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Prepared by: Tracey Colley

Sustaining Australia (Colley Consulting Pty Ltd)

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Economic and technical potential for cogeneration in industry

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Executive Summary

Cogeneration is the combined production of electricity and thermal energy (heating and/or cooling) from the one fuel source. Thermal energy can be produced as hot water, steam or cold water via absorption refrigeration. A cogeneration plant can be designed to meet site requirements in terms of electricity and heating/cooling, but can also be designed to provide backup power in the event of electricity supply grid failure. Cogeneration plants are most economic when the electricity and heating/cooling is required at the same time and when this occurs during peak electricity tariff periods.

The primary benefit of cogeneration is reduced energy supply costs, but it also substantially reduces the total site greenhouse emissions from energy use by 40-70%.

Existing cogeneration plants in the red meat industry include Midfield Meat and Rockdale Beef, both of which produce electricity and hot water. Cogeneration is ideally suited to the red meat industry as it uses heat and electricity at the same time and requires only low pressure steam (800-1200 kPa) for rendering. This can be provided by a gas engine or gas turbine cogeneration system.

Cogeneration is more widely used in other industries, such as brewing, sugar refining, oil refining, metals processing, pulp and paper, steel and chemical plants. It is used in building applications such as hospitals, office buildings, aquatic centres, educational facilities and data centres.

Although cogeneration is technically feasible, it generally has a payback period of more than 5 years. If the site is facing capital expenditure for energy supply (such as replacing or upgrading a boiler or increasing the electricity supply to the site) or if capital grants are available, this may bring the payback period to less than 2 years. Several red meat processing plants have obtained funding support from various State and Federal Government agencies in the recent past, such as $2.9M to Cargill Wagga for its biogas capture 1.2MW cogeneration project.

It is likely that a carbon price will become a reality in the next 2 – 5 years. This will improve the economic signals for cogeneration, due to its significantly lower greenhouse gas emissions intensity. The exact extent will depend on what the carbon price is, how much of it is passed through for electricity supply and the fuel supply options for a cogeneration plant at the site in question. Cogeneration utilising renewable fuels has an significantly lower emissions intensity than grid supplied electricity. This can include biomass using a boiler and steam engine or turbine system or biogas from ponds in a gas engine or turbine system.

1. Potential cogeneration configurations

1.1 What is cogeneration

Cogeneration is the production of electrical and/or mechanical power and useful heating and/or cooling from the same fuel source, meaning that the overall fuel efficiency of the system is 70-90%. This significantly increases the efficiency of energy use and production, with commensurate reductions in the greenhouse emissions intensity of the electricity and thermal energy it produces. The size of cogeneration plants can range from a few hundred kilowatts to several hundred megawatts, depending on the needs of the host site.

Cogeneration can double energy efficiency, halve power costs and reduce carbon dioxide emission by two-thirds. Heat can be recovered from the exhaust gases, lube oil cooling system and jacket water cooling system. As cogeneration is so flexible, a plant can be sized to fit exactly into the site's electrical and thermal loads.

In other countries, cogeneration is referred to as combined heat and power (CHP).

1.2 When to look at cogeneration

The ideal time to investigate whether cogeneration will be economic for your site is:

- When heat and electrical loads occur at the same time
- When the electrical load is over 100kW, ideally over 500kW
- When the existing boiler plant operates for more than 3,000 hours per year
- When the current annual thermal fuel consumption is more than 2,000GJ
- When looking at replacing a boiler
- When looking at augmenting electricity supply to the site
- When looking at providing emergency backup electricity to the site
- When blackouts or brownouts are common in electricity supply system and cause significant delays in production
- When the local electricity distribution network is reaching peak capacity or where distribution and transmission losses are high (DNLF and TNLF)
- When grants or financial support is available to reduce simple payback period from more than 5years to less than 2 years

The most critical requirement for overall efficiency and cost effectiveness is that the heat and electrical loads occur at the same time and that heat recovery is maximised.

1.3 Benefits of cogeneration

The main benefits of adopting cogeneration are

- reduced on-site energy costs through increased efficiency, improving competitiveness for meat processing plants
- increased reliability and quality of electricity supply
- reduced greenhouse gas emissions
- reduced sensitivity to future electricity price rises
- opportunity to move towards a more decentralised form of electricity generation, where plant is designed to meet the site needs, providing high efficiency, increasing flexibility of system use and avoiding electricity transmission losses
- promotes liberalisation and competition in energy supply market
- increased employment and employment security in rural and regional areas
- can use renewable fuels, such as biomass and biogas
- if replacing coal fired boiler, can reduce particulate emissions from site

1.4 Different cogeneration plant configurations

Topping cogeneration systems generate **electrical** or **mechanical** power first, and then the exhaust heat is used for **heating** or **cooling** (via absorption refrigeration). Topping-cycle systems are the most common type of cogeneration plant.

Bottoming cogeneration systems generate heat first, then electricity and are much less common than topping cycle plants. These plants occur in heavy industries where very high temperature furnaces are used, such as glass manufacturing, where furnaces operate at temperatures up to 1,575°C. A waste heat recovery boiler recaptures waste heat from the manufacturing process and uses this to generate steam. The steam is then used in a steam turbine to produce electricity. For example, for 100 fuel units going into a bottoming cogeneration plant, about 70 units of steam would be produced but only about 14 units of electricity.

Baseload cogeneration plants operate 24 hours a day, seven days a week. **Peaking** cogeneration plants are designed to switch on at peak times, such as when the site electrical load exceeds a certain threshold, when the peak electricity tariff period commences or when the electricity supply system exceeds either a certain volume or price threshold. Cogeneration plants can be designed for **standby** applications to ensure reliability of electricity supply to the site, where they only startup in the event of grid electricity supply failure or they may switch to non-cogeneration mode in the event of grid failure.

Cogeneration plants can be used to produce mechanical power rather than electricity. This was used extensively in the sugar industry in the past, where plants has steam drives on equipment.

Heat recovery from cogeneration is usually via in intermediate media, such as steam. However, as the exhaust gases are clean and contain very low levels of water vapour, they can be used directly for drying. However, in food related industries, such as red meat rendering, the exhaust may need to be passed through a gas-gas heat exchanger, to avoid direct contact of exhaust gases with product.

1.5 Components of a cogeneration system

Cogeneration systems can be designed to match whatever the electrical and thermal needs of the site are. This is done by selecting the right combination of equipment. There are four basic components to a cogeneration system: the prime mover, heat recovery system, electrical/ motive power generator and the control system. The former two are covered in more detail here.

1.5.1 Reciprocating engines (prime mover)

Reciprocating engines are ideal where high pressure steam (less than 12 bar or 1,200 kPa) is not required, where only hot water is required and are generally smaller in size (less than 3MW). Reciprocating engines can be spark ignition (industrial gas or automotive derived gas) or compression ignition (diesel). Duel fuel systems (gas/diesel) or multi fuel systems are available in larger sizes.

Reciprocating engines range in size from 10kW up to 17MW, and can be combined in modular units to create almost any electrical output required.

In term of heat available, the exhaust gases (25-35% of fuel input) range from 55 – 400 °C, the jacket water cooling system (22-30% of fuel input) ranges from 55 – 75 °C and the lube oil cooling system (5% of fuel input) ranges from 50 – 70 °C. Reciprocating engines have a heat to power ratio of 0.5:1, up to 1.2:1, so for each kilowatt of electrical power generated half to 1.2 kilowatt of thermal energy can be recovered. However, more of the heat available for recovery is at lower temperatures when compared to a gas turbine, so the ratio is closer to 1.2:1 for hot water plants, but closer to 0.5:1 for steam plants. The cooling systems use water in cooling towers at a rate of about 1 L/second for a 2MW unit.

For small plants (less than 2MW), reciprocating engines have higher electrical efficiencies than gas turbines, and the capital cost of reciprocating engines is lower per unit of power than gas turbines. The electrical efficiency of newer reciprocating engines ranges from 45 – 48%, meaning that they produce a relatively large amount of electricity per unit of fuel input, but proportionally less heat.

Reciprocating engines can be fuel by natural gas, diesel, light fuel oil, heavy fuel oil, waste gases, or combinations of these fuels (ie duel fuel or multi fuel systems).

Manufacturers include GE Jenbacher (distributed by Clarke Energy in Australia), Wartsila, MWM, Cummins, MTU Friedrichshafen, Caterpillar, Perkins, Dresser-Waukesha, Deutz, MTU, MAN, Yanmar and more recently, manufacturers such as Shengdong from China.

Packaged micro-cogeneration systems are available for the residential and small business market, such as the Honda Ecowill, Baxi SenerTec and Vaillant PowerPlus Technologies, all are about 5kW in size. They generally produce electricity and hot water.

1.5.2 Gas turbines (prime mover)

Gas turbines are generally used where the site electrical load is over about 3MW or if high pressure steam (12 bar or 1,200kPa or more) is required. Thermal energy is recovered from the exhaust gases.

Gas turbines range in size from 1 MW to over 200MW. There are two main types – industrial and aeroderivatives. Aeroderivatives are, as the name suggests, derived from aircraft engines. They are lighter, smaller, have lower fuel consumption, higher reliability, are more expensive and have a higher electrical efficiency but slightly lower overall efficiency. Industrial gas turbines are heavy duty machines, can use lower quality fuels and although they have a lower electrical efficiency than aeroderivatives, they maintain their performance over a longer time period.

Gas turbines have a heat to power ratio of about three / two to one, so for each kilowatt of electrical power they generation three / two kilowatts of thermal energy. This is due to the higher exhaust gas temperatures (ranging up to 500 °C) exiting a gas turbine when compared to a reciprocating engine. The electrical efficiency of newer gas turbines ranges from 28-40%, meaning that they produce a relatively lower amount of electricity per unit of fuel input when compared to reciprocating engines. Gas turbines do not use cooling water, which can be an advantage where water availability is an issue.

Capital costs for gas turbine cogeneration plants are significantly lower than steam turbine cogeneration plants, ranging from 50-70 per cent.

Manufacturers include Allison, Cooper Rolls, Centrax, Dresser Rand, European GT, GE, MAN, Mitsubishi, Mitsui Engineering, MTU, Nuovo Pignone, Pratt & Whitney, Rolls Royce, Ruston, Siemens, Solar and Westinghouse.

1.5.3 Steam turbines or engines (prime mover)

Steam turbines are less efficient than gas turbines but can use solid fuels, such as biomass. Steam turbine cogeneration systems are widely used in the sugar industries which has seasonal energy demands and feedstock availability. In the sugar industry bagasse, a waste product from cane processing, is used as the fuel. The steam is generated in a boiler and then directed to steam turbines which generate electricity or steam is used directly in drives to produce motive power. The waste steam is then used for process heating, such as turning the sugar cane juice into syrup and then into sugar crystals.

Steam turbines have a higher cost per unit when compared to gas turbines, but are usually used where the solid fuel is much cheaper. A condensing steam turbine produces only power and all the steam in converted to condensate. A extraction or back pressure steam turbine allow some of the steam to be extracted before it is converted to condensate, and the back pressure is selected to match process requirements. Steam boilers can also be condensing-extraction types, which mean that when there is no process heat requirement, they can produce only electricity.

Steam turbine manufacturers include ALSTOM, Siemens AG, GE Power Systems (GE), Mitsubishi Heavy Industries (MHI), Hitachi, Toshiba Corp, Leningrad Metallic Works (LMZ), Ansaldo Energia, Turboatom and Skoda, as well as newer manufacturers from China such as Shandong.

Overall, the cogeneration efficiencies can be up to about 85%, but they typically produce a higher proportion of heat than electricity.

Steam engines are generally used in smaller applications and Spilling are the major producer of steam engines for power generation, particularly suited to biomass applications.

1.5.4 Microturbines (prime mover, micro cogeneration)

Microturbines are small gas turbines sized from 20 – 500kW and offer some of the same advantages as turbines over reciprocating engines – fewer moving parts, compact size, lightweight, can run on waste gases, less noise, lower air emission levels. They can be designed to be fully automated, as well as being well suited to direct mechanical drive markets such as compression and air conditioning. They evolved for uninterruptible power supply units for aircraft.

They can operate on a variety of fuels such as gases and liquids and can operate on waste gases such as biogas. Waste heat is available at 200-320°C.

The most common applications are those that require high reliability, such as hotels, hospitals, data centres, office buildings, telecommunications, retailers, gas compression and transmission. They are designed as packaged units and for completely unattended operation.

Manufacturers include Capstone, Elliott Energy Systems, Ingersoll-Rand, Turbec, Global Energy, Honeywell Power Systems and Bowman Power Systems.

1.5.5 Fuel Cells (prime mover, micro cogeneration)

Fuel Cell systems are electrochemical devices that convert the chemical energy of the fuel directly into electricity, with no combustion. The fuel cells are normally fuelled by hydrogen, which can be generated from methane (ie natural gas). They are modular and so can be bundled together in a stack to provide whatever the site requirement is, from 40kW to 25MW but mostly in the 50 – 200kW range. They are used in the residential and small business market in Japan and Europe. They have good electric load following capability without losing efficient have low emissions and quiet operation. Recovered heat can be as hot water or steam. There are only a limited number of units commercially available, and so fuel cells are not considered further in this report.

1.5.6 Heat recovery

To produce steam from a gas turbine or reciprocating engine prime mover, a heat recovery steam generator (HRSG) or heat recovery boiler is included in the design. This is basically a specialised type of boiler, which allows for such design considerations as a need to keep pressure losses to a minimum to avoid back pressure on the prime mover exhaust. This may involve some auxiliary firing if very high pressure steam is required, although this would be unlikely in a meat processing plant.

For reciprocating engine type plants, steam can be generated at 700-1,000 kPa (7-10 bar), higher pressure would require auxiliary firing. Steam production from reciprocating engines leads to a lower overall efficiency – more in the order of 65-70%, rather than the 85% or more for reciprocating engine hot water or trigeneration plants.

If steam is not required, standard plate or shell and tube heat exchangers can be used on the prime mover exhaust and engine cooling systems. Alternatively, the exhaust gases can be used directly.

1.5.7 Combined cycle plants

Combined cycle plants are used in the power generation industry. Normally, there is a gas turbine, heat recovery steam generator (or equivalent) which produces steam from the gas turbine exhaust gases, and steam turbine producing additional electricity. The end result is electricity and low grade (pressure) steam which is generally not used but exhausted to atmosphere. These plants can be located anywhere natural gas is available, and so can be located close to the electrical load as long as the air quality of the local area is adequate. Although this type of plant does use the waste heat from the gas turbine, it is not considered to be true cogeneration, but rather is referred to as combined cycle. The overall efficiency of combined cycle plants ranges from 30-50%, which is much lower than cogeneration (which can achieve up to 80-90%).

Combined cycle cogeneration plants are used where the heat to power ratio varies, such as where the process has a widely varying need for heat such as a batch process.

1.6 Trigeneration – electricity, heating and cooling

Trigeneration is a relatively new term and relates to a scheme which would produce electricity, heating and cooling from a single fuel source. For example, the Crown Casino in Melbourne has a trigeneration scheme installed which produces electricity, space heating in winter and cooling via absorption refrigeration in summer. The electricity is required to provide emergency backup for the gaming machines in the event of a failure of the electricity supply grid. If this occurs, the unit switches to non-cogeneration mode.

Absorption refrigeration allows the refrigeration cycle to be driven by waste heat, rather than electricity. The two most widely used systems are outlined in Table 1.

Table 1: Absorption refrigeration systems

Type	Target Temp	Required heat temp	Suppliers	COP	Unit Cost per kW
Lithium Bromide / Water	Above 0°C	60-95 °C for single effect, 150°C for double effect	York, Carrier, Thermax, Broad, Trane	Single – 0.5 to 0.6 Double – 0.9 to 1.1	Single - $400-450 Double - $450 – 500 Fuel costs comparable to conventional chillers
Water/ Ammonia	Down to -60°C	100-200 °C	Mattes Engineering, Colibri-Stork	0.6 to 0.7	$650-850 Fuel costs slightly higher at -10°C, but nearly half at -20°C

Source: CSIRO Maine's Power Project Stage 2 Report

2. Cogeneration Fuel Supply options

The type of fuel available will depend on the plant location and not all meat processing plants have access to all fuel types. The type of fuel has an impact on the air emission levels likely to result, which may be an issue if the meat processing plant is located in an airshed with existing air quality problems, such as Melbourne, Brisbane or Perth.

2.1 Non-renewable fuels

Natural gas in the most commonly used fuel in cogeneration plants. Natural gas has an energy content of 39.3MJ/m^3 and is less dense than air. There have been significant new developments in lean burn gas engines in the last decade, which have substantially lower air emissions than older engines. The emissions factor for natural gas is 51.33 kg $CO_{2\text{-}e}$/ GJ.

Installed natural gas cogeneration plants in Australia range in size from 0.2 MW to over 200MW, with well over 10,000 MW of installed capacity.

Natural gas may be blended with biogas, the key issue is ensuring that the prime mover is designed to handle the fuel characteristics.

Other gaseous fuels used in cogeneration include LPG (gross heating value of 93.3MJ/m^3 or 25.7 GJ/kL and is more dense than air) and butane (gross heating value of 122MJ/m^3 and heavier than air). LPG and butane are generally only used when natural gas is not available and are stored onsite in pressurised containers. Unfortunately, the LPG and butane price is linked to the oil price, so has undergone significant price increases in recent years, making it less economic as a cogeneration fuel.

Some industries have waste gases which can be used for cogeneration, such as coke ovens gas in the steel industry and oil refinery offgases. BHP Steel at Port Kembla has about 60MW and Whyalla has about 60MW of cogeneration using waste gas, the Shell Refinery at Clyde has about 12MW of cogeneration, Caltex at Kurnell 7MW and Shell at Corio about 45MW.

Diesel is a common liquid fuel used in cogeneration plants, but due to the higher costs, it is generally only used in remote applications where natural gas (and often, grid electricity) is not available. Diesel is suitable for use in reciprocating engines, and may be used in dual or multi fuel engines which also use natural gas or another liquid fuel, such as fuel oils. The emissions factor for diesel in stationery combustion systems is 69.5 kg $CO_{2\text{-}e}$/ GJ.

Heavy fuel oil (HFO) is used in the power generation industry in steam turbine systems, such as combined cycle cogeneration plants. Nabalco at Gove has 3 x 35MW units as part of their Alumina operations. HFO can also be used in reciprocating engines. The emissions factor for fuel oil in stationery combustion systems is 73.13 kg $CO_{2\text{-}e}$/ GJ.

Other liquid fuels, such as **light fuel oil** (LFO) and crude oil, may be used in dedicated engines, in dual or multi fuel engines or may be used as the pilot fuel in gas engines. The emissions factor for crude oil in stationery combustion systems is 69.12 kg $CO_{2\text{-}e}$/ GJ. Gas turbines can also use light fuel oils.

Coal could be used in a **steam turbine** cogeneration plant and is used in the paper industry (6MW unit at Shoalhaven, 7.5MW at Petrie, 11.5MW at Burnie) and in the minerals sector (25MW at Queensland Alumina at Gladstone, 37.5MW at Queensland Nickel at Yabulu, previously 135MW at Worsley Alumina). The emissions factor for coal is 88.43 kg $CO_{2\text{-}e}$/ GJ.

Basically, there are any number of different combinations of gaseous and liquid fuels which can be used in reciprocating engines. One of the key differences is the emission levels, particularly for nitrogen oxides, as indicated in the following table:

Table 2: Performance comparison of diesel and natural gas engines

Fuel	Diesel	Natural gas
Shaft output	9200kW	9000kW
Shaft efficiency	45.3%	46.5%
Nitrogen oxides (NOx)	**14.8** g/kWh	1.2 g/kWh
Carbon monoxide (CO)	0.9 g/kWh	2.1 g/kWh
Hydrocarbons (THC)	0.7 g/kWh	6.5 g/kWh
Particulates	**0.5** g/kWh	0.03 g/kWh
Carbon dioxide (CO2)	650 g/kWh	435 g/kWh

Source: Wartsila website, paper presented to ICCI 2004 Conference on Cogeneration and Emissions

2.2 Renewable fuels

Renewable gaseous fuels currently used in cogeneration in Australia include sewage gas (from sewage treatment plants), landfill gas and gases from food and agricultural wastes. Biogas has an energy content of 38.8MJ/m^3, slightly less than natural gas and is less dense than air. The emissions factor for biogas is 4.83 kg $CO_{2\text{-}e}$/ GJ, which is substantially less than natural gas.

Biogas is often produced from anaerobic digestion, which converts carbon compounds to methane in the absence of oxygen. This is a common feature of anaerobic wastewater treatment ponds at red meat processing plants. Capturing and utilising the methane generated in wastewater treatment can significantly reduce direct greenhouse emissions from a site.

Renewable liquid fuels currently used in cogeneration in Australia include black liquor in the paper industry.

Renewable solid fuels currently used in cogeneration in Australia include wood waste, bagasse (in the sugar industry, with 475MW installed capacity) and food and agricultural waste. Generally speaking, the solid fuel is combusted in a boiler and the cogeneration is based on a steam turbine system. However, there are some newer systems that use pyrolysis or fluidised beds to convert the solid to a gas, and it can then be used in gas engine or turbine systems. A thorough review of solid waste energy capture technologies is covered in the MLA report “A review of waste solids processing with energy capture technologies summary”, prepared by GHD Pty Ltd, December 2003.

Although paunch material does have some energy content, the water content generally means that the net energy contribution would be fairly low if used in a boiler – steam cogeneration system (3 MJ/kg[1], compared to dry wood which is 16.2 MJ/kg and green wood which is 10.4 MJ/kg).

[1] Pers Comm, Ken Holland, Steam Systems Australia

3. Sizing the cogeneration plant

3.1 Site heat vs power load

A cogeneration plant can be designed to meet the total heat or electrical load, or part of either load. A key issue with whether or not the heat and electrical load coincide, as this will determine if thermal storage is required. Cogeneration is most efficient, and therefore most economic, when as much of the waste heat as possible is used at the same time as the electricity.

For a typical meat processing plant which includes rendering of all onsite produced mixed abattoir material, the heat load will be twice or more the electrical load. This means that if the cogeneration plant is sized to meet the heating load, there may be excess electricity available for export if a reciprocating engine is used.

The peak heating load will only occur for a few hours each day and will coincide with the startup of the rendering plant first thing in the morning (assuming that the rendering plant does not operate overnight), when steam is required for both hot water production in meat processing areas and bringing rendering equipment up to full temperature. The extent to which the peak heat consumption relates to the average will depend in part on the design of the rendering plant, with low temperature continuous rendering using less thermal energy than batch cooking (where there is a certain amount of cooling and reheating of equipment between batches).

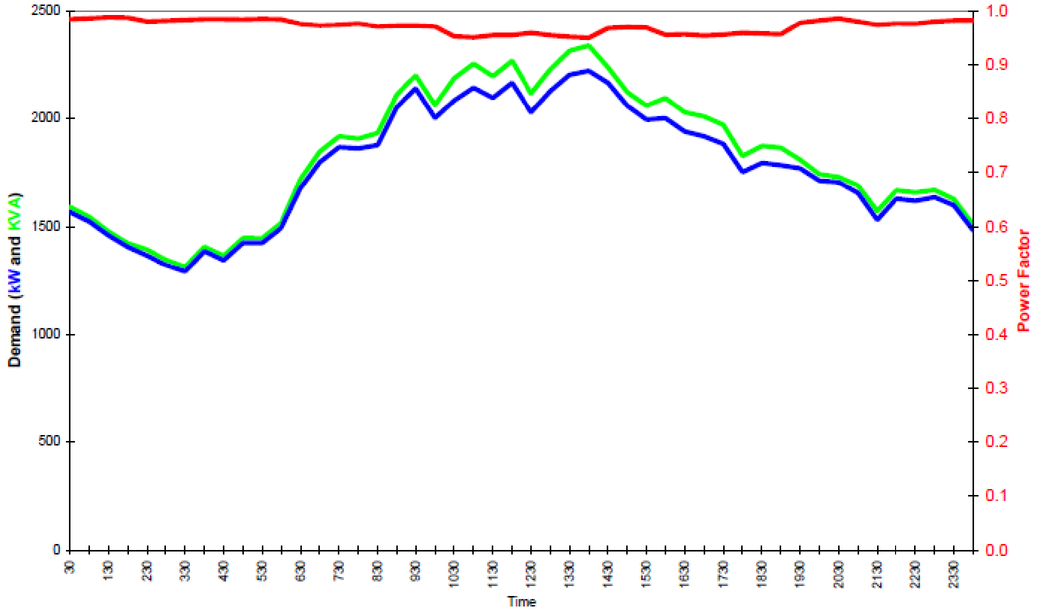
The peak electrical load tends to occur in the early to mid afternoon, the exact timing depends on plant design and operation issues (such as when shifts start and finish, and chiller management practices).

Cogeneration plants can be designed to provide all the thermal requirements, but, depending on the peak to average thermal demand, this may result in installed plant not being fully utilised for most of the time. This is not generally cost effective. The optimum plant design is often therefore not for the peak thermal or electrical requirement, but is a question of working out the design that optimises the economic return.

If a cogeneration plant for a meat processing plant with rendering is designed to meet the average electrical load, then additional thermal energy will need to be provided for steam production.

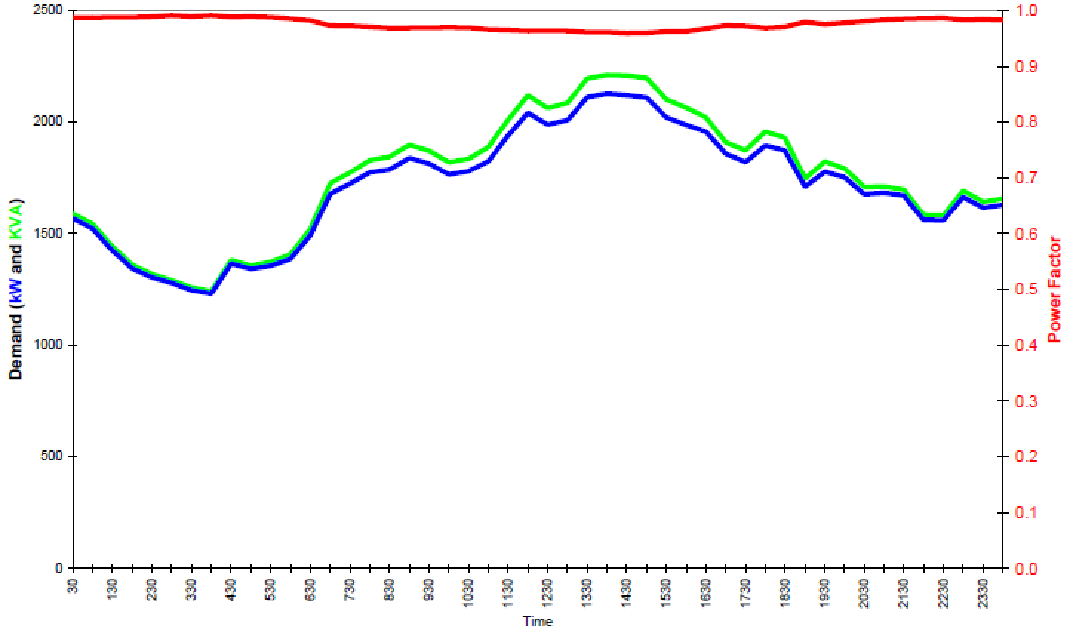
The **electricity load profile** for a single shift plant with rendering in Figure 1 indicates lower consumption overnight, when only the refrigeration system is running, down to the lowest value at about 3am. The consumption then climbs, with the peak occurring in the early afternoon. The peak value is almost twice the lowest overnight value. Refrigeration accounts for about 70% of total electricity use, with motors about 20%, air compression about 8% and lighting about 2-3% (MLA, 2002). Refrigeration loads are impacted primarily by product loads, but also by climatic conditions, such as ambient temperatures and humidity. A recent MLA report (MLA, 2009) found that as little as 20% of the electrical load could be directly attributed to the product load in some plants.

Figure 1: Daily electricity load profile, red meat processing plant, single shift, summer



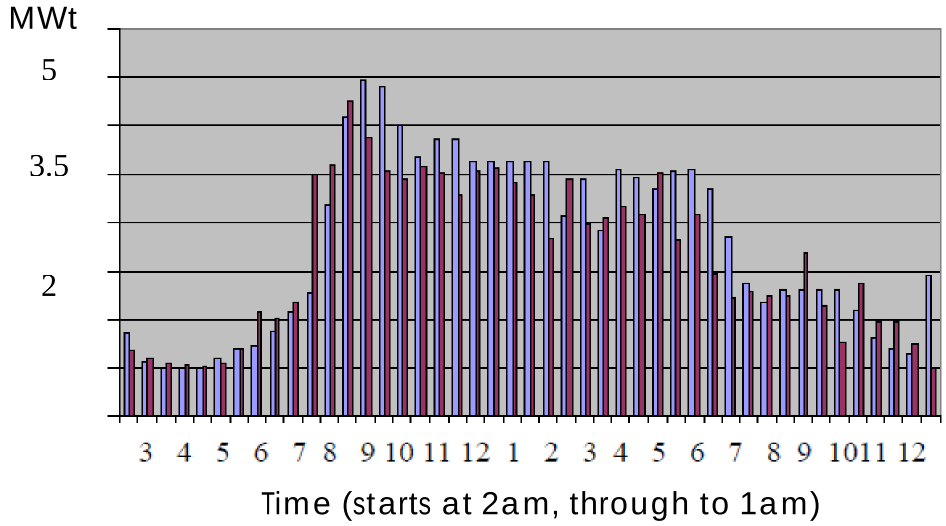
The **winter electricity load profile** is basically the same as the summer profile, but the afternoon peak is lower, due to cooler ambient temperatures and humidity reducing the load on the refrigeration system.

Figure 2: Daily electricity load profile, red meat processing plant, single shift, winter



Steam flowrates are the major indicator of thermal energy use in the plant. In plants that have rendering, there is significant heat recovery from the rendering process for hot water production, so that once rendering is fully operational, steam consumption tends to reduce slightly from an early morning peak at about 6-7am. Therefore, for most plants with rendering, hot water cogeneration plants are unlikely to be economic, but rather steam is required to supply the rendering plant. The heat recovered from rendering is often not measured but is inferred from the drop in steam use once rendering heat recovery comes online.

Figure 3: Steam flowrates, red meat processing plant, single shift, Thursday (blue) and Friday (red)

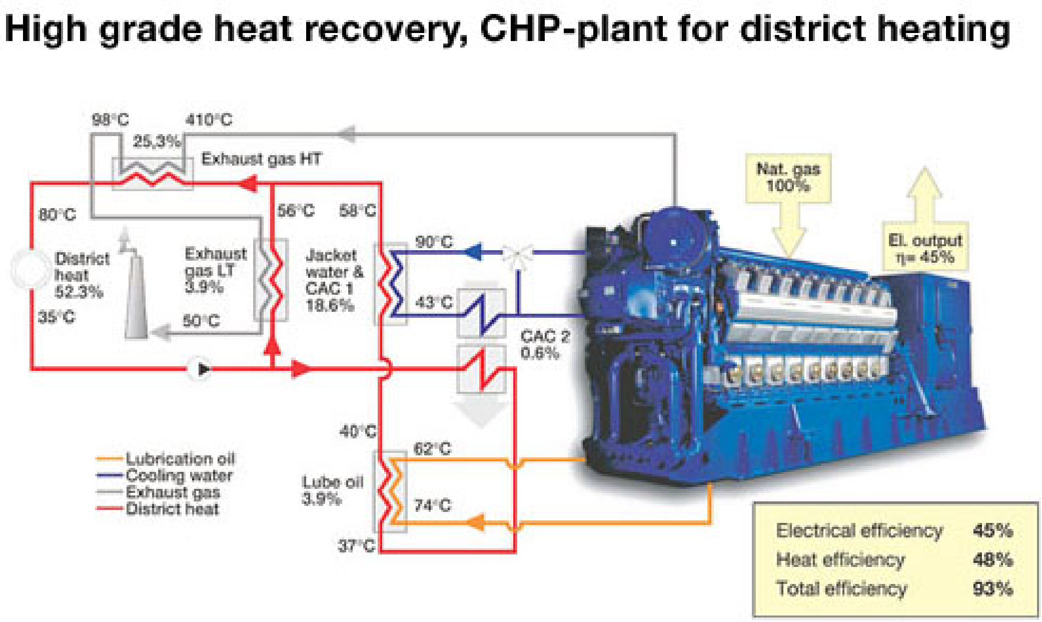


The difference between the peak electrical and thermal loads (2.5MWe vs 4.9MWt) clearly indicates that **if the cogeneration plant were sized to meet the thermal load, there could be excess electricity available for export to the grid, depending on the type of prime mover selected.**

3.2 Hot water cogeneration plant, no power export

The simplest form of cogeneration plant is a reciprocating engine that produces hot water from the recovered heat. Depending on the temperature of hot water required, it may not require a HRSG, but may just require heat exchangers. The hot water can then be used for the process heating requirement, such as sterilisation or space heating. The overall efficiency of hot water plants using reciprocating engines can be over 90% as indicated in Figure 4. It is likely that this sort of plant would only be **suitable for meat processing plants which do not have rendering**.

Figure 4: Hot water cogeneration plant



Source: Wartsila website www.wartsila.com note district heat = hot water

An example of this from the meat industry is the Midfield Cogeneration plant at Warrnambool. As the site does not have rendering, the cogeneration plant is effectively used as a preheater for the hot water system.

Table 3: Case Study – meat processing plant with hot water cogeneration, no power export

MIDFIELD COGENERATION PLANT, WARRNAMBOOL, VICTORIA

Key plant details

- Midfield plant processes beef, lamb, veal and mutton
- 2 small stock and 2 large stock floors, single shift
- Two boning rooms, each operate on double shift
- 2006 production - 72,000 t HSCW
- 2007 production – 47,766 t HSCW
- No onsite rendering

Cogeneration development details:

- Investigation commenced 2004, installed March 2009
- Build Own Operate by SDA Engineering
- Plant purchases electrical and thermal energy from SDA
- Designed for unmanned operation

Cogeneration construction details:

- 2 skid mounted units, equipment factory tested prior to delivery
- Onsite installation took 3 weeks

Cogeneration plant details:

- **Prime mover**: 1.5MW MWM reciprocating gas engine
- **Fuel**: natural gas
- **Sizing**: 2/3rd site maximum demand (ie sub export), 70-80% of overall electricity consumption
- **Heat recovery**: 1.732 MW in plate heat exchanger for lube oil and jacket water cooling system, shell and tube heat exchanger for exhaust gases, used to preheat boiler feedwater to 75-80°C after geothermal bore (40°C input)
- **Heat use**: 82 °C sterilisation circuit in plant
- **Greenhouse emissions:** reduced by 10,000 t $CO_{2\text{-}e}$
- **Electricity security:** provides stand-by power supply during electricity grid outages

Cogeneration operation & maintenance details:

- Remotely monitored by SDA and MWM
- Operates 5am Monday to 5am Saturday
- Designed for automatic oil top up
- Linked to site SCADA system
- Regular preventative maintenance scheduled for weekends
- Local company does minor maintenance, major overhauls arranged with MWM

Cogeneration performance details:

- Greater than 98.4% availability
- Electrical efficiency above 42%
- Overall energy efficiency is 89%

Cogeneration financial details:

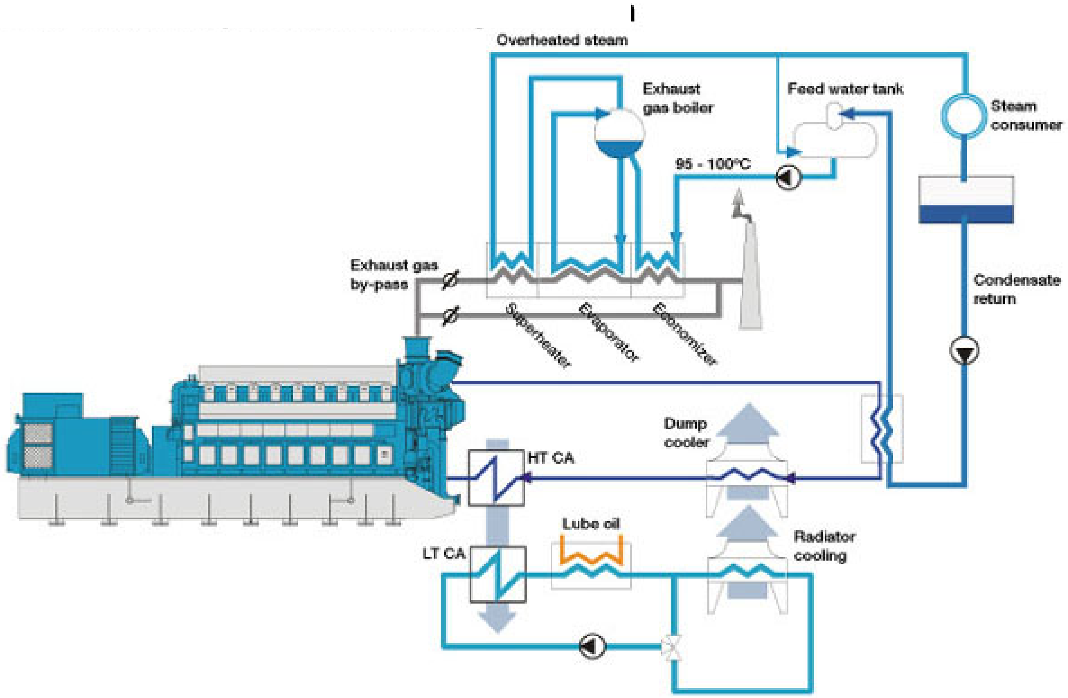
- Funding from Sustainability Victoria for feasibility study and upgrades to onsite SCADA monitoring system
- $900K grant from Rural and Regional Victoria for project

Western Water has updated its Melton recycled water plant west of Melbourne to use power generated by cogeneration from a microturbine powered by biogas from the wastewater anaerobic digester. This gas is treated, compressed and then combusted in a Capstone 200 kilowatt microturbine to produce about 1.7 gigawatt hours of electricity a year. A heat exchanger provides approximately 60 per cent of the plant's energy needs in the form of hot water.

3.3 Steam cogeneration plant, no power export

Steam cogeneration plants are the most usual type of plant, and the exact setup depends on the pressure of the steam required. If only low pressure steam is required, then a HRSG or exhaust gas boiler will suffice, as indicated in Figure 5. The overall efficiency of hot water plants using reciprocating engines is about 65%. These sorts of cogeneration plants would be **suitable for plants that have onsite rendering**.

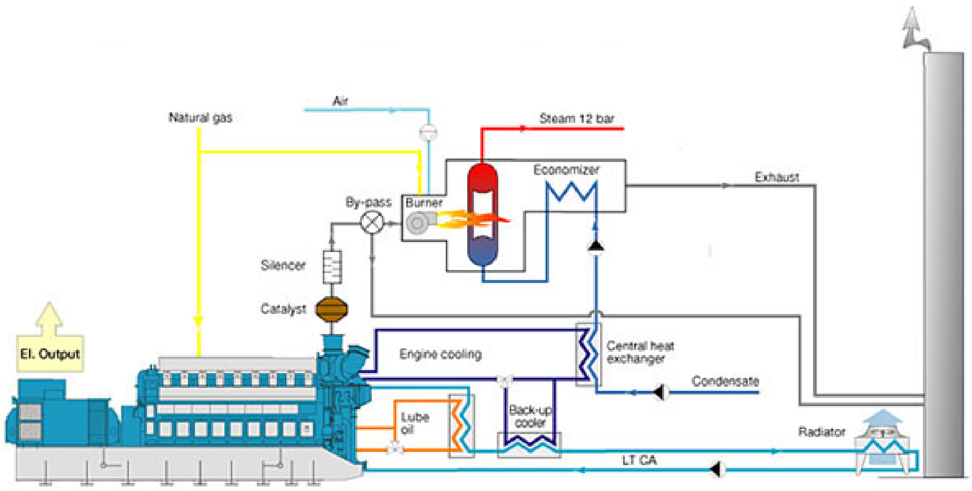
Figure 5: Reciprocating Engine Cogeneration with low pressure steam generation



Source: Wartsila website www.wartsila.com

If higher pressure (12 bar or 1,200 kPa or above) steam is required from a reciprocating engine cogeneration scheme, then auxiliary firing may be required, as indicated in Figure 6. It is unlikely that most meat processing plants require steam of this pressure, as mostly the steam pressure requirement is 800-1000kPa (8-10 bar).

Figure 6: Higher pressure steam generation with supplementary firing



Source: Wartsila website www.wartsila.com

The Big River Timber plant uses solid waste from its process in a boiler to generate steam and then runs the steam through a steam engine to generate electricity. This is the sort of system that could be used at meat processing sites that have biomass available and a high pressure boiler, such as Wingham Beef Exports.

Table 4: Case Study – timber processing plant with steam engine, with no power export

BIG RIVER TIMBERS COGENERATION PLANT, GRAFTON, NSW	
Key plant details • Factory produces rotary veneers, plywood and other structural panels • Produces 20,000m^3 plywood annually, which is 87% of production **Cogeneration development details:** • In 2000, plant needed a new boiler, upgraded to higher pressure boiler • 2004 – electricity price increase + Forestry Industry Structural Adjustment Package funding of $360K (20% of project costs) • Use mill waste and wood chip as fuel, reducing onsite stockpiles • Fully commissioned in Feb 2007, fully operational by April	**Cogeneration plant details:** • **Prime mover**: 500kW Spilling steam engine • **Fuel**: wood waste • **Sizing**: meets 40-50% of site electricity needs and all heat needs • **Steam boiler:** produces steam at 3,800kPa, directed to steam engine, leaves at 1,500kPa then used in factory • **Greenhouse emissions:** reduced by 228 tCO_{2-e} • **Electricity security:** allows plant to stay on line during grid outages **Cogeneration performance details:** • Economics – about 6 year payback period • Electricity prices have since risen 40% or more
Cogeneration financial details: • $1.84million for plant or $3.6K per kW (due mostly to small size of plant) 'A Pidcock Family Enterprise'	**Cogeneration operation & maintenance details:** • Maintained and operated by plant personnel • Operated 24 hours per day, 5 days per week with occasional Saturday shift • Initial problem with water carryover from boiler to steam engine due to unlagged pipes and insufficiently sized knock out drum on engine feed line, now rectified

3.4 Cogeneration plant with power export

A cogeneration plant could be designed to produce steam, hot water or both, depending on site requirements. For a purely technical and energy efficiency perspective, if a cogeneration plant were designed to match the heat load of a meat processing plant, then it could generally have excess power to export to the grid, depending on the type of prime mover selected. The issue then becomes the economics, and the price obtained for power exports can be critical to the overall financial payback. If the price is not high enough, it may be more economic to downsize the overall cogeneration plant and size it for sub export electricity production levels.

Although it has now shut down due to a site rationalisation by Don KRC, the Toowoomba Cogeneration project is an interesting example of a cogeneration project sized to meet the meat processing plant heating requirement, meaning that excess electricity is available for export to the grid. **This plant is now for sale.** Queensland has a mandatory target for gas-fired electricity generation to increase from 13 per cent to 15 per cent in 2010, with is an option to increase the target further to 18 per cent by 2020. Interestingly, the site where the operations moved to, Castlemaine in Victoria, in currently investigating the installation of a 4-6MW cogeneration unit, as part of the results from the CSIRO Maine's Power Project.

Table 5: Case Study – meat processing plant with steam cogeneration with power export

KR CASTLEMAINE COGENERATION PLANT, TOOWOOMBA, QUEENSLAND – FOR SALE	
Key plant details • KR Castlemaine plant was a pork processing and smallgoods manufacturing plant, bought by George Weston foods in April 2008, closed November 2009. Smallgoods production relocated to Castlemaine in Victoria, pork processing plant closed in early 2010 **Cogeneration development details:** • Investigation commenced in January 2005, installation contract signed in December 2005, fully operational October 2006 • Designed, constructed, owned and operated by DDC Energy Services, 15 year agreement • Worked with Ergon Energy • Excess electricity exported to grid • Up until cogeneration plant closure, electrical output of plant was 100 GWh • Plant now remains in service as a peaking plant for electricity only supply	**Cogeneration plant details:** • **Prime mover**: 3 x 1.5MW MTU gas engines • **Fuel**: natural gas • **Sizing**: all site electricity and heat requirements, 2.6MW used onsite, 1.9MW exported to grid every hour • **Heat recovery**: standby boiler and 3 waste heat steam boilers produced 1.5MW of steam per hour at 800 kPa (8bar) from engine exhaust, heat from engine jacket cooling system used to produce 2.4MW of hot water per hour • **Greenhouse emissions:** reduced by 12,000 t CO_{2-e} • **Electricity security:** allows plant to stay on line during grid outages, which included one week in 2008 when mains underground feeder to the plant had failed **Cogeneration performance details:** • Availability was better than the state grid • Electrical efficiency about 41% • Overall energy efficiency was 78-79%
Cogeneration construction details: • Integrated into existing plant, on skid mounted enclosures mounted on flat pad 1500m^2 • Onsite installation took 10 months • Engines housed within sound-proof stainless steel enclosures • Started operating October 2006 **Cogeneration financial details:** • $6million for plant or $1.3K per kW	**Cogeneration operation & maintenance details:** • Remotely monitored by DDCES, including monitoring national electricity market prices • Operated 24 hours per day, 7 days per week, 52 weeks of the year from electrical point of view, abattoir and smallgoods operated 5 days • Scheduled maintenance included oil changeovers, timing varied according to plant requirements • Linked to site SCADA system • DDCES managed local support for maintenance, major overhauls arranged with MTU

The Coopers Case Study provides an example of a company that was looking at expanding its existing onsite operations, and found that it would need to augment the electricity supply to the site and its boilers. When cogeneration was investigated, it was found to be more cost effective than augmenting the existing electricity supply to the site.

Table 6: Case Study – food processing plant with steam trigeneration with power export

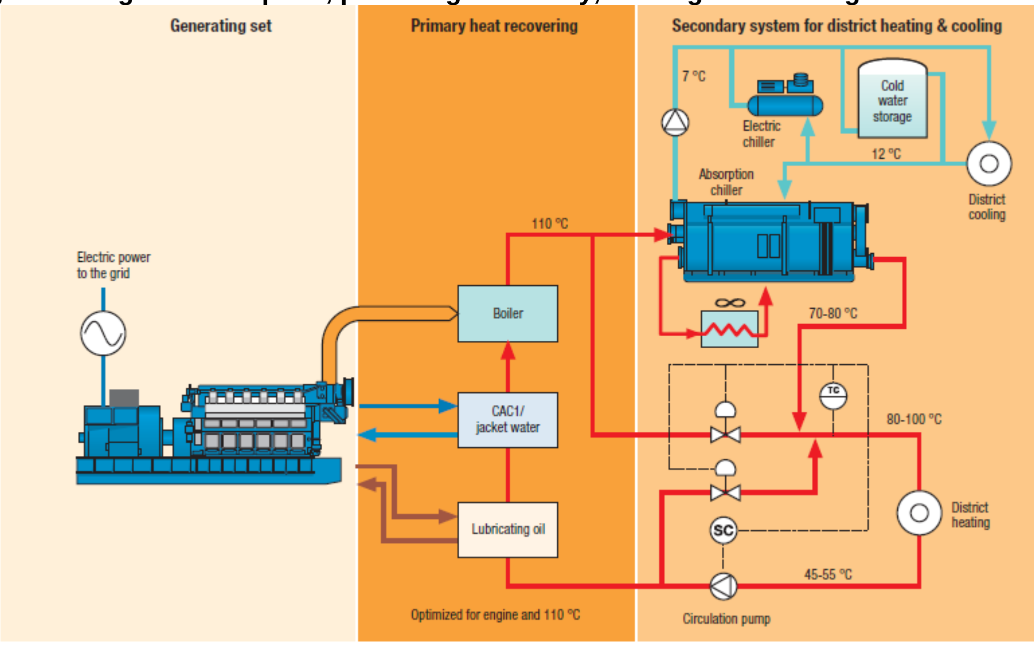
COOPERS TRIGENERATION PLANT, REGENCY PARK, ADELAIDE	
Key plant details • Coopers brewery produces 35 million litres of beer and 8,000 tonnes of extracts • Largest supplier of home brew extracts in the world • Facility operates 24 hours a day, five days a week, 50 weeks a year **Cogeneration development details:** • Investigation commenced January 2000, installed during 2002, fully operational January 2003 • Designed and constructed by SDA Engineering • 20 year agreement with AGL, who own and maintain the facility and sell electricity and steam to the site • Excess electricity exported to grid 	**Cogeneration plant details:** • **Prime mover**: 4.4MW Solar Centaur gas turbine • **Fuel**: natural gas • **Sizing**: all site electricity and heat requirements, 1.3MW used onsite for 6000 hours, rest exported to grid. It can also be used for power peak shaving during weekend, subject to electricity market price • **Heat recovery**: waste heat recovery steam generator produces steam at 1000 kPa (10 bar), up to 21 t/hour (or 14MW heat per hour, about 10 times electrical demand) with supplementary firing in the exhaust duct, or 10.4 t/hour or 7MW steam without duct firing. Surplus steam is used to produce chilled water for Coopers refrigeration plant via absorption chiller. • **Greenhouse emissions:** reduced by 15,000 t CO_{2-e} • **Electricity security:** allows plant to stay on line during grid outages **Cogeneration performance details:** • Availability of 99% • Electrical efficiency about 30-32% • Overall energy efficiency is 85-88%
Cogeneration construction details: • Integrated into existing plant, was constructed onsite • Onsite installation took 9 months **Cogeneration financial details:** • Existing gas-fired boilers were dated and did not have required capacity for additional growth • Electricity supply security critical for sensitive brewing operations • Looked for long term agreement to control energy costs • Now have full redundancy for steam and power	**Cogeneration operation & maintenance details:** • Can be remotely monitored • Operates Monday to Saturday • Scheduled service once every 4,000 hours (ie twice per year) • Linked to site SCADA system, fully unmanned and automated, monitored by Coopers • Regular preventative maintenance scheduled for weekends to minimise production disruptions • AGL does minor maintenance, Solar are involved in major overhauls

3.5 Trigeneration plant

Trigeneration produces electricity (or motive power), heating and cooling. Heating may be steam or hot water and cooling is usually chilled water produced from an absorption refrigeration system. They are relatively common in building applications such as office buildings, airports, hotels, shopping centres, universities, hospitals and some process industries (those that require chilling and heating), data centres and manufacturing that requires climate control (such as electronics). The prime mover can be a reciprocating engine or turbine, and the absorption chiller can be driven by steam, hot water or directly from the prime mover exhaust.

Trigeneration is used in applications where security of power supply is critical, such as hospitals and electronics manufacturing. After the failure of the electricity supply grid in California a few years back, service based industries, such as hotels, have been installing trigeneration systems using microturbines. At the moment, most meat processing plants use ammonia refrigeration system, with only a few using glycol systems in areas such as the boning room for climate control, so using chilled water would require substantial piping modifications in most plants. Figure 7 shows a scheme using steam to drive the absorption chiller, but the steam could be used for process heating at it can be generated at 6-8 bar (600-800kPa) and the chiller driven by hot water instead.

Figure 7: Trigeneration plant, providing electricity, heating and cooling



Source: Wartsila website, www.wartsila.com

A trigeneration plant was recently installed at the Tooheys site in Lidcombe, NSW. One of the key issues at this site was that of power security, as various stages in the brewing process are very sensitive to any electricity interruption.

Table 7: Case Study – food processing plant with steam trigeneration, no power export

TOOHEYS TRIGENERATION PLANT, LIDCOMBE, NEW SOUTH WALES

Key plant details

- site has been in operation since 1960s, initially a packaging facility. Brewing commenced at the site in 1978.
- brewery has undergone several small scale upgrades during this time and a major plant upgrade in 2007
- production output to 3.3 million hl per annum
- plants operates 24 hours a day, 7 days a week

Cogeneration development details:

- June 2006 approval of upgrade at Tooheys Brewery, included installation of two new natural gas boilers and decommissioning of the existing, 30 year old, natural gas boilers
- Sep2009 – proposal to install cogeneration system submitted to government, fully commissioned July 2010
- Designed and constructed by SDA Engineering
- Owned by Tooheys
- Designed for unmanned operation

Cogeneration construction details:

- Integrated into all 3 site utility systems, installed in existing boiler house
- Onsite installation took 3 staff 18 days

Cogeneration financial details:

- Total project cost $4.5M ($2.25K per kW)
- $2M grant from NSW State Government as part of Climate Change Fund

Cogeneration performance details:

- New plant, so availability not yet determined
- Electrical efficiency above 43%
- Overall energy efficiency is 70-75% (as steam generation from recip engine not as efficient as hot water)

Cogeneration plant details:

- **Prime mover**: 2MW MWM reciprocating gas engine
- **Fuel**: natural gas
- **Sizing**: 2MW covers baseload (never go below this), site maximum demand 7MW(ie sub export)
- **Heat recovery**: 750kWt of steam (1t/hour) generated from the exhaust discharge via an exhaust gas heat exchanger at 900 kPa and 750kWr of chilled water generated from the engine cooling system via absorption chiller to be supplied to the existing cooling circuit within the brewery at 6-7°C (ie provides most of the cooling load), 750 kW absorption chiller from Broad
- **Heat use**: steam into plant steam system, chilled water into plant chilled water system
- **Greenhouse emissions:** reduced by at least 9,500 $tCO_{2\text{-}e}$
- **Electricity security:** provides stand-by power supply during electricity grid outages

Cogeneration operation & maintenance details:

- Remotely monitored by SDA and Tooheys
- Operates 24 hours a day, 7 days a week
- Designed for automatic oil top up
- Linked to site SCADA system
- SDA does all maintenance

LION NATHAN

Tooheys is part of the Lion Nathan group

The Crown Casino in Melbourne is an example of an application where maintaining electricity supply is critical, due to legal issues associated with the gaming machines. The original 5.5MW plant was installed in 1999, and a new 0.9MW plant was installed at a separate location in the Crown Complex in 2002, and the site is looking at increasing the size of the original plant by 6.6MW to 12.2 MW.

Table 8: Case Study – building with trigeneration, no power export

CROWN CASINO TRIGENERATION PLANT, MELBOURNE, VICTORIA	
Key plant details • 39 storey, six star hotel and casino complex built in 1996, located in centre of Melbourne city **Cogeneration development details:** • 1994 – 12 month cogeneration feasibility study by Lincolne Scott consultants • Designed by Energy Power Systems • Original unit commissioned 1997, operated in standby mode until 1999 • Owned by Crown Limited • Crown Metropol Hotel – new 2 x 0.45MW cogen • Ongoing support from Energy Power Systems • Looking at adding 6.6MW to the original units, to make it 12.2MW **Cogeneration performance details:** • Overall energy efficiency is 77% **Cogeneration construction details:** • Integrated into onsite system, was included in building design	**Cogeneration plant details:** • **Prime mover**: 6 x 0.97MW + 2 x 0.45MW Caterpillar reciprocating gas engine (6.4MW total) • **Fuel**: natural gas • **Sizing**:30% of electricity needs • **Heat recovery (6 original units)**: waste heat from engines used in absorption chiller and for domestic hot water and space heating at 105 – 110 °C • **Heat recovery (2 new units)**: produces hot water via hot water heat recovery system for Crown Metropol Hotel, preheats water for site boilers • **Heat use**: hot and chilled water production • **Greenhouse emissions:** reduced by 25,000tCO_{2-e} per annum • **Electricity security:** provides stand-by power supply during electricity grid outages • **Heat supply security:** cogen plant backup up by standby boilers **Cogeneration operation & maintenance details:** • Original unit - remotely monitored by Crown, operates 7am until 11pm during week days • New unit – designed with auto start and auto parallel • Linked to site SCADA system **Cogeneration financial details:** • Original project cost $4M ($2.25K per kW), saved over $500K per year, internal rate of return was 19%

4. Economic overview

4.1 Capital costs

The capital costs for a fully installed and commissioned natural gas cogeneration unit is likely to cost between **$1,500 and $2,200 per kilowatt**[2] for cogeneration, possibly even higher for smaller units (less than 800kW more likely to be $2,200 or above[3]) and trigeneration costs with absorption chillers tend to be higher again ($2,500 per kilowatt or more).

The actual cost will vary depending on:

- Size – generally, unit costs reduce with size
- Whether prime mover is reciprocating engine or gas turbine (gas turbines tend to be more expensive at smaller sizes, but produce higher grade heat)
- For solid fuel fired system, fuel handling and delivery systems
- Civil engineering works required
- Water treatment costs
- Connection costs to site, such as steam and water piping
- Electrical interconnection and safety works at the plant, such as switch gear
- Foreign exchange rate (as prime movers are mostly sourced from overseas)
- For power export, connection charge to export to the local distribution network, which will depend on existing local issues such as voltage control, incident stability, protection issues and power quality
- For power export, any demand side incentive schemes available (capital offset)

For bioenergy systems, such as a wood waste fired boiler feeding a steam engine or turbine, the capital costs are generally higher. For example, in 2008 the capital cost for new entrant bioenergy plants was **$2.65K per kilowatt** (Clean Energy Australia 2009 Report, Clean Energy Council). This is offset by lower operating costs for fuel. For the Big River Timbers Cogeneration project, which involves a biomass fired boiler and steam engine cogeneration system, the capital cost was closer to **$3.6K per kilowatt**.

The AJBush Beaudesert biogas capture and power generation project uses generating sets from China, where biogas capture projects are widespread. This plant was cheaper than American or European equivalents, and the idea is that the engines can be replaced when they wear out rather than undergoing a major overhaul. Modifications were required to the equipment to ensure that it met Australian standards for electrical and gas safety, and as labour is much cheaper in China it was not originally designed for automated operation with remote monitoring, which is a feature of many of the American and European plants.

4.2 Operating & maintenance costs

For natural gas cogeneration plants, the main operating cost is the natural gas supply. A natural gas price of $6/GJ equates to about $60/MWh or 6c per kWh (assuming about a 36% electrical efficiency), without allocating any of the costs to the heat recovery.

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[2] $1,500 to $2,000 per KW from July 2009 figure from CSIRO report on Maine's Power Project, $1,750 to $2,200 from Leon Daych, SDA Engineering, $1.8 - $2M per MW installed from Resource Smart Victoria

[3] Personal communication, Leon Daych, SDA Engineering

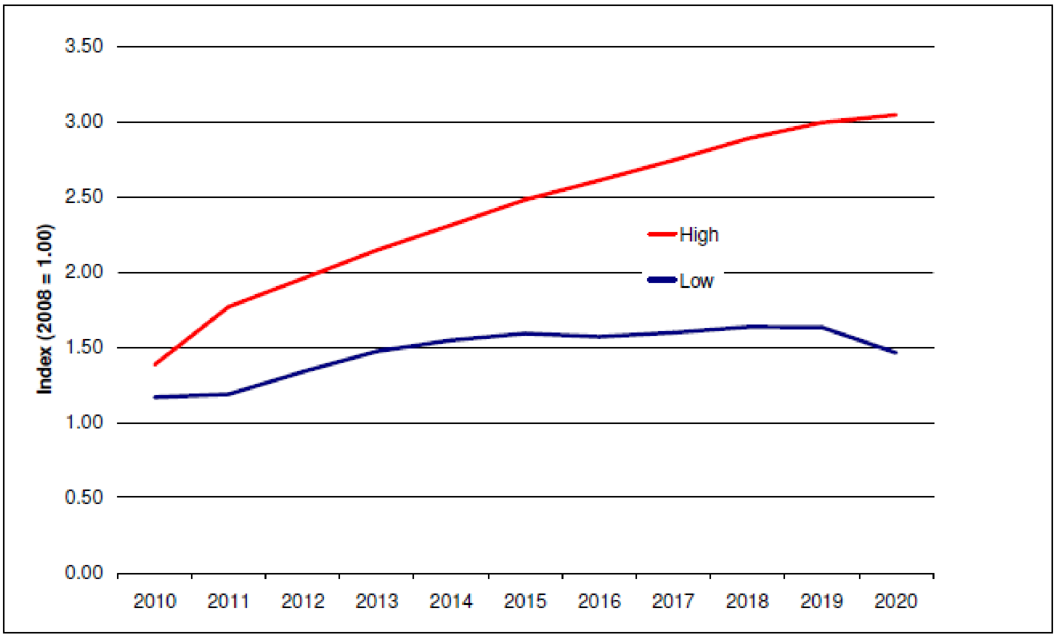
The major operations and maintenance costs vary depending on what the cogeneration system is comprised of, but can include

- Gas engine - major overhauls every 40,000 hours to 64,000 (depending on engine supplier) - $300-400K+ 3-4 weeks downtime - may be cheaper to replace engine, O&M& water ranging from $15 - 20 per MWh (lower for larger units
- Gas turbines – 4-6% of capital costs for small plants, less for plants above 50MW ie $10-20 per MWh, major overhauls every 12,000 – 50,000 hours
- Steam turbines – maintenance $5/MWh, major overhauls every 50,000+ hours, extra costs for fuel handling and boiler operation
- Microturbine – O&M costs $20+ /MWh, major overhaul every 5,000 – 40,000 hours

For natural gas fired cogeneration systems, the economics depend heavily on the differential between gas and electricity price, and how this varies over time. At the present point in time, natural gas is relatively expensive compared to electricity, which is why cogeneration projects often have a 5 year or more payback period. However, if future price increases see a higher rise in electricity price compared to natural gas, this would mean that the price signals for natural gas fired cogeneration improve.

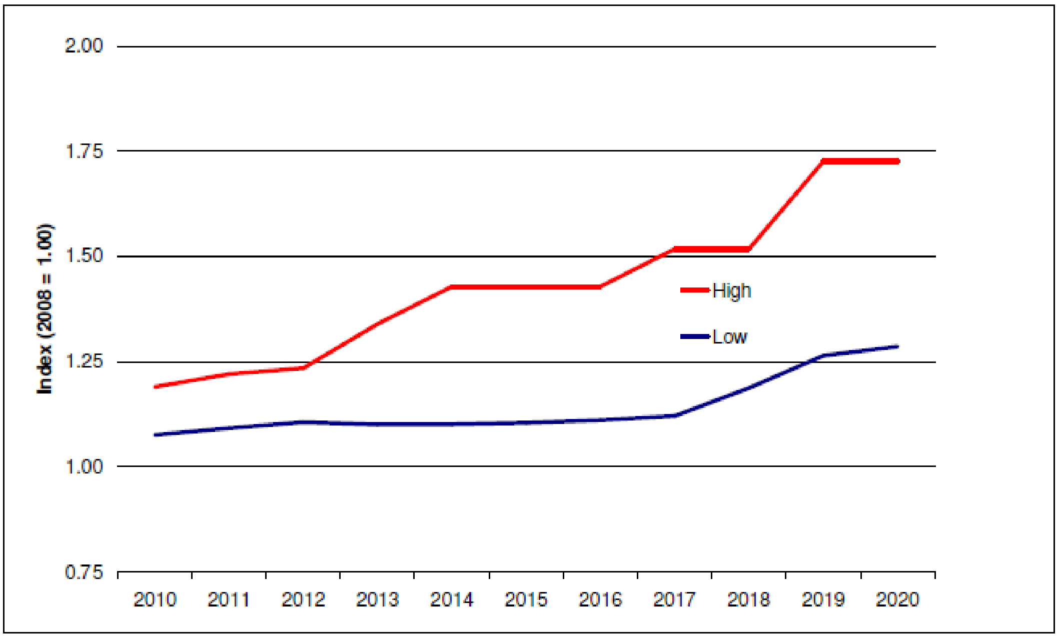
During their investigation of cogeneration at Castlemaine, CSIRO reviewed current price forecasts and produced the following graphs for electricity and natural gas. This included a price for carbon – the lower price being $20 per tonne, while the higher price indicates the most stringent carbon price scenario (a stringent emission reduction target to 2020, no cap on carbon permit prices (carbon prices reach around $130/tCO2e by 2020 in real terms) and ‘free auction’ of permits to some polluters which increases the cost of GHG abatement to the economy).

Figure 8: Retail electricity price projections, 2010-2020, National Electricity Market



Source: CSIRO Maine’s Power Project, Stage 2 Report: Options Development, October 2008

Figure 9: Retail natural gas price projections, 2010-2020



Source: CSIRO Maine's Power Project, Stage 2 Report: Options Development, October 2008

This clearly indicates that electricity will become proportionally more expensive than natural gas in the next 10 years. The worst case forecast for natural gas is that it will be about 1.75 times the current price by 2020, whereas the worst case forecast for electricity is that it will be more than 3 times the 2008 price by 2020.

Figure 10: Comparison of industrial electricity prices, OECD countries

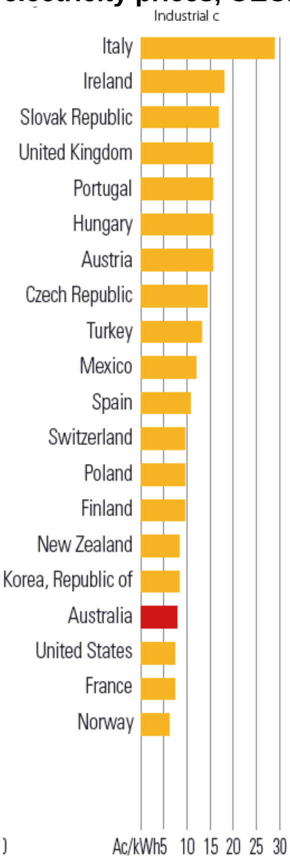
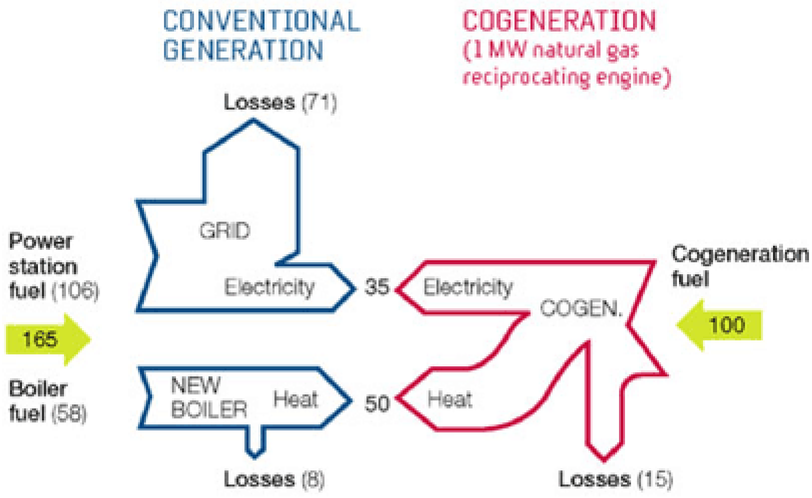


Figure 10provides an indication of Australia electricity prices compared to other industrialised countries. It indicates that Australian prices are currently on par with America, and only more expensive than Norway (which has substantial hydro power) and France (which has substantial nuclear power).

4.3 Greenhouse costs & savings

Cogeneration using **natural gas** produces electricity at about 0.5 t $CO_{2\text{-e}}$ per MWh[4] if all the energy use is attributed to the electricity and none to thermal energy production. This is about half the emissions intensity of electricity purchased from the grid as indicated in the following figure.

Figure 11: Conventional and Cogeneration Energy Efficiencies



Source: Resource Smart Business, Victoria (website)

At a typical meat processing site with rendering, about one third of the energy consumed is electricity and two thirds boiler heat. However, about two thirds of the cost and greenhouse emissions from the site will be due to electricity use, whereas about one third will be due to boiler fuel use. This is largely due to the higher emissions intensity of electricity in Australia, where most electricity comes from coal-fired generators. The exact emission factor for electricity varies by State, with Victorian emissions significantly higher than other states due to the use of brown coal for power generation (1.23 kg $CO_{2\text{-e}}$ per kWh for Victoria in 2009-2010, compared to 0.9 for NSW and ACT, 0.89 for Queensland and 0.72 for South Australia). Cogeneration is therefore an effective means of reducing the total site emissions.

However, if some of the energy consumption in the cogeneration plant is allocated to the thermal energy recovery, then the emissions intensity of the electricity ranges from 0.26 t $CO_{2\text{-e}}$ per MWh (for 77% overall thermal efficiency) to 0.29 t $CO_{2\text{-e}}$ per MWh (for 72% overall thermal efficiency). This is one third to one quarter the emissions intensity of electricity purchased from the grid.

Under the National Greenhouse and Energy Reporting Scheme (NGER), scope 1 emissions are direct emissions from the site, such as boiler fuel use, transport fuel use and emissions from wastewater treatment systems. Emissions from electricity consumption at the site are classified as scope 2, because they do not occur at the actual site, but rather at a remote generator. This would mean that cogeneration, which effectively substitutes grid purchased electricity for electricity generated onsite, would converts scope 2 emissions to scope 1 emissions, although the overall level of emissions would be lower.

The NGER Scheme collects the data for the Federal Government and will be the data capture system for any future emissions trading scheme. Under the proposed Carbon Pollution Reduction Scheme (CPRS), sites were required to participate if they had 25,000 tonnes of $CO_{2\text{-e}}$ per annum of direct (Scope 1) emissions. Although the CPRS was deferred, there is no doubt that in the foreseeable future, there will be a cost attribute to carbon in the Australian

[4] if all the energy consumption in the cogeneration unit is allocated to the electricity and none to the heat recovery, assuming an electrical efficiency of about 36%

economy. On 15th September 2010, the Chief Executive of BHP Billiton, the world's largest mining company and Australia's largest company, urged the Federal government to manage environmental challenges by establishing a clear price signal on carbon as it reviews its emissions trading scheme (ETS). During October 201 the Prime Minister, Julia Gillard, reiterated the Federal Governments commitment to "three big things" – making more use of renewable energy, putting a price on carbon and becoming more energy efficient.

The key issue to understand in the NGER and CPRS debate is that of **operational control**. Under NGER, a site or company only needs to report emissions from sources if it has operational control of them. Operational control is defined as "if the company has the authority to introduce and implement any or all of the operating, health and safety and environmental policies for the facility".

Therefore, if the cogeneration project has been developed as a Build Own Operate or lease facility, where the site has an agreement to purchase the electricity and thermal energy from the cogeneration plant but the plant is operated and maintained by an external party, the host site would not meet the definition of operational control and so would not have to report emissions from the cogeneration unit along with it's other site emissions.

The 25,000 tonnes of carbon dioxide equivalent ($tCO_{2\text{-}e}$) per annum of direct (Scope 1) emissions at 0.51$tCO_{2\text{-}e}$/MWh equates to about 49,020 MWh. If we assume the plant operates the same as the Midfield cogeneration plant (5am Monday to 5am Saturday, 48 weeks per year), this equates to about an **8.5MWe** unit. If the cogeneration unit operated 24 hours per day, 365 days of the year, this would equate to a **5.6MWe** cogeneration unit.

At this size plant and assuming that it is producing steam, a **gas turbine** could be used, which has a heat to power ratio of about 1.7 to 1, meaning a **8.5MWe** unit would produce about **15MWt** of thermal energy, and a **5.6MWe** unit would produce about **10MWt** of thermal energy. If a **reciprocating engine** were used, the heat to power ratio of about 0.6 to 1 for steam production, meaning a **8.5MWe** unit would produce about **5MWt** of thermal energy, and a **5.6MWe** unit would produce about **3.4MWt** of thermal energy. It is expected that if the cogeneration unit were sized to match the plant heat load to maximise the overall scheme efficiency, then the 8.5MW unit could be approaching the maximum size of meat processing plant currently existing in Australia.

There will be cost increases for energy when a CPRS or equivalent scheme is introduced, and the key issue is how much of the cost increase is passed through from the electricity retailers to host sites. In their study of cogeneration at the George Weston Foods plant at Castlemaine in Victoria, CSIRO looked at the issue of cost pass through, based on a carbon price of $20 per tonne in 2010 increasing to around $36 per tonne in 2020. CSIRO looked at whether it would be more economic to install a plant that was sized under the 25,000 tonnes of $CO_{2\text{-}e}$ per annum of direct (Scope 1) emissions, and compared the economics to a plant sized to meet the site requirements. They analysed the difference between electricity retailers passing through from 0 to 100% of the costs of the CPRS.

As electricity purchased from the grid is much more emissions intensive than electricity generated from natural gas fired cogeneration, it was found that it was more economic to install the larger plant, by over $4M over a 10 year period (for the 6MW plant vs 4MW plant) as indicated in Table 9.

Table 9: CPRS costs over a 10 year period for a hypothetical cogeneration facility

	Site Emissions	Total Emissions	Cost (PT 0%)	Cost (PT 80%)	Cost (PT 100%)
3 Units	27 000	27 000	$8,350,000	$8,350,000	$8,350,000
3 Units at 90% load	24 300	32 201	$7,520,000	$9,475,000	$9,950,000
2 Units	20 250	40 265	$6,265,000	$11,220,000	$12,500,000

PT = pass-through

Source: Maine's Power Project, State 3 Report, Planning Implementation, Jun 2009, CSIRO

To comply with the National Greenhouse and Energy Reporting Regulations 2008, subregulation 4.23 (a), the quantity of fuel consumed and allocated to the production of electricity should be estimated using the **efficiency** method as described in the Allocation of Emissions from a Combined Heat and Power (CHP) Plant Guide to calculation worksheets (September 2006) v1.0 (the cogeneration guide) issued by World Resource Institute and World Business Council for Sustainable Development. This can be downloaded from the internet at http://www.ghgprotocol.org/calculation-tools/all-tools. This is really only relevant if the electricity or heat is being exported.

If we analyse the Midfield case using the efficiency method, the electricity emission factor ranges from 0.22 – 0.28[5] t CO_{2-e} per MWe, which is less then half the 0.51 t CO_{2-e} /MWh used above (43% to be exact).

Cogeneration using **renewable fuels,** such as **biogas** or **biomass,** produces electricity at substantially lower greenhouse emission levels than natural gas fired cogeneration. The emission factor for natural gas is 51.33 kg CO_{2-e} per GJ, whereas biogas has an emission factor of 4.83 kg CO_{2-e} per GJ. If we assume that the efficiency of the **biogas** generator is about 31% (lower than natural gas engines) then the emissions intensity is about **0.056t CO_{2-e} per MWh** if all the emissions are allocated to the electricity, which is up to one twentieth the emissions intensity of electricity from the grid. If we assume that the same rule of thumb applies to the allocate of emissions to heat and electricity as for the Midfield case, then the end electricity emissions factor would be **0.02 – 0.03 tCO_{2-e} per MWh**, which is 50 times lower than the Victoria electricity factor and 38 times lower than the NSW/ ACT electricity factor.

Table 10: Comparing grid electricity to biogas cogeneration

State or Territory	Emission factor kg CO_{2-e} / kWh	Multiplier compared to biogas cogen
NSW + ACT	0.90	36
Victoria	1.23	50
Queensland	0.89	36
South Australia	0.72	29
South West Interconnect, WA	0.82	33
Tasmania	0.32	13
Northern Territory	0.68	27

This clearly shows that the biogas cogeneration projects with the greenhouse saving will be in Victoria, then NSW/ACT and Queensland are about the same.

A rough estimate of the amount of energy available from **biogas** for an average plant can be obtained by using Method 1 from the National Greenhouse and Energy Reporting Scheme.

$$t\ CO_{2-e} = \text{Production (t HSCW)} \times 13.7 \times 6.1 \times 0.4 \times 5.3 / 1000$$
$$= \text{Production (t HSCW)} \times 0.1771684$$

[5] Refer to Appendix for details of how numbers were derived

GJ methane	= Production (t HSCW) x 0.1771684 x 39.3 x 10^{-3} x 1000 / 0.755[6]
	= Production (t HSCW) x 0.439

This assumes that the COD of wastewater entering the ponds is 6,100 mg/L, that 40% of the COD is degraded anaerobically and that 13.7 kL of wastewater are generated for each tonne of hot standard carcase weight produced.

Alternatively, the equation for gigajoules from methane using actual wastewater data is:

GJ methane	= ML wastewater x change in COD across pond (mg/L) x 0.013

The change in COD refers to the change in COD across the anaerobic pond.

Biogas generation rates have been covered in a number of earlier Meat and Livestock reports, namely:

- "The Use of Abattoir Waste Heat for Absorption Refrigeration", Neil McPhail & Darren Rossington, CSIRO, March 2010-09-27 and
- "Renewable Energy and Energy Efficiency Options for the Australian Meat Processing Industry", Simon Franklin, Joshua Jordan, Phillipe McCracken, Julia McDonald and Joseph Gordon, IT Power (Australia) Pty Ltd, May 2010.

The CSIRO report found that it was more cost effective to use biogas in the existing boilers than using it in a direct fired absorption chiller and that using biogas in a direct fired absorption chiller was more economic than using it in trigeneration.

The CSIRO report quotes values of 0.15 – 0.3 m^3 methane produced per kg removed, which equates to:

GJ methane = ML wastewater x change in COD across pond (mg/L) x 0.00582
up to
=ML wastewater x change in COD across pond (mg/L) x 0.01164

These values are lower than the values provided above from the NGER calculation, and indicate that biogas capture from anaerobic ponds in the red meat industry in Australia is still in its infancy, in terms of some of the basic scientific information.

4.4 Simple Payback Period

Cogeneration normally has a payback period in the order of 5 – 10 years unless there is some other factor, such as needing to augment electricity supply to the site. An issue for the red meat industry is that it generally requires payback periods of 2 years or less. At the moment with the global financial crisis putting pressure on capital availability and a high Australian dollar compared to other currencies, the required payback period are likely to be shorter, more in the range of 1 year or less. **This means that funding equating to 50% or more of the installed capital costs would need to be found to bring the simple payback period back to within acceptable levels for the red meat industry**.

One quick way of determining whether cogeneration is worth investigating for natural gas systems is the "spark-ratio", which is the ratio of natural gas to electricity price. If the ratio is greater than 3:1, then cogeneration would be worth investigating further.

Gas cost = \$4/ GJ
Convert to c/kWh = \$4 x 0.36 = \$1.44 c/ kWh
Electricity cost = \$8c/kWh
Ratio (gas to electricity) = 8:1.4 or 6:1 → worth investigating further

[6] 1 t CH_4 = 21 t $CO_{2\text{-e}}$, methane density = 0.755 kg/m^3, methane energy content = 39.3 x 10^{-3} GJ/m^3

Another quick calculation is to just look at the electricity saving, and see what sort of payback period that produces. Assume a site selects a 4MW gas turbine cogeneration unit producing steam 6.6MW of steam (ie heat to power ratio of 1.65:1), with a unit cost of $2.2K per kW, that the site pays an average of $0.10 per kWh, electrical efficiency 31%, boiler efficiency 80%, gas cost is $5.50 per GJ, assume it runs 5am Monday to 5am Saturday (ie 5,760 hours per year) to cover the 5 day operation.

Total installed capital costs	4,000 x $2.2K = $8,800,000
Annual electricity saving	4,000kW x 5,760h x $0.10 = $2,304,000
Annual boiler fuel saving	[6.6 MW x 5,760h x 3.6 GJ/MWh X $5.50]/0.8 = $940,896
Generator operating costs	[4MW x 5,760h x 3.6 GJ/MWh x $5.50]/0.31 = $1,471,587
Net cash flow	$1,773,309 per year
Simple payback period	5 years

Note that this does not include non fuel costs, such as maintenance. Similarly, this does not allow for the fact that most of the electricity will be in the peak tariff period, so that the actual electricity price saving would be higher than the average.

A free software program which runs on a Windows system, designed in Australia, called the Cogeneration Ready Reckoner v3.1 (2002), is available online at http://www.ornl.gov/sci/engineering_science_technology/cooling_heating_power/oetd/der/sia.htm . This can be downloaded and enables a user to do a more detailed “first pass” technical and financial analysis to determine if cogeneration could be economic for their site. It is recommended that the user conduct more detailed economic and technical feasibility studies prior to committing to the project.

4.5 Government Support

Various state and Federal Government agencies have provided capital funding for cogeneration in the recent past as indicated in the following table.

Table 11: Cogeneration grants from Government

Agency	Project	Funding	Industry
NSW Energy Saving Fund	Sydney Olympic Park Aquatic Centre Cogeneration Plant	$300K	Recreation
NSW Energy Saving Fund	Co-generation at Willoughby Leisure Centre (pool)	$200K	Recreation
NSW Energy Saving Fund	Retail Shopping Centre Embedded Cogeneration program, Charlestown Square	$1.96M	Retail
NSW Energy Saving Fund	Biogas Cogeneration at the Kincumber Sewage Treatment Plant	$138K	Water treatment
NSW Forest Industry Structural Adjustment Package	Big River Timbers biomass cogeneration, using steam engine	$360K	Wood
NSW Renewable Energy Development Program	Cargill Australia Limited Wagga Wagga Biogas Project (will generate 1200 kW of electricity (3 phase, 415 V) and 500 kW equivalent of steam)	$2.9M	Meat
NSW Green Business Program	Mirvac Cogeneration System, Royal Newcastle Hospital Site	$320K	Residential
NSW Green Business Program	Tooheys 2MW Cogeneration Project	$2M	Food
NSW Green Business Program	Cogeneration Energy initiative for Westfield Sydney City	$2M	Retail
Business Victoria – Driving Low Emissions Industry Growth	Cogeneration plant at the Unilever Australasia factory in Tatura	$1.25M	Food
Business Victoria – Driving Low Emissions Industry Growth	Midfield Meats International in Warrnambool to install a 1.55 MW natural gas-fired cogeneration unit	$990K	Meat
Victorian Government	George Weston Foods, establishing a 4 MW cogeneration unit	$3M	Meat
Federal Renewable Energy Showcase Program	Rocky Point Sugar Mill (for construction)	$3M	Sugar
Renewable Energy Industry Program	Rocky Point Sugar Mill	$350K	Sugar

The US Department of Energy Industrial Technologies Program is aiming to assist US industry to reduce its energy intensity by 25% in ten years, and cogeneration has been identified as among the most promising energy efficient technologies available. Deployment of more cogeneration is a major focus of the DOE's industrial programs, and there are Regional Application Centers which provide assistance to sites in the form of funded feasibility studies, and assistance with hiring engineers for the detailed design.

5. Development options

5.1 Overall issues

There are a number of risk issues relating to any project such as cogeneration, including technical, construction, financial, market, operational and regulatory risk.

Depending on the type of development option selected, a plant can take all of the risk and potential returns, or very little.

The host site could organise the project themselves, from design through to construction, commissioning, operation and maintenance of the plant. This would be the **capital purchase** option, where the site accepts most or all of the risks and potential returns. This includes design and construct and build own operate and transfer type projects.

The other end of the spectrum is the meat processing plant acting as the host for the cogeneration plant, and another party designing, constructing, operating and maintaining the cogeneration plant. This is the **energy purchase** option, where the site purchases electricity and thermal energy. This includes build-own-operate, lease and energy performance contracts.

5.2 Design and construct (D&C)

This is typically used for most projects in the red meat industry – an external company designs and arranges for the construction of the project. After commissioning, the operation and maintenance of the plant is handed over to the host site, with certain warranties provided for key equipment items.

If the host site fails to maintain the plant according to the instructions provided by the D&C company, it may void the warranty on key equipment items.

If the site decides to design, construct, operate and maintain the cogeneration plant, then they are effectively taking on all these risks themselves. Meat processing plants are used to managing meat processing, but will not necessarily have the skills to manage a power generation plant. This was the model used by the biogas capture cogeneration plant at Burrangong Meat Processors at Young.

5.3 Build, Own and Operate (BOO), Build, Own Operate and Transfer (BOOT)

Under a Build Own and Operate (BOO) contract, an external party, such as an energy services company, would design, construct, commission, operate and maintain the plant. The meat processing plant purchases electricity, heating and cooling from the cogeneration plant owner, and the cogeneration plant owner must guarantee certain levels of utility quality (eg steam pressure and temperature), availability and reliability. This means that the meat processing plant does not outlay any capital upfront and most of the risk resides with the BOO company, who clearly has an incentive to ensure that the plant is operating reliably. BOO are similar to lease agreements in terms of the levels of risk that the site carries for the project life ie low level. This is the option selected by Midfield Meat for their cogeneration plant and the KR Don Toowoomba plant.

Under a Build Own and Operate Transfer (BOOT) contract, an external party, such as an energy services company, would design, construct, commission, operate and maintain the plant. After a certain period of time, such as 5 years, the ownership of the plant would transfer to the host site. From then onwards, the host site would be responsible for maintaining and operating the cogeneration plant. This enables the risk associated with startup and early operation of the plant to be borne by the external party, and that once it has proven its performance and all technical issues have been sorted, the risk is transferred to the host site. This was the option selected by Rockdale Beef for their 1MW cogeneration project.

5.4 Energy Performance Contracting (EPC)

Energy Performance Contracting involves an energy services company being hired to improve the energy efficiency of a site and this can include a cogeneration plant.

The energy services company guarantees the energy savings it will produce and they are paid for from the savings for the term of the contract. If the savings are not achieved according to the contract, the energy services company will not be paid. Once all the work is completed and the contract has ended, the ongoing savings accrue to the host site.

The energy services company acts as a project manager and manages all the third parties required to carry out the works, so that the site deals with only one party. EPCs are commonly used in the building and public sector such as hospitals and schools.

The Griffith Base Hospital Cogeneration plant was part of a total site EPC. It is unclear whether EPCs have ever been used in the red meat industry before.

5.5 Maintenance Contracts

Just as plants often have a contract with external parties to maintain major equipment items, such as their boilers, cooling towers and refrigeration system, so they could have a maintenance contract covering the cogeneration plant. This would usually be used where the host site has opted to own the plant themselves. In BOO and EPC type projects the maintenance and operating costs are factored into the sale price of electricity and thermal energy.

Issues that need to be included in maintenance include:

- Weekly availability of equipment for preventative maintenance
- Annual shutdown periods
- Access to equipment and site for contractors
- Penalties/ incentives for meeting performance targets

5.6 Skid mounted units

One feature of cogeneration plants is that, if host site requirements dictate it, they can be containerised and delivered onsite as complete units. This minimises the amount of onsite work required and therefore the construction and commissioning period required. All that is required onsite is that the modules are connected to the site utilities, such as gas supply, hot and chilled water systems and electrical systems. The unit can be factory tested prior to shipping, minimising the risk of commissioning delays onsite.

This was used for the Midfield cogeneration project, and as a result the onsite construction and commissioning of the cogeneration plant took only three weeks.

5.7 Energy Service Companies

Energy Service companies range from energy retailers (such as AGL, Origin, Energex) through to cogeneration equipment suppliers and small or medium sized engineering companies who do D&C, EPC, BOO and BOOT type projects.

One key issue to keep in mind is that the larger energy service companies will probably subcontract out the design, construction and commissioning of any cogeneration plant on a tender basis, so that the actual work will end up being done by the small or medium sized engineering companies. In this case, both companies will need to make money. It is therefore advisable to consider dealing directly with engineering companies who have already completed cogeneration projects.

5.8 Information required to assess cogeneration

The sort of information that would be required to undertake a detailed investigation of cogeneration would include:

- Current electrical information, such as daily, weekly, monthly load profiles and hourly consumption data for a 12 month period
- Current boiler fuel information, such as daily, weekly, monthly load profiles and hourly consumption data for a 12 month period
- Any planned changes to current consumption, such as upgrades
- Extent to which energy efficiency measures have been fully identified and implemented (normally cogeneration is considered after energy efficiency measures implemented)
- Details of the requirements of the thermal load ie steam, hot water, chilled water, temperatures and pressures required, out and return circuits
- Details of existing utility systems, such as site electrical system distribution diagram
- Plan drawing showing location of utilities and probable location of cogeneration plant
- Network study to determine how the cogeneration unit will impact on network performance, including where network business is in 5 year planning cycle, using an approved consultant
- Availability of fuel, including biogas or other renewable fuels

6. References

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CSIRO, Maine’s Power Project, Stage 3 Report: Planning Implementation, June 2009, available from http://masg.org.au/?page_id=140

Meat and Livestock Australia, “Eco-Efficiency Manual for Meat Processing”, August 2002

Meat and Livestock Australia, “Red meat Processing Industry Energy Efficiency Manual”, January 2009

National Greenhouse Account Factors, available from http://www.climatechange.gov.au/publications/greenhouse-acctg/national-greenhouse-factors.aspx

Oak Ridge National Laboratory, Guide to Combined Heat and Power Systems for Boiler Owners and Operators, C. B. Oland, Report Number ORNL/TM-2004/144, July 2004

Appendix 1 Midfield Cogeneration GHG Emissions allocation

Worst case – 47% thermal efficiency

Operating hours:
5am Monday to 5am Saturday = 120 hours per week
Plant operates 48 weeks per year
Total annual operating hours = 5,760 hours

Fuel efficiency
1.5MWe engine, 42% electrical efficiency
= 3.57MW fuel used per hour
= 12.86 GJ per hour

Greenhouse emissions = $\left[\frac{12.86 \text{ GJ/h} \times 5{,}760 \text{ h/yr} \times 51.33 \text{ kgCO}_{2\text{-e}}\text{/GJ}}{1000 \text{ kg/t}}\right]$
= 3,801.35 t $CO_{2\text{-e}}$/yr [*ghg emissions*]

Total electrical energy production = 1.5MW/ h x 5,760 h/ yr
= 8,640 MWe [*elect output]*

Total thermal energy production = 1.732MW/ h x 5,760 hours/yr
= 9,976 MWt [*steam output*]

Total energy production = 18,616 MW per yr

Allocation using efficiency method

Assumed efficiency of typical steam production = 47% [*thermal eff*]
Assumed efficiency of typical electricity production = 42% [*elect eff*]

Emission share to steam production = ghg emission x $\frac{\textbf{(steam output/ steam eff)}}{\textbf{((steam output/ steam eff)+(elect output/elect eff))}}$

= 3,801 x $\frac{\textbf{(9,976 / 0.47)}}{\textbf{((9,976 / 0.47) + (8,640/0.42))}}$

= 1,930 t $CO_{2\text{-e}}$

Emissions factor, steam = 1,930 / 9,976 = $\boxed{0.19 \text{ t CO}_{2\text{-e}} \text{ / MWt}}$

Emissions share to Electricity production = ghg emissions – emission share to steam production

= 3,801 – 1,930 = 1,870 t $CO_{2\text{-e}}$

Emissions factor, electricity =1,870 / 8,640 = $\boxed{0.22 \text{ tCO}_{2\text{-e}} \text{ /MWhe or } 0.22 \text{ kgCO}_{2\text{-e}} \text{ / kWhe}}$

Best case – 85% thermal efficiency

Operating hours:
5am Monday to 5am Saturday = 120 hours per week
Plant operates 48 weeks per year
Total annual operating hours = 5,760 hours

Fuel efficiency
1.5MWe engine, 42% electrical efficiency
= 3.57MW fuel used per hour
= 12.86 GJ per hour

Greenhouse emissions = $\dfrac{[12.86 \text{ GJ/h} \times 5{,}760 \text{ h/yr} \times 51.33 \text{ kgCO}_{2\text{-e}}/\text{GJ}]}{1001 \text{ kg/t}}$
= 3,801.35 $tCO_{2\text{-e}}$/yr [*ghg emissions*]

Total electrical energy production = 1.5MW/ h x 5,760 h/yr
= 8,640 MWe [*elect output]*

Total thermal energy production = 1.732MW/ h x 5,760 hours/yr
= 9,976 MWt [*steam output*]

Total energy production = 18,616 MW per yr

Allocation using efficiency method

Assumed efficiency of typical steam production = 85% [*thermal eff*]
Assumed efficiency of typical electricity production = 42% [*elect eff*]

Emission share to steam production = ghg emission x $\dfrac{\textbf{(steam output/ steam eff)}}{\textbf{((steam output/ steam eff)+(elect output/elect eff))}}$

$$= 3{,}801 \times \frac{(9{,}976 / 0.85)}{((9{,}976 / 0.85) + (8{,}640/0.42))}$$

= 1,381 $tCO_{2\text{-e}}$

Emissions factor, steam = 1,381 / 9,976 = $\boxed{0.14 \text{ t CO}_{2\text{-e}} / \text{MWt}}$

Emissions share to Electricity production = ghg emissions – emission share to steam production

= 3,801 – 1,381 = 2,420 $tCO_{2\text{-e}}$

Emissions factor, electricity =2,420 / 8,640 = $\boxed{0.28 \text{ tCO}_{2\text{-e}} /\text{MWhe or } 0.28 \text{ kgCO}_{2\text{-e}} / \text{kWhe}}$

Appendix 2 Directory of suppliers from this report

* please note that this is the list of suppliers found as part of this project, so if not an exhaustive list

Company name	Contact Details	Cogen/ *Trigen* Projects
Aquatec-Maxcon (agent for Capstone)	Head Office 119 Toongarra Road, Leichhardt QLD 4305 Australia Postal: P.O. Box 455, Ipswich QLD Australia 4305 Phone: 07 3813 7100 Fax : 07 3813 7199 E-mail: sales@aquatecmaxcon.com.au	**Western Water, Melton, Vic (Cogen), Queensland Emergency Operations Centre (QEOC), Kedron Park (cogen),** *Australian National Gallery, Canberra (trigen)*
Cogent Energy Blair Healy Managing Director Owned by Origin Energy	Suite 302, 91 Murphy Street, Richmond, VIC 3121 Phone: 03 9652 5025 Fax: 03 9425 9196 Suite 2, Level 9, 1 Chandos Street, St Leonards NSW 2065 Phone: 02 8345 5034 Fax: 02 9966 4800	*Blackmores Campus, Warriewood (trigen)*, **101 Miller St Sydney (cogen-cooling)**, *200 Victoria St Melbourne (trigen), 133 Castlereagh Street Sydney (trigen), Lowy Cancer Research Centre at the University of New South Wales (trigen)*
DDC Energy Services Gary Parkhill	Head Office: Queensland Mobile: 0409 890 593 Phone: 07 3260 5933 Fax: 07 3260 5002 Email: gary@synchrotechcontrols.com.au	**KR Castlemaine, Toowoomba(cogen),** *Southern Foods Group, Millicent, SA(trigen)*, **Toowoomba Base Hospital and Baillie Henderson Hospital (for Origin)(cogen),** *Townsville Hospital (for Origin) (trigen)*, *Redcliffe Hospital (for Origin) (trigen)*
Enerflex Australasia Holdings (agent for Waukesha)	82-86 James Street Northbridge, WA, 6003, Australia Phone: 08 6218 3300 Email: australasia@enerflex.com	**Couran Cove Resort (cogen), Launceston General Hospital (cogen)**
Energy Power Systems (a division of CAT)	HEAD OFFICE 47-51 Westpool Drive Hallam VIC 3803 AUSTRALIA Phone: 03 9703 4000 Fax: 03 9703 4004 Offices in QLD, NSW, SA, NT	
I Power Solutions	Offices in Brisbane, Mackay, Cairns, Sunshine Coast, Townsville, Perth, Newcastle, Victoria Email: For general sales enquiries sales@ipowersolutions.com.au	**Isis Central Sugar Mill (for Ergon) (cogen)**
Origin Energy	Head office: Level 45, Australia Square 264 - 278 George Street Sydney NSW 2000 Phone: 02 8345 5000 Fax: 02 9252 9244	**Worsley Cogeneration Plant (120MW cogen), BP Bulwer Island, QLD (32MW cogen), Osborne, SA (180 MW cogen), OneSteel Plant, SA (9.5MW cogen)**
SDA Engineering	Head office: 26 Anderson Street ,	**Midfield Meats (cogen)**, **Coopers Brewery, Adelaide**

Company name	Contact Details	**Cogen**/ *Trigen* Projects
Leon Daych, Director of Engineering	Thebarton, SA, 5031 Phone: 08 8238 9400 Fax: 08 8152 0722 Email: sda@sdaengineering.com.au	**(cogen, for AGL**), *Tooheys Brewery, Sydney (trigen))*, **Symex, Melbourne (cogen, for AGL)**

Appendix 3 Key characteristics for prime movers

Prime mover characteristic	Steam turbine	Gas turbine	Microturbine	Reciprocating engine: Compression ignition	Reciprocating engine: Spark ignition	Phosphoric acid fuel cell (PAFC)
Capacity, MW	0.05 to more than 250	0.5 to 250	0.03 to 0.35	0.03 to 4	0.05 to 5	Up to 0.2
Power-to-heat ratio	0.05 to 0.2	0.5 to 2	0.4 to 0.7	0.5 to 1	0.5 to 1	1
Fuels	Steam turbines do not burn fuel, but all types of fuels can be burned to produce steam (see Table 4.3)	Natural gas, biogas, propane, and distillate fuel oil	Natural gas, waste and sour gases, gasoline, kerosene, diesel fuel, and distillate fuel oil	Natural gas, diesel fuel, and residual oil	Natural gas, biogas, propane, landfill gas, and gasoline	Hydrogen, natural gas, propane, manufactured gas, and biogas
Installed cost, $/kW	200 to 1,000	400 to 1,800	1,300 to 2,500	900 to 1,500	900 to 1,500	2,800 to 5,500
Maintenance cost, $/kWh	up to 0.002	0.003 to 0.01	up to 0.018	0.005 to 0.015	0.007 to 0.02	0.007 to 0.02[b]
Overhaul period, h	More than 50,000	12,000 to 50,000	5,000 to 40,000	25,000 to 30,000	24,000 to 60,000	10,000 to 40,000
Start-up time	Hours	Minutes	Minutes	Seconds	Seconds	Hours
Total CHP efficiency (HHV)[c]	70% to 85%	70% to 75%	65% to 75%	70% to 80%	70% to 80%	65% to 80%
CHP electrical efficiency (HHV)[d]	20% to 40%	22% to 36%	18% to 29%	27% to 45%	22% to 40%	30% to 36%
Availability	Near 100%	90% to 98%	90% to 98%	90% to 95%	92% to 97%	90%
Noise	High	High	Moderate	High	High	Low
Service life	30 year or more	30,000 to 100,000 h	40,000 to 80,000 h	15 to 25 years	15 to 25 years	10 years
Part-load operation	Good	Poor	Satisfactory	Good	Satisfactory	Good

Prime mover characteristic	Steam turbine	Gas turbine	Microturbine	Reciprocating engine: Compression ignition	Reciprocating engine: Spark ignition	Phosphoric acid fuel cell (PAFC)
NO_X control options	NO_X control unnecessary but may be required as part of steam supply system (see Tables 4.4, 4.5, and 4.6)	Steam or water injection, lean premixed combustion, SCR, SNCR, and SCONOX™	Lean premixed combustion, SCR, SNCR, and SCONOX™	Lean air-fuel mixture, SCR, SNCR, and SCONOX™	Lean air-fuel mixture, staged ignition, catalytic three-way conversion (TWC), SCR, SNCR, and SCONOX™	Usually not required
Preferred uses for recovered heat	Process heat, hot water, and low-pressure to high-pressure steam	Process heat, hot water, and low-pressure to high-pressure steam	Process heat, hot water, and low-pressure steam	Hot water and low-pressure steam	Hot water and low-pressure steam	Hot water and low-pressure steam
Temperature of rejected heat, °F	Varies depending on extraction conditions	500 to 1,100	400 to 600	180 to 900	180 to 1,200	140 to 240
Operating mode	Load-tracking and continuous base-loaded operation	Base-loaded, load-tracking, and peak shaving operations	Base-loaded, load-tracking, and peak shaving operations	Base-loaded, load-tracking, emergency, and peak shaving operations	Base-loaded, load-tracking, emergency, and peak shaving operations	Base-loaded and load-tracking operations
Potential applications	Topping-cycle, bottoming-cycle, combined-cycle, and trigeneration CHP systems	Topping-cycle, combined-cycle, and trigeneration CHP systems	Topping-cycle, combined-cycle, and trigeneration CHP systems	Topping-cycle, combined-cycle, and trigeneration CHP systems	Topping-cycle, combined-cycle, and trigeneration CHP systems	Topping cycle

[a] Based on CHP systems that operate at least 8,000 h/year.
[b] Excluding stack replacement.
[c] Total CHP efficiency is a measure of (the net electricity generated plus the net heat supplied to the process), divided by the total fuel input.
[d] CHP electrical efficiency is a function of the net electricity generated, divided by the total fuel input.
Source: Refs. 2, 4–8.

Source: Oak Ridge National Laboratory, 2004 nb **$ are US dollars, not Australia**