final report

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Feed Lot Energy Strategy

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Executive Summary

This report summarizes the findings of a cost-benefit analysis (CBA) for energy options at an Australian feedloting operation with associated grain steam flaking.

Thermal Energy for Steam: Table 1 below summarizes the findings of a base case scenario compared to a number of scenarios for raising steam. The “fully costed” scenario includes the capital costs for the plant and associated operating costs (fuel, maintenance and staffing costs) for each fuel option.

Table 1: Estimated Levelized Cost of Energy based on concept design. 10 years if not otherwise indicated.

Fuel	$/GJ - calculated; fuel supply only	Basis of calculation GJ pa	$/GJ - fully costed 10 yrs
Diesel	20.52	47,295	23.11
Coal	4.56	47,295	8.70
Biomass #1: chipped hardwood	4.14	47,295	8.29
Biomass #2: forestry mulch	4.64	47,295	8.79
Concentrated solar	25 yr plant life	31,536	10.45
Biogas - 2 modules	25 yr plant life	56,420	10.81
Extract fuel oil	11.82	47,295	14.42
SORBO 15 (refined fuel oil)	13.88	47,295	16.48
Biogas - 1 module	25 yr plant life	28,210	18.89
LNG	16.57	47,295	21.07
LPG	18.42	47,295	21.25

Power: Presented in Table 2 below is a preliminary Levelized Cost of Power (LCoP) analysis, which considers a wide range of on-site power generation options and takes into account all capital and operating costs over the first 10 years of plant life.

Table 2: Estimated Levelized Cost of Power (LCoP) based on concept design for first 10 years of operation. Biogas and wind are calculated over a 25 year plant life, including op ex and maintenance costs.

Power Generation Technology		Value of heat generated	Value of RECs credits	Op ex & maint. based on $0.025/kWh	LCoP 10 yrs $/kWh
BASE: Diesel gen sets		N.A.	NA	62,817	$ 0.283
Backpressure turbine / expanding screw – biomass		Low pressure steam used in mill	70,168	30,698	$0.061
Backpressure turbine / expanding screw - coal		Low pressure steam used in mill	NA	30,698	$0.142
Biogass Renewables - cogen run on biogas from 2 modules		$65,948	201,130	87,994	$ 0.087
Biogass Renewables - cogen run on biogas from 1 module		$65,948	201,130	87,994	$ 0.140
PV Solar - roof mount < 100 kW		NA. Op ex based on Electronic Power Research Inst., PV Power Plants, 2010.	Incl. as cap ex reduction	2,193	$ 0.085
PV Solar - roof mount > 100 kW			12,602	2,193	$ 0.054
PV Solar - pen shading			Incl. as cap ex reduction	2,349	$ 0.199
PV Solar - ground mount			30,698	5,576	$ 0.086
Batteries - 40' container flow cell					$ 0.244
Gas Engine with engine heat recovery		65,948	NA	62,817	$ 0.382
Gas turbine		$578,167	NA	62,817	$ 0.398
Wind Turbine - 10 kW		NA	720	NA	$ 0.963

A number of scenarios combining thermal / power options have been analysed against a base case of diesel gen sets and a coal fired boiler with a specific view as to potential arena funding. A “levelized cost of energy” is presented which includes the capital cost, operating and maintenance costs, fuel costs, personnel / labour costs and, where pertinent, renewable Energy Credits. Due to the similarity of the $ per GJ lower heating value of coal and wood residue (wood chip co-product from local saw mills) and the similarity in installed capital cost, the economic viability of coal and wood are similar, except in the case where the steam is used to generate power, the economics of the wood option increases due to the creation of Renewable Energy Credits.

Table 3: Summary of estimated cap ex and combined Levelized Cost of Energy for the generation of power and steam onsite, based on 10 year period of operation, except for biogas from anaerobic digesters which is based on a 25 year life of plant. Where diesel gen sets are providing auxiliary power, no additional capital has been included i.e. it is assumed that diesel gen sets are a sunk cost.

Scenario	Power sources	Boiler fuel	Combined Levelized Cost of Energy $ pa over 10 yr period*	Fuel $ pa	Payback (compared to base case)
Base Case	Diesel gen sets	Diesel	$1.64 mil	$1.40 mil	NA
1	Diesel gen sets	Coal / wood residue	$0.98 mil	$0.66 mil	0.47 yrs
2	Biogas cogen; diesel as auxiliary	Coal / wood residue	$0.76 mil	$0.23 mil	3.11 yrs
3	Biogas cogen; diesel as auxiliary	Biogas; fuel oil as auxiliary	$0.68 mil	$0.06 mil	3.12 yrs
4	Backpressure turbine, diesel gen sets, PV solar, SWRL line	Wood residue	$0.82 mil	$0.46 mil	1.25 yrs

This report includes concept level design and associated cost estimation, hence all of the works require further detailed design and capital costing to improve the accuracy of the estimates. Concept design shall not be interpreted as a guarantee of plant performance. Capital cost (Capex), operating cost (opex) and economic analyses are concept budget estimates only. The passage of time, manifestation of latent conditions or impacts of future events may result in the actual contents differing from that described in this report. In preparing this report, All Energy Pty Ltd has relied upon data, analysis, designs, plans or other information provided by fuel and equipment vendors, the client, and other individuals and organisations referenced herein. No responsibility is accepted for use of any part of this report in any other context or for any other purpose by third parties. This report does not purport to provide legal or financial advice.

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1 Background

A feedlot would like to implement energy and water savings technologies as part of the expansion from 9000 head to a design capacity of 24,000 head (licenced capacity is 30,000 head). The feeding operations will require increased amounts of power and waste management options. In order to assist to achieve a more sustainable operation, it is necessary to consider an Energy Management System capable of autonomous optimization of the multiple on-site generation systems and on-site loads, thereby managing total energy consumption and costs.

2 Project Objectives

Milestone 1: Steam generation and fuel options. Completion of business case and concept design (target accuracy +/- 30 to 40%) for steam generation options including biogas from an anaerobic digester, waste heat recovery and concentrated solar thermal for 7 barg steam. Solar shading and savings in fuel usage will be documented. Fuel options for the transport fleet will be briefly considered within this milestone.

Milestone 2: Completion of business case and concept design for an Energy Management System (target accuracy +/- 40 to 50%) which will include analysis of an integrated power system including PV solar and cogeneration systems. Linking of feedlot to cloud based SCADA, advanced control, real time optimization, motor hierarchy, automated load management and battery storage will also be considered.

Milestone 3: ERF assistance and project management.

Milestone 4: Final report summarizing findings. The public version of the final report will contain all critical information necessary for objective engineering and cost-benefit analysis and associated consideration of the key parameters to determine the viability of resource efficient technologies.

3 Methodology

3.1 Basis of design

Table 4 below summarizes the key basis of design requirements. A detailed mass and energy balance approach is presented in the Appendix.

Table 4: Basis of Design – cattle numbers.

Current	Expansion	Total
	Commencing Sep 2016	Anticipated from April 20127
6,000	18,000	24,000

3.2 Assumptions

The key CBA assumptions that were made are as follows:

- Scenarios are for Earnings Before Income Tax, Depreciation and Amortization (EBITDA) with no discount rate or price indexing (i.e. CPI) applied.
- 25 year plant life used for calculations of biogas and concentrated plants, with cap ex for fossil fuel storage calculated over 5 year periods.
- "Overnight capital" (All start-up costs are expended at the start of the first year of full scale operation).
- Vendor data and budget quotations utilized in all instances where possible.

3.3 Background Information – Anaerobic Digestion and Manure Collection

Anaerobic digestion is the processes in which microorganisms break down the biodegradable material in the absence of oxygen. Commonly used in industrial application to treat waste and/or produce fuels and energy.
A brief Explanation of the processes involved in the digestion are included below:

1. Bacterial Hydrolysis Insoluble organic polymers (Think Carbohydrates) are broken down to soluble derivatives opening availability to other bacteria.
2. Acidogenic Bacteria convert sugars and amino acids into Carbon Dioxide, Hydrogen, ammonia, and organic acids. The organic acids are broken down to acetic acid, ammonia, hydrogen and carbon dioxide[6]
3. Methanogens convert these compounds to methane and carbon dioxide[7]

Anaerobic digestion acts to reduce the emissions of GHG gas and is widely used as a source of renewable energy. This process can be used to generate capturable biogas which consists of the methane and carbon dioxide as well as other trace gases.[1] This gas can then be fed through a generator in combined heat and power engines to offset emissions and reduce energy costs or alternatively be upgraded to biomethane. The digestate remaining can be utilized as a liquid fertilizer and can be pumped to surrounding pastures. Improved technology has allowed for the reduction of capital costs and Germany, UK and Denmark especially has seen an influx of installation of these facilities and manufactures. Handling systems can influence the production of biogas and methane from cow manures[1,2]. A comparative work within a dairy farm looked at scraper, slatted floor, and flushing. The scraper did not significantly affect the original characteristics of manure. Slatted floor produced a manure that has a lower methane potential in comparison with scraper, due to: a lower content of volatile solids caused by the biodegradation occurring in the deep pit, and a lower specific biogas production caused by the change in the characteristics of organic matter. Flushing can produce three different fluxes: diluted flushed manure, solid separated manure and liquid separated manure. The diluted fraction is unsuitable for conventional anaerobic digestion since its content of organic matter is too low to be worthwhile. The liquid separated fraction could represent an interesting material, as it appears to accumulate the most biodegradable organic fraction, but the organic matter concentration is too low. Finally, the solid-liquid separation process tends to accumulate inert matter in the solid separated fraction and, therefore, its specific methane production is low1. In this study, the feed alley (3.5 × 80 m) and the resting alley (3×80 m) were covered with a rubber mat pavement and equipped with scrapers for manure removal. Scrapers were used twice a day. At the end of the alleys, manures were collected in a catch basin. Scraped manure generated 185 +/- 22 L methane / kg VS.

The new pad for the pens is compacted, laser levelled crushed gravel. Pens will then be covered by a further 100mm of composted manure. Calibrated Laser height monitoring and GPS will be used by operators to scrape off collected manure to ensure that no gravel/soil/rocks are collected. Around 6-9% of total manure is expected to be recovered in a slurry via runoff into a single ditch. The balance can be obtained via scrapings at an estimated average time between scrapings of 21 to 30 days (this is an accelerated rate compared to the industry average). However as pens need to be scraped via about a dozen runs, the top scraping could be less than an average of 2 days in age.

3.4 HHV versus LHV

The *lower heating value* (LHV) or *higher heating value* (HHV) of a gas is an important consideration LHV of the gas. Whenever a hydrocarbon fuel is burned one product of combustion is water. The quantity of water produced is dependent upon the amount of hydrogen in the fuel. Due to high combustion temperatures, this water takes the form of steam which stores a small fraction of the energy released during combustion as the latent heat of vaporization; in simple terms, as heat energy stored in the vaporized 'state' of water.

The total amount of heat liberated during the combustion of a unit of fuel (the HHV) includes the latent heat stored in the vaporized water. In some applications it is possible to condense this vapor back to its liquid state and 'recover' a proportion of this energy. However, engine exhaust temperatures are above that at which the water vapor would condense, and hence the steam 'escapes' with the exhaust gases carrying with it the stored energy.

The amount of heat available from a fuel after the latent heat of vaporization is deducted from the HHV, and it is this, that is available when the fuel is burned in an engine. The energy input into a gas engine should be defined using the LHV of the fuel[2]. The LHV of a fuel determines the fuel flow rate required when going into the engine because the total quantity of energy input necessary for the engine to produce a specific output power is defined and fixed. Hence the gas flow rate has to be such in order to provide the required energy input. Fuel LHV is normally quoted using units of kWh/Nm[3].
Fuel suppliers will usually quote the HHV and it will be this measure that will be used when unit charges are applied for the fuel.

$$LHV = HHV - 0.212 \times H - 0.0245 \times M - 0.008 \times Y$$

[1] Coppolecchia, D, et al. Journal of Agricultural Engineering 2015; volume XLVI:449
[2] Hill, D.T. 1984. Methane productivity of major animal waste types. Trans. ASAE 27:530–534.
[2] https://www.clarke-energy.com/2013/heating-value, accessed 5 July 2016.

Where:
HHV = Higher heating value
H = Percent hydrogen
M = Percent moisture
Y = Percent oxygen (from an ultimate analysis which determines the amount of carbon, hydrogen, oxygen, nitrogen and sulphur as received (i.e. includes Total Moisture (TM)).[3]
Hence, for typical fuel oils, it is assumed that SORBO 15 is closest to Fuel Oil #4 (43.4, 0.953 kg/L): O at 0.4% w/w, H at 11.7% w/w, moisture at 0.25% and that Extract Fuel Oil is closest to Fuel Oil #2: O at 0.4%, H at 11.7% w/w, moisture at 1%.

Table 5: Properties of Typical Liquid Fuels[4].

Gasoline	Percent by weight					Ash	Specific gravity	Heating value (10^6 J kg^{-1})
	C	H	N	O	S			
Kerosene (No. 1)	86.5	13.2	0.1	0.1	0.1	Trace	0.825	46.4
Fuel oil								
No. 2	86.4	12.7	0.1	0.1	0.4–0.7	Trace	0.865	45.5
No. 4	85.6	11.7	0.3	0.4	<2	0.05	0.953	43.4
No. 6	85.7	10.5	0.5	0.4	<2.8	0.08	0.986	42.5

[3] 2006 IPCC Guidelines, Vol. II, Section 1.4.1.2, Box 1.1, as reported at http://cement-co2-protocol.org/en/Content/Internet_Manual/tasks/lower_and_higher_heating_values.htm
[4] Flagan, Richard C. and Seinfeld, John H. (1988) Fundamentals of air pollution engineering. Prentice-Hall, Inc, New Jersey (US).

4 Results

4.1 Boiler Capital Cost Estimation Summary

The table below summarizes the findings from a concept level analysis of options for raising stream at the Feedlot. The findings are based on, in order of preference, vendor data, costings from previous works and generic price heuristics.

Table 6: Summary of Steam Raising Options. Note: Concentrated Solar Thermal with Thermal Oil Boiler.

Boiler Options	Rating kWt	Payback yrs
Gas fired 3MW firetube package boiler with economizer	3400	Base
Gas boiler - generic 5MW	5000	Check
Coal / biomass fired 5MW fire tube boiler	3000	0.4
Saacke - Fuel oil & Biogas dual fuel 4 MW	4000	0.3
Saacke - LPG & Biogas dual fuel 4 MW water tube package boiler	4000	0.3
HRSG - for diesel gen sets	350	7.6
HRSG - for Capstone turbines	971	4.5
Concentrated Solar Thermal with Thermal Oil Boiler – Potential at full scale	3,400	5.7

Boiler vendors were requested to include budget pricing for a full package boiler and all ancillary equipment such as de-aerator, blowdown vessel, condensate tank, exhaust handling, stack; full water treatment plant: raw water tank, water softener (etc.; as required), treated water tank. Fuel receiving, fuel storage at boiler (is required) and fuel train(s) to burner. Water tube boilers are normally utilized for milling. The boiler package requires a local DCS with link to site-wide SCADA. Steam is routinely supplied via a 3" delivery pipe (mill provides a pressure regulating valve set).

4.1.1 Boiler attendance

A water tube boiler (i.e. gas fired or oil fired) can be run “unattended” in that checks are required at 24 hour intervals by a trained person. A fire tube (i.e. biomass / coal) boiler up to 5 MW requires checks at 12 hour intervals by an “Accredited Boiler Attendant – High Risk Work Licence”, hence running coal fired boiler will require higher trained staff to operate with an associated cost. The table below provides further information.

Table 7: Australian Standard AS2593 – 2004 for boiler attendance.

ATTENDANCE CATEGORY	TYPE	MAXIMUM OUTPUT CAPACITY	SUPERVISION BY	CHECKS
1. Unattended Operation	Water tube steam boilers Fire Tube Hot water Boilers Combined water tube fire tube steam boilers	10MW 5 MW 10 MW	Trained person	24 hr interval
2. Limited Attendance Boiler	Water Tube Boilers Combined water tube fire tube boilers Other types including fire tube steam boilers	20MW 20 MW 5 MW	Accredited Boiler Attendant (HRW Licence)	4 hr intervals 4 hr intervals 12 hr intervals
3. Attended Operation	All Types of Boiler	No Limits	Accredited Boiler Attendant (HRW Licence)	Continuous monitoring

4.2 Anaerobic Digester and Biogas Reciprocating Engine Capital Estimation

Presented in Table 8 below is the concept level analysis of a cattle manure to biogas facility, based on actual manure samples taken from site and analysed in a NATA lab.

Table 8: Concept level mass/energy balance results for anaerobic digester facility utilizing cattle manure.

	1 AD Module – for 600 kWe & 1.2 MWt	2 AD Modules – for 600 kWe & 3.6 MWt	@ 24,000 SCUs
TS	41.7%	41.7%	41.7%
VS %	55.0%	55.0%	55.0%
kg VS / kg manure	22.9%	22.9%	22.9%
cattle	5,376	10,752.81	24,000
%	22%	45%	100%
tpa manure @ 20% solids into digester	30,417	60,834	135,780
tpa 2 day manure AS DELIVERED	14,600.16	29,200	65,174
tpa total solids	6,083	12,167	27,156
tpd manure @ 20% solids	83.33	166.67	589.09
tpd total solids	17	33	118
"Summer slurry": Nov-April			
"Summer" Ave rainfall mm	436.90	436.90	436.90
VS tpd	4.02	4.02	4.02
tpd water runoff - average EXPANSION ONLY	138.25	138.25	138.25
"Winter slurry" Apr-Sept			
"Winter" ave rainfall	167.20	167.20	167.20
VS tpd	1.23	1.23	1.23
tpd water runoff - average EXPANSION ONLY	52.91	52.91	52.91
tpd VS in slurry AVE	2.62	2.62	
tpd VS required	9	18	64.80
tpd 2 day old manure to be added to slurry AVE	28.55	68.55	178.56
tpd 2 day old manure to be added to slurry as % available	16%	38%	
tpa water required	24,334	48,667	
tpa water in manure scrapings	8,517	17,034	
tpa water required in slurry	15,817	31,634	
tpd water required in slurry	43.33	86.67	
tpd from water softener reject	21.96	21.96	
tpd trough water	8.40	8.40	
tpd runoff - averaged EXPANSION ONLY	96.05	96.05	96.05
Total water available - tpd AVE	126.41	126.41	
Total water available - tpd SUMMER	168.61	168.61	168.61
Total water available - tpd WINTER	83.27	83.27	83.27
Total water required from pond - tpd WINTER	12.79	12.79	12.79
VS kg/day	9,167	18,334	64,800
m^3 CH4/day	0	4121.90897	0
m^3 biogas/pa	1,282,584	2,565,167	9,066,600

	1 AD Module – for 600 kWe & 1.2 MWt	2 AD Modules – for 600 kWe & 3.6 MWt	@ 24,000 SCUs
GJ pa	28,602	57,203	202,185
Electrical kW - continuous 40% eff.	363	726	2,116
Electrical kW @ 8 hrs per day	1,088	2,177	3,808
Spare thermal kW	1,250	3,563	4,360
Thermal equivalent at 85% efficiency, 8 hrs per day	2.31	4.63	16.35
Thermal available MW - 2 modules	3.38	7.65	20.71
% biogas	86.86%		
GJ pa fuel to run cogen	22,611		
Spare GJ pa	5,990		

Considered in this section is the concept design for an automated biowaste to renewable energy facility. The capital cost estimate for an appropriately sized facility is outlined in Table 9.

Table 9: Concept design capital cost estimation for anaerobic digester facility.

Estimated Total Capital Investment		Subtotal
	Digester #1, control room, flare, materials handling, feed tank, gas cleaning. Sized for providing all mill area power requirements and towards 38% of boiler requirements.	2,810,090
	Digester #2. Sized for providing the balance of boiler requirements.	870,536
	Biogas reticulation: trenched poly pipe	187,900
SUBTOTAL		3,680,626
	Containerized Cogen Engine – 600 kW	954,000
TOTAL		4,634,626

The key components of an anaerobic digester plant are outlined in the following Figure 3, provided by Biogass Renewables Pty Ltd. Note that only one cogen engine would be used (with the balance of the biogas reporting to the boiler) and that the cogen engine would be located adjacent to the boiler house as per Figure 4.

Discussions during the site visits implied that the effort to transport manure scraping to a digester are similar to that for transport to a composting area. The main change in operating procedure is that the top layers of scrapings (~16% of available tonnage for 1 module or 38% for 2 modules) are directed to the a digester whilst the lower levels are sent to composting.

4.2.1 Project Phasing

To prevent a single large capital outlay and to minimize project risks, the project could be delivered in phases, with a possible suggested staging approach outlined below.
Such phasing allows the capital outlay to occur over 2 or more financial years and also sets up milestone payments under potential funding from the Australian Renewable Energy Agency (ARENA).

All items in Phase 1 are to be delivered to have a functioning anaerobic digester. The items in Phases 2 and 3 can be delivered in any combination of one or more items.

Table 10: Biogas facility staging options.

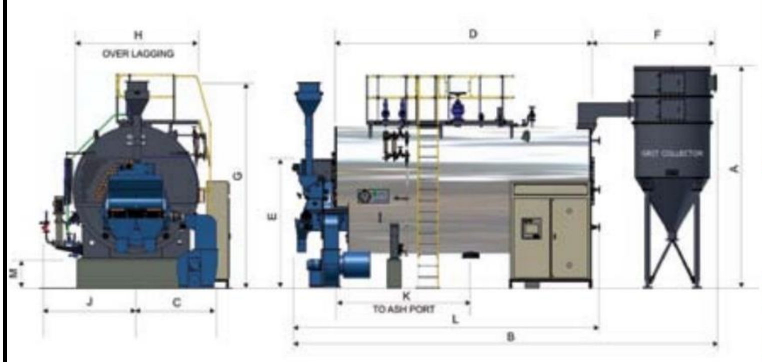
Phase 1:	BIOGAS PHASED DELIVERY	
	Digester #1, control room, flare, materials handling; biogas reticulation	
	Power cabling	
	Cogen #1	
Phase 2:		
	Digester #2	
	Biogas valve train	
Phase 3:		
	Heavy vehicle modification to run on dual diesel and biogas	TBA
	Storage and loadout for biogas transport fuel	TBA
	Biogas compressor (~10 bar)	TBA

Indicative Biogass (AD only) Payment Terms:

- 40% of Contract Value upon placement of order
- 40% of Contract Value at dispatch of main equipment (6.5 months).
- 15% of the Contract Value upon completion of construction (10.5 months).
- 5% of the Contract Value on completion of commissioning (12 months).

4.3 Solid Fuel Boiler

Budget pricing was obtained for a full D&C package boiler, John Thompson chaingrate stoker coal/biomass fired boiler with spiral tubes. At 85% efficiency, it is estimated that a boiler will need to be rated to ~3.9 MW to deliver 4.4 tph, with around 4.3 MW of thermal energy required if a backpressure turbine (267 kW) is utilized. Indicative boiler sizing is presented in Figure 5 below.



Boiler Model Number			TU675
Evaporation:	From & at 100°C	kg/h	6 750
	At 1 000 kPa, feedwater 20°C	kg/h	5 651
Boiler Rating		kW	4 231
Dimensions in mm:	A	mm	5 196
	B	mm	11 167
	C	mm	1 990
	D	mm	6 010
	E	mm	2 606
	F	mm	3 800
	G	mm	4 400
	H	mm	2 980
For Ash Trolley Removal:	J	mm	2 390
	K	mm	3 184
	L	mm	7 367
	M	mm	7 367
Main Steam Valve Diameter		mm	150
Safety Valve Exhaust Diameter		mm	65
Safety Valve Exhaust Diameter		mm	65
Feed Check Valve Diameter		mm	32
Blowdown Valve Diameter		mm	50
Feedpump Inlet Diameter		mm	40
Recommended Stack Diameter		mm	600
Fuel Consumption		kg/h	663
Mass:	Empty	tons	22
	Operating	tons	40

Figure 5: Indicative boiler size for meeting mill requirements and superheating steam to generate power via a backpressure turbine.

4.4 Power Load and Generation – Mill Area

4.4.1 Load and Power Generation Estimate – With AD Plant and peak load shedding

Table 11: Mill area load estimate including an anaerobic digester plant.

	kW averaged over 24 hrs	% of total	kW during milling	% of milling time total
Intake	19.63	6%	31.23	5%
Reclaim	4.13	1%	9.90	2%
Weighing	1.16	0%	2.79	0%
Wetting	3.29	1%	7.91	1%
Tempering	9.58	3%	23.00	4%
Milling	97.08	28%	233.00	39%
Liquids	8.16	2%	8.04	1%
Batch Mixing	68.34	20%	164.01	27%
Misc Equipment	7.18	2%	13.42	2%
Boiler	13.38	4%	26.50	4%
AD – biogas for engines & boiler	113.92	33%	83.00	14%
TOTAL - kW	345.86		602.80	

The aggregated loads of Table 10 are presented over a 24 hour period in Figure 7 below, showing a model where a 600 kW rated biogas engine is available with the balance made up by power from diesel gen sets.

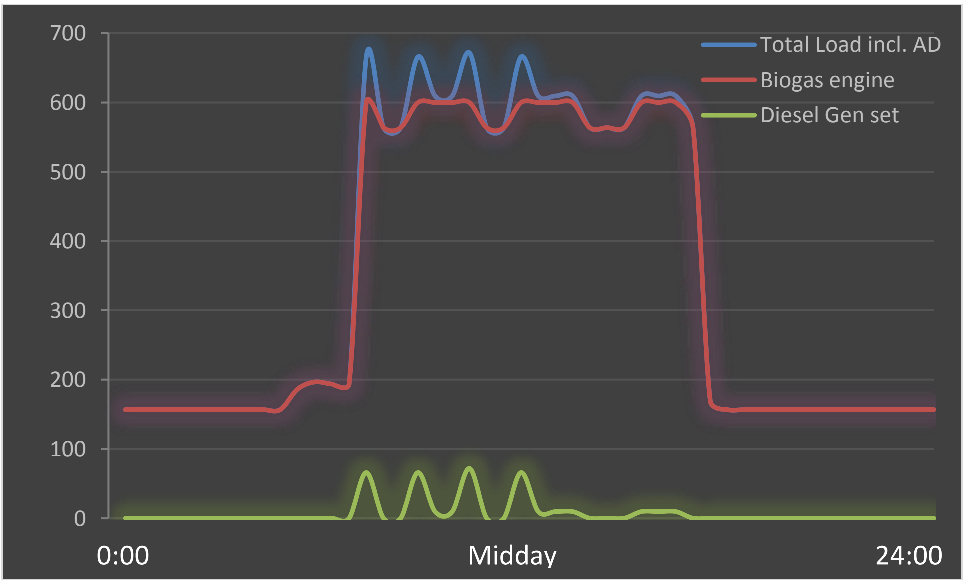


Figure 7: Mill area power generation option with biogas engine.

With an AD facility, the daily load is estimated at 8,301 kWh per day (of which 5,567 kWh per day is attributed to the milling, boiler and associated operations). On the generation side, 97.9% of power requirements can be met via a 600 kW biogas engine with the balance from diesel gen sets. It is anticipated that at time of low load, a capacitor or load bank would be required to modulate the biogas engine. No power is anticipated to be required from the SWRL line except in times of simultaneous unavailability of all on-site gen sets.

4.4.2 Load and Power Generation Estimate – With Solid Fuel Boiler and load optimization

Average power load for the mill area from 5:30am - 4:30pm is estimated at 357 kW. Estimated total site power load, with anticipated power supplied from each of an expanding screw / back pressure turbine (267 kWe net) and diesel gen sets is as per the following diagram.

The most suitable Ergon tariff appears to be the "Tariff 62 Farm Time of Use" where off-peak from 9pm to 7am is charged at $ 0.17215 / kWh[5]. At other (peak) times, cost is $0.48685/kWh, hence from 7am to 9pm it is more economically viable to use, in the following order:

- Roof mounted PV solar (dust considered a major issue; unknown impact on economics),
- Backpressure steam turbine,
- Ground mounted PV solar (dust considered a major issue; unknown impact on economics),
- Diesel gen sets.
- SWER line.

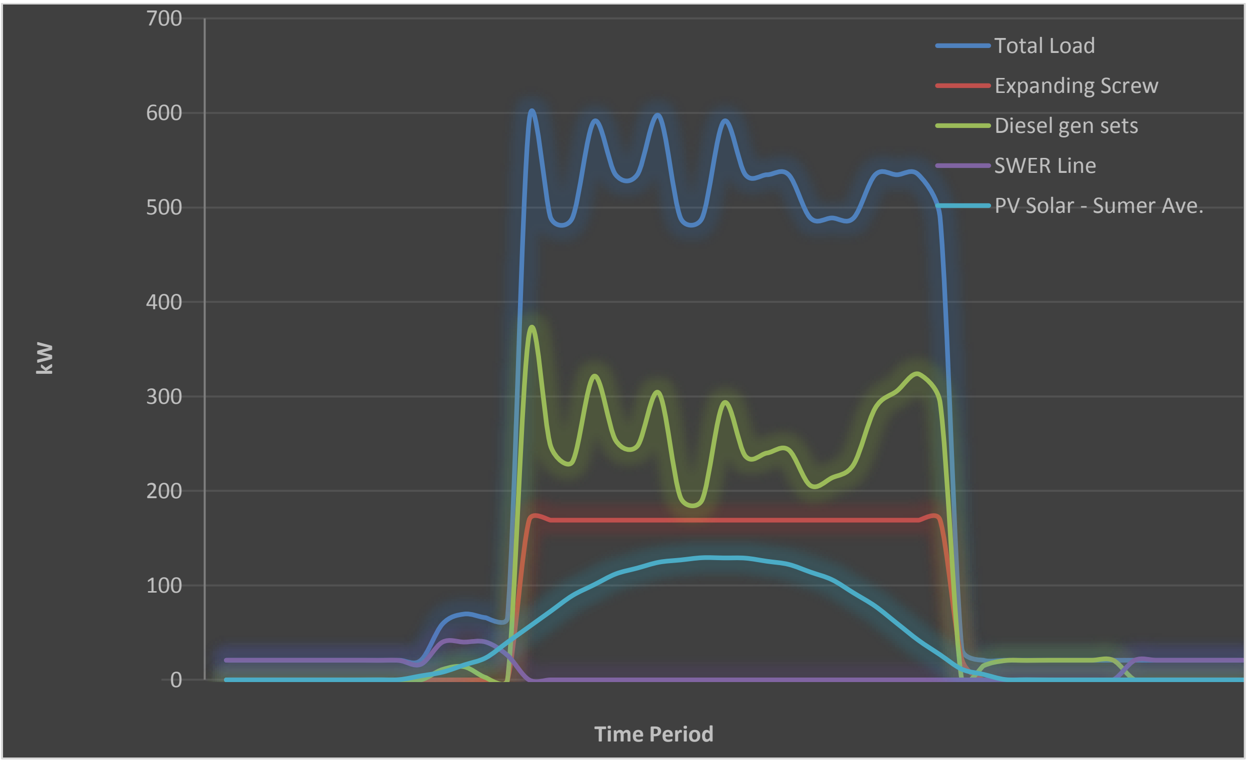


Figure 9: Mill area power generation option with 267 kW backpressure turbine.

A solid fuel boiler able to utilize coal and all forms of woody biomass has been specified. Preliminary pricing has been received for a Hi-Tech Qld Pty Ltd for a 7 barg and 24 barg boiler and on an Energent backpressure micro-turbine. It is assumed that there is an additional 30% capital cost increase for the higher pressure steam system over the lower pressure steam system.

[5] https://www.ergon.com.au/retail/residential/tariffs-and-prices/rural-tariffs, accessed 16th Sept 2016.

4.4.3 Energy Management System

Gordyn-Palmer (electrical engineering sub-contractor) has been tasked with the power and communication management and design. Gordyn-Palmer, throughout the detailed design phase, will analyse the site power and control requirements based upon plant design and load mapping with an associated capital cost estimate. Detailed energy management and design network will not only control power load shedding but control and synchronise multiple power sources. The custom design solution is to be specifically designed to match the load profile to the most economic source of power seamlessly, while maintaining the production requirements of the plant. As this site is remote the system can operate autonomously or linked to cloud based SCADA (Ignition) for monitoring and reporting. The capital cost will be completed during the detailed design stage.

The PLC Based system is to be liked via Ethernet IP system to all motors on the site. Current is to be monitored and predicted prior to starting allowing for correct source of supply to be determined

Detailed works still to be done include

- Detail analysis of appropriate sources of supply
- Refinement of load shifting to suit sources of supply
- Motoring all metrics including but not limited to electrical power, water, gas, diesel, thermal
- Detail design in the collection of data.
- Detail sensors and positioning for accurate data collection
- Data analysis and reporting back to ERP & SCADA systems

The overall package will provide a seamless system of data collection stored on a central SQL database accessible via appropriate workstations as outline in Figure 11 below.

4.5 Power Load and Generation – Camp and Water Pumping Area

The proposed facility is anticipated to have twp micro-grids: one at the mill area and a second for the camp and water pumping area.

4.5.1 Water Demand for Expansion

Table 12: Estimated water demand for expansion.

	L per head per day	ML per head pa	Size
NSW DPI , Minimum[6]	35	0.013	400 kg
Winter, CATTLE STANDARDS AND GUIDELINES[6]	45.0	0.016	500kg
Ref #1	50.0	0.018	Not defined
NSW DPI, Maximum[5]	80.0	0.029	400 kg
Summer, CATTLE STANDARDS AND GUIDELINES[7]	90.0	0.033	500kg

	ML/head pa	Head	Total		Continuous pumping		PV Solar @ 4.65 h per day	
			ML pa	L per day	L/sec	m^3 per hour	L/sec	m^3 per hour
Total Feedlot - Summer	0.033	24000	788.4	2,160,000	25.00	90.00	129.03	464.52
Expansion - Summer	0.033	18000	591.3	1,620,000	18.75	67.50	96.77	348.39
Total Feedlot - Winter	0.013	24000	306.6	840,000	9.72	35.00	50.18	180.65
Expansion - Winter	0.013	18000	240.09335	657,790	7.61	27.41	39.29	141.46

[6] http://www.dpi.nsw.gov.au/__data/assets/pdf_file/0009/96273/Water-requirements-for-sheep-and-cattle.pdf
[7] CATTLE STANDARDS AND GUIDELINES – BEEF FEEDLOTS DISCUSSION PAPER Prepared by the Cattle Standards and Guidelines Writing Group, February 2013, referring to Canadian Recommended Code of Practice for the Care and Handling of Farm Animals – Beef Cattle (1991).

4.5.2 Pipe Diameter Estimation for Expansion – PV Solar Powered

For 4.65 hours per day of pumping, the optimal pipe diameter is 300 ND mm with a power draw of 22.5 kW averaged over the 4.6 hour period. As water is extracted from the system, the pipe diameter can be reduced. For example, delivery of boiler water to the raw water tank over an equivalent period of 4.7 hours has an optimal pipe diameter of 65 ND mm (at 1.54 kW power draw).

4.5.1 Pipe Diameter Estimation and Pump Load – Continuous

At a continuous pumping rate of 67.5 m^3/h, the pipeline optimization is 125 ND mm and pump requirements are estimated at 5.82 kW.

4.5.2 PV Solar Modelling

Optimal tilt angle estimated to be 27.8 to 28.1° [8]. The following provides a summary of the potential power generation per 1.00 kW of installed capacity, based on analysis using the PVWatts Calculator[9] for "typical year" solar radiation incident at a specific site taking into account weather conditions at the site, ambient temperature, wind speed geographic coordinates, elevation, and hourly time stamps. Ambient temperature and wind speed are used to calculate the temperature of the photovoltaic cells in the array. The data set is sourced from the including from the American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc.

Table 13: Estimated PV solar radiation and associated power.

Month	Solar Radiation (kWh / m2 / day)	AC Energy (kWh)
January	6.1	143
February	5.93	124
March	6.6	155
April	5.92	137
May	5.29	125
June	5.36	127
July	5.1	127
August	5.69	135
September	5.73	133
October	6.19	147
November	6.11	138
December	6.27	143
Annual	5.86	1,634

PV System Specifications	
DC System Size	1 kW
Module Type	Standard
Array Type	Fixed (open rack)
Array Tilt	28°
Array Azimuth	0°
System Losses	14.08%
Inverter Efficiency	96%

[8] http://pvwatts.nrel.gov/pvwatts.php.
[9] National Renewable Energy Laboratory (NREL) is operated for the U.S. Department of Energy by the Alliance for Sustainable Energy, LLC.

DC to AC Size Ratio	**1.1**
Performance Metrics	
Capacity Factor	**18.60%**

The analysis shows that for an average summers day (4.65 kWh per 1.00 kW installed), a PV array of 30.1 kW is required to provide the required amount of pumping energy. The minimum modelled PV solar output for a single day was 1.23 kWh, hence an array of 114 kW is required to provide the maximum amount of pumping.

4.5.3 PV Solar Analysis

W / m^2: 155.8 W / m^2 (assuming 265 W for a 1 m by 1.7 m panel; Q Cell 15 min extra at dawn and dusk). Based on the Energy Map, the maximum winter load for the eastern area is estimated at 78 kW, which equates to 501 m^2.
Available roof space:

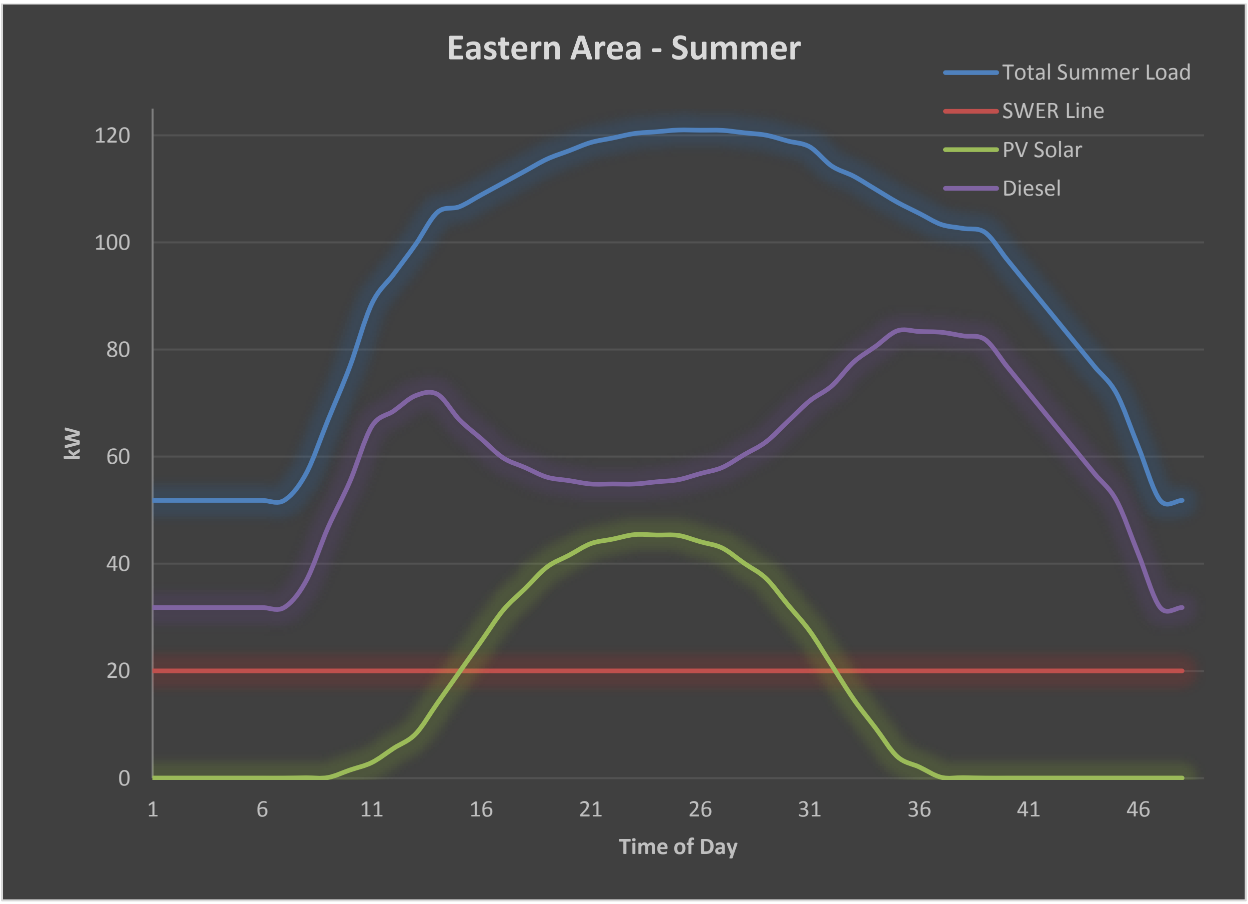
- Stage 1 arrival: (18 x 3 + 20 x 3) = 114 m^2
- Stage 2 Induction: (18 x 3 + 22 x 3) = 120 m^2
- Camp area: 237 m^2. Equates to ~9 rooms.

Table 14: Summary of Levelized Cost of Power analysis for a range of PV solar options. Maintenance based on Electronic Power Research Inst., PV Power Plants, 2010, which is in the range of $22 to 27 per kW.

Power Generation Technology	$ Turn Key	Rating kW	$/kW	Op ex & maint. based on $0.025/kWh	LCoP 10 yrs $/kWh	RECs $pa @ $80/MWh	kWh pa
PV Solar - roof mount < 100 kW	111,339	99.68	1,117	2,193	$ 0.085	NA	157,520
PV Solar - roof mount > 100 kW	188,814	99.68	1,894	2,193	$ 0.054	12,602	157,520
PV Solar - pen shading	249,255	87	2,865	2,349	$ 0.199	NA	137,042
PV Solar - ground mount	581,981	253.44	2,296	5,576	$ 0.086	30,698	383,723

Serious consideration needs to be given to the available roof space of:

- Commodities shed: at 892 m^2 able to provide 147 kW.
- Feed shed: at 180 m^2 about to provide 30 kW.
- Boiler house / gen sets: at 273 m^2 able to provide 45 kW.
- Camp area: estimated at 336 m^2 able to provide 55 kW.



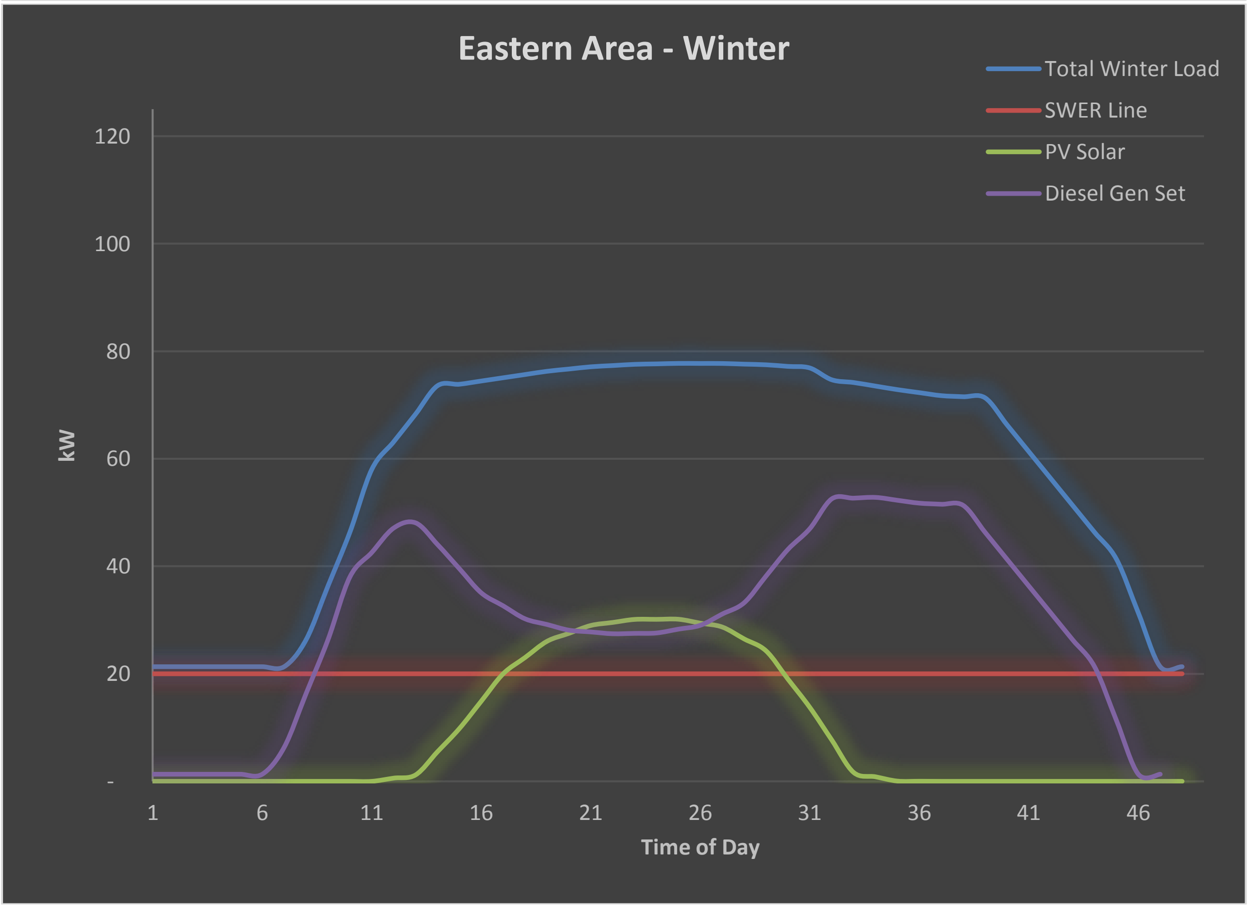


Figure 14: Total load with PV Solar, gen set and SWER line incoming power overlay.

Figure 15: Solgen ground mounted system at NBN Broken Hill.

Pile driven frame posts eliminate pre-made concrete foundations reducing construction lead time and costs. When selecting panels, consider impacts of frost (negative earthing) and temperature stability on panel efficiency over its life.

4.6 Emissions reduction Fund (ERF) Opportunities

4.6.1 Land Based Abatement

As of 5 Feb 2016, there were:

- 15 Grazing Method projects, including, by way of example: WALLAROBBA CATTLE COMPANY PTY. LIMITED: Sequestering Carbon in Soils in Grazing Systems, offsets project that aims to remove carbon dioxide from the atmosphere by sequestering carbon in a soil grazing system. 6/10/2015 New South Wales 2339.
- 129 x Regen: O'Connell Grazing Trust, Yenloora Regeneration Project Human-Induced Regeneration of a Permanent Even-Aged Native Forest - 1.1, The human-induced regeneration of native forest on land that was subject to deforestation and suppression activity. 14/09/2015 Queensland 4490.
- 1 avoided deforestation.
- 0 herd management projects (was too new).
- 0 nitrates projects (too new).
- 18 Alternative waste projects (mostly avoided landfilling)

Some general comments:

- Carbon Sequestration: avoided deforestation and reforestation (fence + 100 yrs).

- Whole Herd Management Method: productivity, better feed. >~40k head.
- Nitrates: urea replaced with nitrate lick blocks (non-protein nitrogen). Feedlots.
- Soil Carbon: increase in soil carbon over time.
- Savannah Fire Management: Nth Australia, >600mm rain pa.

A number of scenarios were run by Dr Tom Davidson (MLA), as summarized below.

Financial Scenario

Herd Management

	Total ACCUs	Total Revenue	Total Expenses	Net Income
1. Kimberley: 70% weaning, 10,000 breeders	21,000	$292,950	$100,000	$192,950
2. VRD: 70% weaning + heavier weaning LW	35,000	$585,900	$100,000	$485,900

Avoided Clearing

	Total ACCUs	Total Revenue	Total Expenses	Net Income
Jundah (QLD) avoided clearing 1,000Ha	13,350	$150,000	$150,000	$0

Native Forest from Managed Regrowth

	Total ACCUs	Total Revenue	Total Expenses	Net Income
Laura (QLD) managed regrowth 1,000Ha	125,000	$1,000,000	$150,000	$850,000

Savanna Burning

	Total ACCUs	Total Revenue	Total Expenses	Net Income
1. Project 1 (Net Area 15,000 km²)	285,000	$2,425,000	$200,000	$2,225,000
2. Project 2 (Net Area 8,700 km²)	475,000	$4,000,000	$200,000	$3,800,000

Note: Herd management and nitrates scenarios are based on a 7 year crediting period; avoided clearing, native forest regrowth and savanna burning scenarios are based on 25 year crediting periods.

Some general guidance on ERF land base projects:
[1] Does it make sense? Does the method align with the core business of the farm.
[2] Is data collection and auditing feasible.
[3] Is it at the appropriate scale – is it worth the effort?
[4] Register before implementation – the project must be "new".

4.6.2 Facility based abatement

The utilization of renewable energy to off-set fossil fuels provides an opportunity to generate ERF credits. Some examples are outlined below.

4.6.2.1 Feedlot

The main opportunities for abatement at a feedlot include:
[1] Fuel oil: emissions estimated at 3,412 tpa CO2-e based on 46,208 GJ pa.
[2] Diesel for power: emissions estimated at 1,743 tpa CO2-e based on 642 kL diesel pa.
By setting a baseline and then shifting to wood or biogas, the above emissions can be avoided.

4.6.2.2 Meat Processing Plant (MPP)

The main opportunities for abatement at a MMP are:
[1] Coal: emissions estimated at 12,971 tpa CO2-e based on 5,324 tpa coal consumption.
[2] Grid power: emissions estimated at 20,232 tpa CO2-e based on 2015 power consumption (NGER Det 2016 Indirect Scope 2).

Avoided landfilling is also an opportunity, however would require a track record of documented landfilling of wastes, which is considered unable to be shown due to the range of waste management options for organics (e.g. some landfilled, some composted, some for direct land application, etc.).

A number of options exist for increasing renewable energy. Two scenarios considered were:
[1] Firing of wood chip within the existing boiler. Most solid fuel boiler system are able to take a certain percentage of biomass (e.g. 10%) with no considerable impact on the boiler. Further, some solid fuel boilers may be able to combust 100% biomass with no major modifications if the fuel meets a certain specification (e.g. 20% moisture or less, low ash).

[2] A separate package boiler for firing biomass to create high pressure steam for a back pressure turbine, with the steam then fed into the main header.

A biomass package boiler to generate 24 barg steam, 6.23 tph is estimated to cost $2.4 mil fully installed, is estimated to generate around 200 kW when dropped down to 3 barg through a backpressure turbine at a further $0.5 mil installed. Over 10 years, the power cost is estimated at $0.07 / kWh, where the steam is then used to off-set steam raised from coal.

Utilizing a larger system is expected to deliver high economics of scale, however the capital costs will also be high.

[3] Overpressurizing steam then running the steam through a backpressure turbine where the boiler and steam header are suitably rated to the higher pressure.

5 Conclusions/Recommendations

5.1 Key Findings

Anaerobic digestion is one of the limited number of opportunities for facilities to generate revenue from their own waste management practices. Biomass fired boilers offer a lower cap ex option for generating renewable energy and hence can provide the shortest payback period for shifting from a fossil fuel to a renewable fuel. The information created as part of this project can be utilized in an Expression of Interest (EoI) as part of the process for obtaining third party funding via the Australian Renewable Energy Agency (ARENA).

The accuracy of the findings are impacted by:
[1] Majority of capital equipment estimated to concept level accuracy of +/- 5 to 40%. No equipment yet estimated to "fixed and firm, lump sum". Progressing through the detailed design phase will improve estimate accuracy.
[2] A trial digestion pilot should be run to confirm the solids, volatiles content and digestability of the available manure.
[3] Securing 3rd party (i.e. ARENA; Biofutures Queensland) funding. There exists the possibility that the project economic may be too strong. A preliminary analysis suggests that at a discount rate of 7% with no CPI, and capital being expended over 2 years before creating revenue, the IRR is approximately 8.9%, hence the project could be in the region for attracting federal support.

5.2 Future Areas of R&D for industry

Suggested areas for future R&D for the industry are recommended as being:
[1] Trial in a pilot scale digester of anaerobic conversion of manure into biogas. This will confirm the manure collection and slurrying is suitable for a full scale system and provide a basis of design for optimizing a future AD facility.

[2] Lump sum pricing for biomass boiler generating steam suitable for backpressure turbine (e.g. 19 to 40 Barg) and associated backpressure turbine / expanding screw.

[3] Informing the industry of alternative funding models such as Build-Own-Operate-Maintain offerings for a complete biogas facility converting manure into biogas.

[4] Consideration of the environmental permitting requirements for the proposed plant.

[5] Of all of the nodes withint the red meat industry, feedlots are one of the few locations where the presence of concentrated organic wastes means that a feedlot could be a net exporter of renewable energy by creating biogas from manure. A key improvement required is the manure collection process to ensure that the highest levels of volatiles remains in the manure. It could be possible for a feedlot and associated milling operation to generate all of its energy needs (power and thermal heating for steam flaking) from 45% of the available manure, with the balance of the energy exported to the grid after firing of the biogas in reciprocating engines or the creation of a transport fuel in the form of Bio-CNG.

[6] The red meat industry will continue to operate within Australia for hundreds of years or more. This long time horizon should provide motivation for exploring how the red meat industry at large can be

firstly neutral and then, ideally, a net exporter of nutrients and renewable energy whilst also being carbon neutral or having a net negative carbon footprint. The occurrence of land based emissions reduction methods has shown to the industry the technical and economic viability of large scale emissions reduction projects.