final report

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Onsite cogeneration options for commercial meat processing plants

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Executive summary

In response to escalating electricity and natural gas prices, a large meat processing plant undertook the following prefeasibility study to assess the potential associated with a number of onsite cogeneration opportunities. The site consumes approximately 30 GWh of electricity, 250 TJ of natural gas and 50 TJ of biogas per annum.

To assess these opportunities this study included developing an energy baseline, site assessment, identification of cogeneration options, assessment of costs and benefits (to an accuracy of ±30%), and recommended next steps.

This pre-feasibility study identified and evaluated eleven different cogeneration options available to the site (which could be replicated at other meat processing plants within Australia). The four projects listed in Table 1 are recommended for further development and feasibility studies. Two of these projects use existing onsite biogas sources for electricity only and incorporating cogeneration. These projects have been recommended on the basis of short payback period, medium sized investment and low risk of achieving savings. The digester biogas cogeneration project has been recommended due to the potential for such a project to attract funding, making it much more economically viable. The natural gas cogeneration option has also been recommended for further investigation due to the potential for implementation costs to decrease and business as usual operating costs to continue to increase, making the project increasingly economic.

Table 1: Recommended projects

Energy source	End use variation	Capital cost ($)	Payback (years)
Existing biogas	Electricity only	$2,000,000	4
Existing biogas	Cogeneration	$2,600,000	3
Natural gas	Cogeneration	$20,000,000	5
Digester biogas	Cogeneration	$6,850,000	7

The seven projects not recommended for implementation should be reassessed if significant changes to capital cost, fuel availability and changes in gas and electricity pricing occur. In particular:

- The digester biogas electricity only project could become favourable if capital costs decrease or if onsite capability for biogas production volumes increase; and
- The various woodchip projects could become favourable if capital cost decreases and/or availability of biomass products increases.

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1 Background

1.1 Introduction

Large energy users such as meat processing facilities are increasingly exposed to escalating electricity and natural gas costs across the country. For a large commercial meat processing facility, an annual consumption of 20-40GWh of electricity and 100-300 TJ of natural gas is typical. Many such facilities have onsite wastewater treatment facilities which often produce biogas, with the potential for higher yield based onsite specific operations.

Potential opportunities exist to change energy sources and introduce conversion technologies at the site in order to realise cost savings and/or revenue generation. This pre-feasibility study reviewed a number of electricity, heat and cogeneration scenarios for applicability to a typical large scale meat processing facility. These scenarios include natural gas, biogas, digester and biogas (wood chip) supply options and a number of variations to how these energy sources are used.

2 Project objectives

The objective of this project was to assess the potential for cogeneration, in combination with biogas generation for the site with a pre-feasibility study.

3 Methodology

3.1 Energy baseline

The first step in the study was to create an energy baseline to understand how electricity and gas are used at the site on an hourly/half hourly basis. The information utilised included:

- Electricity single line diagram for the site
- Electricity interval data for all site National Meter Identifiers (NMIs)
- Electricity contract and a recent electricity invoice (for all NMIs)
- Natural Gas reticulation diagram
- Natural Gas Interval data (from site or gas retailer)
- Natural gas contract and a recent natural gas bill
- Biogas production/use metered data (from site)
- Previous energy studies undertaken for the site.

Using this data an energy baseline was developed which provided an understanding of electricity and gas demand and production at the site. Energy is used onsite 24 hours per day, 5 days per week. Electricity represents approximately 25 percent of site energy consumption; however it accounts for up to 70 percent of site energy costs. A peak electricity demand of approximately 3,000 kVA is observed onsite. Natural gas accounts for 30 percent of site energy costs, while representing approximately 60 percent of the site's energy consumption. Biogas consumption makes up the remaining 15 percent of site energy consumption at no cost to the site.

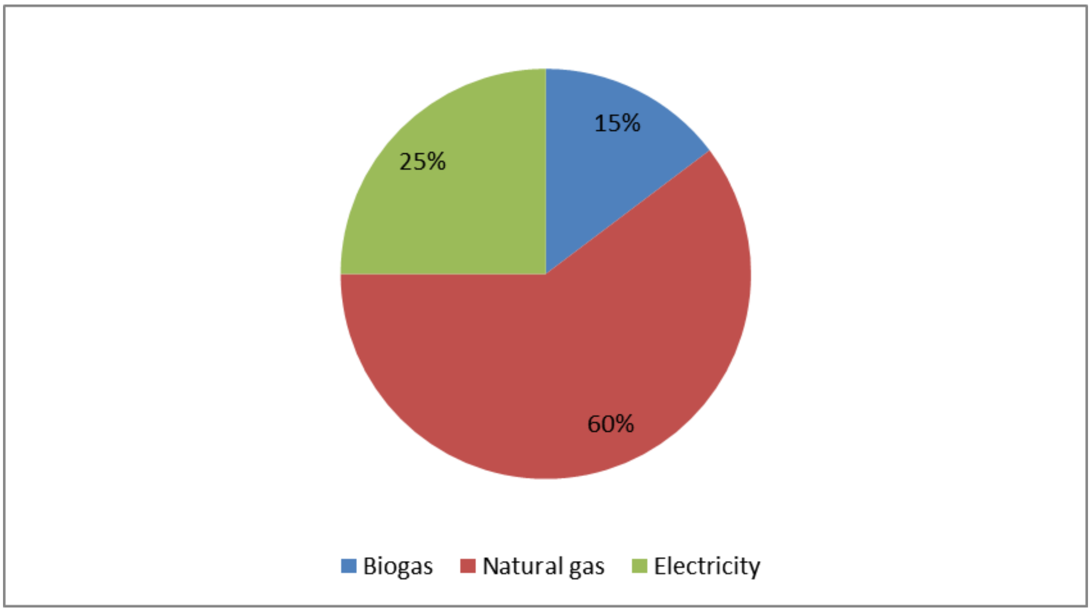

Fig. 1 Break-up of onsite energy consumption for typical meat processing facility

3.2 Site assessment

Following the development of the energy baseline, two days was spent onsite to better understand site characteristics including layout, limitations and restrictions. This allowed these characteristics to be accounted for when determining feasible cogeneration options.

3.3 Assess cogeneration options

The study then identified cogeneration options which would be feasible for the site, including consideration of the following variables:

- System sizing: Matched to heat load, matched to electrical load, sizing to maximise benefits
- Connection point: supply one or multiple NMIs
- Fuel input: Biogas, reticulated natural gas or both
- Connection to the electricity grid: remaining grid-connected, off-grid approaches and impacts on security of supply
- Energy conversion technologies: Gas reciprocating engines, microturbine systems, Stirling and other waste heat recovery technologies, combined cycle variations and absorption chillers (for excess heat)
- Supplementary electricity supply, including impact on proposed Solar PV installation.

For the options/variations that were appropriate for the site the study assessed the costs and benefits to an accuracy of ±30%. The following costs and benefits were included:

- Capital costs of implementation (estimated from published capital cost information)
- Other implementation costs such as synchronisation, protection and approvals
- Projected electricity costs (based on current electricity prices), including network and other charges
- Projected natural gas costs (based on current natural gas prices), including commodity, distribution, other charges and impact on contract volumes
- Revenue streams such as renewable energy certificates and Australian Carbon Credit Units (ACCUs)
- Funding sources such as State and Federal Government and ARENA
- Finance options such as CEFC, energy retailers, and specialist companies (e.g. Enerji).

3.4 Report and recommendations

This report outlines the results of the study and recommended next steps.

4 Results

4.1 Cogeneration options identified

Eleven energy source and end use scenarios were assessed and compared with the current baseline scenario.

The four energy source scenarios assessed were:

- Natural Gas – natural gas currently provided by gas network connection
- Existing biogas – biogas volumes currently produced in the covered anaerobic lagoon (CAL)
- Digester biogas – existing and additional biogas produced by constructing a digester
- Woodchip biomass – Wood chip purchased and delivered to site for use as an energy source

For each energy source scenario, three end-use variations were assessed:

- Heat only – using the energy source to provide heat as steam through existing or new boilers
- Electricity only – using the energy source to produce electricity through a generator
- Cogeneration – using the energy source to produce both electricity and heat as steam.

The rationale for considering the various scenarios is provided in

Appendix A. For each of the eleven new scenarios the capital cost, energy and cost savings, NPV, payback period and IRR were assessed. Capital cost and payback are summarised in Table 2. In each scenario the optimal energy conversion technology was selected to give the shortest payback period. Options in bold have been recommended for further investigation.

Table 2: Energy source and end use scenario summary

Energy source	End use variation	Capital cost ($)	Payback (years)
Existing biogas	*Heat only*	*Current practice (baseline scenario)*	
	Electricity only	**$2,000,000**	**4**
	Cogeneration	**$2,600,000**	**3**
Natural gas	Heat only (no biogas)	$0	>10
	Electricity only	$16,000,000	7
	Cogeneration	**$20,000,000**	**5**
Digester biogas	Heat only	$3,500,000	>10
	Electricity only	$6,000,000	9
	Cogeneration	**$6,850,000**	**7**
Wood-chip biomass	Heat only	$10,000,000	>10
	Electricity only	$13,000,000	>10
	Cogeneration	$15,000,000	9

For the existing biogas electricity only and cogeneration scenarios, microturbines are recommended to generate energy savings and revenue streams. Sizing of these is based on the current volumes of biogas produced in the covered anaerobic lagoon and electricity produced feeding the largest NMI at the site. Heat produced in the cogeneration unit (for this and all scenarios) is in the form of steam that can be utilised for rendering, offsetting boiler steam production.

The natural gas heat only scenario assesses the impact of losing the existing biogas production and replacing this with additional natural gas purchases. The natural gas electricity only and cogeneration scenarios involve disconnecting from the electricity grid completely and require significant capital investment for microturbines, an upgrade of the natural gas distribution infrastructure due to limited capacity for the additional gas use and the implementation of an electricity ring main to supply electricity to all NMIs across the site.

Additional biogas is produced in the biodigester biogas scenarios, boosting existing biogas production by roughly 30%. The capital cost to produce this additional biogas is large, making the heat only variation non-economic; however this improves if electricity is produced due to the generation of LGCs. The electricity only and cogeneration variations are based on both the existing biogas from the CAL and the new digester biogas being used, feeding the largest NMI only. Due to the novel approach of this cogeneration variation the project may be a good candidate for ARENA funding.

The wood-chip biomass scenarios involve utilising 100% of known available woodchip supply from the surrounding region. Due to the long transportation distances, costs for this energy source are not as low as desired. Materials handling, biomass boiler, steam turbine, heat recovery and grid synchronisation would need to be installed for the cogeneration variation resulting in large capital costs. If a closer source of biomass is found and the capital costs can be reduced, or combined with another project onsite the cost effectiveness of this project would improve.

Four scenarios are recommended for further investigation including potential to attract funding:

1) Existing biogas – electricity only
2) Existing biogas – cogeneration
3) Natural gas – cogeneration
4) Digester biogas – cogeneration

These scenarios are detailed in the following sections to test feasibility and consider technical aspects for application to the site.

4.2 Analysis of recommended options

4.2.1 Existing Biogas electricity only

This option consists of the installation of gas micro-turbines to supply electricity to the NMI which services the site's largest load. The installation of micro-turbines for this application, over other forms of generation such as reciprocating engines, is recommended due to their small size, ability to use variable quality fuel, high exhaust temperature, modularity and ease of adding heat recovery at a later date. The technology and capital cost assumptions for the gas micro-turbine system include all appropriate equipment required including a micro-turbines, biogas treatment (contaminant, particulate, carbon dioxide and moisture removal), installation and grid synchronisation. It has been assumed that existing compressors used onsite in the supply of biogas to the boilers will be sufficient to deliver the biogas to the microturbines at the required temperature.

All biogas produced by the existing anaerobic wastewater treatment system will be diverted from the boilers to the microturbines. Based on the annual biogas production volume a micro-turbine system of approximately 600 kW_e was used for the analysis. Estimated savings, capital costs and payback for the project are provided in the project summary in Table 3. Demand (kVA) savings have not been included in total savings due to the variable nature of biogas supply.

With a low to moderate capital investment and short payback period this project has the potential to reduce site costs materially. Electricity and LGC prices are expected to remain at elevated levels for the next three years, providing some certainty of savings. Biogas can be directed to electricity generation or the existing boilers over the life of the project as electricity and natural gas prices vary.

Table 3: Biogas electricity only project summary

Annual Savings		Costs and payback	
Electricity savings	4,000,000 kWh	600 kW_e microturbine	$1,100,000
LGC generated	4,000 MWh	Biogas treatment	$500,000
Demand savings	0 kVA	Controls and installation	$400,000
Natural gas savings	-50,000 GJ	**Total capital costs**	**$2,000,000**
		Simple payback	**4 years**

4.2.2 Existing Biogas Cogeneration

This option consists of the installation of microturbines with heat recovery to supply electricity to the NMI which services the site's largest load as well as partially replace process steam produced by the boilers. The technology and capital cost assumptions for the micro gas turbine system includes the additional heat recovery equipment.

All biogas produced by the existing anaerobic wastewater treatment system will be diverted from the boilers to the gas turbine system. Based on the annual biogas production volume installation of a micro-turbine system of approximately 600kW_e is appropriate. Further detail is provided in the project summary in

Table 4. Demand (kVA) savings have not been included in total savings due to the variable nature of biogas supply.

With a low to moderate capital investment and short payback period this project has the potential to reduce site costs materially. Electricity and LGC prices are expected to remain at elevated levels for the next three years, providing some certainty of savings. This project provides a hedge against escalating electricity and gas prices and can be scaled up to use additional biogas at a later date.

Table 4: Biogas Cogeneration project summary

Annual Savings		Costs and payback	
Electricity savings	4,000,000 kWh	600 kW_e Microturbine	$1,100,000
LGC generated	4,000 MWh	Heat recovery unit	$400,000
Demand savings	0 kVA	Biogas treatment	$500,000
Natural gas savings	-25,000 GJ	Controls and installation	$600,000
		Total capital costs	**$2,600,000**
		Simple payback	**3 years**

4.2.3 Natural gas Cogeneration

This scenario involves disconnecting completely from the electricity grid with all electricity supply to come from gas powered microturbines, along with heat to augment boiler steam supply. Facilitating this involves two significant additional costs:

- A likely upgrade of the gas distribution supply line to provide sufficient gas flow rates for the new gas users
- A high voltage ring-main to link all of the NMIs together so that the site can be supplied from a single point.

Variations such as only supplying some of the NMIs (the largest) or supplying NMIs with separate generation units have not been assessed in this report.

The current maximum flow-rate of gas at the site must be evaluated, as up to 150 GJ/h may be required for a typical meat processing plant to produce the electricity and stream required in this scenario. The distance from the site to the gas transmission line must be considered, with estimated costs of $1 million/km for upgrading the distribution line to the site. This cost estimate may change significantly upon enquiry and discussions with the natural gas network operator.

Microturbines have been selected to generate electricity and heat for this scenario for modularity and high heat output; however alternative technologies are also likely to be feasible, particularly with improved electrical conversion efficiency.

The project would change the energy cost exposure and energy supply risk profile of the site significantly. The site would be very exposed to natural gas prices which have escalated significantly over the last three years and are forecast to be constrained before 2020. Reliability of electricity supply would be contingent on reliability of the cogeneration system. This change and associated risks should be considered before considering this project for further assessment.

Savings, implementation costs and financial metrics are provided in Table 5. Demand savings are estimated based on peak load. Implementation costs may change significantly with further investigation, particularly the gas pipeline upgrade (following a request with the network operator) and electricity ring main costs (when the optimal configuration is determined and HV upgrade costs are factored in). Current estimates are likely to be conservative suggesting the project is worth further investigation and development.

Table 5: Natural gas cogeneration project summary

Annual Savings		**Costs and payback**	
Electricity savings	32,000,000 kWh	Gas pipeline upgrade	$5,000,000
LGC generated	0 MWh	8,000 kW_e Microturbines	$7,500,000
Demand savings	8,000 kVA	Heat recovery units	$3,000,000
Natural gas savings	-200,000 GJ	Electricity ring-main	$3,000,000
		Controls and installation	$1,500,000
		Total capital costs	**$20,000,000**
		Simple payback	**5 years**

4.2.4 Digester Biogas Cogeneration

This option consists of the installation of additional biogas generation capacity. The biogas produced by this additional digester will be fed, alongside the existing biogas, to microturbines with heat recovery to supply electricity to the NMI which services the sites largest load as well as partially replace process steam produced by the boilers. The technology and capital cost assumptions for the system include the supply and installation of the anaerobic digester, microturbines with heat recovery, biogas treatment, controls and installation.

Potential biogas production from the digester is estimated at 20,000 GJ per annum. It is assumed biogas produced by the new digester system will have a similar energy content to that produced in typical anaerobic wastewater treatment systems found at meat processing facilities. All biogas produced by the existing system, in addition to that produced by the new digester system will be diverted from the boilers to the gas turbine system.

Based on the current annual biogas production volume, and the additional biogas expected to be produced from the anaerobic digester, installation of a micro-turbine system of approximately 900 kW_e is appropriate. Further detail is provided in the project summary in Table 6. Demand (kVA) savings have not been included in total savings due to the variable nature of biogas supply.

The payback period for this project is long; however with the volatility of electricity and gas prices, this option provides significant potential to mitigate the cost and potential supply impacts of future energy market fluctuations. It is also the most likely project to attract significant ARENA, SA Energy Productivity Program (SAEPP) and PIP funding due it being a novel concept with applicability to the meat and food industries in Australia.

Table 6: Digester cogeneration project summary

Annual Savings		**Costs and payback**	
Electricity savings	5,500,000 kWh	Anaerobic digester	$3,200,000
LGC generated	5,500 MWh	900 kW_e Microturbine	$1,650,000
Demand savings	0 kVA	Heat recovery unit	$600,000
Natural gas savings	-15,000 GJ	Biogas treatment	$600,000
		Controls and installation	$800,000
		Total capital costs	**$6,850,000**
		Simple payback	**7 years**

5 Discussion

5.1 Achievement of project objective

The objective of this project was to assess the potential for cogeneration in combination with biogas generation for the site with a pre-feasibility study. This objective was met and this report summarises the outcomes of the study.

5.2 Further evaluation required

Two of the four recommended options have financial or operational aspects which would warrant further evaluation prior to making a final investment decision. In addition the natural gas cogeneration option has risks which would need to be managed if this project was selected. These are outlined in Table 7.

Table 7: For further evaluation prior to final investment decision

Option	For consideration prior to investment decision
Natural gas cogeneration	• **Technology selection**: The analysis assumed the use of microturbines however alternative technologies may also be feasible • **Financial risk:** The project would change the energy cost exposure and energy supply risk profile of the site significantly including elevating the exposure to natural gas prices. This should be considered when evaluating preferred options • **Supply risk:** Reliability of electricity supply would be contingent on reliability of the cogeneration system.
Digester biogas cogeneration	• **Volatility/hedging opportunity:** The payback period for this project is long; however with the volatility of electricity and gas prices, this option provides significant potential to mitigate the cost and potential supply impacts of future energy market fluctuations. There is potential for implementation costs to decrease and business as usual operating costs to increase over time potentially making this project increasingly economic. • **Funding opportunity:** This is the most likely project to attract significant ARENA and PIP funding due it being a novel concept with applicability to the meat and food industries in Australia.

5.3 Development of co-generation CBA model for industrial meat processors

A CBA model has been developed in conjunction with this report to assist users in preliminary assessment of the potential for implementation of onsite co-generation technologies. Detailed instructions are provided in this model, but in summary:

- Site details: input site specific information around electricity, natural gas and biogas consumptions; maximum on-site biogas production capacity; and current electricity, natural gas and biogas costs.

- Alternative energy options: input potential splits of natural gas to electricity generation and co-generation systems. These scenarios involved the conversion of natural gas and biogas (if applicable) in electricity generation and co-generation systems. Following input of the desired natural gas splits, review the resultant operating costs associated with site energy requirements in each scenario.

6 Conclusions/recommendations

The four projects listed in Table 8 are recommended for further development and feasibility studies. These projects have been recommended on the basis of their capital cost, operating cost and payback period.

Table 8: Recommended projects

Energy source	End use variation	Capital cost ($)	Payback (years)
Existing biogas	Electricity only	$2,000,000	4
Existing biogas	Cogeneration	$2,600,000	3
Natural gas	Cogeneration	$20,000,000	5
Digester biogas	Cogeneration	$6,850,000	7

7 Key messages

Biogas and cogeneration options are becoming increasingly economic with a number of viable opportunities for the meat industry which can be implemented with a three to five year payback. Review of such projects should take into account the financial benefits of Government and industry grants and subsidies along with potential new revenue streams, including ACCUs.

Appendix A - Scenario Rationale

Energy source	End use variation	Rationale for scenario
Existing biogas	*Heat only*	*Baseline scenario*
	Electricity only	Arbitrage electricity and natural gas prices, generate LGCs, 100% biogas utilisation
	Cogeneration	Arbitrage electricity and natural gas prices, generate LGCs, 100% biogas utilisation, utilise waste heat
Natural gas	Heat only	Assessing the impact of losing biogas and having to import additional natural gas for boilers.
	Electricity only	Arbitrage electricity and natural gas prices
	Cogeneration	Arbitrage electricity and natural gas prices and use waste heat
Digester biogas	Heat only	Free energy source to reduce natural gas consumption/cost
	Electricity only	Free energy source, generate LGCs, 100% biogas utilisation
	Cogeneration	Free energy source, generate LGCs, 100% biogas utilisation, utilise waste heat
Wood-chip biomass	Heat only	Low cost energy source to reduce natural gas consumption/cost
	Electricity only	Low cost energy source, generate LGCs
	Cogeneration	Low cost energy source, generate LGCs, utilise waste heat