b of network investment in the current 5 year regulatory period, it is expected that further electricity demand will be placed on the network over time through general growth, choosing electricity over gas as the price goes up and becomes more scarce for uses such as heating and potentially electric cars.

Common mistakes in Cogeneration

Unsuitable design, sizing and strategy

20. Many Cogeneration projects have suffered the consequences of poor advice, strategy and design. This is due to a lack of understanding of how the electricity grid works.
21. The grid is primarily designed to take electricity from remote generation, and deliver it to houses. It is designed in 1 direction, and contains wires, transformers and sub-stations to provide appropriate services to customers. Figure 1 shows how this works with water as an analogy. To simply generate at the customer end, and expect to use the same infrastructure to feed back into the grid is not possible without large re-engineering, and this is widely not understood by those who do not work for distribution companies.

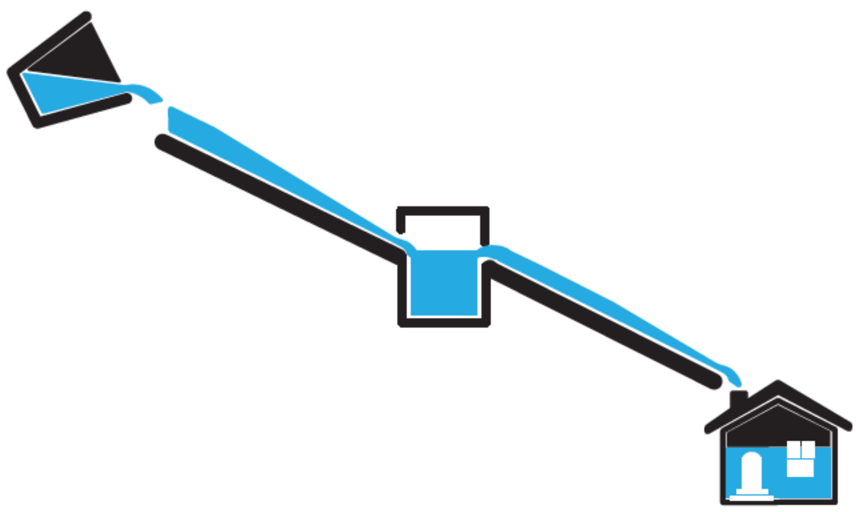

Figure 1 *– Analogy on how the electricity grid is designed*

22. Another analogy, using water again, is to compare a house having a small backyard water tank to supplement grid supplied water compared to a house having a large scale tank on stilts (Figure 2) designed to provide pressure to the water supply for the local community. It is obvious that a house cannot have such a tank, and expect to feed excess back into the water grid using the garden hose.

***Figure 2** – Large-scale water tank.*

23. In-building embedded generation seeks to direct electricity back up the building's existing grid connection. While this may seems a simple solution, the resulting redesign works of fault protection, transformers, wiring and other equipment often sees costs blow out to over $1 million, making such a connection unfeasible.
24. In addition to this, DNSP's commonly request that any augmentation to the grid to allow in-building cogeneration to feed back into the grid is paid for by the applicant. This is understandable, as the DNSP will not see large electricity flow using the new infrastructure, as the intention is for the applicant to only export excess electricity during low building electricity demand times. It is also debatable that the embedded generation in such a situation provides any benefit to the grid due to the feed in to the grid on an irregular basis.
25. Typically, precinct scale embedded generation connects via a High Voltage line to the local substation, from which electricity is distributed to local buildings. Electricity is not directed back up the grid, requiring fault level protection and other grid redesign works. Such connections depend on the distance from generation to the local High Voltage line, but are generally more than $100k but less than $500k.
26. The above unfeasibility of grid connection by in-building has lead to frustration by building owners and the community, and subsequent enquiries by Climate Works and inclusion in this inquiry. However, to truly address this issue, it is important that it is fully understood in the first place.
27. We recommend that the inquiry proceeds with it's proposal to support Climate Works proposed streamlined and regulated connection process, but also considers that greater awareness and communication is required by in-building cogeneration applicants and DNSP's.

<u>New Development</u>

28. Careful consideration must be made prior to developing Cogeneration for new developments. It faces the following challenges:
    a. Electrical and thermal loads are unknown
    b. Returns through sale of energy are uncertain
    c. Investment is required up front while returns can take time to occur as buildings develop and energy demand increases
    d. When connecting several buildings, streets and underground infrastructure are built in advance of buildings. This requires large up front investment for uncertain timing of returns
29. In such cases, we recommend on our projects that:
    a. Cogeneration is designed for, but not installed until energy demand is known and customers are procured
    b. Cogeneration only be installed after aggregation of thermal loads of several customers
    c. Thermal loads can be serviced by conventional plant in the short term (gas boilers and electric chillers)
    d. Cogeneration does not suit every circumstance, cogeneration is only one of a series of innovative technologies that can be used to save money, improve energy efficiency nd reduce GHG emissions.
    e. Once aggregation of thermal loads has occurred, other technologies can be introduced that suit the energy loads and costs.

Cogeneration as a stand-alone or lead technology

30. As discussed in earlier sections, Cogeneration is just one technology of many that are available. It is part of a broader energy efficiency or district energy approach.
31. A more appropriate approach is to promote District Energy, where many buildings are connected to a central plant. Then a project can develop organically, on a commercial basis, and new technologies introduced over time.
32. We hope that the property development and energy industry appreciate the potential of district energy over time and better understanding is achieved of district energy and cogeneration. We actively seek to educate industry and clients on this approach.

Economics of Cogeneration

33. Many advisers concentrate on the capital cost of Cogeneration, and in particular the cost of Cogeneration engines. A cogeneration engine is typically 25% of the capital cost a cogeneration installation due to the cost of installation, space, connections, pipework and ancillary plant.
34. Furthermore, over a 15-year term, 70% of the cost of Cogeneration is the fuel. This is a much more important consideration compared to the cost of engines.

Economic Viability

General economic viability of Cogeneration

35. The best way to explain this is through a simple demonstration of feasibility of Cogeneration. For this demonstration, we make the following inputs and assumptions:
    a. Size – 4MW Gas Engine, 3MW heat recovery and 3MW absorption chiller
    b. Cost of Installation - $12m
    c. Operation – 3,800 hrs per year
    d. Use of heating or cooling – 50/50 split

e. Utilisation – 100%
f. Output:
  i. Electricity – 15,200,000 kWh p.a.
  ii. Heating – 5,700,000 kWh p.a.
  iii. Cooling – 5,700,000 kWh p.a
g. Energy Prices
  i. Electricity – 20 c/kWh
  ii. Gas - $10/GJ
h. Gas Cost - $1,200,000 per annum
i. Value of Energy Created
  i. Electricity – $3,000,000 per annum
  ii. Heating – $260,000 per annum
  iii. Cooling - $230,000 per annum
  iv. Total - $3,500,000 per annum
j. Resultant annual margin on energy cost vs energy production - $2,300,000
k. Resultant payback period – 5 years

36. The above analysis is high level only, and depends on many assumptions. A 5 year payback period is attractive to most investors or customers.
37. In the above example, if the energy center was supplying several buildings using the local grid, it would also have to pay $1,200,000 per year in network charges. This sees the payback period extended to 10 years.
38. Most projects are not so black and white, and land somewhere between these example payback periods. But it is obvious in the above example that network charges are a major factor holding back the development of precinct cogeneration projects.

<u>Gas Increase over time</u>

39. There is a lot of discussion about gas cost increases in the near future, and indeed some of it has already occurred. While the ACIL Tasman forecast included in BREE's latest report sees a doubling of the gas price over time, I note that this occurs over a long period, and is a 3 to 5 percent year-on-year increase which is not much more than CPI.
40. A doubling of the gas cost does not see a doubling of the cogeneration costs of operation. This is explained by several steps, if we consider a doubling of the gas cost over 5 years:
  a. A doubling of the gas cost will not see a doubling of the delivered price. The delivered price of gas is typically made up of 50% of the gas commodity cost, and 50% of other costs including transport. Therefore a doubling in the gas cost is only a 50% increase in the delivered cost of gas.
  b. The cost of cogeneration includes cost of capital, operation and gas. Gas is typically 70% of the cost of cogeneration. Therefore if delivered gas cost rises 50%, the cost of cogeneration rises 35%.
  c. Cogeneration utilises waste heat to reduce normal gas consumption for heating. Therefore, a 35% increase in cogeneration sees a net increase of approximately of 25% of Cogeneration
  d. In this example, if the gas price doubles, the cost of cogeneration energy may only increase, in net, 25%. During this time, cost of grid electricity may have increased by the same portion, or more or less.
41. We believe that an increase in gas cost will make cogeneration more feasible as part of our overall energy systems due to its energy efficiently, but only in the right circumstances for the right projects.

Risks to Customers

42. Cogeneration technology is typically reliable and suitable for urban dense areas.
43. Electricity customers are typically able to choose where they purchase their electricity, so there is little risk to energy price risk over time.
44. Where larger customers have committed to long-term energy contracts to justify investment into cogeneration, there is the potential for cogeneration energy costs to increase over time more than normal energy services. Customers should perform appropriate due diligence. As future energy markets are currently hard to forecast, we take a risk management approach that can include methods of contract structuring or downsizing.

Current Regulations and unintended consquences

45. Current regulations restrict the development of precinct cogeneration and trigeneration. They encourage all embedded generation to only provide energy 'behind the meter' with no interaction with the electricity grid. This has the following negative effects:
    a. Embedded generation is sized down so that energy generation is lower than the host site energy demand on days of low demand
    b. Embedded generation is only done on a building-by-building as collaboration or coordination between several buildings is dis-incentivised.
    c. As network charges are set irrespective of location of use of the electricity network, new generation is encouraged in areas of low land value and access to fuel, rather than the most cost effective location. New power generation in remote areas as afar as 200km away from use are charged the same amount as embedded generation, despite the additional cost of losses and transporting such electricity to point of use. This also sees the need to develop new transmissions lines at great cost and impact to land owners in rural NSW.
46. The above actions see embedded generation not used to its potential.

Policy Design Considerations

47. As discussed earlier in this submission, we recommend a policy or adjustment in regulation to reduce the restrictions to embedded generation. This would include cost reflective network charges.
48. We refer to other submission by the City of Sydney and EEC, as well as work done by ISF, TEC and Climateworks.
49. The setting of cost reflective network charges could be based on distance between generation and use or the use of the local electricity distribution network. We belive that either would be applicable, but it is import that the setting of such charges is simple, clear and certain.
50. It is imperative that such charges, as a reduction to normal network charges for embedded generation are able to be known at the point of investment decision. It is not helpful if benefits of embedded generation are seen after the investment decisions. Therefore, the benefits of embedded network charges, such as cost reflective network charges, should be

able to be measured and confirmed based on concept designs. This reduces project development costs and increases the certainty of investments

51. Based on discussions with Distribution Network Service Providers, while acknowledging the potential of cost reflective network charges to encourage embedded generation and reduce the requirement for investment in network upgrades, there is a feeling of uncertainty as to the scale of such discounted network charges. We recommend that for a period of time, say the net 5 year regulatory period, a cap or target for such schemes is set. For example, if cost reflective network charges are 50% less than normal network, a cap of $50 million a year of discounted (cost reflective) network charges would enable 400MW of embedded generation in NSW. After such a period, the regulation and policy can be reviewed, and further adjustments could be made.

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