AUSTRALIAN MEAT PROCESSOR CORPORATION

Emissions Reduction Fund: Energy Efficiency and Offsetting Opportunities

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Project objectives

Technical solutions exist for reducing energy use and managing waste in the Australian red meat processing industry. The challenge is to select optimized solutions that meet the required economic drivers. The proposed Emissions reduction Fund (ERF) provides an additional revenue stream for "new" energy efficiency and greenhouse gas (GHG) emissions offset projects.

This project has analysed a number of efficiency and emissions offset projects and provides the results in the form of a Marginal Abatement Cost Curve (MACC) which prevents the $ (as a cost or saving) per tonne of carbon dioxide equivalent (t CO_2-e) abated and an Energy Cost Curve (ECC) which presents the $ revenue/savings per kWh generated for power projects and $ revenue/savings per GJ heat generated for process heating projects. A 10 year life cycle approach has been taken where capital costs, operating and maintenance costs, and revenue/savings for power, heat, waste management and the ERF (where indicated) have been estimated.

The basis of the analysis is a 625 cattle per day processing facility with an associated rendering plant.

Abstract

The capital cost, operating cost and abatement implication of various energy efficiency and GHG emissions abatement technologies were estimated for a "typical" 625 head of cattle per day (hpd) facility with an associated rendering plant. The abatements costs in the absence and presence of the proposed Emissions Reduction Fund (ERF) were estimated. The largest abatement potential is for conversion of waste to biogas with associated combustion, due to the high comparative global warming potential (GWP) of methane which is 21 times that of carbon dioxide (CO_2). Generation of heat and/or power from the biogas provided an economic return to the facility whilst waste converted into biogas then flared did not break even over a 10 year period (even with Emissions reduction Fund (ERF) support. The only technology found to move from net cost to net revenue/ savings after ERF support was the flaring of biogas, where the base case is that biogas is currently vented from a single point.

Energy efficiency projects were all found to provide favourable cost savings/revenue, even in the absence of ERF support; however the abatement potential was generally two to three orders of magnitude less than the waste to biogas combustion projects. Natural gas (NG) fired co-generation (cogen) for the generation of power and heat provided sound economic returns, however, the abatement potential was approximately an order of magnitude less than the waste to biogas opportunities. Conversion of organic waste to offset coal via a torrefaction process was not found to be economically attractive over a ten year period; the economics are improved where the torrefaction solid product (i.e. bio-char) can be sold as a higher value fertilizer.

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1. Summary Table of Key Findings

Table 1 below provides a summary of the estimated implications of various energy efficiency and GHG emissions abatement technologies for a "typical" 625 hpd day facility with an associated rendering plant. Detailed assumptions are provided in the following sections. It must be noted that the estimates presented in this report are general in nature; detailed analysis for each technology should be completed for specific facilities before implementation. Key assumptions for all technologies were:

- 10 year equipment lifespan for all technologies.
- Grid electricity costs were assumed to be $0.23 / kWh and reticulated (piped) natural gas costs were assumed to be $7.00 / GJ.
- All costs associated with co-generation (cogen) were accounted for in power generation calculations, hence heat generated is "free".
- A negative cost shows that the technology will generate revenue or provide savings against the "base case".
- The ERF provided revenue for the first three (3) years of each project only at a rate of $ 6.00 / t CO_2-e abated.

Table 1: Summary data for energy efficiency and abatement technologies showing the marginal abatement costs and energy costs (power and heat) with no Emissions Reduction Fund (ERF) support and a marginal abatement cost with ERF support.

		Abatement Costs No ERF		Energy Cost Curve - Power		Energy Cost Curve - Heat		Cap ex	Operating & Maintenance	Abatement Cost With ERF
#	Technology – 10 yr lifespan	t CO_2-e abatement	$ / t CO_2-e	kWh saving lifespan ($ / kWh)		GJ saving lifespan ($ / GJ)		$	$ pa	$ / t CO2-e
1	Waste to anaerobic digester (AD) vessels to biogas cogen	568,421	- 36	142,359,840	$ 0.102	384,826	$ 0.00 ["free" heat]	$ 7,620,578	$ 693,800	- 38
2	Waste to AD vessels to existing boiler	435,324	- 10	No power		821,669	$ 6.40	$ 3,893,443	$ 136,271	- 8
3	Waste to AD vessels to biogas flare	426,238	12	No power		No heat		$ 3,793,443	$ 132,771	10
4	Waste to CAL to Biogas to cogen	463,408	- 35	116,059,525	$ 0.108	313,731	$ 0.00 ["free" heat]	$ 6,124,081	$ 641,422	- 39

		Abatement Costs No ERF		Energy Cost Curve - Power		Energy Cost Curve - Heat		Cap ex	Operating & Maintenance	Abatement Cost With ERF
5	Waste to CAL to Biogas to Existing boiler	354,900	- 10	No power		669,869	$ 4.83	$ 2,396,946	$ 83,893	- 11
#	Technology – 10 yr lifespan	t CO_2-e abatement	$ / t CO_2-e	kWh saving lifespan	($ / kWh)	GJ saving lifespan	($ / GJ)	$	$ pa	$ / t CO2-e
6	Waste to CAL to Biogas to Flare	347,493	9	No power		No heat		$ 2,296,946	$ 80,393	7
7	Biogas flaring instead of venting 10 yrs	347,493	1	No power		No heat		$ 300,000	$ 6,000	- 1
8	Power management system	12,772	- 193	10,643,519	$ 0.009	No heat		$ 95,000	NA	- 194
9	Boiler optimization and management system	2,157	- 100	No power		42,019	1.85	$ 77,542	NA	- 111
10	Lighting - Replace Metal Halide with LED	5,443	- 190	6,328,636	$ 0.056	No heat		$ 351,591	$ 7,032	- 192
11	Lighting - Replace Halogen with LED	6,082	- 202	7,072,000	$ 0.047	No heat		$ 331,500	$ 6,630	- 204
12	Lighting - Replace Fluorescent with LED	3,421	- 192	3,978,000	$ 0.054	No heat		$ 214,370	$ 4,287	- 194
13	Boiler exhaust (215 °C) waste heat recovery	3033	- 86	No power		59,094	3.50	$ 153,124	$ 5,359	- 88
14	Boiler exhaust (400 °C) waste heat recovery	8940	- 96	No power		174,172	2.82	$ 363,572	$ 12,725	- 98
15	Torrefied organic waste co-firing in coal boiler (10 yrs)	93,734	7	No power		296,250	4.86	$ 1,526,866	$ 53,440	5
16	Nat gas cogen - 2000 kW	58,504	- 110	126,412,791	$ 0.123	158,357	0.00	$ 3,183,743	$ 538,511	- 112
17	PV Solar - 99 kW	1,280	- 100	1,580,000	$ 0.149	No heat		$ 235,670	$ 8,248	- 102
18	Refrigeration efficiency (5% saving)	1,860	- 197	2,268,000	$ 0.068	No heat		$ 115,000	$ 4,025	- 199
19	Motor efficiency (5% saving)	262	-49	320,000	$ 0.190	No heat		$ 45,000	$ 1,575	- 51

2. Summary Curves

Presented below in Figure 1 is the Marginal Abatement Cost Curve or MACC for a range of energy efficiency and GHG emissions abatement projects. The MACC shows the cost (or revenue / savings when negative) per tonne of CO_2-e abated (t CO_2-e) for a 10 year life cycle approach with associated estimates for capital costs, operating and maintenance costs, and revenue / savings for power, heat, and waste management. Generally, projects are considered viable where the abatement cost is negative. As can be seen from Figure 1, projects associated with methane combustion have the highest abatement potential (due to the methane global warming potential being 21 times that of CO_2).

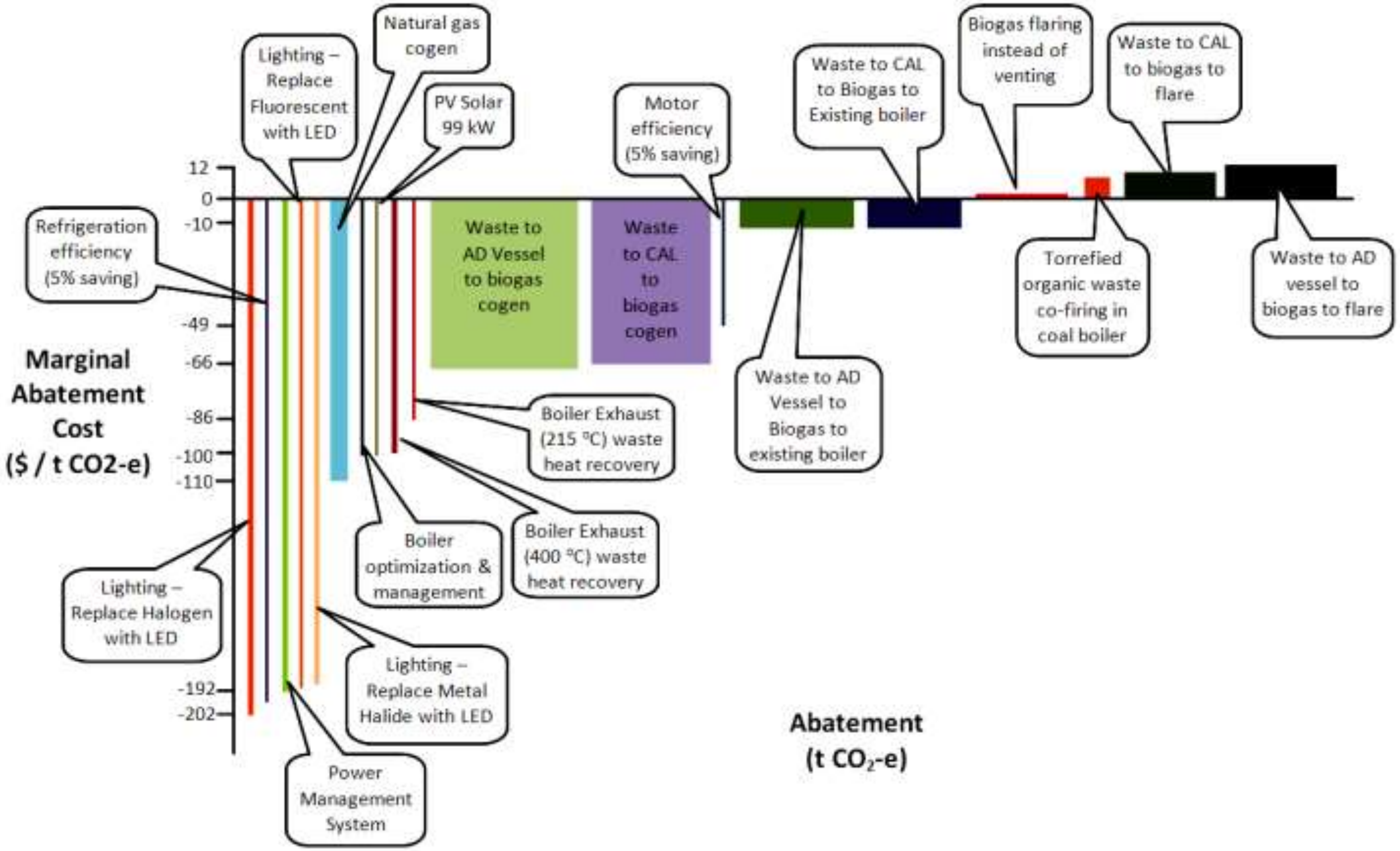
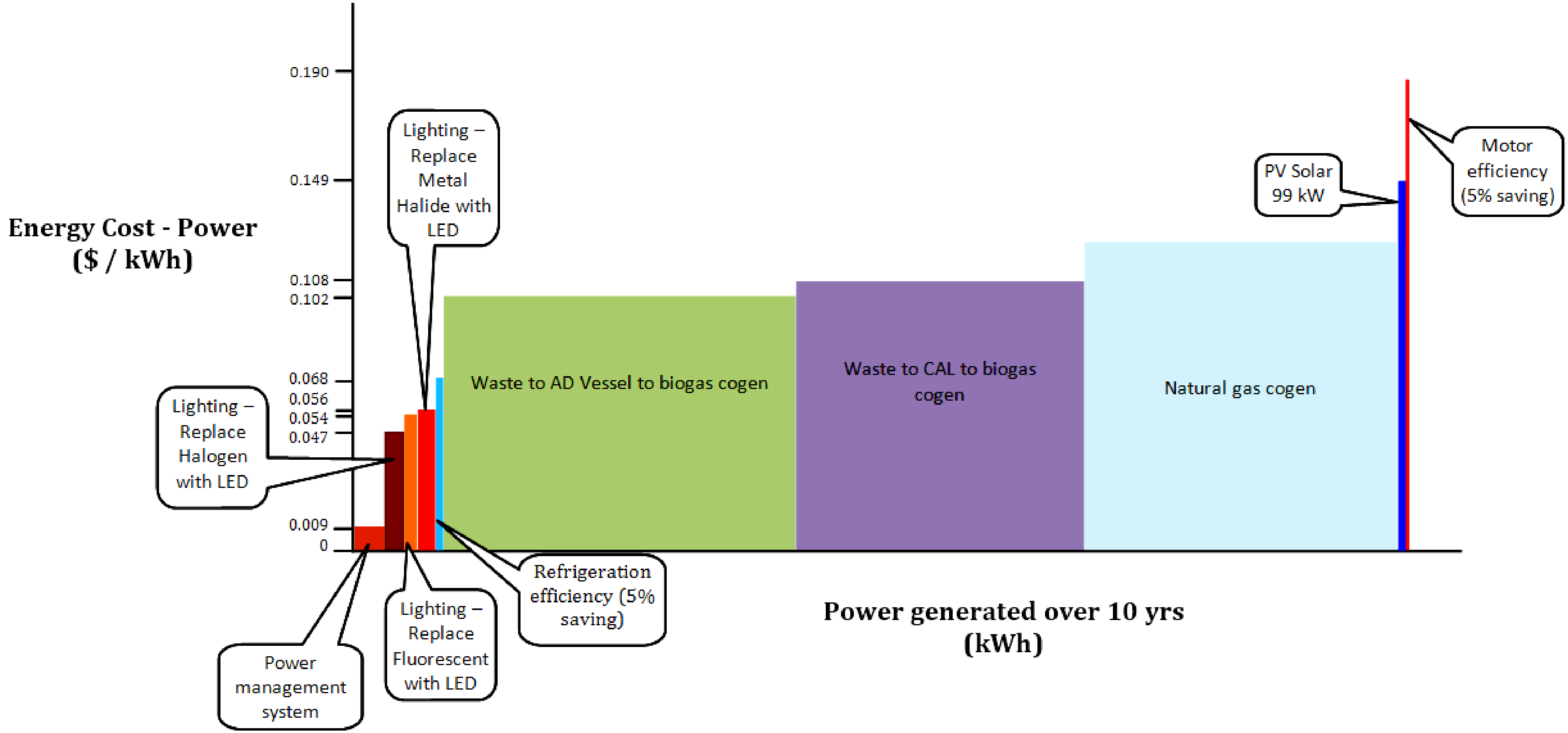


Figure 1: Marginal Abatement Cost Curve (MACC) for energy efficiency and GHG emissions abatement projects.

The Energy Cost Curve (ECC) for power is shown in Figure 2 below where the cost per kilo Watt hour (kWh) over a 10 year life cycle taking into account estimates for all costs and savings. Generally, power projects are considered viable where the technology is able to provide an energy cost below the cost of power purchased from the grid. Power efficiency projects generally are the most economically viable projects due to the high relative cost of electricity.

Figure 2: Energy Cost Curve for energy efficiency and GHG emissions abatement projects that save or generate power.



The Energy Cost Curve (ECC) for heat is shown in Figure 3 below where the cost per Giga Joule ($/GJ) over a 10 year life cycle has been estimated inclusive of all costs and savings. Generally, projects are considered viable where the technology is able to provide energy at a cost below purchased energy (e.g. reticulated natural gas). No distinction has been made between high pressure steam, low pressure steam or hot water – the form of heat able to be generated would be the subject of a more detailed analysis of each technology. Note that for the torrefaction co-firing in a coal boiler, the technology would be breakeven when it is able to offset the cost of solid fuel (e.g. coal, saw dust, wood, etc).

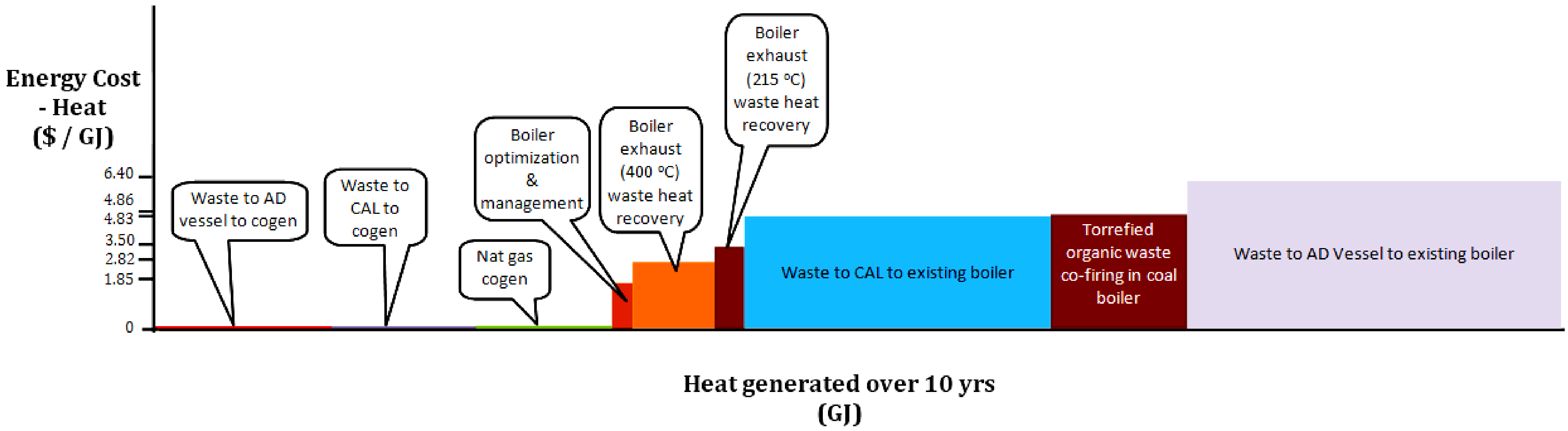


Figure 3: Energy Cost Curve for energy efficiency and GHG emissions abatement projects the save or generate heat.

3. Assumptions

3.1 ERF and RECs

It was assumed that each tonne of carbon dioxide equivalent (t CO_2-e) abated was able to attract \$6.00 of revenue via the proposed ERF scheme for a contract period of three (3) years. This is an assumption based on publish analytical data, with the estimated ERF value per t CO_2-e estimated to be in the range of \$3 to \$20.

It is expected that no ERF credits / income would be able to be created for renewable energy which attracts Renewable Energy Credits (RECs) - this ruling has been flagged in a draft Method Determination under the proposed ERF. Under the REC Large-scale Generation Certificate (LGC) scheme, each Mega Watt hour (MWh) of renewable electricity generated via biogas fired cogen was assumed to create \$30 / MWh. The PV solar system was capped at 99 kW in order to be able to maximise the benefit of Small Technology Certificates (STCs) assumed to be valued at \$36 / MWh. If renewable electricity was able to offset electricity from, for example, the Queensland grid under the ERF scheme, the equivalent value of offsets would be worth approximately \$5 / MWh (where revenue is generated at a rate of \$6.00 / t CO_2-e abatement). Hence, it can be seen that it is preferential for renewable electricity to receive support via the current REC scheme rather than the proposed ERF scheme.

It was assumed that heat generated via the technologies considered was able to generate revenue via the proposed ERF scheme by offsetting GHG emissions from the combustion of the base case fuel (i.e. natural gas), taking into account the minor GHG emissions associated with biogas combustion.

3.2 Technology and Equipment

This section of the report outlines the key assumptions made in calculating the outcomes of each opportunity.

3.2.1 Closed Anaerobic Digester (AD) Vessels and Co-generation (cogen)

The organic waste from a typical plant was modelled to generate 1624 kW of power when averaged over the period of one year. An installed capacity of 2330 kW was based on two off MTU-DD biogas cogeneration engines (Model 12V4000L62FB) specifically designed for the variable lower heating value (LHV) biogas generated from an anaerobic system. The installed capacity is higher than the power generation potential of the biogas to allow for times of biogas overproduction (e.g. higher than normal volatile solids loadings), to provide redundancy and to enable one engine to remain functional when the second is undergoing scheduled major and minor overhauls. The capital cost was estimated for a fully installed heat and power generation system including both direct and indirect costs (transport, buildings, site prep, site mobilization and demobilization, concrete, insulation, paint, structural steel, flue gas heat exchanger). All capital and operating costs were accounted for in generating electricity and hence the heat generated by the cogen engines was considered "free".

Waste from the facility was concentrated via a continuous centrifuge before being fed into one of eight (8) by 100,000 L stainless steel, lagged and temperature controlled vessels arranged in parallel operation. Heat was assumed to be supplied via waste heat recovery from the cogen engines (if required). Allowances were made for waste and digestate handling and biogas handling (water knockout, scrubbing and reticulation) before firing in the designated biogas cogen engines.

Bioreactor selection, design and management should be tailored to site specific waste streams to ensure sufficient mixing, residence time and control over the process.

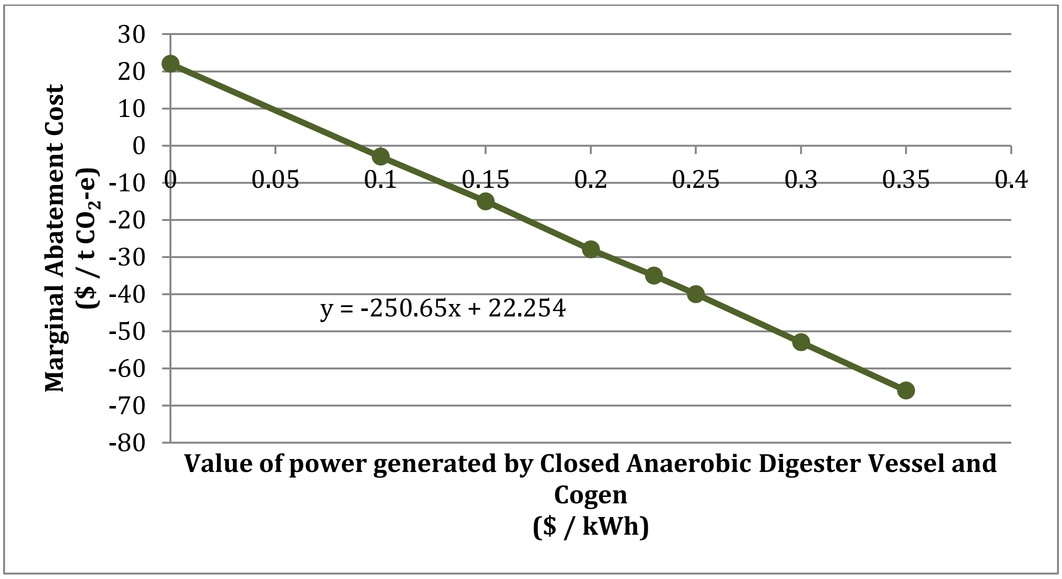


Figure 4: Sensitivity analysis where the effect of the value of power generated is compared to the marginal abatement cost for the closed anaerobic digester and cogen plant.

A sensitivity analysis was run for the scenario of the closed anaerobic digester vessel where all biogas is sent to a cogen plant with the value of the generated power varied whilst keeping all other parameters constant. Figure 4 above shows the marginal abatement cost, not including the ERF, for a range of power values from $0.00 to $0.35 / kWh. The "breakeven" point (where project costs equal revenue / savings over 10 yrs) is for a power value of $0.089 / kWh.

3.2.2 Closed Anaerobic Digester Vessels with Biogas Sent to an Existing Boiler

The same AD Vessel arrangement as per [1] was assumed with the added cost of a Type B gas reticulation system to transport the biogas to an existing boiler and the retrofitting of an appropriate burner.

3.2.3 Closed Anaerobic Digester Vessels with Biogas Sent to a Flare

The same AD Vessel arrangement as per [1] was assumed with the added cost of a Type B gas reticulation system to a new continuous sparking flare.

Whilst the biogas to flare estimates did not indicate that these projects were economically viable, there were various "externalities" that were not included in this economic analysis such as the advantages of odour reduction, reduced COD / BOD loadings in effluent (leading to the potential for water recycling), and improvements to the overall health, safety and environment of the facility.

3.2.4 Covered Anaerobic Lagoon (CAL) and Cogen

The base case was assumed to be deep (> 2.0 m), anaerobic lagoons with no coverings or biogas capture system in place. The key assumptions were:

- The cogen plant assumptions were assumed to be the same as per [1] above.
- Existing lagoons covered with high density polyethylene (HDPE)
- Dissolved air flotation system to manage influent.
- Allowance made for a buffering lagoon to moderate spikes in fats, oils, and greases and volatile solids.

Depending upon the feed composition (volatile solids concentration; fats, oils and greases (FOGs) concentration), CAL systems will have different rates of biogas generation and different maintenance requirements. It is recommended to remove as much FOGs as possible beforehand in order to reduce the tendency to form a crust – this can be achieved via the use of centrifuges, tricanters, grease traps, dissolved air floatation (DAF) systems and/or process optimization. However, CALs will still require an ongoing maintenance program for crust removal (e.g. flushing) or removal as part of the mechanical excavation maintenance program. Mechanical excavation of CALs is required periodically (e.g. every several years) to remove solids and sludge build up which reduces the residence time in the CALs and hence reduces the performance of the CALs. Where practical, pipe work can also be introduced into the base of the CAL to enable periodic pump out of the accumulated sludge and/or recirculation of the sludge CAL contents to promote greater biogas production. The advantage of the latter is that cover removal is avoided, however, care must also be taken to ensure pumping occurs regularly to avoid blockage of sludge lines. An allowance has been made for routine maintenance costs.

3.2.5 CAL with Biogas Sent to an Existing Boiler

The key assumptions were:

- The boiler modification assumptions were assumed to be the same as per [2] above.
- The CAL assumptions as per [4] above.

3.2.6 CAL with Biogas Sent to a Flare

The key assumptions were:

- The flare system assumptions as per [3] above.
- The CAL assumptions were assumed to be the same as per [4] above.

3.2.6 Biogas from an existing Waste Water Treatment Plant (WWTP) Sent to a Flare

Assumed that the existing WWTP has an existing single point source of biogas exiting the WWTP.

3.2.7 Power management system

A power management systems (PMS) implemented into processing plants, where no PMS currently exists, can deliver energy savings of up to 30% or more. This is achieved via the use of an automated system that, for example, turns equipment down or off when it is not required. This is achieved via a “motor hierarchy” which decides which motors are critical and which motors can have speeds reduced. Examples include air compressors and air conditioning where a 20% reduction in motor speed results in an approximate 49% lower power draw with no impact on the short term operation of the compressed air system or change in temperature of a controlled environment. Other examples include: automated shut-down of equipment during out of shift hours to ensure that parasitic loads are minimized, set point control / floating set points; duty / standby optimization. For this analysis, the power savings was conservatively estimated at 10% of total annual kWh consumption. Reference: Emerson.

3.2.8 Boiler optimization and management system

Examples of improvements include burner efficiency analysis, new burners, furnace pressure controllers, reconciliation of steam level data to natural gas consumption to determine a 'best case', automation of boiler control, cycling minimization, load matching, peak efficiency operation (especially pertinent for multiple boilers operated in parallel). Energy savings of over 10% are routinely achieved for boilers that have not been recently optimized (i.e. last 5 to 10 years); hence a conservative energy saving of 5% has been assumed.

3.2.9 Lighting - Replace Metal Halide with LED

Assumes a base case where the facility currently uses metal halide lighting with all lighting replaced by high efficiency LED lights.

3.2.10 Lighting - Replace Halogen with LED

Assumes a base case where the facility currently uses halogen lighting with all lighting replaced by high efficiency LED lights.

3.2.11 Lighting - Replace Fluorescent with LED

Assumes a base case where the facility currently uses fluorescent lighting with all lighting replaced by high efficiency LED lights.

3.2.12 Boiler exhaust (215 °C and 400 °C) waste heat recovery

On average, 15% of boiler heat is lost through the stack. Two scenarios were modelled where the exhaust is at:

- 215 °C which is the exhaust temperature that would be expected if an economizer is in place
- 400 °C which is a conservative exhaust temperature that would be expected if no economizer is in place.

Whilst the capital cost is higher for the 400 °C, an economy of scale is achieved and the overall driving force for heat exchange is higher. Other sources of waste heat not considered in this analysis are blow downs which releases waste heat to drainage and boiler room heat which is often used for combustion air pre-heating.

3.2.13 Organic waste boiler co-firing

Based on the findings from the AMPC Report 2013/3009 ("Torrefaction of animal waste for beneficial reuse, reduced emissions and cost reduction"), a torrefaction plant was scaled to a 625 hpd operation. Key assumptions included the:

- torrefied feedstock was wet DAF sludge and paunch material.
- torrefaction product, when co-fired, reduced coal costs by $78,429 pa, reduced waste management costs by $92,813, however cost $31,225 pa to run.

The plant was not found to be economically viable after 10 yrs. With ERF funding, the plant was break even after approximately 15 years. Where the torrefied material is sold as fertilizer for $100 / t instead of off setting coal consumption, with ERF funding the payback was found to be 9.7 years.

3.2.14 Natural gas (NG) fired co-generation (cogen)

The NG fired cogen system was sized to off-set the majority of the power demand during the shift, that is, to provide 2000 kW electrical (kWe) of the 2661 kWe of electrical load. This arrangement could provide approximately 43% of a typical plant's process heating requirements if all low grade (engine) and high grade (flue gas) heat is used. The balance of the facility heat load would continue to be provided by the existing NG boiler house. The cogen system modelled included the gas engine gen set, alternator, radiators, acoustic canopy, mechanical and electrical installation, control system and horizontal fire tube waste heat boiler including testing, all valves, fittings, controls and safeguards, two independent low water devices, feed water pumps and management system for automatic operation without the continual supervision of a boiler attendant. It is assumed that the natural gas tie-in and main switch board are located within a reasonable distance from the cogen system. Excluded are switch boards, switch-rooms, breakers, and concrete works.

This cogen plant is able to easily be turned down to 50% load (1000 kW). Data shows that the off-peak (10pm to 7am) power draw for red meat processing facilities can range between 43 – 85% of the load during peak times (7am – 10pm) due predominantly to the refrigeration loads. Data for a typical plant indicates an off-shift power load of 49%. Hence, a typical plant with a 2661 kWe load during the shift was assumed to have an off-shift load of 1304 kWe. Hence, it is assumed that the cogen system is generating 2000 kWe for 4000 hrs pa (in-shift) and 1304 kWe for 4000 hrs pa (off-shift). For heat generation, it is assumed that the cogen system is generating 2495 kW thermal (kWt) for 4000 hrs pa (in-shift) and 0 kWt for 4000 hrs pa (off-shift). Taking the lower engine efficiency and operating costs into account, it remains economically viable to run the engine at partial load even if there is no use for the waste heat.

In terms of CO_2-e abatement, it is assumed that the NG that would have otherwise been burnt in a boiler is consumed in the cogen system thereby partially off-setting the total NG demand in the cogen system. Additional process heat not sourced from the cogen engines will be generated as per normal in the existing boilers. At full load, it was assumed that the cogen engine consumes NG at a rate of 4888 kW.

3.2.15 PV Solar

A 99 kW system installed on existing roof space. This sized system was chosen so as to receive small scale Renewable Energy Target (RET) credits and was expected to be easily installed on top of existing roof space at a typical process facility.

3.2.16 Refrigeration Efficiency

It was assumed, conservatively, that 5% of typical refrigeration load (1134 kW) is reduced via no to minimal cost efficiency retrofits such as a power management system or lagging.

A power management systems (PMS) implemented into processing plants, where no PMS currently exists, can deliver energy savings of up to 30% or more. This is achieved via the use of an automated system that, for example, turns equipment down or off when it is not required. This is achieved via a "hierarchy" which decides which drives / motors are critical and which motors can have speeds reduced. As an example for the refrigeration system, this means utilizing the highest efficiency compressors first then cycling through the lower efficiency units.

3.2.17 Motor efficiency

It was assumed that motors consume 6% (or 160 kW) of total facility power draw. A motor efficiency program was assumed, conservatively, to reduce motor power draw by 5% of typical motor loads via no to minimal cost efficiency gains such as a power management system (PMS). Examples of efficiency gains include turning equipment down or off when it is not required. This is achieved via a “hierarchy” which decides which drives / motors are critical and which motors can be turned off or have speeds reduced. Specific examples include air compressors and air conditioning where a 20% reduction in motor speed results in an approximate 49% lower power draw with no impact on the short term operation of the compressed air system or change in temperature of a controlled environment. Other examples include: real time sensing and automated control; automated shut-down of equipment during out of shift hours to ensure that parasitic loads are minimized, set point control / floating set points; duty / standby optimization.

4 Annual Estimated Abatement Potential

The annual estimated GHG abatement potential in t CO_2-e for each technology is presented in Table 2 below.

Table 2: Annual estimated GHG abatement potential in t CO_2-e

#	Technology	Annual estimated abatement potential (t CO_2-e pa)
1	Waste to AD vessel to biogas cogen	56,842
2	Waste to AD vessel to existing boiler	43,532
3	Waste to AD vessel to biogas flare	42,624
4	Waste to CAL to biogas to cogen	46,341
5	Waste to CAL to biogas to Existing boiler	35,490
6	Waste to CAL to biogas to Flare	34,749
7	Biogas flaring instead of venting 10 yrs	34,749
8	Power management system	1,277
9	Boiler optimization and management system	216
10	Lighting - Replace Metal Halide with LED	544
11	Lighting - Replace Halogen with LED	608
12	Lighting - Replace Fluorescent with LED	342
13	Boiler exhaust (215 °C) waste heat recovery	303
14	Boiler exhaust (400 °C) waste heat recovery	894
15	Torrefied organic waste co-firing in coal boiler	18,747
16	Nat gas cogen - 2000 kW	9,373
17	PV Solar - 99 kW	5,850
18	Refrigeration efficiency (5% saving)	128
19	Motor efficiency (5% saving)	186

5 Marginal Abatement Cost: Investment cost only versus full life cycle

The results in the above section of this report estimated all costs (capital, operating, maintenance) and revenue / savings (power, heat, where indicated: waste management and ERF) over a 10 year life cycle to determine the abatement cost ($ / t CO_2-e). Due to record high power costs in Australia, those technologies saving or generating power have comparatively large negative abatement costs compared to previous studies. Additionally, some previous studies have concentrated on investment (capital outlay) costs only when determining abatement costs. Table 3 below shows the investment (capital) only abatement costs for the technologies that were considered.

Table 3: Investment only marginal abatement cost (does not include operating costs or revenue / savings).

#	Technology	Investment abatement cost ($ / t CO_2-e)
1	Waste to AD vessel to biogas cogen	$ 13.41
2	Waste to AD vessel to existing boiler	$ 8.94
3	Waste to AD vessel to biogas flare	$ 8.90
4	Waste to CAL to biogas to cogen	$ 13.22
5	Waste to CAL to biogas to Existing boiler	$ 6.75
6	Waste to CAL to biogas to Flare	$ 6.61
7	Biogas flaring instead of venting 10 yrs	$ 0.86
8	Power management system	$ 7.44
9	Boiler optimization and management system	$ 35.95
10	Lighting - Replace Metal Halide with LED	$ 64.60
11	Lighting - Replace Halogen with LED	$ 54.51
12	Lighting - Replace Fluorescent with LED	$ 62.66
13	Boiler exhaust (215 ^{o}C) waste heat recovery	$ 50.48
14	Boiler exhaust (400 ^{o}C) waste heat recovery	$ 40.67
15	Torrefied organic waste co-firing in coal boiler	$ 16.29
16	Nat gas cogen - 2000 kW	$ 54.42
17	PV Solar - 99 kW	$ 184.15
18	Refrigeration efficiency (5% saving)	$ 61.84
19	Motor efficiency (5% saving)	$ 171.76
Total Average		$ 10.41

Due to the large range of different power installations, associated power factor levels and PFC equipment, and variation in financial incentives for PFC throughout Australia, it was decided to not include PFC as a separate opportunity. However, PFC could be an economically viable option if the power faction is low and there exists sufficient financial incentive, hence businesses should review PFC opportunities for individual sites.

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