Final Report

AUSTRALIAN MEAT PROCESSOR CORPORATION

AMPC Decarbonisation Pathways Update 2025

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1.0 Abstract

The Australian red meat processing (RMP) sector faces increasing pressure to reduce greenhouse gas emissions in response to national climate targets, evolving regulatory frameworks, and growing market expectations for low-emissions products. While previous studies have identified potential decarbonisation pathways, uncertainty remains regarding their feasibility under current Australian energy market conditions, technology maturity, and policy settings. Recent developments in electrification, renewable energy integration, and market dynamics necessitate an updated assessment.

This project, commissioned by the Australian Meat Processor Corporation (AMPC), updates earlier analyses conducted in 2019 and 2023 by evaluating viable and scalable emissions reduction pathways for the sector. The study incorporates 2024 Environment Performance Report (EPR) data, a review of international decarbonisation progress, assessment of emerging and established technologies, and consideration of relevant Australian policy frameworks. These inputs are integrated into updated decarbonisation pathway modelling.

Four representative site pathways were developed to assess sector-wide opportunities. Results indicate a significant shift since previous analyses, with increased viability of on-site renewable energy generation and battery storage, driven by declining capital costs and the growing prevalence of low and negative wholesale electricity prices.

The findings provide an updated evidence base to support investment planning, technology adoption, and strategic decision-making across the Australian RMP sector.

2.0 Executive Summary

The Australian red meat processing (RMP) sector faces increasing pressure to reduce greenhouse gas emissions in response to national climate targets, evolving regulatory frameworks, and growing market expectations for low-emissions products. While previous studies have identified potential decarbonisation pathways, uncertainty remains regarding their feasibility under current Australian energy market conditions, technology maturity, and policy settings. Rapid developments in electrification, renewable energy integration, and grid decarbonisation necessitate an updated assessment of emissions reduction opportunities.

This project was commissioned by the Australian Meat Processor Corporation (AMPC) to review and update emissions reduction pathways for the sector, building on earlier analyses undertaken in 2019 and 2023. The objective of this study is to identify the most viable and scalable decarbonisation pathways for the Australian RMP sector under current technological, economic, and policy conditions, and to provide an updated evidence base to support industry decision-making.

The research objectives included: updating the sectoral emissions profile and progress; assessing decarbonisation technologies and their commercial readiness; undertaking international benchmarking; evaluating supply chain and retailer-driven decarbonisation pressures; assessing fugitive emissions and bioenergy opportunities; reviewing off-site power purchase options and grid decarbonisation; and developing emissions reduction pathways through scenario modelling.

The study adopts a desktop analysis approach, drawing on data from the 2024 Environmental Performance Report (EPR), relevant domestic and international literature, and prior AMPC decarbonisation studies. The methodology included review and synthesis of sector emissions data, evaluation of technology options based on abatement potential and economic performance, and benchmarking against international markets. Additional analysis was undertaken to assess supply chain requirements, fugitive emissions, and energy procurement strategies, including power purchase agreements. Four representative site pathways were developed to assess sector-wide opportunities.

2.1 Key Findings

Key findings from the research include:

- The primary drivers of carbon abatement remain a combination of internal corporate targets and compliance with state and federal emissions reduction targets.
- A review of emerging regulatory risks found that there is no immediate or forecast exposure of the Australian Red Meat sector to international carbon border adjustment mechanisms (CBAMs) currently.
- External pressure from supply chains, particularly retailers with scope 3 emissions targets, is expected to become an increasingly important driver for decarbonisation in the sector.
- Energy market operator projections indicate gas pricing is anticipated to remain relatively steady across Australia out to 2050.
- Irrespective of this, decarbonisation of non-rendering sites is already economically favourable.
- The sector has continued to improve both energy efficiency and emissions intensity; however, fluctuations in production levels have influenced trend analysis, highlighting the importance of considering throughput when evaluating energy and emissions performance.
- Energy consumption for processors is largely driven by thermal requirements, particularly, steam for rendering and hot water, alongside substantial electrical demand for refrigeration and processing. These systems present the most significant opportunities for emissions reduction.
- Rendering configuration is a major determinant of site energy intensity. Batch dry rendering exhibits the highest energy demand, followed by continuous dry systems, while continuous low-temperature wet rendering systems deliver the lowest energy intensity and the greatest potential for heat recovery.
- Electricity market dynamics (i.e., 24h price variability, solar & battery costs, innovative commercial energy agreements) are challenging the classical approach to energy and emissions management (i.e., efficiency first, renewable energy/fuel switch activities later), which now needs to be reviewed on a case-by-case basis.
- On-site renewable energy generation and battery storage can provide the most cost-effective carbon abatement activity, providing immediate decarbonisation of grid electricity and acting as an enabler for broader electrification of fossil fuel thermal loads.
- The economics for energy storage and electrification is improving year-on-year and is underpinned by declining capital costs and the growing prevalence of low and negative wholesale electricity prices.

Aggregated results indicated a total investment of $793 million, corresponding to a net present value (NPV ~18-year asset life[1]) of $541 million (2026 basis), is required for the 43 sites that responded to the EPR2024 to achieve net zero emissions by 2045. Extrapolating this estimate to the full sector, assuming EPR respondents represent

[1] Net NPV is the summation across the representative site mix. Asset life varies based on the mixture of decarbonisation activities selected in the pathway from 15-25 years.

approximately 68% of industry throughput and the site make-up of non-respondents is similar, suggests an indicative total investment on the order of ~$1.2 billion.

2.2 Recommendations

To support continued decarbonisation of the Australian RMP sector, the following is recommended:

- **Assess rendering systems as a priority**, particularly for facilities operating batch dry rendering, where conversion to continuous wet rendering can deliver substantial energy and emissions reductions.
- **AMPC members should develop site-specific decarbonisation pathways** that account for local energy supply, plant configuration, and operational constraints.
- **Increase adoption of electrification technologies**, including heat pumps and electric boilers, where suitable.
- **Expand on-site renewable energy generation**, particularly solar PV, to reduce reliance on grid electricity and improve long-term energy cost stability.
- **Investigate biogas recovery opportunities** from wastewater and organic waste streams to offset fossil fuel use in thermal systems.
- **Leverage available funding programs and policy mechanisms** to improve project economics, particularly for capital-intensive upgrades and emerging technologies.
- **Continue industry-led research, pilot projects, and knowledge sharing,** particularly for technologies such as MVR, high-temperature heat pumps, and integrated energy systems.
- **Prepare for increasing supply chain requirements**, including retailer-driven scope 3 emissions targets, by developing transparent emissions baselines and reduction strategies.

3.0 Introduction

The Australian red meat processing (RMP) sector faces increasing pressure to reduce greenhouse gas emissions in response to national climate targets, evolving regulatory frameworks, and growing market expectations for low-emissions products. While previous studies have identified potential decarbonisation pathways, there remains a gap in understanding their current feasibility given recent changes in energy markets, technology maturity, and regulatory settings in Australia. In particular, the rapid evolution of electrification technologies, renewable energy integration, and policy mechanisms necessitates an updated assessment of emissions reduction opportunities for the sector.

This project was commissioned by the Australian Meat Processor Corporation (AMPC) to review and update emissions reduction pathways for the Australian RMP sector, building on earlier work conducted in 2019 (AMPC report 2019-1059) and subsequently updated in 2023 (AMPC report 2023-1004). The primary research question addressed in this study is:

What are the most viable and scalable emissions reduction pathways for the Australian red meat processing sector under current technological, economic, and policy conditions?

To address this question, the project includes a review of the 2024 Environment Performance Report (EPR) results, international decarbonisation progress within the red meat processing industry, emerging and established decarbonisation technologies, and relevant Australian government policies. These inputs are integrated into updated decarbonisation pathway modelling to reflect current industry conditions.

This research is targeted at key stakeholders within the RMP sector, including processing facility operators, industry bodies, and policymakers, who require robust and up-to-date information to inform strategic planning and investment decisions. The findings are also relevant to technology providers and researchers involved in industrial decarbonisation.

The results of this study are intended to inform capital investment decisions, support technology adoption, and guide policy and industry alignment with Australia's emissions reduction objectives. By incorporating the latest data and developments, this project provides an updated and more comprehensive assessment than previous studies.

4.0 Project objectives

The objectives of the research conducted are:

1. Review and update sectoral emissions profile and progress assessment.
2. Assess decarbonisation technology options and commercialisation readiness.
3. Undertake international benchmarking and competitive analysis.
4. Review supply chain pressure analysis and retailer requirements
5. Assess fugitive emissions and bioenergy opportunities
6. Review off-site power purchase agreements and grid decarbonisation
7. Develop carbon offset and insetting strategy
8. Undertake strategic pathways development and scenario modelling

5.0 Methodology

This project is a desktop analysis which draws on the data and research in the Environmental Performance Report (EPR) 2024, domestic and international literature resources, and updates the Decarbonisation Pathways report, 2023. The phases of the project were as follows:

- Conduct a project kick-off meeting with AMPC.
- Review the 2024 Environmental Performance Review report.
- Update sectoral emissions profile and review grid decarbonisation, updating future emissions factors.
- Review decarbonisation technologies for RMP drawing on first-hand experience from consortia partners, and desktop research.
- Present a revised list of suitable technologies, including assessments of commercial readiness, emissions abatement potential, and economic metrics.
- Perform desktop research to benchmark AMPC sectoral decarbonisation performance against key international markets.
- Review supply chain decarbonisation pressures and retailer requirements, including scope 3 disclosure expectations from major retailers, carbon neutral targets assessments, and scope 3 inventory framework.

- Review sector-wide fugitive emissions from wastewater treatment, current biogas adoption, and future sector opportunities.
- Evaluate off-site Power Purchase Agreement (PPA) options for RMP.
- Develop a report outlining revised decarbonisation pathways under business-as-usual, technology-accelerated, policy-driven, and high-offset reliance scenarios.
- Prepare the final report and assist the graphics provider with visual content.
- Deliver a final presentation to AMPC.

6.0 Results

6.1 2024 EPR Results

The 2024 Environmental Performance Review (EPR) provided key energy metrics for AMPC members. Five EPRs have been conducted since 2010, using voluntary participation from RMP facilities and applying a consistent questionnaire to enable comparison between years. Participation has increased substantially – from 14 sites in 2010 to 43 sites in 2024 – and now covers approximately 68% of national RMP production. Table 1 summarises historical emissions and energy intensities including the breakdown of energy sources.

Table 1: Historic average emissions intensity across voluntary RMP facilities

Resource	2010	2015	2020	2022	2024
GHG intensity (kg CO_2-e/ t HSCW)	554	432	397	447	343
Energy intensity (MJ/ t HSCW)	4108	3005	3316	3435	2984
Electricity (%)			35%	32%	31%
Natural gas (%)			30%	30%	37%
Coal (%)			20%	15%	11%
Other fossil fuels (%)			6%	7%	7%
Biomass (%)			4%	8%	7%
Biogas from WWT (%)			6%	8%	7%
Wind or solar (%)			-	0.1%	0.3%

The EPR results indicate a 26% reduction in emissions intensity since 2022, indicating that for organisations actively pursuing emissions reduction measures, energy and emissions intensities are trending downward[2]. A linear reduction from 2010 to 2024 shows an 11% average annual reduction[3]. Figure 1 shows RMP emissions with a linear trend line indicating estimated emissions in 2005, and projecting emissions to 2035. It also shows historic national emissions to 2024 and national policy expectations for emissions reductions in 2030 and 2035 (DCCEEW, 2025).

EPR data indicates emissions from RMP production in 2024 have decreased approx. 45% from 2005 levels, which is ahead of current national emissions reduction of 28%. However, RMP emissions reduction will need to accelerate in order to stay ahead of national emissions reduction targets otherwise the sector may not meet 2035 targets nor achieve net zero by 2050.

[2] Voluntary participation means results may not reflect the full sector and may overstate performance.
[3] Lack of key statistical parameters such as historic standard deviation and total state-level production data limits confidence in sector-wide trend analysis

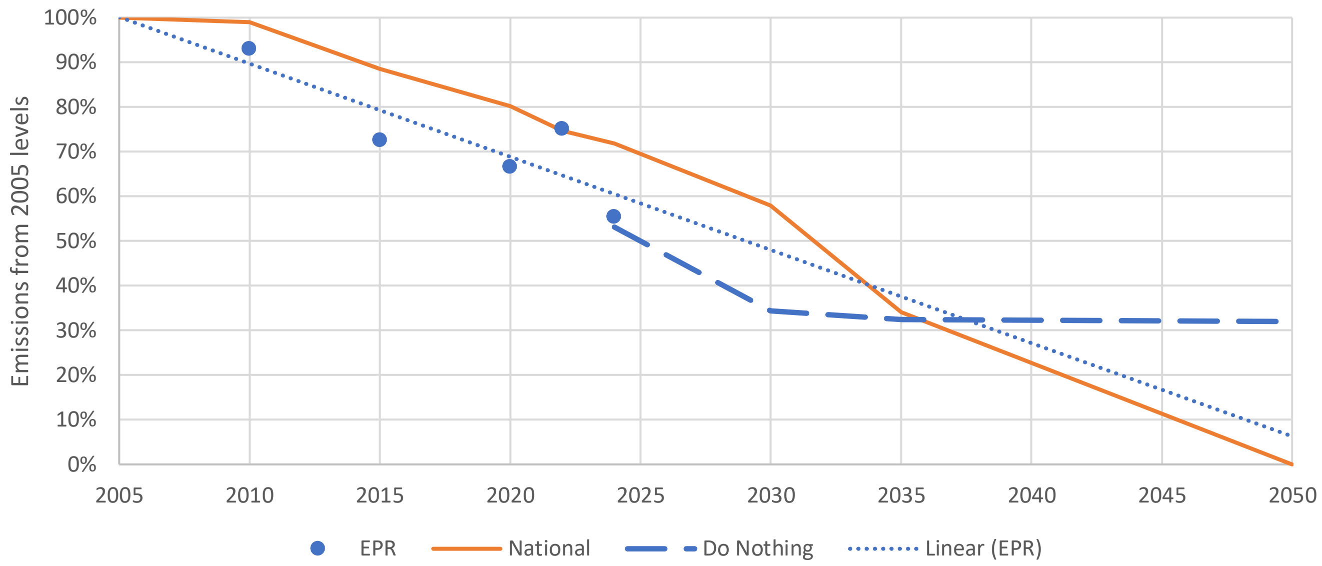


Figure 1: Recorded and targeted emissions levels from RMP and National

Table 2 provides the associated Scope 1 and Scope 2 emissions intensity by state. This shows that electricity use constitutes the primary source of emissions, especially in states with higher grid emissions factors, such as Queensland. Wastewater emissions are also considerable, but highly varied between states. Refrigerant emissions represent a small fraction of total Scope 1 emissions with the average refrigerant emissions intensity of refrigerant reporting sites being 7.2 $kgCO_2$/tHSCW. However, 65% of sites did not report emissions from refrigerants, which suggests sites may be underreporting. Whilst most medium and large-scale sites generally use ammonia for refrigeration, and these sites account for 80% of industry production, some sites also use HFC refrigerants which have much higher global warming potential (GWP) factors. HFC refrigerants can therefore result in higher refrigerant emissions, but are subject to a staged phase-down.

Table 2: Scope 1 and Scope 2 emissions intensities by state.

States	Scope 1 Energy	Wastewater	Refrigerants	Scope 2 Electricity	Total
	Emission Intensity (kgCO2/tHSCW)				
NSW	83	142	2	182	409
QLD	124	47	0	232	403
SA	98	63	2	80	243
TAS	36	16	10	57	118
VIC	109	16	5	173	303
WA	85	32	2	124	243
Average	**102**	**58**	**3**	**180**	**343**

6.1.1 Wastewater

Wastewater emissions are primarily measured using one of two methods: Method 1 estimates emissions using standard emissions factors applied to specific pre-recorded wastewater data such as Biochemical Oxygen Demand (BOD), or Chemical Oxygen Demand (COD) and sludge content. Method 2 directly measures methane emissions from wastewater. It is recommended that a facility use Method 1 to estimate emissions if the facility has not yet made effort to reduce wastewater emissions, however emissions reducing opportunities such as biogas development or methane flaring reduces emissions released after COB/BOD are measured. As a result, Method 2 is recommended if they have actively worked to reduce wastewater emissions. A comparison of the two methods is presented in Table 3.

Table 3: Comparison table between Method 1 & 2 wastewater emissions reporting

Method 1: Default / Factor Based	Method 2: Site-specific / Measured
Uses standard emissions factors	Measured wastewater characteristics
Based on proxy activity data (Wastewater volume, estimated COD/BOD or production)	Based on actual COD/BOD loading
Assumes average wastewater system performance	Reflects real performance
No Site-specific monitoring required	Requires sampling, monitoring and data management
Low accuracy	High Accuracy
Low cost/ low effort	Higher cost / higher effort
Suitable for baseline inventories and screening	Suitable for robust reporting, compliance and emissions incentives
Not Suitable for ACCU generation	Required for ACCU verified emissions reduction

6.1.2 Effect of Rendering

Figure 2 presents the energy and emissions intensity of different size facilities, categorised by the type of rendering operations. The data shows sites without rendering use 40% less energy than sites with rendering - average energy intensity of sites with rendering was 3,140 MJ/tHSCW, while the average energy intensity of sites without rendering was 1,880 MJ/tHSCW. The data also shows that there is a strong correlation between energy intensity and emissions intensity for non-rendering sites, however this is not the case for rendering facilities. This is likely due to several factors, including, the type of rendering process employed by sites, and that some rendering facilities process additional rendering material from third party sites, material which is not captured by the tHSCW measurement to compare emissions intensities in this study.

More information on rendering processing types and their energy intensity can be found under Appendix 11.2.1 Rendering and Opportunities.

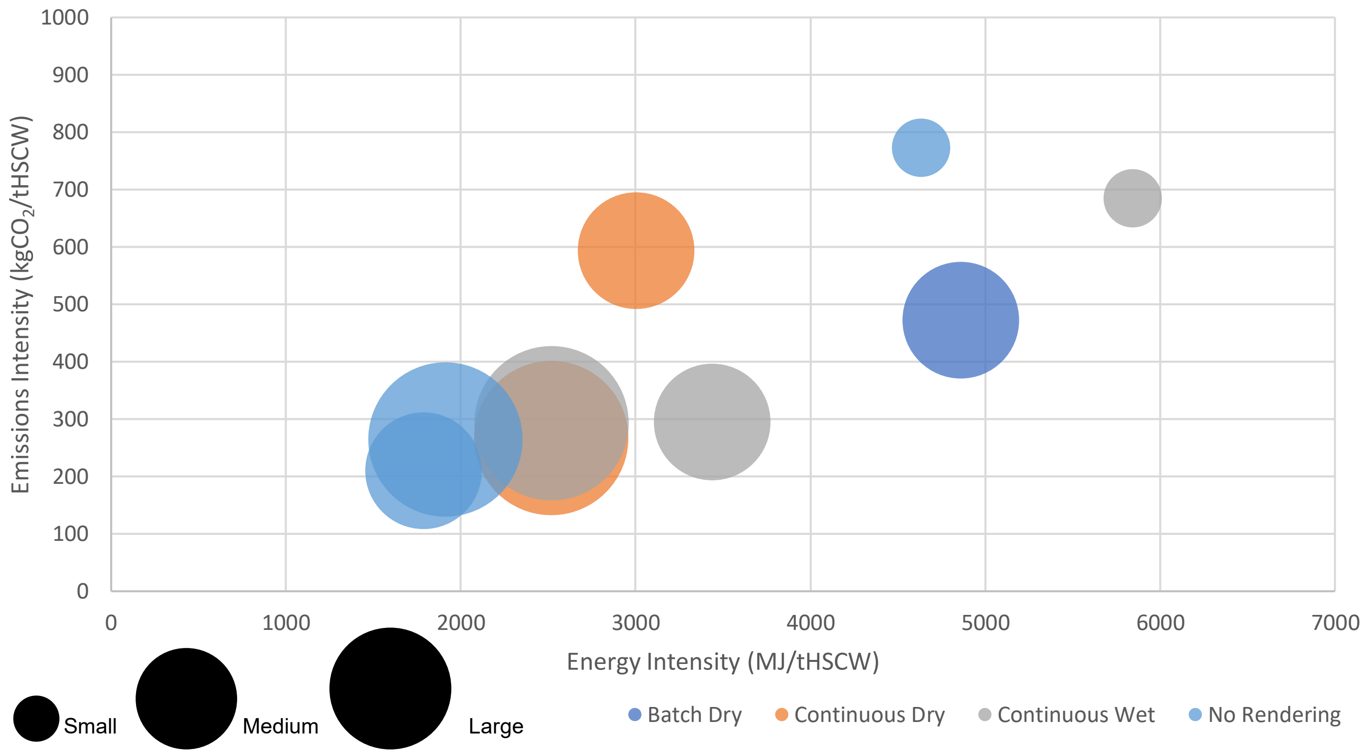


Figure 2: Graph of energy intensity compared with emissions intensity of different sizes sites, separated by rendering type.

6.1.3 Successful Opportunities

EPR showed through surveys of 43 sites (68% of national production) that Australia is continuing to take steps towards decarbonising RMP. Table 4 shows the list of opportunities RMP sites are implementing, and how they relate to energy and emissions reduction.

Table 4: EPR Results indicate opportunities implemented by RMP Sites.

Opportunity	Relevance
Water submeters	Measuring energy used in hot water
Electricity Submetering	Measuring energy used through electricity
Water pressure reduction in washing bays and cleaning	Reduced hot water demand
Flow limiting nozzles in handwash stations	Reduced hot water demand
Automated sensors	Reduced hot water demand
Rendering plant upgrades	Process energy efficiency increase
Steam and water process control improvements	Reduced steam and hot water demand
Steam boiler economiser	Energy reduction through steam boiler efficiency
Automation upgrades	Energy reduction through automation efficiency
Energy use efficiency actions	Energy reduction through efficiency
LED Lighting upgrades	Electricity reduction through lighting efficiency
Refrigeration and water pump upgrades	Electricity reduction through pump efficiency
Solar PV system installations	Supply of renewable electricity
Covered anaerobic lagoons for biogas production	Supply of renewable energy
Biogas system improvements	Supply of renewable energy

6.2 Key Decarbonisation Technologies

Key decarbonisation technologies and opportunities for Australian RMP facilities are shown in Table 5 (a complete list of opportunities is presented in Appendix 10.1). A weighted multicriteria assessment was used to evaluate the relative merits of each, considering the following criteria:

Criteria	Abbreviation	Weighting
Technology readiness	TRL	1
Installation complexity	INST.	1
Greenhouse gas reduction	GHG	4
Payback period	PB	4

Each opportunity or technology was assigned a score out of 5 for each criteria, which was then multiplied by the associated weighting factor and summed to give an overall score out of 50. Criteria were weighted to prioritise decarbonisation and economics, often stated as the key barriers to adoption.

Table 6 explains the criteria scoring methodology.

Note: Detailed description of the technologies presented in this section can be found in Appendix 10.2.

Table 5: Summary decarbonisation opportunity matrix (See APPENDIX 10.1 for complete list). Note: Max score = 50. Action priority: green = high, amber = medium, red = low.

Group	Opportunity / Technology (hyperlinks to more info)	Description	TRL	INST.	GHG	PB	Overall Score
EE	Wet rendering	Converting Batch Dry to Wet Continuous Rendering	5	2	5	5	47
Elec	Heat pump	Hot Water Heat Pump up to 90°C using waste heat (liquid source)	3	3	5	4	42
Bio	Biogas	General effluent (Covered Anaerobic Lagoons), paunch or DAF (Hydraulic Reactor)	5	2	5	3	39
EE	Continuous rendering	Batch to Continuous Rendering optimisation	5	2	4	4	39
EE	Low water sterilisation	Reduce volume of 82°C consumed in Sterilisers using nozzle types or Econoliser	4	3	3	5	39
RE	Rooftop solar	Flush and tilt rooftop solar PV on existing buildings, including factories and sheds.	5	5	4	3	38
RE	Ground-mount solar	Fixed tilt and E/W tracking solar PV connected behind the meter	5	5	4	3	38
EE	Lagging steam	Insulation on steam lines	5	4	2	5	37
EE	Fine crusher	Reduce particle size of raw rendering material before cooker	5	3	3	4	36
EE	Refrigeration heat recovery	Recovering waste heat from condenser and oil coolers	5	3	2	5	36
EE	Condensate return system	Installing, improving or maintaining the condensate return in a steam system	5	3	2	5	36
Bio	Biomass boilers	Steam Generation using some form of biomass	5	2	5	2	35
Elec	E-boiler - Spot market	Electric boiler for steam generation, exposed to spot electricity market	4	3	4	3	35
EE	Lagging hot water	Insulation on hot water lines	5	5	2	4	34
EE	Boiler tuning	Tuning boiler yearly to maintain nameplate combustion efficiency	5	5	1	5	34
RE	Boiler economisers	Utilising waste heat to preheat incoming water	5	3	2	4	32
Elec	E-Boilers - Green Electricity	Electric boiler steam generation, purchasing green electricity for supply	4	3	5	1	31
EE	Heat recovery - Rendering	Heat Recovery to supply hot water from various processes	5	2	3	3	31

Table 6: Assessment criteria scoring methodology

Score	Technology Readiness (TRL)	Installation Complexity	GHG Reduction (% site)	Payback (years)
1	TRL 7	Fundamental process change - extended shutdown required	<1%	>10 years
2	TRL 8	Significant process change – shutdown required	≥1%	<7 years
3	TRL 9	Simple integration –multiple off hours required	≥5%	<5 years
4	TRL 10	Simple integration – little/no downtime	≥10%	<3 years
5	TRL 11	No process change required	≥20%	<1 years

$$Overall\ Score = \sum Score \times Weighting = (TRL \times 1) + (Install\ Complexity \times 1) + (GHG\ Reduction\ \times 4) + (Payback \times 4)$$

6.3 Decarbonisation Pathways

The decarbonisation pathways adopted by Australian RMP facilities will vary considerably depending on many factors, including their size, location (state), existing thermal fuel mix, whether the site renders or not, and more. The following sections present **possible decarbonisation pathways** using representative but fictional sites.

It should be noted that it is not possible to capture the exact pathway for all AMPC members without site specific investigations and data. The objective of the decarbonisation pathways is to illustrate the strategy that may be adopted in different circumstances and the rationale to support this.

Key information that RMP facilities should consider from the following pathways are the:

- Sequencing of energy efficiency, renewable energy implementation and fuel switching activities.
- Magnitude of carbon emissions reduction and economics of different initiatives.
- Indicative financial investment requirements to meet required emissions reduction targets.

6.3.1 Representative AMPC Sites

The following nominal facilities are used as "illustrative" examples to represent the entire Australian red meat processing industry, based on EPR2024 data:

1. **Large facility with rendering (continuous wet)**
   Large-scale sites with rendering represent 26% of all respondents to the EPR 2024 survey. All large sites process beef, while a third also process small animals. Large sites have an average combined processing volume of ~105,000 tHSCW per year, and ~29,000 tonnes of rendered product annually.
2. **Medium facility with rendering (batch dry)**
   Medium-scale sites with rendering represent 44% of all respondents to the EPR 2024 survey (18% use batch dry rendering). Animal type processed is varied, with a mixture of multi-species, small animal or beef only sites. The average processing volume in medium sites with rendering is 47,500 tHSCW per year, and 17,250 tonnes of rendered product annually.

   For illustrative purposes, a site with batch dry rendering was selected for decarbonisation pathway development. The average processing volume for medium sites with batch dry rendering is ~34,000 tHSCW per year, and ~12,200 tonnes of rendered product annually.
3. **Medium facility with no rendering**
   Medium-scale sites with no rendering represent 7% of all respondents to the EPR 2024 survey. These sites are either small animal or beef only with an average processing volume of ~39,000 tHSCW per year.
4. **Small facility with no rendering**
   Small-scale sites with no rendering represent 23% of all respondents to the EPR 2024 survey. These sites are either small animal or mixed-species processors. Small sites have an average processing volume of ~9,500 tHSCW per year.

The illustrative specific energy and production data for the four representative sites is summarised in Table 7.

Table 7: Summary of key illustrative production and energy statistics for representative AMPC sites.

#	Size	Rendering Type	Throughput (tHSCW)	Total Energy Intensity (MJ/tHSCW)	Thermal (GJ/y)	Electrical (GJ/y)	Total (GJ/y)	Indicative Boiler Capacity (MW)
1	L	CW	104,669	2,869	193,211	107,058	300,268	10
2	M	BD	33,986	4,488	117,930	34,599	152,529	6
3	M	None	38,957	1,787	44,134	25,479	69,613	4
4	S	None	9,449	1,994	10,921	7,924	18,845	1

Key notes and assumptions:

- Facility size classification is based on throughput, as follows:
    - small (S): tHSCW < 25,000
    - medium (M): 25,000 < tHSCW < 75,000
    - large (L): tHSCW > 75,000
- Throughput for the given facility size is the average for this size class from EPR2024 data
- Energy consumption figures are average for this size class from EPR2024 data
- Energy intensity is calculated using average throughput and total energy.
- For rendering type, CW = continuous wet, and BD = batch dry
- The business-as-usual (BAU) pathway presented assumes no opportunities are implemented, and only grid emissions reduction is accounted for.

6.3.2 Marginal Abatement Cost (MAC) Curve & Decarb Pathway Methodology

Marginal abatement cost (MAC) is the cost of reducing one additional unit of emissions (typically expressed as \$/tCO_2e), expressed as:

$$MAC = \frac{-NPV\ (\$)}{Lifetime\ emissions\ abatement\ (tCO_2e)}$$

MAC provides one comparative metric for assessing projects by indicating the relative cost-effectiveness of emissions reductions across different abatement options. The MAC for different carbon abatement initiatives can be compared in a Marginal Abatement Cost Curve (MACC), which plots the MAC for different actions from most favourable (largest negative MAC) to least favourable (largest positive MAC). The width of each action indicates the total lifetime emissions abatement (tCO_2e). When plotted for a site or organisation, the decarbonisation actions are typically shown until their cumulative emissions abatement reaches the total site emissions – i.e., they indicate all actions required to achieve Net Zero. It is also prudent to consider the cost of direct action (project implementation) against the cost of emission offsets, which can also be indicated in a MAC curve.

However, a major limitation with MACC is that it is challenging to present mutually exclusive options (e.g., biomass vs. electric boilers). When plotted in ascending MAC values, they also do not necessarily convey a realistic or strategic project implementation sequence which account for facilities capital constraints, known variances in emissions factors (e.g., cleaning up of grid electricity), and consideration of operational impacts.

A decarbonisation pathway plot can help address these limitations by illustrating how selected measures are sequenced over time under illustrative real-world constraints, showing the evolution of emissions and costs while accounting for dependencies, mutually exclusive choices, and expected changes in external factors such as grid emissions intensity.

For this reason, each of the representative AMPC sites described above have had both a MACC and an indicative decarbonisation pathway developed for them.

6.3.3 Large Site with Continuous Wet Rendering

The MACC and proposed decarbonisation pathway are shown in Figure 3 & Figure 4 respectively. The MACC shows that all initiatives have negative MACs (except for the purchase of emissions offsets), indicating they offer emissions savings and have a positive net present value (NPV ~19-year average asset life). The total investment of $39.3m delivers $7m in annual energy cost savings, achieving a weighted average payback of 6.2 years.

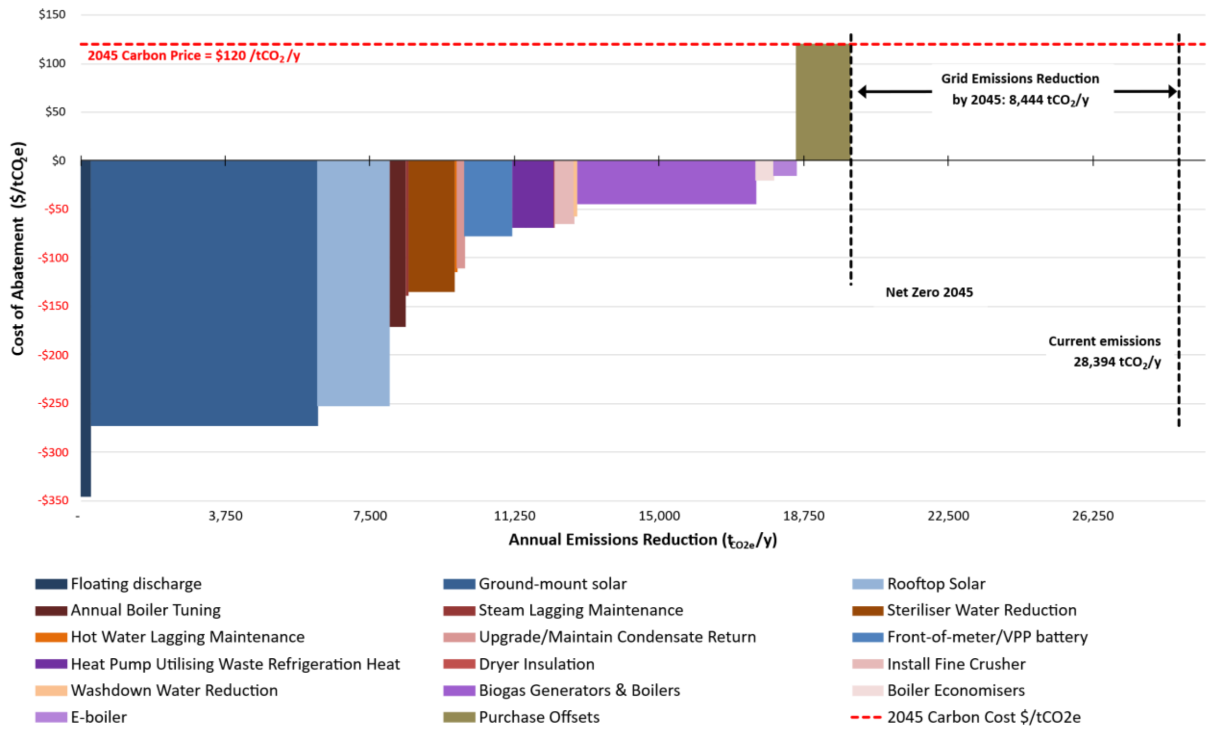


Figure 3: Marginal Abatement Cost Curve for a large site operating continuous wet rendering.

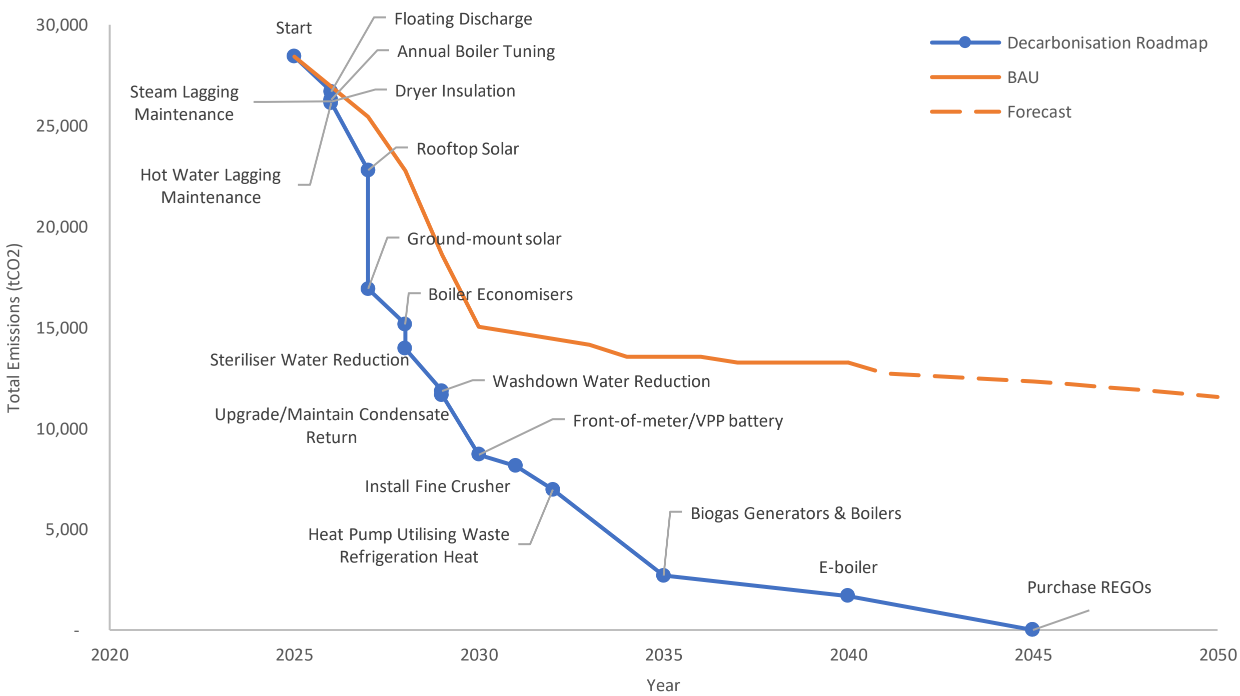


Figure 4: Proposed decarbonisation pathway for a large site operating continuous wet rendering.

THE DECARBONISATION STRATEGY
The roadmap is structured in four phases between 2026 to 2045, with each phase building on the previous phase to minimise risk and optimise returns.

Phase 1: Efficiency Foundation (2026-2031, $3M)

This phase delivers a suite of operational efficiency improvements, reducing site energy consumption by approximately 60,000 GJ/year (20%), equivalent to 3,200 tCO_2e/year and around $1M in operational savings.

An efficiency-first approach is critical, as each unit of energy saved reduces the scale and cost of subsequent renewable and electrification investments. Many measures have short paybacks (<5 years), improving cashflow and, where savings are reinvested, supporting future capital projects. In addition, measured savings help validate business cases and build stakeholder confidence for larger investments.

Phase 2: Renewable Electricity Investment (2027-2030, $27.5M)

This phase significantly reduces grid dependency by displacing approximately 75% of grid electricity through on-site solar generation and battery storage, equating to 80,000 GJ/year (26% of total demand) and up to 9,000 tCO_2e/year of emissions reduction. Estimated electricity cost savings are approximately $4.3M/year.

This phase precedes thermal electrification for several reasons:

- **Cost reduction:** Solar lowers electricity costs from ~$180/MWh (grid) to ~$80–95/MWh (LCOE), improving the economics of electrification.
- **Load alignment:** Solar generation aligns well with daytime refrigeration loads, the site's primary electrical demand driver.
- **Infrastructure validation:** Installing ~10 MW of solar utilises existing transformer capacity and helps validate network capability before adding further electrical load.

Phase 3: Thermal Fuel Switching (2032 – 2040, $9.6M)

Thermal electrification is deliberately staged after earlier phases, when grid emissions intensity is lower, on-site generation is established, and efficiency gains have been realised. This phase reduces fossil fuel use by approximately 135,000 GJ/year (70% of thermal demand) and 7,000 tCO_2e/year, with operational savings of around $2M/year.

- **Heat Pump (from 2032):**
  A heat pump is deployed to meet hot water demand (~30% of thermal load), leveraging waste heat from refrigeration systems. This is prioritised due to lower integration risk, immediate gas reduction (~26,000 GJ/year), and strong performance (COP >4.5), delivering a ~4.3-year payback.
- **Biogas Boiler:**
  Where viable, a biogas boiler is implemented ahead of electrification to provide low-cost, low-emissions energy and system resilience. A ~5 MW unit operating ~14 hours/day is sized based on biogas availability and peak steam demand (primarily rendering). A dual-fuel (biogas/natural gas) configuration is recommended to maintain reliability during transition.
- **Electric Boiler:**
  The electric boiler is implemented last due to higher operating costs and is intended for flexible operation. Its business case relies on exposure to wholesale electricity pricing, operating during low or negative price periods and when excess solar generation is available. While utilisation is relatively low, it becomes cost-competitive as grid emissions decline and when compared with the cost of carbon offsets. The expected simple payback is ~5.6 years.

Phase 4: Purchase Offsets (2041 – 2045)

The remaining emissions that cannot be abated are from wastewater processing and electricity consumption that continues to come from non-renewable generation. The final phase of decarbonisation is the purchase of emissions offsets to achieve Net Zero emissions by 2045. This initiative will cost $203k/year in additional opex and offset 1,629 tCO_2e/year.

Additional information about this pathway can be found in Section 7.1.1.

6.3.4 Medium Site with Rendering

The MACC and proposed decarbonisation pathway are shown in Figure 5 & Figure 6 respectively. The MACC shows that all initiatives have negative MACs (except for the purchase of emissions offsets), indicating they offer emissions savings and have a positive net present value (NPV ~18-year asset life). The total investment of $16.4m delivers $2.85m in annual energy cost savings, achieving a weighted average payback of 6.4 years.

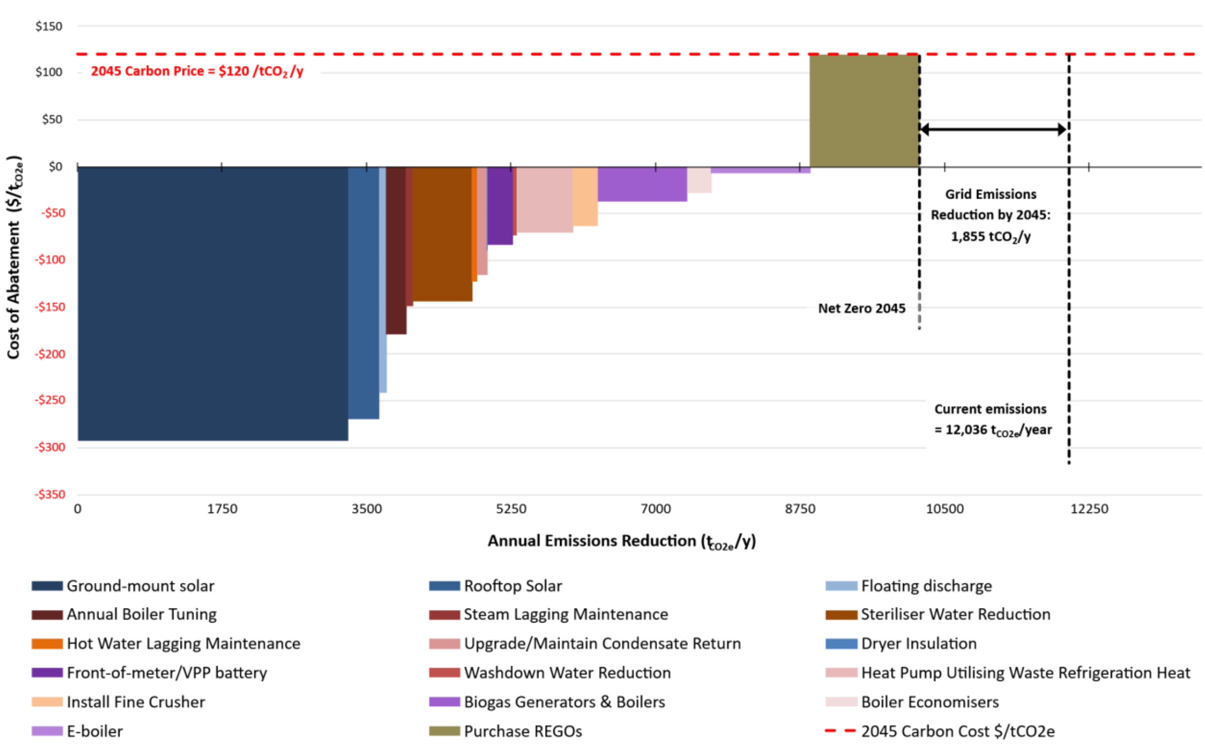


Figure 5: Marginal Abatement Cost Curve for a medium site operating batch dry rendering.

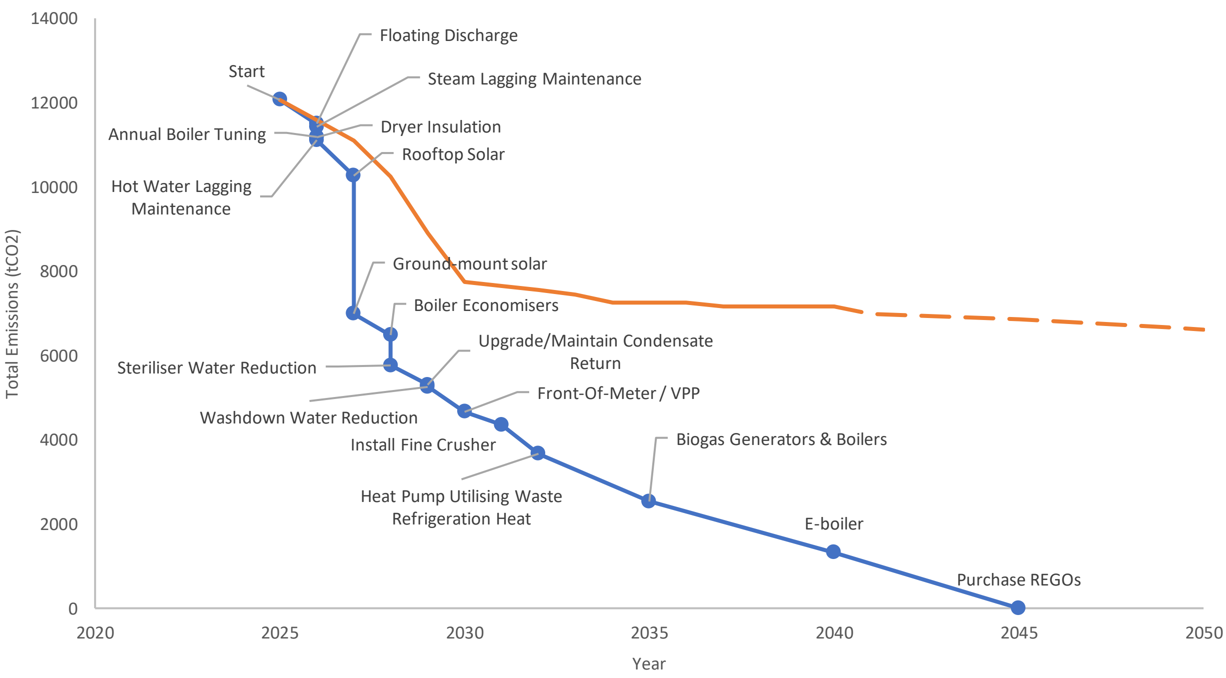


Figure 6: Proposed decarbonisation pathway for a medium site operating batch dry rendering.

THE DECARBONISATION STRATEGY
The roadmap is structured in four phases between 2026 to 2045, with each phase building on the previous phase to minimise risk and optimise returns.

Phase 1: Energy Efficiency (2026-2029, $1.43M)

This phase includes a programme of minor energy efficiency projects intended to achieve immediate improvements, reducing site energy consumption by approximately 30,850 GJ/year (20%), equivalent to 1,645 tCO_2e/year and around $510k in operational savings.

An efficiency-first approach is critical, as each unit of energy saved reduces the scale and cost of subsequent renewable and electrification investments. Most measures in this tranche have short paybacks (<5 years), improving cashflow and, where savings are reinvested, supporting future capital projects. In addition, measured savings help validate business cases and build stakeholder confidence for larger investments.

Phase 2: Renewable Electricity Investment (2027-2030, $10M)

This phase significantly reduces grid dependency by displacing approximately 74% of grid electricity through on-site solar generation and battery storage, equating to 31,500 GJ/year (21% of total demand) and up to 3,950 tCO_2e/year of emissions reduction. Estimated electricity cost savings are approximately $1.65M/year.

This phase precedes thermal electrification for several reasons:

- **Cost reduction:** Solar lowers electricity costs from ~$180/MWh (grid) to ~$80–95/MWh (LCOE), improving the economics of electrification.
- **Load alignment:** Solar generation aligns well with daytime refrigeration loads, the site's primary electrical demand driver.
- **Infrastructure validation:** Installing ~4.5 MW of solar utilises existing transformer capacity and helps validate network capability before adding further electrical load.

Phase 3: Thermal Fuel Switching (2032 – 2040, $5M)

Thermal electrification is deliberately staged after earlier phases, when grid emissions intensity is lower, on-site generation is established, and efficiency gains have been realised. This phase reduces fossil fuel use by approximately 82,000 GJ/year (100% of thermal demand) and 2,965 tCO_2e/year, with operational savings of around $2.2M/year.

- **Heat Pump (from 2032):**
  A heat pump is deployed to meet hot water demand (~19% of thermal load), leveraging waste heat from refrigeration systems. This is prioritised due to lower integration risk, immediate gas reduction (~15,400 GJ/year), and strong performance (COP >4.5), delivering a ~4.8-year payback.
- **Biogas Boiler:**
  Where viable, a biogas boiler is implemented ahead of electrification to provide low-cost, low-emissions energy and system resilience. A ~3.3 MW unit operating ~5 hours/day is sized to meet anticipated steam demand during peak electrical cost periods (i.e., provides a physical hedge for the e-boiler below). A dual-fuel (biogas/natural gas) configuration is recommended to maintain reliability during transition.
- **Electric Boiler:**
  The 4 MW electric boiler is implemented last due to higher operating costs and is intended for flexible operation. Its business case relies on exposure to wholesale electricity pricing, operating during low or negative price periods and when excess solar generation is available (assumed to be approx. 11-hours a day). While utilisation is relatively low, it becomes cost competitive as grid emissions decline and when compared with the cost of carbon offsets. The expected simple payback is ~8.7 years.

Phase 4: Purchase Offsets (2041 – 2045)

- The remaining emissions that cannot be abated are from wastewater processing and electricity consumption that continues to come from non-renewable generation. The final phase of decarbonisation is the purchase of emissions offsets to achieve Net Zero emissions by 2045. This initiative will cost $159k/year in additional opex and offset 1,326 tCO_2e/year.

Additional information about this pathway can be found in Section 7.1.2.

6.3.5 Medium Site with No Rendering

The MACC and proposed decarbonisation pathway are shown in Figure 7 & Figure 8 respectively. The MACC shows that all initiatives have negative MACs (except for the purchase of emissions offsets), indicating they offer emissions savings and have a positive net present value (NPV ~18-year asset life). The total investment of $7.5m delivers $1.3m in annual energy cost savings, achieving a weighted average payback of 6 years.

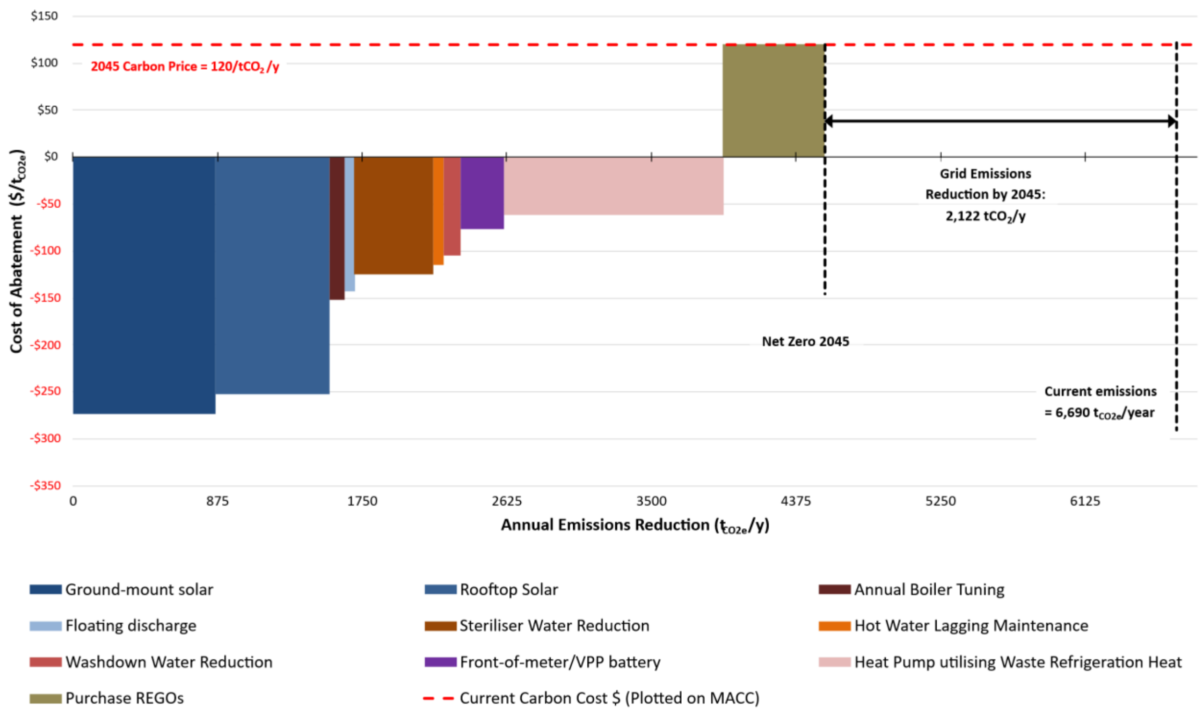


Figure 7: Marginal Abatement Cost Curve for a medium site with no rendering.

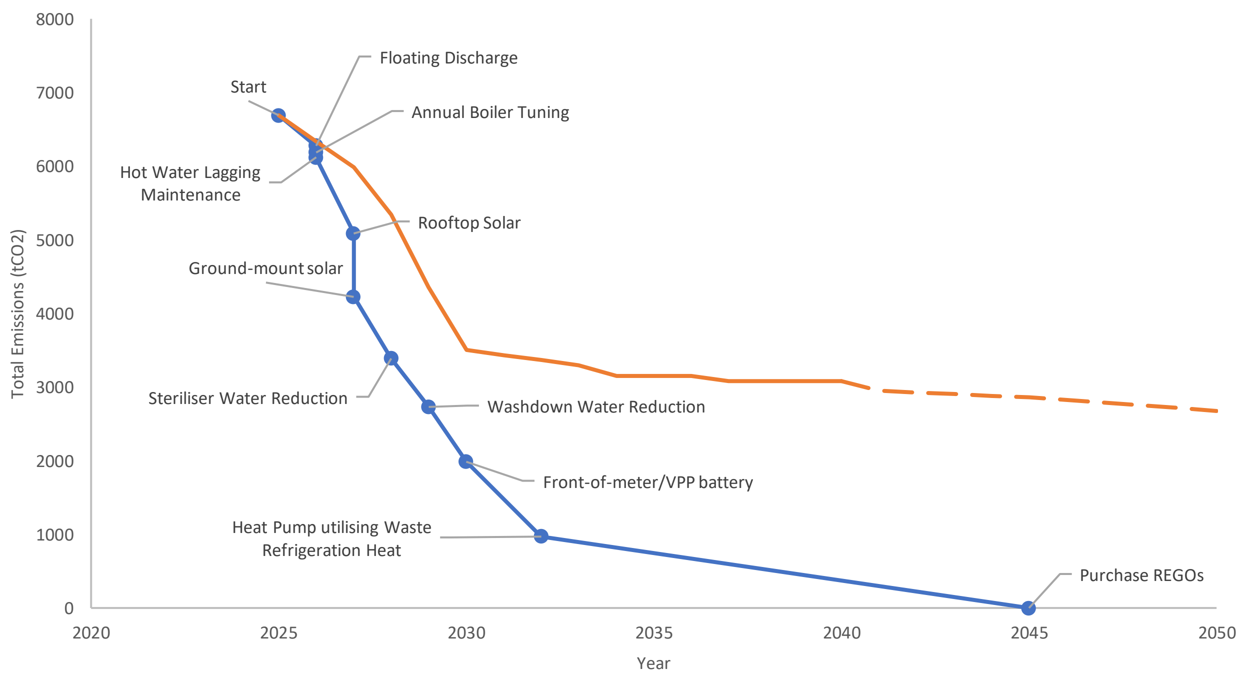


Figure 8: Proposed decarbonisation pathway for a medium site with no rendering.

THE DECARBONISATION STRATEGY
The roadmap is structured in three phases between 2026 to 2032, with each phase building on the previous phase to minimise risk and optimise returns.

Phase 1: Efficiency Foundation (2026-2029, $534k)

This phase delivers a suite of operational efficiency improvements, reducing site energy consumption by approximately 14,500 GJ/year (21%), equivalent to 790 tCO_2e/year and around $246k in operational savings.

An efficiency-first approach is critical, as each unit of energy saved reduces the scale and cost of subsequent renewable and electrification investments. Many measures have short paybacks (<5 years), improving cashflow and, where savings are reinvested, supporting future capital projects. In addition, measured savings help validate business cases and build stakeholder confidence for larger investments.

Phase 2: Renewable Electricity Investment (2027-2030, $2.85M)

This phase significantly reduces grid dependency by displacing approximately 65% of grid electricity through on-site solar generation and battery storage, equating to 16,300 GJ/year (23% of total demand) and up to 1,810 tCO_2e/year of emissions reduction. Estimated electricity cost savings are approximately $877k/year.

This phase precedes thermal electrification for several reasons:

- **Cost reduction:** Solar lowers electricity costs from ~$180/MWh (grid) to ~$80–95/MWh (LCOE), improving the economics of electrification.
- **Load alignment:** Solar generation aligns well with daytime refrigeration loads, the site's primary electrical demand driver.
- **Infrastructure validation:** Installing ~2.1 MW of solar utilises existing transformer capacity and helps validate network capability before adding further electrical load.

Phase 3: Thermal Fuel Switching (2032, $1.3M)

Thermal electrification is deliberately staged after earlier phases, when grid emissions intensity is lower, on-site generation is established, and efficiency gains have been realised. This phase reduces fossil fuel use by approximately 30,000 GJ/year (100% of thermal demand) and 1,325 tCO_2e/year, with operational savings of around $400k/year.

- **Heat Pump (from 2032):**
  Without the need for steam on site, a heat pump can be deployed to meet all hot water demand (100% of thermal load), leveraging waste heat from refrigeration systems. With an assumed COP >4.5, this initiative has a ~4.6-year payback.

Phase 4: Purchase Offsets (2035 – 2045)

The remaining emissions that cannot be abated are from electricity consumption that continues to come from non-renewable generation. The final phase of decarbonisation is the purchase of emissions offsets in the form of REGOs to achieve Net Zero emissions by 2045. This initiative will cost $116k/year in additional opex and offset 970 tCO_2e/year.

Additional information about this pathway can be found in Section 7.1.3.

6.3.6 Small Site with No Rendering

The MACC and proposed decarbonisation pathway are shown in Figure 9 & Figure 10 respectively. The MACC shows that all initiatives have negative MACs (except for the purchase of emissions offsets), indicating they offer emissions savings and have a positive net present value (NPV ~19-year asset life). The total investment of $2.9m delivers $518k in annual energy cost savings, achieving a weighted average payback of 6.6 years.

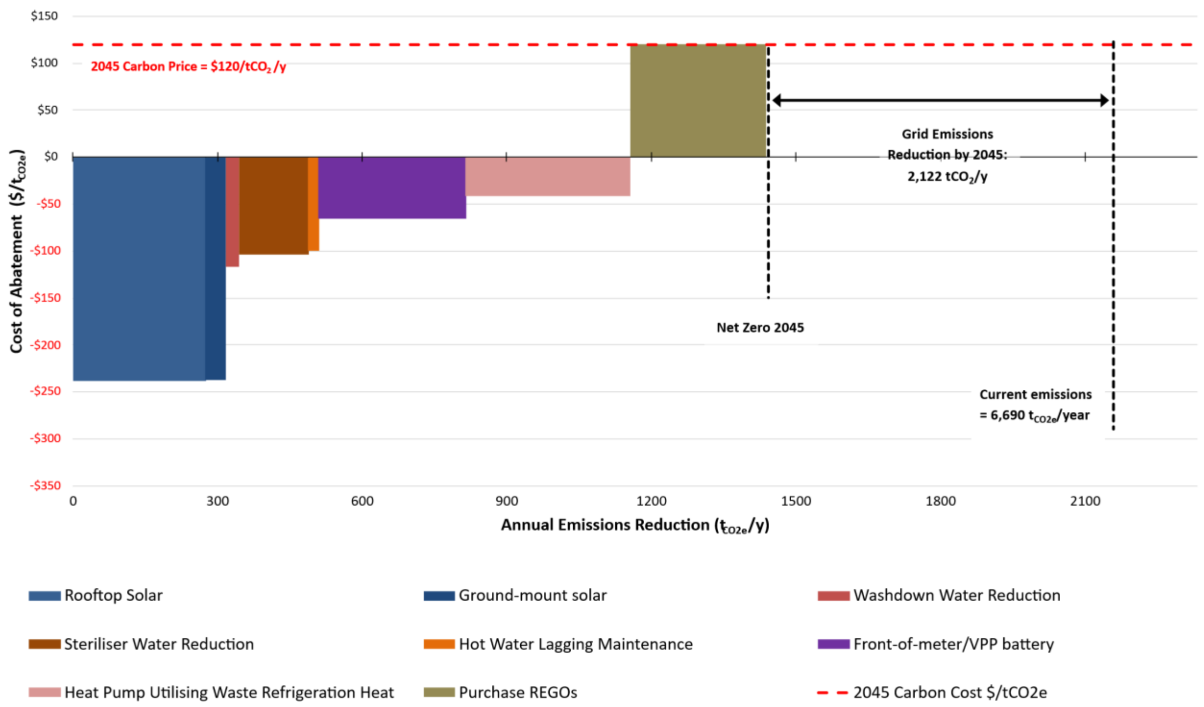


Figure 9: Marginal Abatement Cost Curve for a small site with no rendering.

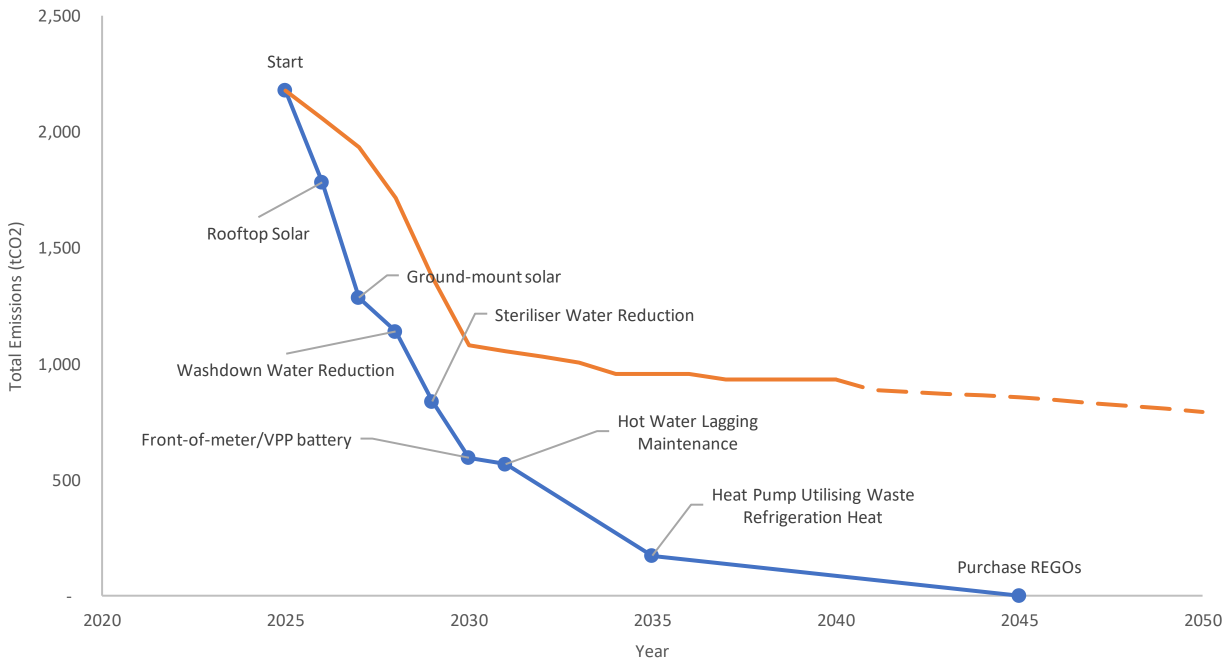


Figure 10: Proposed decarbonisation pathway for a small site with no rendering.

THE DECARBONISATION STRATEGY

The roadmap is structured in four phases between 2026 to 2035, with each phase building on the previous phase to minimise risk and optimise returns.

Phase 1: Renewable Electricity Investment (2026-2027, $1.2M)

For this site, renewable energy investment is adopted first as it offers the lowest MAC of all decarbonisation initiatives. Furthermore, it can be implemented with minimal disruption to site operations. Dependency on grid electricity is reduced by approximately 51% of grid electricity through on-site solar generation and battery storage, equating to 4,490 GJ/year (21% of total demand) and up to 673 tCO_2e/year of emissions reduction. Estimated electricity cost savings are approximately $4.3M/year.

This phase precedes thermal electrification for several reasons:

- **Cost reduction:** Solar lowers electricity costs from ~$180/MWh (grid) to ~$80–95/MWh (LCOE), improving the economics of electrification.
- **Load alignment:** Solar generation aligns well with daytime refrigeration loads, the site's primary electrical demand driver.
- **Infrastructure validation:** Installing ~875 kW of solar utilises existing transformer capacity and helps validate network capability before adding further electrical load.

Phase 2: Efficiency Foundation (2028-2031, $180k)

This phase focuses on demand reduction through operational efficiency improvements, reducing site energy consumption by approximately 3,765GJ/year (18%), equivalent to 195 tCO_2e/year and around $60k in operational savings.

All adopted measures have short paybacks (<4 years) offering quick return on investment.

Phase 3: Battery Storage (2030, $1M)

Installation of a front-of-meter/VPP battery (800 kW capacity, 2hrs storage) allows excess solar energy and negative price wholesale electricity to be stored and then used to offset grid consumption by approximately 2,100 GJ/year (10%), equivalent to 100 tCO_2e/year and around $128k in operational savings.

Phase 4: Thermal Fuel Switching (2035, $500k)

A heat pump is deployed to meet all hot water demand (100% of thermal load), leveraging waste heat from refrigeration systems. With an assumed COP >4.5, this initiative has a ~4.7-year payback.

This initiative reduces fossil fuel use by approximately 8,565 GJ/year (100% of thermal demand) and 370 tCO_2e/year, with operational savings of around $375k/year.

Phase 5: Purchase Offsets (2035 – 2045)

The remaining emissions that cannot be abated are from electricity consumption that continues to come from non-renewable generation. The final phase of decarbonisation is the purchase of emissions offsets in the form of REGOs to achieve Net Zero emissions by 2045. This initiative will cost $68k/year in additional opex and offset 567 tCO_2e/year.

Additional information about this pathway can be found in Section 7.1.4

6.3.7 Sectoral Decarbonisation Investment

Total investment and associated emissions for all EPR survey participants were **estimated** using the nominal decarbonisation pathways presented in Section 6.3, scaled according to the proportion of the sector represented by each representative site.

Based on this approach, a total investment of $793 million, corresponding to a net present value (NPV) of $541 million, is required for the 43 EPR2024 respondent sites to achieve net zero emissions by 2045. Roughly extrapolating this estimate to the full sector, assuming EPR respondents represent approximately 68% of industry throughput and the site make-up of non-respondents is similar, suggests an indicative total investment on the order of ~$1.2 billion (2026 basis).

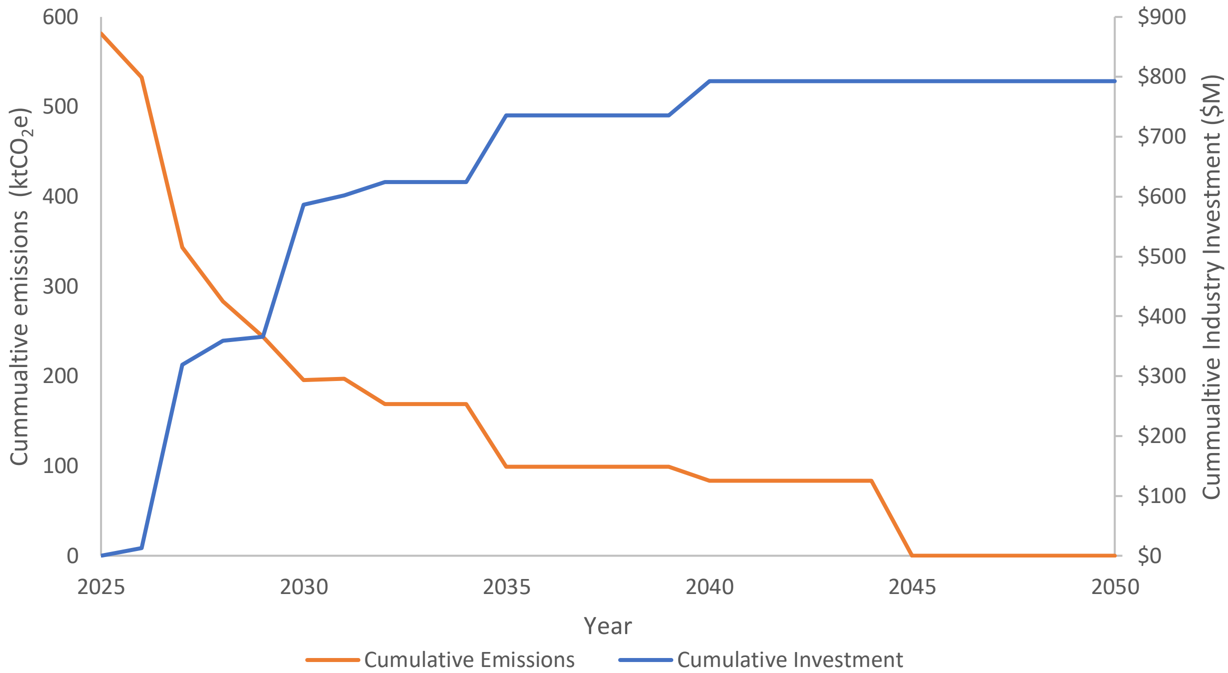


Figure 11: Cumulative investment and emissions for the EPR2024 respondents (43 sites), based on the possible decarbonisation pathways presented in Section 6.3.

7.0 Discussion

7.1 Decarb Pathway Scenarios

7.1.1 Large Site with Continuous Wet Rendering

Table 8 shows a breakdown of financials, energy and emissions changes for each opportunity.

Operating Parameters:

- **Schedule**: 5,600 hours annually (16 hours/day, 7 days/week, 50 weeks/year)
- **Production**: 105,000 tHSCW/year, 30,000 t/year rendering throughput
- **Thermal Demand**: 193,000 GJ/year of Natural Gas (10 MW boiler size), split 70% steam, 30% hot water.
- **Electrical Demand**: 107,000 GJ/year of grid electricity assuming NEM emissions factors
- **Baseline Emissions**: 28,400 tCO_2/year (10,000 tCO_2 Thermal, 18,000 tCO_2 Electrical)
- **Emissions Intensity**: 270 $kgCO_2$/tHSCW

Technology Context

Continuous wet rendering is approximately 50% more energy efficient than batch dry rendering processes, requiring only 47% of the energy per ton of rendered product. However, rendering remains the single largest energy consumer, especially for large sites that may also accept raw rendering material from non-rendering sites, resulting in longer operational time in a week. The steam requirements for rendering (approximately 70% of the thermal load) and the continuous 7-day operating schedule are critical factors that shape the decarbonisation strategy.

Renewable Electricity Generation Capacity

This facility has capacity for 10 MW of solar PV across several installation areas:

- Rooftop Arrays: 3 MW of processing buildings and cold storage roofs
- Ground-Mounted System: 7 MW on approximately 6-7 hectares of available land adjacent to the facility

The combined solar capacity could generate 66,600 MWh annually (based on other known sites with an irradiance of 1,600 kWh/kW/year). With the facility's 7-day operating schedule, 85% of self-consumption is achievable, reducing grid electricity demand by 53% at full solar deployment.

Heat Pump Capacity Sizing

The facility's hot water demand (30% of thermal load) can be fully supplied by a 1.6 MW Ammonia water-to-water heat pump (for example), taking 60°C water produced from rendering heat recovery and lifting it to 92°C by utilising waste heat ejected from the refrigeration plant. The heat pump and accompanying thermal storage tanks are sized to operate for 75% of a 24-hour period, designed to match when the refrigeration system rejects the most heat, and avoid high electricity spot prices.

Biogas Resource Assessment

The facility's organic waste streams, primarily from rendering operations provide significant opportunity for on-site renewable energy generation. Larger sites were observed to produce 20% more rendered product than medium sites. It was assumed that this was a result of the site accepting external raw material for processing, and operating rendering 18 hours per day. The analysis of biogas production from the EPR data showed large sites produced on average 34% of rendered output from the total tHSCW input, and the energy generated from waste produced from the rendering process (e.g. stick water or paunch grass) was 2200 MJ/t of rendering output. This resulted in 90 GJ/day of biogas production.

The biogas production capacity is sufficient to displace 40% of the facility's baseline fossil fuel demand, operating for 14 hours of the daily steam demand, making it the single largest emissions reduction opportunity for thermal loads. The biogas system requires a dedicated 5 MW thermal capacity dual fuel boiler[4] as existing natural gas burners cannot reliably modulate for biogas combustion.

[4] While dual fuel burners can be retrofitted to an existing boiler vessel, a feasibility would be needed to determine if the vessel size remains adequate, and if the vessel material can handle the corrosive nature of 100% biogas.

Electric Boiler Sizing
16% of the facilities' thermal demand is still being generated by fossil fuels after the previously identified initiatives are implemented. This demand is primarily for rendering steam during peak production periods or when spot energy prices (excluding network and environmental charges) are less than $0. During these periods electric heating through a 4.3 MW electric resistance boiler can take up the majority of the instantaneous load. It is estimated that this will likely be for approximately 4 hours of the day. The electric boiler operates at around 95% efficiency converting 32 GJ of yearly fossil fuel demand to 23.5 GJ of electricity demand. This configuration minimises operating costs by restricting the boiler's operation to the 85% of hours when total electricity prices are below $25/ /MWh.

Table 8: Breakdown of Opportunities for a large site with continuous wet rendering

Year	Opportunity	Capital Cost ($k)	Savings ($k)	Total Savings (GJ)	Total Em Savings (tCO2)	NPV ($k)	Simple Payback (yr)	MAC ($/tCO2)
2026	Floating discharge	180	80	1,606	254	515	2.2	-346
2026	Annual Boiler Tuning	35	124	7,728	398	1,020	0.3	-171
2026	Steam Lagging Maintenance	24	23	1,463	75	209	1.0	-139
2026	Dryer Insulation	30	5	321	17	23	5.8	-69
2026	Hot Water Lagging Maintenance	54	20	1,254	65	148	2.7	-115
2027	Rooftop Solar	3,300	648	12,960	1,872	3,114	5.1	-252
2027	Ground-mount solar	11,200	2,035	40,698	5,879	8,986	5.5	-273
2028	Steriliser Water Reduction	400	372	23,244	1,198	2,422	1.1	-135
2028	Boiler Economisers	1,400	146	9,122	470	246	9.6	-21
2029	Washdown Water Reduction	150	27	1,705	88	75	5.5	-57
2029	Upgrade/Maintain Condensate Return	75	59	3,709	191	422	1.3	-111
2030	Front-of-meter/VPP battery	13,000	1,600	26,280	1,241	1,121	8.1	-78
2031	Install Fine Crusher	650	152	9,526	491	643	4.3	-65
2032	Heat Pump Utilising Waste Refrigeration Heat	1,600	408	25,592	1,094	1,967	3.9	-69
2035	Biogas Generators & Boilers	6,100	1,244	77,725	4,005	3,596	4.9	-45
2040	E-boiler	1,935	344	31,821	923	618	5.6	-35
2045	Purchase REGOs	-	-203	-	1,689	-	-	
2045	Grid Emissions Factor Reductions	-	-	-	6,755	-		

7.1.2 Medium Site with Batch Dry Rendering

Table 9 shows a breakdown of financials, energy and emissions changes for each opportunity.

Operating Parameters:
- **Schedule**: 5,600 hours annually (16 hours/day, 7 days/week, 50 weeks/year)
- **Production**: 34,000 tHSCW/year, 9,600 t/year rendering throughput
- **Thermal Demand**: 117,000 GJ/year of Natural Gas (6 MW boiler size), split 70% steam, 30% hot water.
- **Electrical Demand**: 35,000 GJ/year of grid electricity assuming NEM emissions factors
- **Baseline Emissions**: 12,000 tCO_2/year (6,000 tCO_2 Thermal, 6,000 tCO_2 Electrical)
- **Emissions Intensity**: 355 $kgCO_2$/tHSCW

Technology Context
Batch dry rendering is significantly more energy-intensive than continuous wet rendering, requiring approximately 2.1 times more energy per tonne of rendered product. This higher energy intensity is reflected in the facility's emissions intensity of 350 $kgCO_2e$/tHSCW – approximately 30% higher than the large continuous wet rendering facilities (270 $kgCO_2e$/tHSCW). The batch process requires higher temperatures and longer cooking times to remove moisture. Despite processing over 60% less product (HSCW and rendered throughput) than the larger site, the energy intensive nature of batch dry rendering has resulted in a thermal demand that is 40% lower.

Renewable Electricity Generation Capacity
This facility has capacity for 7 MW of solar PV across two installation areas:
- Rooftop Arrays: 1 MW of processing buildings and cold storage rooves and carpark canopy
- Ground-Mounted System: 6 MW on approximately 6-7 hectares of available land adjacent to the facility

The combined solar capacity could generate 25,300 MWh annually (based on other known sites with an irradiance of 1,600 kWh/kW/year). With the facility's 7-day operating schedule, 85% of self-consumption is achievable, reducing grid electricity demand by 73% at full solar deployment.

Heat Pump Capacity Sizing
The facility's hot water demand (30% thermal load) is 15,000 GJ/year after efficiency improvements and can be fully supplied by a 500 kW Ammonia water-to-water heat pump, taking 60°C water produced from rendering heat recovery and lifting it to 92°C by utilising waste heat ejected from the refrigeration plant. The heat pump, and accompanying thermal storage tanks are sized to operate for 18 hour per day (longer than the assumed 16-hour operational day) to match:

- Refrigeration system operating hours (and waste heat availability),
- Hot water demand profile including processing and wash down,
- Electricity spot pricing, sized to utilise thermal storage when electricity is greater than $52/MWh

Biogas Resource Assessment
The facility's organic waste streams, primarily from rendering operations provide significant opportunity for on-site renewable energy generation. Based on EPR survey data analysis, medium batch dry rendering facilities produce rendered product at approximately 28% of the HSCW input (Compared to 34% for the large site example) with biogas potential of approximately 1,520 MJ/t of rendered product.

For this facility processing 34,000 tHSCW/year and 9,400 t/year of rendered product, the biogas generation potential is estimated at 21,000 GJ/year. This production is sufficient to displace 31% of the facility's remaining fossil fuel thermal demand, operating a dedicated biogas boiler 5 hours each operational day. The biogas system requires a 3.3 MW thermal capacity dual-fuel boiler as existing natural gas burners cannot reliably modulate for biogas combustion.

The critical difference between the medium facility and the large facility is that the medium facility processes one third the HSCW of the larger facility, and processes less rendering product as a proportion of the HSCW, resulting in significantly less biogenic waste processed in anaerobic ponds, producing biogas, this results in biogas production being only 23% of the large site.

Electric Boiler Sizing
38% of the facilities' thermal demand is still being generated by fossil fuels after the previously identified initiatives are implemented. This demand is primarily for rendering steam during peak production periods or when spot energy prices (excluding network and environmental charges) are less than $49 /MWh. During these periods electric heating through a 4 MW electric resistance boiler can take up most of the instantaneous load. It is estimated that this will likely be for approximately 11 hours of the day. The electric boiler operates at 95% efficiency converting 45 GJ of yearly fossil fuel demand to 33 GJ of electricity demand.

Table 9: Breakdown of Opportunities for a medium site with batch dry rendering

Year	Opportunity	Capital Cost ($k)	Savings ($k)	Total Savings (GJ)	Total Em Savings (tCO2)	NPV ($k)	Simple Payback (yr)	MAC ($/tCO2)
2026	Floating discharge	120	26	519	82	116	4.6	-242
2026	Steam Lagging Maintenance	24	23	1,463	75	224	1.0	-149
2026	Annual Boiler Tuning	35	75	4,659	240	644	0.5	-179
2026	Dryer Insulation	15	3	195	10	18	4.8	-90
2026	Hot Water Lagging Maintenance	54	20	1,254	65	159	2.7	-123
2027	Rooftop Solar	660	130	2,592	374	666	5.1	-270
2027	Ground-mount solar	6,240	1,134	22,675	3,275	5,357	5.5	-292
2028	Boiler Economisers	800	88	5,518	284	200	9.1	-28
2028	Steriliser Water Reduction	250	224	13,982	721	1,551	1.1	-143
2029	Upgrade/Maintain Condensate Return	55	36	2,271	117	269	1.5	-115
2029	Washdown Water Reduction	75	16	984	51	56	4.8	-73
2030	Front-of-meter/VPP battery	3,120	384	6,307	298	288	8.1	-83
2031	Install Fine Crusher	450	92	5,774	298	377	4.9	-63
2032	Heat Pump Utilising Waste Refrigeration Heat	500	208	15,424	682	1,281	2.4	-73
2035	Biogas Generators & Boilers	2,100	338	21,140	1,089	807	6.2	-37
2040	E-boiler	1,880	215	45,265	1,193	156	8.7	-7
2045	Purchase REGOs	0	-159	0	1,326	-	-	-

7.1.3 Medium Site with No Rendering

Table 10 shows a breakdown of financials, energy and emissions changes for each opportunity.

Operating Parameters:

- **Schedule**: 4,000 hours annually (16 hours/day, 5 days/week, 50 weeks/year)
- **Production**: 38,900 tHSCW/year, no rendering
- **Thermal Demand**: 44,000 GJ/year of Natural Gas (3 MW boiler size), 100% hot water.
- **Electrical Demand**: 25,500 GJ/year of grid electricity assuming NEM emissions factors
- **Baseline Emissions**: 6,700 tCO_2/year (2,300 tCO_2 Thermal, 4,400 tCO_2 Electrical)
- **Emissions Intensity**: 170 $kgCO_2$/tHSCW

Technology Context

Facilities that do not operate a rendering plant or blood coagulation do not require steam; however, many sites are still likely to operate steam boilers. The highest temperature required at these facilities is 82°C at point of use (or ~92°C at generation). As a result, ***these facilities are very easily capable of completely electrifying with typically low payback periods and positive NPVs.***

Renewable Electricity Generation Capacity

This facility has capacity for 2.125 MW of solar PV across several installation areas:

- Rooftop Arrays: 1.1 MW of processing buildings and cold storage rooves and carpark canopy
- Ground-Mounted System: 1.025 MW on a hectare of available land adjacent to the facility

The combined solar capacity could generate 10,700 MWh annually (based on other known sites with an irradiance of 1,600 kWh/kW/year). With the facility's 5-day operating schedule, but 7-day industrial refrigeration demand, 85% of self-consumption is achievable, reducing grid electricity demand by 42% at full solar deployment.

Heat Pump Capacity Sizing

The facility's hot water demand (100% of thermal load) can be fully supplied by a 1.35 MW Ammonia water-to-water heat pump, taking 35°C water produced from heat recovery off the oil coolers, and heating it to 92°C by utilising waste heat ejected from the refrigeration plant. The heat pump and accompanying thermal storage tanks are sized to operate for 55% of a 24-hour period, designed to match when the refrigeration system rejects the most heat, and avoid high electricity spot prices by utilising thermal storage in large hot water cylinders.

Biogas Resource Assessment

It was assumed sites that do not process rendering cannot generating biogas. Without the use of onsite rendering processing, most inedible are exported from the facility to third party rendering processors, as a result, these meat works produce very little biogenic waste than can be used to produce methane.

Table 10: Breakdown of Opportunities for a medium site with no rendering

Year	Opportunity	Capital Cost ($k)	Savings ($k)	Total Savings (GJ)	Total Em Savings (tCO2)	NPV ($k)	Simple Payback (yr)	MAC ($/tCO2)
2026	Floating discharge	120	19	382	61	51	6.3	-142
2026	Annual Boiler Tuning	35	28	1,765	91	208	1.2	-152
2026	Hot Water Lagging Maintenance	54	20	1,254	65	148	2.7	-115
2027	Rooftop Solar	1,210	238	4,752	686	1,142	5.1	-252
2027	Ground-mount solar	1,640	298	5,959	861	1,316	5.5	-273
2028	Steriliser Water Reduction	250	148	9,251	477	890	1.7	-125
2029	Washdown Water Reduction	75	31	1,912	99	155	2.5	-105
2030	Front-of-meter/VPP battery	2,780	342	5,611	265	236	8.1	-77
2032	Heat Pump utilising Waste Refrigeration Heat	1,350	295	21,870	967	1,298	4.6	-52
2045	Purchase REGOs	0	-116	0	970	0	0.0	

7.1.4 Small Site with No Rendering

Table 11 shows a breakdown of financials, energy and emissions changes for each opportunity.

Operating Parameters:

- **Schedule**: 4,800 hours annually (16 hours/day, 6 days/week, 50 weeks/year)
- **Production**: 10,300 tHSCW/year, no rendering
- **Thermal Demand**: 12,330 GJ/year of Natural Gas (1 MW boiler size, 100% water).
- **Electrical Demand**: 8,800 GJ/year of grid electricity assuming NEM emissions factors
- **Baseline Emissions**: 2,200 tCO_2/year (640 tCO_2 Thermal, 1,560 tCO_2 Electrical)
- **Emissions Intensity**: 210 $kgCO_2$/tHSCW

Technology Context
Facilities that do not operate a rendering plant or blood coagulation do not require steam. At this size of facility, it is more likely that they operate natural gas hot water generators, relatively close to their operation. It is assumed in this facility that the refrigeration plant room is near the processing floor, allowing the use of refrigeration waste heat to provide most heat recovery.

Renewable Electricity Generation Capacity
This facility has capacity for 875 kW of solar PV across several installation areas:

- Rooftop Arrays: 400 kW of processing buildings and cold storage rooves
- Ground-Mounted System: 475 kW on less than a hectare of available land adjacent to the facility

The combined solar capacity could generate 4.5 MWh annually (based on other known sites with an irradiance of 1,600 kWh/kW/year). With the facility's 6-day operating schedule, but 7-day industrial refrigeration demand, 85% of self-consumption is achievable, reducing grid electricity demand by 51% at full solar deployment.

Heat Pump Capacity Sizing
The facility's hot water demand (100% of thermal load) can be fully supplied by a 500 kW water-to-water heat pump, taking 35°C water produced from heat recovery off the oil coolers, and heating it to 92°C by utilising waste heat ejected from the refrigeration plant. The heat pump and accompanying thermal storage tanks are sized to operate for 75% of a 24-hour period, designed to match when the refrigeration system rejects the most heat, and avoid high electricity spot prices by utilising thermal storage in large hot water cylinders.

Biogas Resource Assessment
It was assumed sites that do not process rendering cannot generate biogas. Without the use of onsite rendering processing, most inedible are exported from the facility to third party rendering processors, as a result, these meat works produce very little biogenic waste than can be used to produce methane.

Table 11: Breakdown of Opportunities for a small site with no rendering

Year	Opportunity	Capital Cost ($k)	Savings ($k)	Total Savings (GJ)	Total Em Savings (tCO2)	NPV ($k)	Simple Payback (yr)	MAC ($/tCO2)
2026	Rooftop Solar	440	86	1,728	274	444	5.1	-238
2027	Ground-mount solar	760	138	2,762	399	614	5.5	-233
2028	Washdown Water Reduction	15	12	740	38	76	1.3	-132
2029	Steriliser Water Reduction	150	42	2,608	134	175	3.6	-87
2030	Front-of-meter/VPP battery	1,040	128	2,102	99	90	8.1	-78
2031	Hot Water Lagging Maintenance	18	7	418	22	35	2.7	-82
2035	Heat Pump Utilising Waste Refrigeration Heat	500	106	8,564	370	374	4.7	-40
2045	Purchase REGOs	0	68	0	567	0	0.0	

7.2 Australian Red Meat Decarbonisation

This section summarises the external factors shaping decarbonisation for AMPC members, including government policy settings, grid emissions trajectories, natural gas price outlooks, and state-based programs that influence investment timing and technologies choices.

The red meat processing sector contributes approximately 2% of red meat cradle to grave gross emissions and an estimated 0.26% of Australia's total net emissions. As a result, any organisation that may focus on the scope 3 emissions from red meat will likely focus heavily on the reduction of on-farm emissions, which contributes up to 98% of gross emissions (see Figure 12).

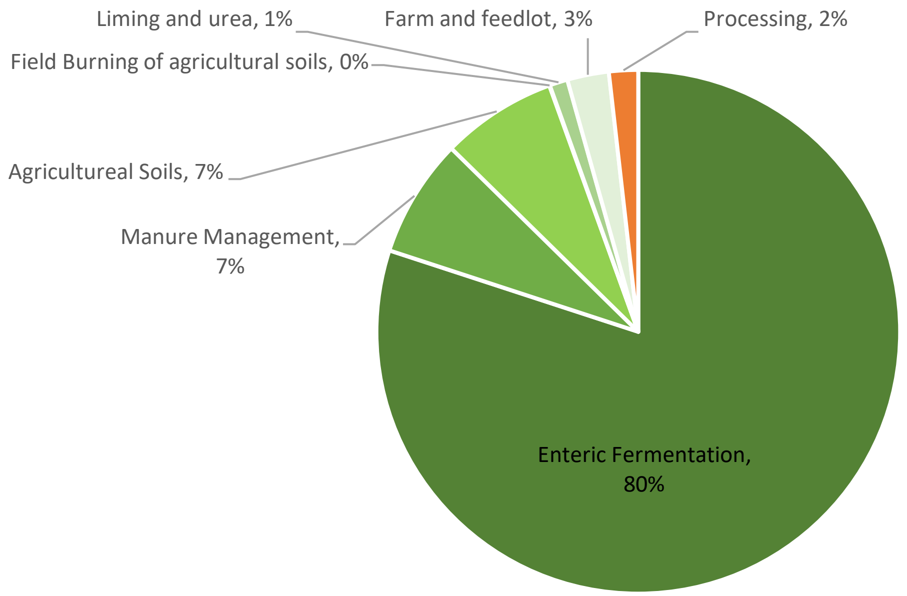


Figure 12: Cradle to grave emissions being released from red meat, excluding sequestration from LULUCF (MLA, 2023).

Meat & Livestock Australia (MLA) had previously set an industry wide target of net zero by 2030 target (CN30), was set in 2017, before technology costs and science-based targets were well understood. This target has since been discontinued within the meat processing space, as it was deemed not practicable, requiring $2.2-3.6bn in capital funding to achieve (AMPC, 2019). Currently, there is no industry wide decarbonisation target, despite growing pressure from supply chains. National legislative targets – net zero by 2050 and the 63-70% emissions reduction by 2035 – provide the most relevant benchmarks for long-term planning.

7.2.1 Adjustments for Economic and Nutritional Value

Commentary on the emissions intensity of the Australian RMP sector is often constrained by the use of simplified metrics, such as tonnes of carbon emissions per unit of raw material or product. While useful for high-level comparison, these metrics are inherently one-dimensional and do not capture the broader economic and social value of the sector. This includes its contribution to regional employment, its role in the national economy, and its importance in supplying affordable, high-quality protein to Australians. These factors are closely aligned with broader societal objectives, including those reflected in the United Nations Sustainable Development Goals.

Greenhouse Gas Emissions per Unit of Value Added (GEVA) is a metric used in UN-aligned economic and sustainability reporting to assess the carbon efficiency of economic activity. GEVA measures the quantity of greenhouse gas emissions generated per unit of economic value added, typically expressed as tonnes (or kilograms) of CO_2-e per unit of GDP or sectoral value added. By linking emissions directly to economic contribution, GEVA provides a complementary lens to product-based carbon footprints, aligning climate assessment with broader sustainable development objectives that balance emissions reduction, economic growth and livelihoods.

GEVA is calculated by dividing total sectoral emissions by total value added. Using headline industry figures, Australian red meat production (~31,000 kt CO_2-e) and processing (~1,089 kt CO_2-e) together generate approximately 32,089 kt CO_2-e against combined value added of roughly AUD $42.3 billion (producer and processor only, excluding wholesale/retail), yielding a GEVA of approximately 0.758 kg CO_2-e per USD of value added (noting currency conversion assumptions). When disaggregated, processing emissions intensity on a value-added basis (~0.067) is materially lower than upstream production, reflecting the relatively small contribution of processing to whole-of-chain emissions.

The relevance of GEVA becomes clear when comparing sectors with very different economic structures. On a pure product basis, beef emissions intensity (producer + processor) may be approximately 15 kg CO_2-e per kg liveweight/carcass weight, compared with approximately 3.8 kg CO_2-e per kg for alternative protein products — implying beef is ~290% more emissions intensive on a mass basis. However, when emissions are assessed relative to economic value generated, the differential narrows substantially. Using indicative figures, red meat (producer + processor) records a GEVA of ~0.758, compared with ~0.61 for the alternative protein sector (based on reported sectoral emissions and value added), meaning beef is approximately 24% more emissions intensive on a value-added basis rather than nearly three times higher on a product-mass basis.

Accordingly, GEVA does not replace product-level life-cycle assessment (LCA), but it provides an important complementary metric. It enables sectoral comparisons that account for economic contribution, supports fair-share climate responsibility discussions, and better aligns emissions reporting with sustainable development objectives that consider employment, regional income generation and economic resilience alongside decarbonisation outcomes.

Some national and global dietary guidelines have recommended a reduction in red meat, and in doing so have overlooked or underestimated its nutritional density and contribution to nutritional adequacy in at risk populations. AMPC is working with global experts on a project that will provide evidence from a red meat nutritional LCA study that will help shape a data-driven, credible case for red meat's role in a healthy, sustainable diet, protecting market access and long-term value. On completion of the project, the nutritionally adjusted footprint for red meat may be more accurately compared to alternate protein types.

In the near future, customers and consumers may be able to compare both nutritionally and value added adjustments to red meat emissions footprints, thereby bringing transparency to the future of sustainable development in this important whole food area.

7.3 Energy Supply & Emissions

7.3.1 Electricity Supply

Overview of Structure

Australia operates two wholesale electricity markets managed by AEMO: The National Electricity Market (NEM) operates across New South Wales (including the ACT), Queensland, South Australia, Victoria, and Tasmania (AEMO, 2026).The NEM generates around 200 terawatt hours of electricity annually, supplying around 80% of

Australia's electricity consumption (AEMC, 2026). The Wholesale Electricity Market (WEM) serves the South West Interconnected System (SWIS) in Western Australia, supplying electricity to more than 1.2 million businesses and households. The WEM supplies around 20 terawatt hours of electricity each year. The Northern Territory operates its own isolated networks centred on Darwin and Alice Springs, which are not connected to either the NEM or the WEM.

The NEM is governed by three institutions: the AEMC, responsible for rule making; the AER, responsible for economic regulation and enforcement; and AEMO, responsible for day-to-day market and power system operation. The WEM is similarly operated by AEMO and regulated by the Economic Regulation Authority (ERA) of Western Australia. The WEM consists of two key components: a capacity market where electricity providers are paid for the capacity they make available, and a wholesale market where participants interact to supply and purchase electricity (ERA, 2026). This Reserve Capacity Mechanism, unique to the WEM, has no direct equivalent in the NEM. In both markets, electricity is transported via high-voltage transmission lines from generators to local distributors, which deliver it to homes and businesses, with generation traded through a pool where output is aggregated and scheduled at five-minute intervals to meet demand (AEMC, 2026).

Breakdown of Costs

There are three main components of electricity costs for AMPC members, varying based on size, location and Distribution and Network Services provider (DNSP).

Energy (wholesale) costs are the largest component and reflect the cost of the electricity itself. Electricity retailers derive a fixed or partially fixed unit rate from financial hedging contracts, embedding their cost of managing spot market risk in the price offered to the customer. In 2024, average NEM spot prices ranged from $101/MWh in Victoria to $150/MWh in NSW. Retail contract prices sit above these levels, varying by region, load profile, contract term, and timing of procurement (AER, 2025). Sites with demand concentrated in morning and evening peak windows generally attract higher energy rates than those with flat or off-peak load profiles.

Network costs cover the use of both the high-voltage transmission network and the local distribution network. Combined transmission and distribution charges typically account for between 35% and 45% of what consumers pay for electricity. For C&I customers on interval metering, network tariffs are structured around a consumption charge (c/kWh) and a demand charge ($/kVA) levied on the customer's recorded peak demand — typically the highest half-hour interval in the billing period. A site with a spiky load profile will therefore pay considerably more in network charges than one with the same total consumption spread more evenly across the day. Managing peak demand is a significant cost lever, and one area where on-site solar and battery storage can deliver direct bill savings. Network tariffs are regulated by the AER, though retailers ultimately determine how these charges are reflected in prices offered to customers (AER, 2025).

Environmental scheme costs reflect compliance obligations under federal and state renewable energy and energy efficiency schemes, passed through to customers as a percentage of consumption. The primary federal schemes are the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES), with state-based schemes — including the NSW Energy Savings Scheme, the Victorian Energy Upgrades program, and the South Australian Retailer Energy Productivity Scheme — adding further charges depending on the site's jurisdiction. Taken together, national and state environmental schemes currently account for approximately 10% of electricity bills. Both the LRET and SRES are legislated to close on 31 December 2030, after which this cost component is expected to reduce (ACOSS, 2024).

Futures Market Overview and Price Trends

The electricity futures market allows generators and retailers to manage the financial risk of spot market volatility by locking in prices for future electricity supply. The ASX lists futures and options contracts across the NEM regions of NSW, VIC, QLD, and SA. The core products are base load quarterly futures, peak load futures covering morning and evening windows, and $300 cap contracts that protect buyers against extreme price spikes (ASX, 2026). A standard swap fixes the price a party pays or receives against the floating NEM spot price, while a cap places a ceiling on the buyer's exposure, with the seller compensating the buyer whenever the spot price exceeds the strike price. The WEM does not have an equivalent exchange-traded derivatives market; hedging in WA is primarily managed through bilateral contracts and the Reserve Capacity Mechanism (Flottmann, 2024).

Over the past decade, NEM futures volumes grew steadily from 2015, more than tripling between 2017 and their 2022 peak, coinciding with record wholesale prices. Annual ASX-traded volumes decreased by 15% in 2024 but remain elevated relative to pre-2021 levels. The annual wholesale price trend across the NEM over the last 20 years is shown in Figure 13 (AER, 2025).

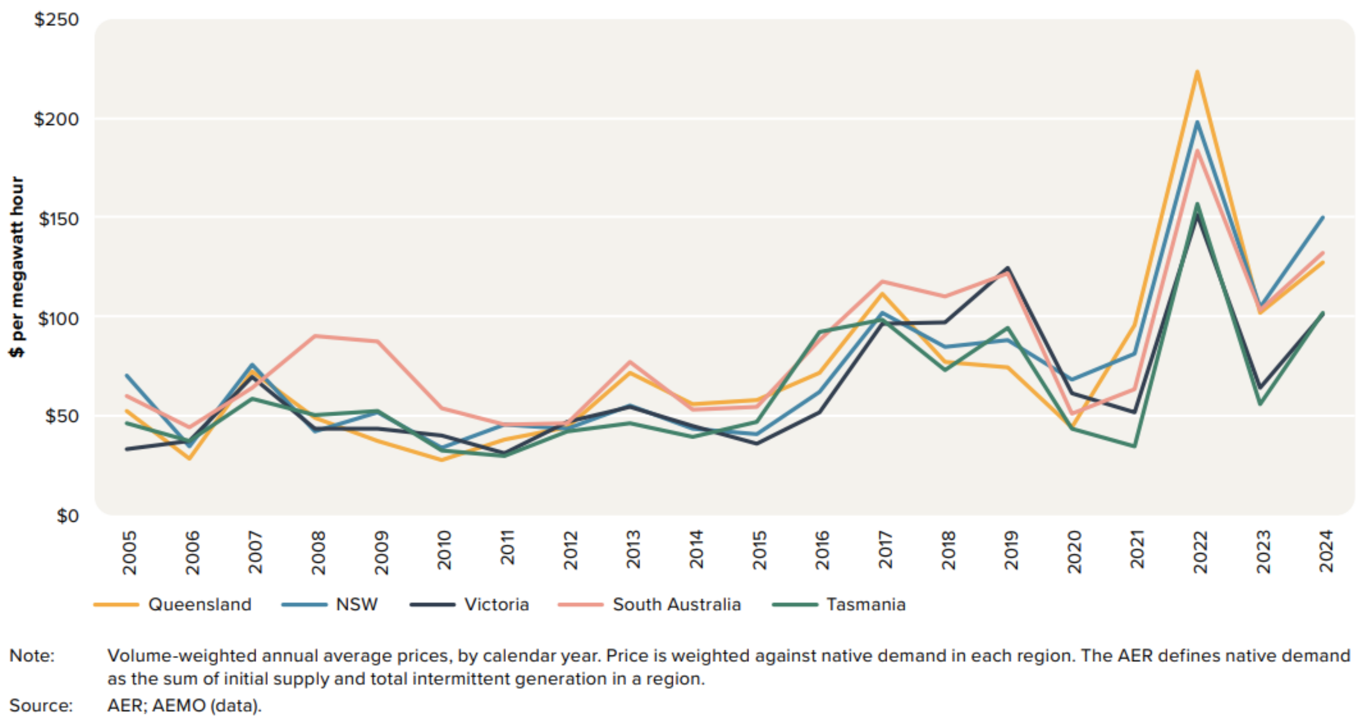


Figure 13: Calendar year base futures contract prices by NEM region, 2005–2024 Source: AER, State of the Energy Market 2025, Chapter 2, Figure 2.12 — available at aer.gov.au

Spot Market Overview and Price Trends

A central dispatch algorithm runs every five minutes, with generators offering availability and prices to AEMO, which clears the market to produce a single regional clearing price received by all dispatched generators. Participants can offer capacity at any price between −$1,000/MWh and the market price cap of $20,300/MWh from 01 Jul 2025, with the highest-priced offer needed to meet demand setting the spot price for each interval (Modo Energy, 2024). The WEM operates under a similar five-minute dispatch mechanism, though its balancing market price cap is substantially lower at $1,000/MWh (AER, 2024). Separate prices are determined for each NEM region, with prices converging when interconnectors are unconstrained and diverging materially when they reach transfer limits.

There are very few, if any AMPC members directly exposed to spot electricity prices, however these prices indirectly impact wholesale futures and retail electricity prices paid by electricity users.

Due to the impact of increased behind the meter residential and commercial and industrial scale solar, and utility scale solar on the electricity spot market, daytime spot electricity prices have decreased, and evening prices have increased over the last 10 years. Figure 14 shows the average spot price per half hour over a day from 2016-2025 for NSW. This shows daytime prices decreasing over time, nighttime prices increasing as well as a large increase in the evening spot price. This trend is mirrored in other regions of the NEM such as Qld, Vic and SA. Outlying years in 2022 and 2024 are also visible.

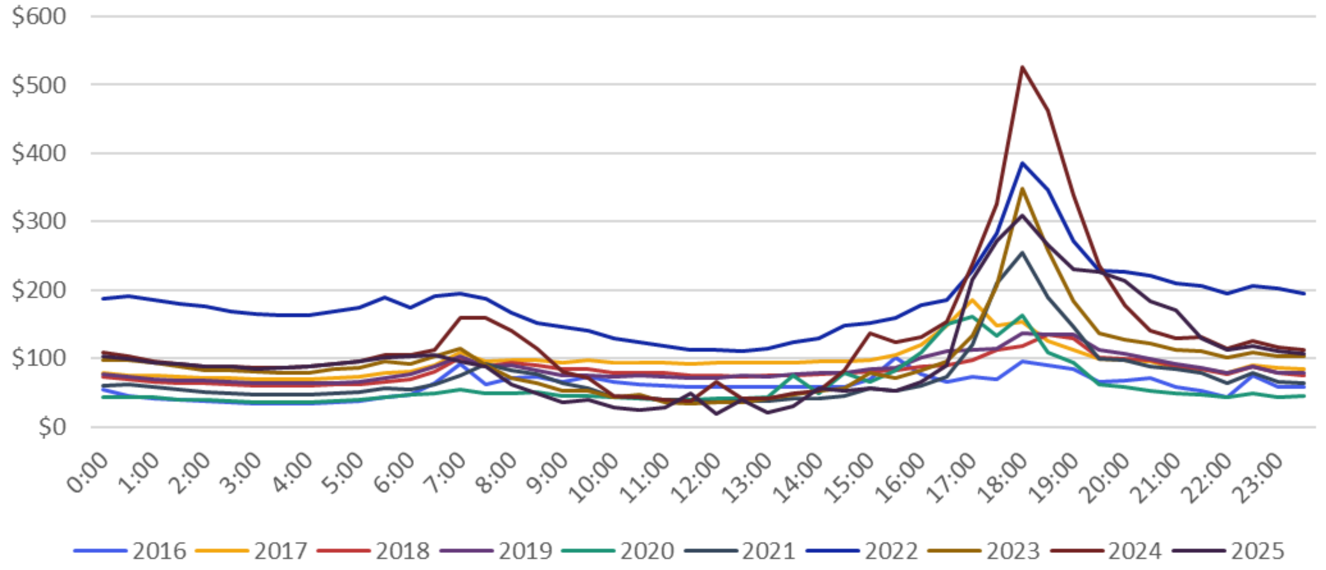


Figure 14: NSW Average spot price per half hour over a day from 2016-2025

Within the daytime low priced period, negative pricing is also becoming more prevalent. Figure 15 shows the number of hours per year when spot electricity prices are negative during traditional work hours (Mon-Fri 9am-5pm). The number of hours can be seen increasing from close to zero in 2018 to half the day or more in 2025 in SA, Vic and Qld. Large energy users, including AMPC members may be able to take advantage of this low priced electricity for electrification projects such as in Electric Boilers and Heat Pumps using a child NMI configuration, discussed in more detail in Appendix 10.2.3 Electrification of Heat.

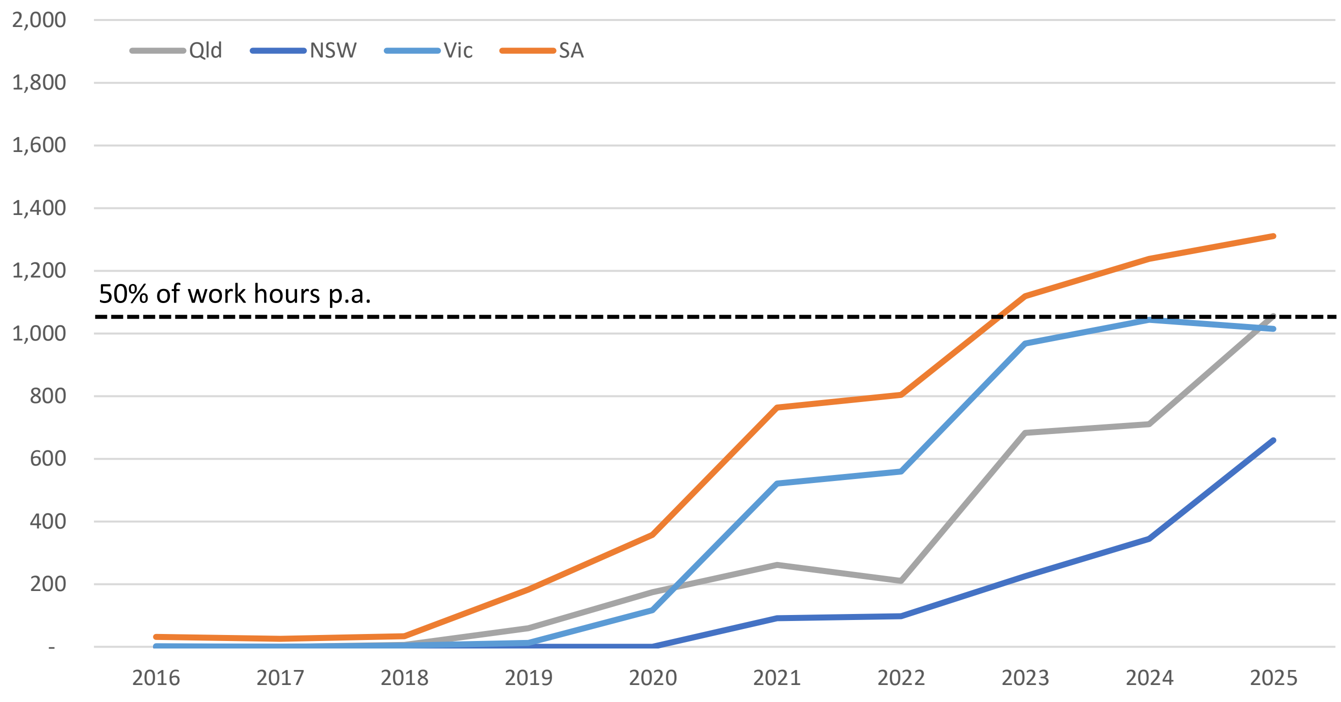


Figure 15: Work Hours (8am-5pm - Mon-Fri) p.a. when prices are negative

7.3.2 Grid Decarbonisation

Emissions intensity across the NEM is set to decline sharply as coal and gas-fired stations are taken out of service while new generation capacity it supplied from renewable sources (Figure 16). Most of this reduction is projected to occur after 2030, when the bulk of announced closures take effect. Table 12 shows that average grid emissions intensity could fall by about 70% by 2030 and up to 89% by 2050.

Australia's national target is a 62-70% emissions reduction below 2005 levels by 2035, and net zero by 2050. As of 2025, grid emissions intensity has already dropped 33% from the 2005 baseline. On current trajectories, the grid will fall below the 2035 emissions-reduction target by 2030 and will sit well below the emissions intensity of coal and natural gas (Figure 17). This shift creates a clear pathway for emissions reductions through electrification.

Table 12: Australia's grid emissions factors and forecasts (kgCO_2-e/kWh).

State or Grid (kgCO2-e/kWh)	2005	2023	2025	2030	2035	2040	%reduction in 2025	%reduced by 2030	% reduction by 2040
Australia, all grid connected	0.92	0.65	0.57	0.17	0.12	0.11	33%	82%	88%
National Electricity Market		0.66	0.57	0.17	0.12	0.11	30%	82%	88%
NSW	0.89	0.68	0.51	0.11	0.07	0.08	28%	88%	91%
QLD	0.88	0.73	0.65	0.19	0.25	0.23	24%	78%	74%
SA	0.86	0.25	0.2	0.06	0.03	0.03	74%	93%	97%
VIC	1.23	0.79	0.75	0.29	0.05	0.03	37%	76%	98%
TAS	0.03	0.12	0.18	0.01	0.01	0.005	-186%	86%	93%
Western Australia (SWIS)	0.88	0.53	0.5	0.13	0.13	0.09	43%	85%	90%
Northern Territory	0.73	0.62	0.61	0.43	0.28	0.14	23%	41%	81%

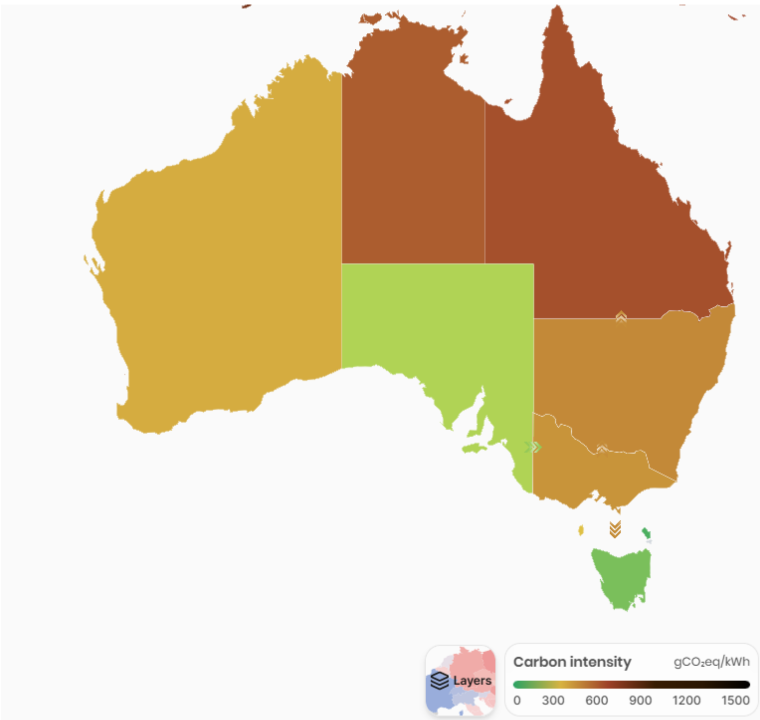


Figure 16: Current emissions intensity of Australia's electricity grid, showing direction of electricity flows (Electricity Maps, 2025).

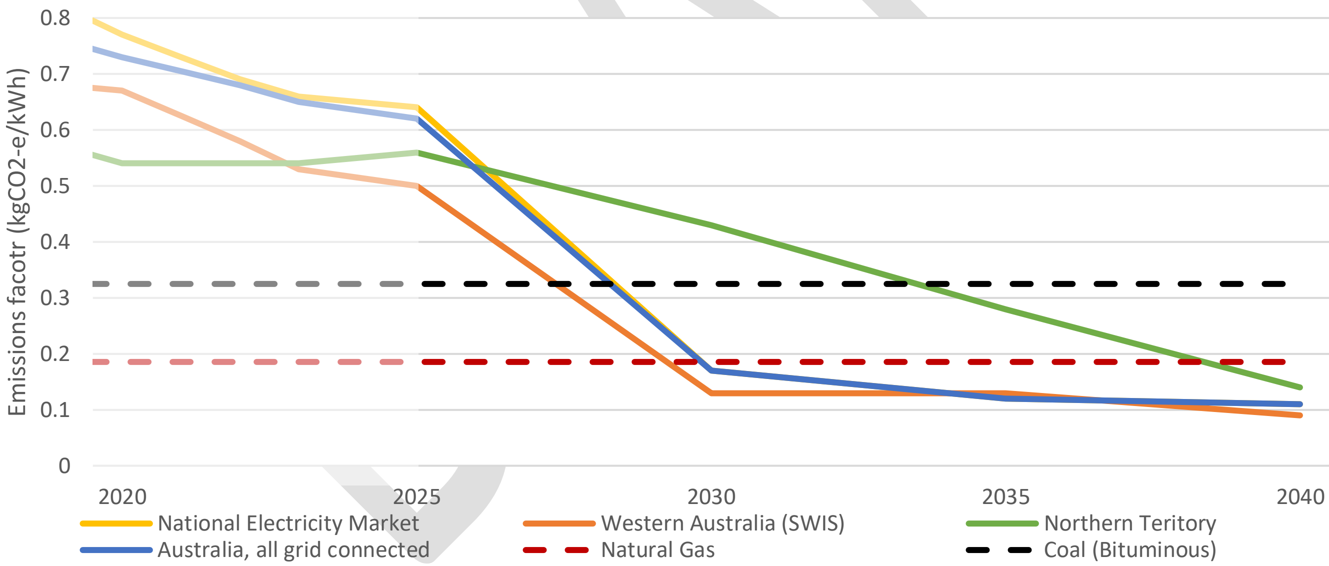


Figure 17: Grid emissions forecasting for Australia's networks to 2040, showing when they fall below common fossil fuel emissions.

7.3.3 Natural Gas Prices

Historically, natural gas prices were around three times lower than current levels, which previously limited the incentive to transition to lower-cost alternatives. The previous (2023) decarbonisation roadmap projected gas prices to double to over $30/GJ; however current modelling suggests prices will remain relatively stable (see Figure 18). As Australia progresses towards decarbonisation, declining demand for natural gas is expected to place downward pressure on retail prices. As industries degasify, the number of users on local supply networks will decrease, resulting in localised upward pressure as fewer customers are sharing the same network maintenance costs. At a macro level this will likely result in an overall net neutral price outlook (AEMO, 2024), however individual customers may face significant network charges, resulting in price surges up to $30/GJ.

Piped renewable natural gas or biogas offers a potential pathway to decarbonise natural gas use. At current pricing, piped biogas could supply up to 10% (excluding electricity generation and LNG processing) of national gas demand (AES, 2025). However, unless overall gas demand falls significantly, piped biogas costs are expected to rise up to $60/GJ once waste and landfill gas resources are fully utilised and the market shifts towards crop residue-based feedstocks (Energy Networks Australia, 2025). Onsite biogas is a beneficial fuel source for current meat processes and nine AMPC members who completed the EPR survey are currently utilising biogas; however, industries may consider a long-term transition to electrified alternatives and supplying biogas to the national grid at cost competitive prices (Energy Networks Australia, 2025).

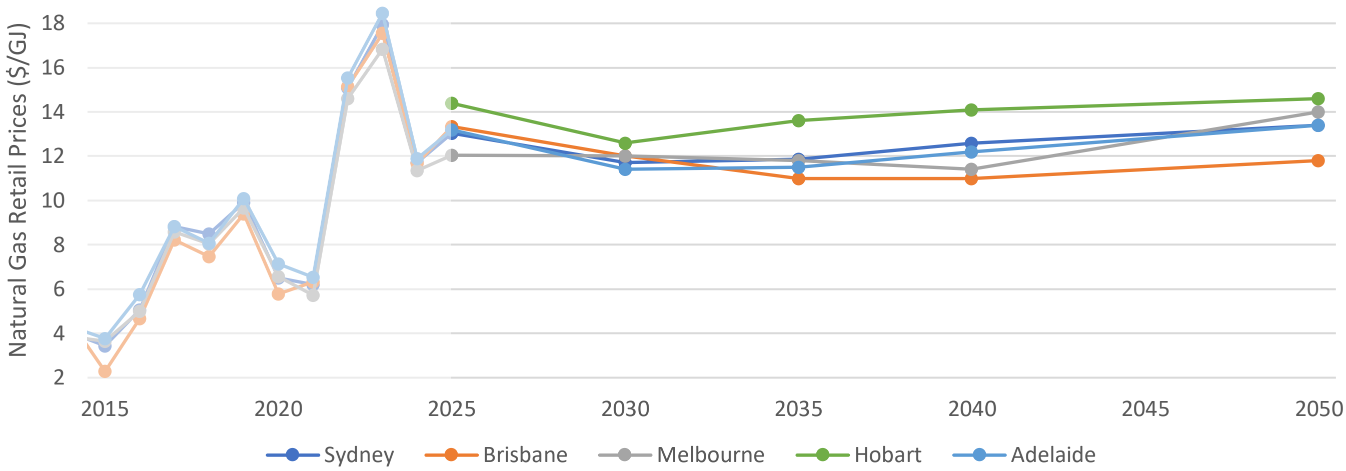


Figure 18: Historic and projected Allens natural gas pricing (AEMO, 2024).

7.3.4 Australian Government Policy and Programs

Australia and all states have set a net zero target of either 2045 or 2050. Interim targets have also been set by some states and at a national level, as shown in Figure 19. The interim targets set 2005 as a baseline to track emissions reductions. Current national emissions are approximately 29% reduction from 2005 levels. The national interim emissions reduction target is 43% reduction by 2030, and 62-70% reduction by 2035. Victoria and NSW have the same interim reduction targets and net zero goal; however Victoria is more on track to reaching its targets. Tasmania has already exceeded its targets, and are net negative emissions reductions, actively sequestering more than it is emitting. Western Australia expects to increase its emissions in the near term and has no interim emissions targets.

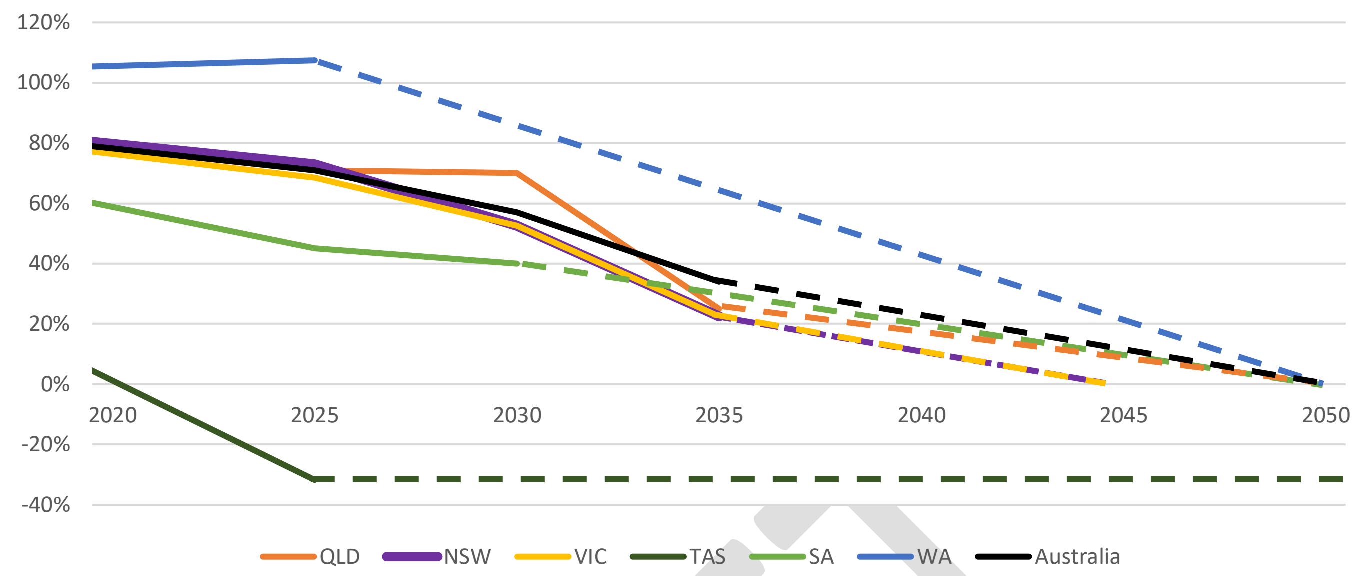


Figure 19: State Emissions Reduction targets based on 2005 levels.

Several national and state level policies may be leveraged by AMPC members to advance them on their decarbonisation journey. The following tables serve as a practical reference to support informed planning and investment in emissions reduction initiatives. The federal government primarily sets national targets, provides large-scale funding, and enables market conditions. A list of current federal policies relating to emissions is presented in Table 13.

Table 13: Federal decarbonisation policies that may impact AMPC members.

Program / Scheme	Description
Net Zero Fund	$5b investment vehicle for retrofits, low-carbon capital, electrification, and deploying decarbonisation tech. Beneficiaries: Large/heavy industry, clean tech developers. *Not yet open.*
Cleaner Fuels Program	$1.1b to support production of low-carbon liquid fuels for hard-to-decarbonise sectors. *Not yet open.*
Capacity Investment Scheme	$72b underwriting vehicle to de-risk private investment in large-scale renewable energy and clean dispatchable capacity (e.g., batteries). Targets developers/investors via competitive tenders. *Tender 8 Open.*
Future Made in Australia (FMiA)	$22.7b (over 10 years) top-level policy and budget framework to direct funding into national programs and streams. *Ongoing.*
FMiA - Powering the Regions Fund (PRF)	$1.9b to enable industrial decarbonisation, expand renewable energy, and support new clean energy industries. For industrial facilities and technology developers. *Ongoing.*
PRF - Regions Industrial Transformation Stream - ARENA	$180m pool, grants up to $500k. Co-funding for industrial decarbonisation at existing regional facilities. Requires material Scope 1/2 emissions reduction. *Round 3 Open.*
Ultra Low-Cost Solar PV R&D Funding Round - ARENA	$60m grant pool for R&D into ultra-low-cost solar PV technology. For universities, research institutes, and developers. *Open.*
Battery Breakthrough Initiative - ARENA	$523.2m grant pool to promote development of battery manufacturing capabilities in Australia. *Open.*

Hydrogen Headstart Round 2 - ARENA	$2b grant pool to enable large-scale renewable hydrogen production. For large project proponents. *Open.*
FMiA - Future Made in Australia Innovation Fund - ARENA	$1.5b in grants to increase tech uptake, improve clean tech manufacturing, and strengthen supply chains. Focus on green metals, renewable tech, and low-carbon fuels. *Ongoing.*
Solar Sunshot - ARENA	$1b grant pool to build solar supply chain and manufacturing facilities in Australia. *Ongoing.*
Advancing Renewables Program (ARP) - ARENA	Grants from $100k-$50m. Funds renewable energy tech projects (TRL 4-9) with max 50% co-funding. *Open.*
Driving the Nation Program - ARENA	~$500m pool to accelerate Zero Emissions Vehicle (ZEV) uptake, support heavy BEV deployment, and charging infrastructure. *Open.*
Recycling Modernisation Fund	~$200m pool for new/upgraded recycling infrastructure to increase Australia's processing capacity. *Open.*
NGER (National Greenhouse & Energy Reporting)	Regulatory requirement for corporations to report emissions and energy use. Mandatory if facility >25ktCO2/100TJ or corporate group >50ktCO2/200TJ. *Open* - likely to reduce over time.
ACCUs (Emissions Reduction Fund)	Tradable carbon credits (~$30-40/tCO2) issued for projects that avoid or store 1 tCO_2e. *Open.*
Safeguard Mechanism	Regulatory requirement. Facilities emitting >100ktCO2/year must reduce emissions by 4.5% annually or purchase ACCUs. *Open* – likely to reduce over time.

State governments focus on implementation through planning controls, regulations, infrastructure investment, and sector-specific programs. Table 14 breaks down the responsibility across policy levers to compare how each jurisdiction addresses similar objectives.

Table 14: State level decarbonisation policies that may impact AMPC members.

State	Program / Scheme	Description
VIC	Transition Planning Stream	Support program to assist manufacturers of gas appliances (i.e., boiler suppliers) transition away from production. Must derive >40% revenue from gas appliances. *Open.*
VIC	Victorian Energy Upgrades (VEUs)	Market-based incentive creating certificates (~$85 each for 1tCO2-e) for implementing approved energy-efficient technologies. Work with accredited providers. *Open.*
NSW	Energy Savings Certificates (ESCs) Scheme	Market-based incentive creating certificates (~$15-35 each for 1MWh saved) for implementing approved electricity savings projects. Work with accredited providers. *Open.*
NSW	High Emitting Industries Grant	$305m grant pool to accelerate decarbonisation of manufacturing/mining (>90ktCO2-e/year). Up to 50% co-funding for feasibility studies, FEED, etc. *Opens 2026.*
NSW	EV Fleet Incentive	$5m pool for $5k-$50k per vehicle to transition ICE fleet vehicles to ZEVs. For businesses with at least 3 fleet vehicles. *Opens Apr-26.*
NSW	Metering & Monitoring Grants	$12m grant pool for energy metering and monitoring (submetering, energy performance services). For sites spending >$200k or using >3,600 GJ of energy. *Open.*
NSW	Heat Pump Feasibility Grant	$1m pool for $30k grants (75% of cost) to assess heat pump feasibility for sites using 5,000-100,000 GJ of gas/year. *Open.*

NSW	Skills for Net Zero	$2,500 incentive to hire an intern ($25/h for 200h min.) for a decarbonisation-focused project in NSW. *Open.*
NSW	Renewable Gas Production Program	$40m funding pool to support deployment of biomethane production (50% of cost) – must export 0.1 PJ of biomethane to the network per year
ACT	Sustainable Business Program	$13k in support (advice, action plan, training) to help businesses reduce emissions and improve energy efficiency. Must operate from commercial premises. *Open.*
ACT	Energy Efficiency Improvement Scheme (EEIS)	Scheme creating a market for energy efficiency by requiring energy retailers to reduce demand. Subsidised improvements available through approved providers. *Open.*
QLD	EcoBIZ	Free coaching to help businesses (<200 FTE) audit resource use, manage carbon, and reduce consumption & waste. *Open.*
QLD	Rural Economic Development (RED) Grants	Grants <$200k to generate jobs in primary production value chains in rural QLD. Must show significant economic benefit. *Open.*
QLD	Manufacturing Sustainability Benchmark Program	Program to help manufacturers (>5 FTE) benchmark sustainability practices (energy, water, waste, emissions). Fee: $2k-2.5k. *Open.*
SA	Retailer Energy Productivity Scheme (REPS)	Scheme creating a market for energy efficiency by requiring retailers to reduce demand. 31 approved activities eligible for subsidies. *Open.*
SA	Sustainability Incentive Scheme	Cashback (<$40k) for businesses and residents for sustainable tech/practices (e.g., electrification, solar PV, EVs, insulation). *Open.*
TAS	Business Energy Efficiency Scheme	$10k-$60k loans (with interest subsidies) for energy efficiency and electrification for businesses using >150 MWh/year. *Open.*
TAS	Energy Saver Loan Scheme	Interest-free loans ($500-$10k for 3 years) for energy efficiency and electrification for businesses using <150 MWh/year. *Open.*
TAS	Power Smart for Small Businesses	$1k grants (from $450k pool) to help small businesses (<19 FTE) understand energy use and identify savings. Requires a purchased energy audit. *Open.*

7.4 Off-site Power Purchase Agreements and Grid Decarbonisation

The Paris Agreement's overarching goal is to limit the global average temperature increase to 1.5°C in an effort to reduce the risks and impacts of climate change (United Nations, 2023). As one of the 195 parties that entered legally binding international treaty in 2016, Australia has a legislated target to reduce greenhouse gas emissions to net zero by 2050, with an interim 2030 target of 43%, and also has a 2030 renewable electricity target of 82% (DCCEEW, 2025).

7.4.1 Renewable Electricity Procurement Options

Australian commercial and industrial (C&I) sectors with voluntarily set Scope 1 and 2 emission reduction targets in the past decade have looked to procure renewable energy in tandem with their procurement processes for Electricity Supply Agreements (ESAs).

Electricity retailers have multiple products that can offer customers green certificates, i.e. Large-scale Generation Certificates (LGCs), alongside their ESAs. Many organisations have typically procured their LGCs through retailers as the intermediary, where each certificate certifies 1 MWh of zero emissions to offset their Scope 2 electricity emissions.

Alternatively, sufficiently large energy users or credible counterparties may be able to enter negotiations directly with renewable energy generators in what are known as wholesale or virtual Power Purchase Agreements (PPAs). These are generally riskier and more complex to both contract and administer, meaning more wholistic electricity retailer packaged PPA products (Retail PPAs) have been more common than wholesale PPAs for their simplicity in addressing both the supply of energy and renewable certificates.

Table 15 below, summarises a range of renewable energy procurement options with general recommendation of which products may suit different AMPC members. The following 5 procurement options are:

1. **Retail ESA + LGCs:** Combining LGC procurement requirements when re-contracting short term retail ESAs.
2. **Retail ESA + GP:** Request GreenPower (GP) be added to a new or existing ESA with electricity retailer.
3. **LGC Strip:** A separate LGC only supply contract, typically through a retailer or broker.
4. **Retail PPA:** A retailer packaged solution backed by a wholesale PPA for a more accessible PPA product.
5. **Wholesale PPA:** A financial Contract-for-Difference (CfD) contract with a renewable energy generator.

Table 15. Renewable energy procurement options most suitable to AMPC members.

Criteria	Retail ESA + LGCs	Retail ESA + GreenPower	LGC Strip	Retail PPA	Wholesale PPA
Tenure	1-3 years	1-3 years	2-5 years	5-10 years	5-15 years
Accessibility	High	High	Low	Med	Low
Complexity	Low	Low	Med	High	High
Administration	Low	Low	Med	Med	High
Load Matching	Yes	Yes	No	Yes	No
Additionality	Low	Low	Low	Med	High
LGC Source Risk	Med	High	Med	Low	Low
LGC Cost	Med	High	Med	Med	Low
AMPC Member Suitability	Small to med. energy users, or low to med. renewable targets		Medium to large energy users, or medium to high renewable targets		

The factors that influence the criteria ranking of items in Table 15 are elaborated below:

- **Tenure:** duration of supply of energy and/or LGCs which would be supplied for as part of the agreement.
- **Accessibility:** availability of options to prospective buyers and buyer requirements/thresholds.
- **Complexity:** difficulty of contracting said options and need for external e.g. legal, commercial etc. advisors
- **Load Matching:** whether the supply of LGCs is matched proportionally to the volume of energy used.
- **Additionality:** if the option helps support the build of new renewable projects and not existing ones.
- **LGC Source Risk:** ability of buyer to have LGC requirements, e.g. source, location, asset-linkage etc. met.
- **LGC Cost:** the relative cost of LGCs procured through the different options compared to generic LGCs.

7.4.2 Power Purchase Agreement Structures

The intricacies of contracting for renewable energy can be as complex as the solutions a business wants to achieve its objectives. This is especially true for PPAs which has been further split into 5 possible options below in Table 16; these are not discrete options but general examples of PPA structures which are better described as a product with a spectrum of options to meet a similarly wide range of PPA buyer needs.

A more in-depth description of these products can be found in the Appendices 10.4.1.

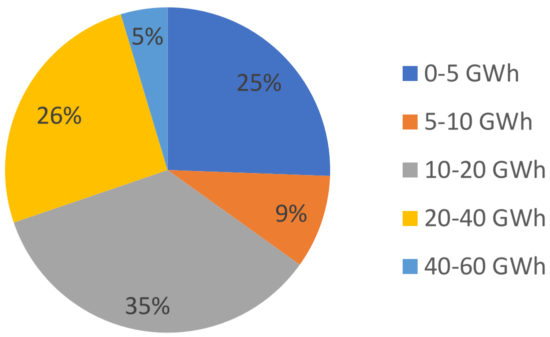
Table 16. A product risk profile overview of five common PPA product structures.

Criteria	Wholesale PPA	Sleeved Wholesale PPA	Sleeved & Firmed Wholesale PPA	Retail PPA	24/7 PPA
Counterparties	1+	2+	2+	1	3+
Accessibility	Med	Low	Low	High	Very Low
Complexity	Med	High	High	Low	High
Administration	High	Med	Low	Low	High
Energy Firming	No	No	Yes	Yes	Yes
Wholesale Exposure	High	High	Med	Low	High
AMPC Member Suitability	**Med**	**Med**	**Med**	**High**	**Low**

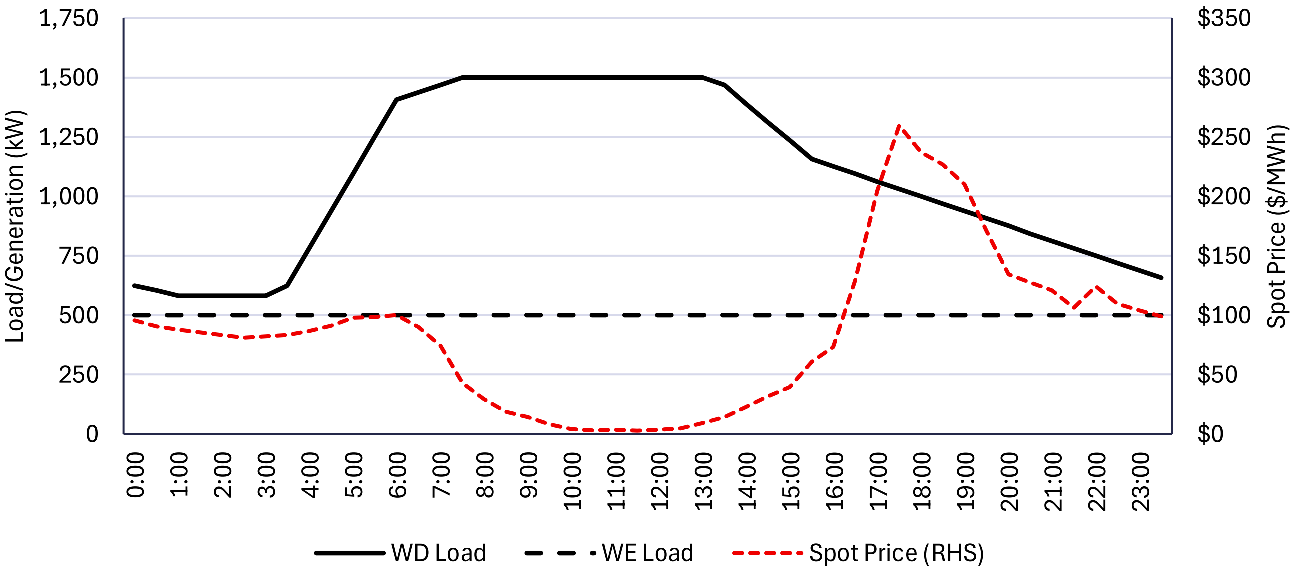
7.4.3 Power Purchase Agreements for AMPC Members

When a C&I business or organisation considers procuring renewable energy to reduce its Scope 2 emissions, it is important that it understands both the volume of electricity it uses, as well as how it is used throughout the day, i.e. its electricity demand profile. These, as well as its broader sustainability ambitions, will inform which renewable energy procurement pathway would be most suitable for individual businesses.

Based on AMPC's EPR 2024 data, Figure 20a shows the annual 2024 energy usages from surveyed members, from which we will define three main groups: small (0-10 GWh), medium (10-20 GWh) and large energy users (20+ GWh). Previously collected data from a previous AMPC report, investigating the low-cost assessment & arrangement of solar PV, (AMPC, 2023) has been used to create a generalised AMPC member electricity demand profile in Figure 20b, which correlates to an annual electricity demand of 16 GWh which is close to the EPR survey's average load. This will be used as the basis of discussions on procurement options.



(a)



(b)

Figure 20. (a) Distribution of AMPC 2024 EPR survey participants' annual energy loads. (b) Generalised AMPC member electricity demand profile for a weekday (WD) and weekend (WE), and the average annual intraday QLD spot price (RHS).

To demonstrate some of the considerations and complexities when considering PPAs, Figure 21 provides an simplified example of what a Retail PPA may look like when unpacking its components; a 0.8 MW PPA with a wind farm providing generation throughout the evenings, a 1.1 MW PPA with a solar farm to meet the weekday daytime demand, and the firming for the balance of supply (i.e. the unders/overs from PPA generation mismatch to demand) would be settled against the regional electricity spot price.

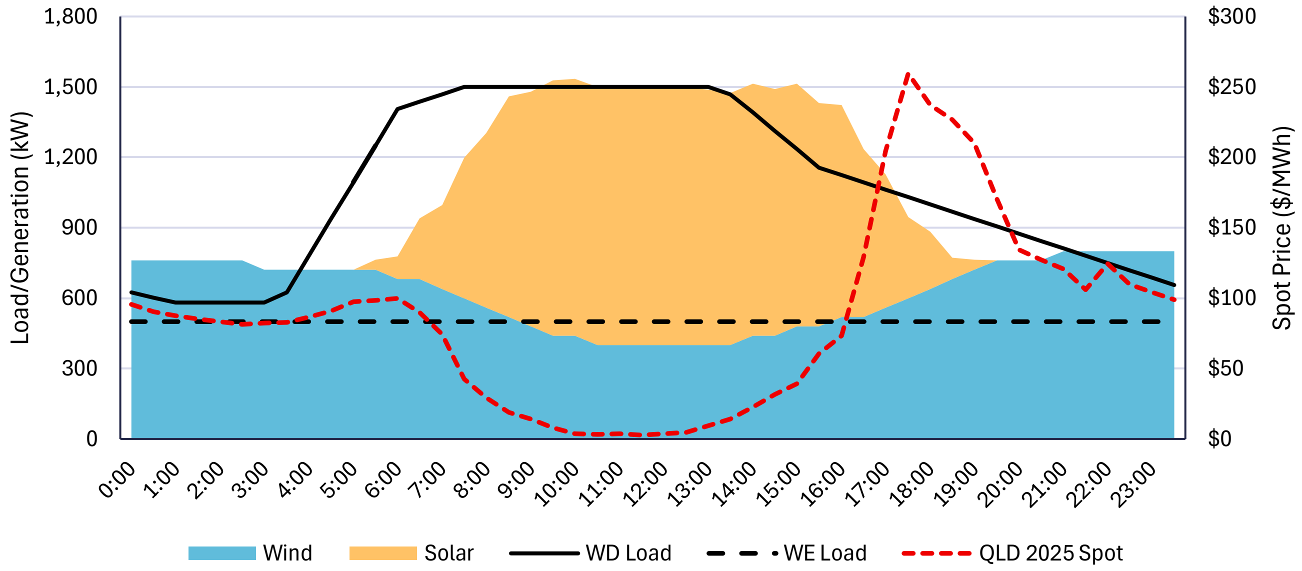


Figure 21. An annualised schematic showing the combination of a generic wind and generic solar asset optimised to fit the estimated load profile of a general AMPC member.

7.4.4 Battery Energy Storage Solutions (BESS)

The Australian renewable energy sector has seen a significant wave of BESS development at both the residential/C&I level as well as at a utility scale. Home battery uptake has increased dramatically with federal and state rebates, with similar commercial drivers applicable to utility scale renewable projects where long duration BESS are being developed, as are BESS being retrofitted alongside solar farms to enhance their value.

Should AMPC members be interested in transacting with utility scale BESS developers, some typical offtake structures for contracting standalone BESS are given below in Table 17. While these are relative assessments, it is important to note that these transactions can be as difficult as wholesale PPA transactions themselves if not more so. Given that energy is not the core business of many AMPC members, generally the less sophisticated structures like a Revenue Swap or Virtual Toll (Time Bands) may be more suitable, however, this depends on what the desired objective is when entering a BESS contract.

Table 17. A product risk profile overview of five common standalone BESS contracting structures.

Criteria	Physical Toll	Virtual Toll (Time bands)	Virtual Toll (Price bands)	Revenue Swap	Bespoke Shape/Times
Accessibility	Med	High	Med	Med	Low
Complexity	Med	Low	High	Med	High
Administration	High	Med	Med-High	Low	Low
Market Participation	High	Med	High	Low	Low
AMPC Member Suitability	**Low**	**High**	**Low**	**High**	**Med**

7.5 International Decarbonisation Comparison

7.5.1 International Emissions

Benchmarking Australian red meat processing emissions against key international markets is inherently challenging due to the limited availability of directly comparable data. Very few sources report processing emissions in a way that enables consistent cross-country comparison. The summary presented in Table 18 is largely derived from a single published study (Jeong et al., 2019) supplemented by contemporary grid electricity data, but even within that dataset the reported emissions intensities are expressed in materially different functional units — including kgCO_2e per kg live weight, kg HSCW, kg bone-free meat, kg pig meat, and aggregated "kg meat" categories. These differing system boundaries, yield assumptions and allocation methodologies significantly constrain comparability. Apparent differences in emissions intensity may therefore reflect methodological artefacts rather than genuine differences in processing efficiency or technology.

Grid electricity intensity varies substantially between jurisdictions — for example, Australia's average grid intensity is considerably higher than that of New Zealand and Sweden — and modern meat processing facilities can operate almost entirely on electricity. In principle, this creates the potential for structurally lower reported processing emissions in countries with low-emissions electricity systems. However, comparison of reported processing intensities does not demonstrate a clear correlation with grid emissions intensity once functional unit differences are considered. This reinforces that throughput assumptions, product mix, rendering integration, co-product allocation, and boundary definitions materially influence results, often more than electricity emissions alone.

It is also important to recognise that processing emissions (from HSCW to finished product) represent a small proportion of total life-cycle emissions for red meat — typically on the order of ~2% for beef — with the dominant share arising from enteric methane and upstream production associated with liveweight. Consequently, while grid decarbonisation can influence reported processing intensity, it has limited impact on whole-of-value-chain emissions outcomes.

Given these limitations, meaningful international benchmarking would be materially improved through adoption of a consistent reporting methodology, including harmonised functional units (e.g., kg HSCW or kg saleable meat), clearly defined system boundaries, and transparent allocation of co-products. Establishing such consistency would enable more robust comparison of operational efficiency and technology deployment across jurisdictions and would provide a stronger foundation for complementary metrics — such as greenhouse gas emissions per unit of value added (GEVA).

Table 18: Breakdown of international emissions for red meat processing (Jeong, et al., 2019; Electricity Maps, 2025).

Country	Avg. Grid Electricity (tCO_2-e/MWh)	Relative to Australia	Total Emissions Intensity (kgCO2/Unit)	Functional Unit	Relative to Australia
Australia	0.62	100%	0.343	kg HSCW	100%
New Zealand	0.0729	12%	10.09	kg live weight	59%
United States	0.403	65%	16.73	kg live weight	166%
United Kingdom	0.175	28%	6.30	kg pig meat	38%
Brazil	0.129	21%	41	kg HSCW	239%
Japan	0.449	72%	34.3	kg beef	545%
Europe	0.187	30%	19	kg meat	55%
Canada	0.148	24%	22	kg beef	116%
Sweden	0.022	4%	22.3	kg bone free meat	101%

7.5.2 International Carbon Market Maturity: Background and Context

Globally, Australia is the largest exporter of sheep and goat meat, and the second largest exporter of beef meat[5]. Mutton and lamb also represent large meat export commodities for Australia.

Australia exported over 2.24 million tonnes of red meat products to 104 countries in 2024. Trends in this export market have shifted in recent years. Most notably this has been due to a combination of China's imposition of tariffs on Australian beef, the impacts of drought in the USA and China, shifts in consumer demand during and following the Covid-19 pandemic, and outbreaks of animal diseases in Brazil and China.

As of 2024, the US, China, Japan and South Korea were the largest importers of Australian meat by value[6]. Beef exports, representing 67% of Australia's red meat exports, increased by 60% to the US, and by 33% to Southeast Asia in 2024.

Given the exposure of Australian meat exports to international markets, AMPC members with exposure to international markets are encouraged to consider the evolving emissions regulations in export destination countries.

The **US, China, Japan,** and **South Korea** were selected given their relative significance. **The European Union** has also been considered given the advanced state of its emissions policies and its influence on other countries' emissions policies globally.

7.5.3 Carbon Market Scheme Overviews

Carbon markets, including for example carbon taxes, emissions trading schemes and voluntary carbon offsetting schemes, have become increasingly wide-reaching in recent years. 113 carbon market schemes across 55 countries are being used to limit or regulate the emissions from various sectors.

Appendix [1] provides a more detailed analysis of the schemes in each jurisdiction. None of the schemes assessed for this research were found to pose a material near-term impact on the Australian RMP sector.

7.5.4 Regulatory risks

Two key emerging regulatory trends have been assessed in the selected jurisdictions: carbon border adjustment mechanisms (CBAMs) and embedded emissions disclosure requirements.

Carbon Border Adjustment Mechanisms

CBAM Explainer

A Carbon Border Adjustment Mechanism (CBAM) is a policy tool designed to price the carbon emissions embedded in imported goods, ensuring they face the same regulatory imposts or costs as products made within the importing jurisdiction. This policy tool is intended to prevent 'carbon leakage', where companies might relocate production to countries with less stringent climate regulations to avoid emissions liabilities and imposts.

As the implementation of a CBAM generally hinges on addressing the risk of carbon leakage and protecting domestic producer competitiveness, the likelihood of red meat imports being captured under such a measure is contingent on domestic red meat production being subject to carbon pricing. To date, very few jurisdictions have

[5] https://www.mla.com.au/globalassets/mla-corporate/prices--markets/documents/trends--analysis/soti-report/mla-state-of-the-industry-report-2425-web.pdf
[6] https://www.abs.gov.au/articles/insights-australian-exports-meat

included or are planning to include the sector specifically under carbon pricing mechanisms with the notable exception of the Danish agricultural carbon tax on livestock and nitrogen emissions.

Currently, the European Union (EU) is the only jurisdiction that has fully implemented a Carbon Border Adjustment Mechanism (CBAM). Other countries such as the United Kingdom, Japan, Canada, and the United States are actively considering or developing similar policies, largely in response to the EU CBAM but they are not yet in force – a snapshot is provided in Table 19 below[7].

Table 19. Overview of international jurisdictions with a Carbon Border Adjustment Mechanism.

Country / Region	Status	Timeline	Sectors Covered	Notes
European Union (EU)	Implemented (Transitional phase since Oct 2023)	Full implementation Jan 2026	Cement, iron and steel, aluminium, fertilizers, electricity, hydrogen	First CBAM in the world; importers must buy CBAM certificates reflecting embedded carbon emissions
United Kingdom (UK)	Planned	Starts 2027	Aluminium, cement, ceramics, glass, hydrogen, iron and steel, fertilizers	Designed to align with UK Emissions Trading Scheme
Norway	Considering	2027	Same as the EU CBAM	
Canada	Proposed / Under consultation	No timeline	Likely carbon-intensive goods (steel, cement, aluminium, fertilizers)	Still in policy design stage
United States (US)	Proposed (debated in Congress)	No timeline	Steel, aluminium, other industrial goods	"Clean Competition Act" and other proposals under discussion
Australia	Considering	No timeline	Not yet defined	Reviewing CBAM options, no legislation yet
Japan	Exploring	No timeline	Not yet defined	Reviewing CBAM options, no legislation yet

China appears unlikely to introduce a CBAM in the near term (pre-2030), having strongly criticised the EU CBAM as a unilateral trade measure.

Japan is more likely to consider the introduction of a domestic CBAM on imported goods, considering it has expressed support for the EU CBAM and considering the extent of domestic emissions covered in its national ETS.

South Korea has not expressly indicated whether it intends to introduce its own CBAM.

[7] https://gmk.center/en/infographic/how-different-countries-around-the-world-reacted-to-cbam-introduction-in-the-eu/

Given the sectoral coverage of existing CBAMs or those in development listed above, embodied emissions from red meat exports from Australia into those countries are not currently directly exposed, nor expected to be in the near-term.

The EU is considering expansion of the CBAM to also cover emissions from imported glass, ceramics, chemicals, and plastics. A legislative proposal is anticipated in early 2026, with additional products introduced gradually from 2027. By 2030, the CBAM is anticipated to extend its reach to virtually all sectors within the EU ETS: maritime, domestic aviation, industry and power. ETS2 is slated to be established in 2027 or 2028, covering sectors not covered in the existing ETS – including building, road transport, and industry sectors not covered under the existing EU ETS.

Given the intended sectoral alignment of the CBAM with the existing ETS, it is considered unlikely that red meat imports will be exposed to the CBAM in the near-to-mid-term.

Ultimately any developments in the EU CBAM regulation will have relative influence on regulatory developments in other jurisdictions. It is recommended that the AMPC and members have regard to any future developments in the EU's CBAM's sectoral coverage in future research reports.

Emissions disclosure requirements

Scope 3 emissions

Scope 3 emissions are the indirect greenhouse gas emissions that occur across an organisation's entire value chain, both upstream (via suppliers) and downstream (via customers). They are often the largest share of a company's total carbon footprint, sometimes dwarfing Scope 1 and 2 emissions.

The emissions generated from the goods sold from AMPC members to retailers such as supermarkets are classified as the Scope 3 emissions from the supermarkets.

Across all industries and jurisdictions, there has been an increase in recent years from corporates monitoring and disclosing their scope 3 emissions. Many have set Scope 3 emissions reduction targets, to drive their supply chains to reduce those emissions. This has partly been driven by new regulatory requirements, and in part for voluntary reporting purposes.

In Australia, the Mandatory Climate Related Disclosure reporting requirements, legislated in 2024 under the Corporations Act 2001, require certain entities to disclose Scope 3 emissions in an annual report. Entities meeting certain size thresholds were required to commence reporting from 1 January 2025, as summarised in Table 20.

Table 20. Non-exhaustive summary of Mandatory Climate Related Disclosure reporting requirement thresholds

Hi	Example of reporting threshold triggers	Annual report period starting
Group 1	At least two of the three following criteria: • Revenue >$500m • Gross assets >$1b • Employees >500 Or	1 January 2025

	• Corporations that meet the publication threshold for the *Greenhouse and Energy Reporting Act 2007* ('NGER Act')	
Group 2	At least two of the three following criteria: • Revenue >$200m • Gross assets >$500m • Employees >250 Or • All other NGER reporters	1 July 2026
Group 3	At least two of the three following criteria: • Revenue >$50m • Gross assets >$25m • Employees >100	1 July 2027

The mandatory climate reporting standard, AASB S2[8], prescribes that reporting entities must disclose: (a) their Scope 3 emissions across the entity's entire value chain, and (b) relevant targets relating to scope 1, 2 and 3 emissions (if they have them).

Research finds that Scope 3 disclosure in the food and beverage processing sector have historically been incomplete and inconsistent, with Scope 3 emissions assumed to be materially underreported globally[9]. Many companies – across all sectors – face challenges accessing accurate and reliable Scope 3 emissions data, requiring the use of proxy data to report on company emissions profiles. The disparate nature of agricultural commodity markets amplifies this challenge, including for the red meat sector.

The use of secondary (proxy) data is becoming less prevalent, with firms preferencing primary emissions data from their supply chains. This means that even smaller food processors within a food retailer's supply chain can expect to be requested to provide primary data on their own emissions, to enable retailers to improve the accuracy of their Scope 3 emissions reporting.

The introduction of the mandatory climate-related reporting regime has amplified this focus on the accuracy of Scope 3 emissions data collection. This also extends to entities not captured under the mandatory reporting thresholds, which may choose to report voluntarily.

Spotlight on Selected Red Meat Retailers

Retailers of Australian red meat products have implemented various targets, programs and initiatives to drive reductions in their Scope 3 emissions. Some of these are voluntary and others are due to regulated disclosure requirements as outlined above.

This section reviews the Scope 3 requirements of five red meat retailers selected by AMPC: Coles, Woolworths, Aldi, Costco and Walmart. The assessment has included and summarised in Table 20:

- Whether the retailer has a Scope 3 emissions reduction target,
- What pressures the retailer is putting on the supply chain partners to reduce emissions, and

[8] https://standards.aasb.gov.au/sites/default/files/2025-01/AASBS2_09-24.pdf
[9] https://www.sciencedirect.com/science/article/pii/S2666791621000026

- Whether the retailer is committed to a sustainability standard or reporting framework which requires Scope 3 emissions reductions.

Table 21. Summary of key red meat retailers' Scope 3 emission reductions or ambitions.

Retailer	Scope 3 target	Supplier pressure to reduce emissions	Committed to a framework requiring Scope 3 disclosures
Coles	Y	Y	Y
Woolworths	Y	Y	Y
Aldi	Y	Y	Y
Walmart	Y	Y	Y
Costco	Y	N	N

Coles
• As part of its Science Based Target[10], Coles is engaging directly with its suppliers to encourage them to reduce their own emissions, in turn reducing Coles' Scope 3 emissions. • This is to achieve a goal to reduce Scope 3 emissions from forest, land and agricultural sectors by 30.3% by FY2030 against a FY24 baseline. These sectors represent 55% of Coles Scope 3 emissions. • These targets include purchased goods and services, and so Coles is working directly with beef and lamb suppliers to reduce emissions[11]. • Coles reports that 42% of its suppliers have set science-based targets to reduce their scope 1 and 2 emissions. Coles has a goal of engaging 80% of suppliers by spend, to encourage them to set emissions reduction targets that are 'science-based' by FY29. Reporting against this target commenced in FY26. It is assumed that a number of AMPC members will be engaged by Coles as part of this initiative. • Coles also has a certified Climate Active beef product, which covers the scopes 1, 2 and 3 emissions associated with the product (explored further below).
Woolworths
• Woolworths Group reports that Scope 3 comprises the majority of its emissions – estimated at 30 million tonnes in FY2023, compared to 1.8 million tonnes of scopes 1 and 2 emissions combined[12]. • Like Coles, Woolworths has a validated SBTi target. This includes a goal to reduce Scope 3 emissions by 55% by FY2033 from a FY2023 base year, and to further reduce them by 90% by FY2050[13][14].

[10] https://sciencebasedtargets.org/target-dashboard
[11] https://www.colesgroup.com.au/FormBuilder/_Resource/_module/ir5sKeTxxEOndzdh00hWJw/file/Sustainability_Report.pdf
[12] https://cer.gov.au/markets/reports-and-data/corporate-emissions-reduction-transparency-report/corporate-emissions-reduction-transparency-report-2024/CRPT-24-M6W038010580
[13] https://sciencebasedtargets.org/target-dashboard
[14] https://www.woolworthsgroup.com.au/content/dam/wwg/sustainability/reports/2025_WG_Sustainability_Report_Interactive_SPREADS.pdf

- To date, Woolworths has engaged 28% of its suppliers to streamline emissions data sharing in the agricultural sector.
- Woolworths also discloses its scopes 1, 2 and 3 emissions as part of its voluntary Carbon Disclosure Project (CDP) reporting commitment.

Aldi

- In 2024, ALDI SOUTH Group set near and long-term targets covering Scope 3 emissions.[15]
- As with Coles and Woolworths, ALDI's targets are validated by SBTi, requiring an absolute reduction in energy and industry Scope 3 emissions of 25% by 2030 and a reduction in Scope 3 Forest, Land and Agriculture (FLAG) emissions of 30.3% by 2030.
- Longer-term ALDI has committed to reaching by 2050 a 90% reduction in energy and industry Scope 3 emissions and a 72% reduction in Scope 3 FLAG emissions.
- Key focus areas in targeting Scope 3 emissions are partnering with suppliers on on-farm practices and addressing upstream decarbonisation opportunities.
- Meat is noted as a specific commodity group in the spotlight for ALDI in targeting Scope 3 emissions.

Walmart

- In 2016, Walmart became the first retailer to validate its emissions reduction targets under the SBTi.[16]
- As part of this goal, the group committed to Project Gigaton, reducing, avoiding or sequestering 1 billion metric tonnes (a gigatonne) of CO2e across its value chain.
- This target was completed in February 2024, ahead of the anticipated 2030 completion date, however, the group continues to engage across its supply chain in key action areas including energy, transportation, product design, waste, packaging and nature.
- Walmart encourages suppliers to increase reporting and transparency by sharing CDP disclosures under the Project Gigaton framework.

Costco

- While Costco has not adopted a Science-Based Target, the organisation states it actively considers SBTi guidance alongside the GHG Protocol and CDP.
- Costco's current Scope 3 target is set at a 20% reduction in emissions intensity by 2030, rather than a reduction in absolute emissions. This target also explicitly excludes fuel emissions.
- Costco partners with suppliers to reduce Scope 3 emissions but does not publicly disclose a requirement for reporting of emissions or firm reduction targets within the value chain.

It is recommended that, if engaged by a retailer, food processing and producing entities should consider adopting emissions reduction targets aligned with the SBTi framework or Climate Active programme. AMPC members should engage with retailers directly to understand their specific requirements before seeking one of these certifications.

[15] https://sustainability.aldisouthgroup.com/stories/aldis-climate-targets
[16] https://corporate.walmart.com/content/dam/corporate/documents/esgreport/2025/FY2025-Walmart-ESG-Report.pdf

7.5.5 Carbon Offsetting and Insetting Strategies

Carbon insetting refers to activities that reduce or remove greenhouse gas emissions within an organisation's own value chain it can control, rather than relying on external carbon offsets. Examples include Scope 1 & 2 emission reduction strategies within an organisation's operational boundaries such as energy efficiency, onsite renewable energy, process re-design, waste and/or methane reduction measures. While pathways to generate credits via these activities do exist in domestic and international carbon offset schemes, proving additionality (i.e. that the activity or reduction would not have taken place in the absence of carbon finance) can be challenging, particularly where technology alternatives or strategies provide economic benefit alongside emissions reductions. Insetting activities relevant to AMPC members are further detailed in Section 6.7 but for clarity these activities would not be automatically eligible for the creation of ACCUs or other credits.

Upstream producers, e.g. farmers who raise livestock, could produce ACCUs through projects onsite, under methods such as Soil Carbon, Environmental Plantings or other upcoming agricultural methods such as Integrated Farm and Land Management. Should AMPC members require offsets, it is worth considering supporting the development of or purchasing from carbon projects within the value chain, supporting the wider red-meat sector's efforts in decarbonising.

7.5.6 Carbon Cost Analysis

With the ability to generate ACCUs limited for most meat processors, organisations seeking credits will most likely need to procure from the secondary market. Below, CORE Markets has provided its view of the forward price forecast for these credits, split between several common methods, out to 2040.

CORE expects the (weighted) average ACCU price to begin at around $45 per unit in FY27, steadily growing through to FY29, supported by sufficient supply including holdings to meet demand.

From FY29 onward, sharper price increases occur across all methods as steepening Safeguard baseline decline rates drive stronger demand.

Beyond FY36, prices continue to rise, albeit at a slower pace, as existing land-based methods get closer to reaching their maximum issuance potential. With limited scope to expand supply without the development of new methods, scarcity persists. The finalisation of the Integrated Farm and Land Management (IFLM) method is also expected to become an important price driver in the later years.

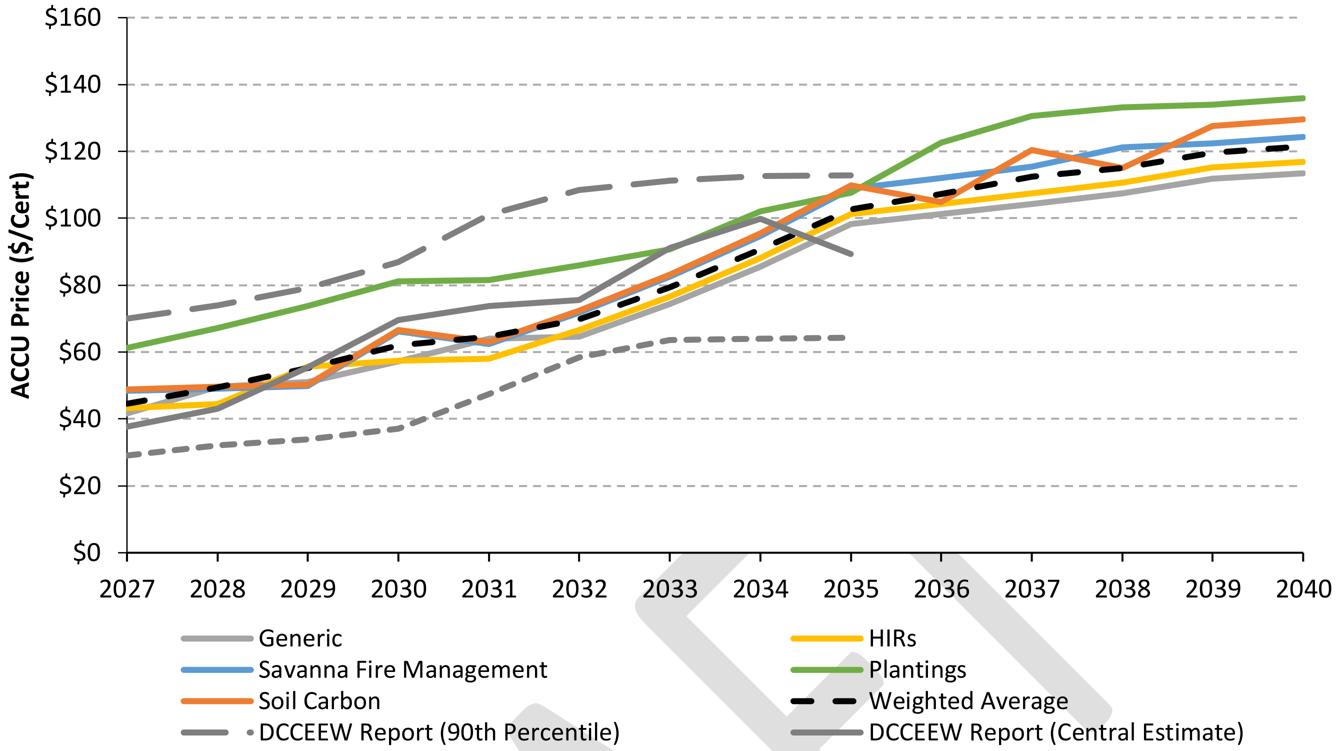


Figure 22: CORE Markets ACCU price forecast.

8.0 Conclusions & Recommendations

8.1 Conclusions

The Australian red meat processing sector has a clear pathway to reduce scope 1 and 2 emissions; however, the rate and extent of decarbonisation will vary significantly across facilities. Key findings from this research include:

- The sector has demonstrated ongoing improvements in energy and emissions intensity, although recent variability in production has impacted trend interpretation and highlights the importance of throughput in assessing performance.
- Energy demand is dominated by thermal processes, particularly steam generation for rendering and hot water, alongside significant electrical loads for refrigeration and processing. These systems represent the primary opportunity for emissions reduction.
- Rendering configuration is a key driver of site energy intensity. Batch dry rendering represents the highest energy intensity, followed by continuous dry, then continuous, low-temperature, wet rendering providing the lowest energy demand and greatest opportunity for heat recovery.
- Proven technologies such as energy efficiency upgrades, solar PV, and biogas recovery are commercially available and already being implemented, while technologies such as high-temperature heat pumps and MVR are emerging as key enablers for deeper decarbonisation.
- The decarbonisation pathway for each facility is highly site-specific, influenced by factors including plant size, throughput, existing infrastructure, fuel sources, and grid electricity emissions intensity.

- Government policy, funding programs, and carbon pricing mechanisms are expanding and improving project viability, however capital cost, integration complexity, and operational disruption remain key barriers, particularly for brownfield sites.
- External pressure from supply chains, particularly retailers with scope 3 emissions targets, is expected to become an increasingly important driver for decarbonisation in the sector.

8.2 Recommendations

To support continued decarbonisation of the Australian RMP sector, the following actions are recommended:

- **Assess rendering systems as a priority**, particularly for facilities operating batch dry rendering, where conversion to continuous wet rendering can deliver substantial energy and emissions reductions.
- **AMPC members should develop site-specific decarbonisation pathways** that account for local energy supply, plant configuration, and operational constraints.
- **Increase adoption of electrification technologies**, including heat pumps and electric boilers, where suitable.
- **Expand on-site renewable energy generation**, particularly solar PV, to reduce reliance on grid electricity and improve long-term energy cost stability.
- **Investigate biogas recovery opportunities** from wastewater and organic waste streams to offset fossil fuel use in thermal systems.
- **Leverage available funding programs and policy mechanisms** to improve project economics, particularly for capital-intensive upgrades and emerging technologies.
- **Continue industry-led research, pilot projects, and knowledge sharing,** particularly for technologies such as MVR, high-temperature heat pumps, and integrated energy systems.
- **Prepare for increasing supply chain requirements**, including retailer-driven scope 3 emissions targets, by developing transparent emissions baselines and reduction strategies.

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10.0 Appendices

10.1 Appendix – Full List of Decarbonisation Opportunities

Table 22. Decarbonisation opportunity matrix. Note: Criterion weighting: Technology readiness (TRL) = 1, Installation complexity (INST.) = 1, Greenhouse gas reduction (GHG) = 4, Payback period (PB) = 4. Overall score (Max score = 50). Action priority: green = high, amber = medium, red = low.

Group	Opportunity Technology	Description	TRL	INST.	GHG	PB	Overall Score
EE	Wet Rendering	Batch Dry to Wet Continuous Rendering - Reduces Rendering Temperature and Process	5	2	5	5	47
Elec	Heat Pump - Waste Refrig. Heat	Hot Water Heat Pump up to 90°C using waste heat	3	3	5	4	42
EE	Biogas Generators & Boilers	General effluent (Covered Anaerobic Lagoons), paunch or DAF sludge (Hydraulic Reactor)	4	3	3	5	39
EE	Continuous Rendering	Batch to Continuous Rendering optimisation	5	2	4	4	39
Bio	Low water sterilisation	Reduce volume of 82°C consumed in Sterilisers using nozzle types or Econoliser	5	2	5	3	39
RE	Rooftop Solar	Flush and tilt rooftop solar PV on existing buildings, including factories and sheds.	5	5	4	3	38
RE	Ground-mount solar	Fixed tilt and E/W tracking solar PV systems connected behind the meter	5	5	4	3	38
EE	Lagging Steam	Insulation on steam lines	5	4	2	5	37
EE	Fine crusher	Reduce particle size of raw rendering material before entering cooker	5	3	2	5	36
EE	Refrigeration heat recovery	Recovering waste heat from condenser and oil coolers	5	3	2	5	36
EE	Condensate Return System	Installing, improving or maintaining the condensate return in a steam system	5	3	3	4	36
Bio	Biomass Boilers	Steam Generation using some form of biomass	4	3	4	3	35
Elec	EBoilers - Spot market	Electrode or resistance electric boiler for steam generation, exposed to spot electricity market	5	2	5	2	35
EE	Rendering Process Automation	Smart Processing Automation	5	5	1	5	34
EE	Lagging Hot Water	Insulation on hot water lines	3	3	3	4	34
EE	Boiler Tuning	Boiler should be tuned every year - rated efficiency based on tuning to operating pressure.	5	5	2	4	34
RE	Boiler Economisers	Utilising waste heat to preheat incoming water	4	4	1	5	32
EE	Demand response programs	Get paid to allow electricity network to shut down electricity supply if grid capacity constrained.	5	3	2	4	32
EE	EBoilers w/ Green Electricity	Electric boiler for steam generation, purchasing green electricity for supply	5	2	3	3	31
Elec	Heat recovery from Rendering	Heat recovery from: evaporators, cooker vapor, shell & tube condenser, & dryer exhaust	4	3	5	1	31
EE	Lagging Refrigerant	Insulation on refrigerant and glycol lines	1	1	3	4	30
EE	UV knife sterilisation	Eliminate 82°C water in knife sterilisation	5	5	1	4	30
EE	Underfloor heating optimisation	Refrigeration Optimisation - lower temp, utilise heat recovery, increase monitoring	5	5	1	4	30
Elec	ETES - Hot Water - Spot market	Thermal energy storage for hot water, exposed to spot electricity market via child NMI	3	3	4	2	30
Elec	ETES - Hot Water	Thermal energy storage for hot water, supplied by excess solar or cheap energy tariffs	3	3	4	2	30
EE	Floating discharge	Refrigeration Optimisation - floating discharge temperature	5	4	1	4	29
EE	Dryer Insulation	Insulation on rendering steam dryer	5	4	1	4	29

Group	Opportunity Technology	Description	TRL	INST.	GHG	PB	Overall Score
EE	Hot Water Flow restrictors	Hot wash hoses with flow restrictors, pressure increasers - reduce overall hot water demand	5	4	2	3	29
EE	Lights	Replace old lights with LED	5	4	1	4	29
EE	EC fans etc.	Refrigeration Optimisation	5	4	1	4	29
EE	Variable Speed Drives	VSDs where necessary	5	4	1	4	29
EE	Steam Heat Pumps	Steam Generation at higher efficiency (Heat pump)	3	5	2	3	28
EE	Off-site solar farm	Ground-mount solar farm connected to the grid in a off-site/separate location	2	2	2	4	28
EE	Engine Room AI Digital Twin	AI Digital twin to identify efficiencies and faults	5	3	1	4	28
EE	Vibratory Shear Enhance Process	Rendering optimisation - increases product output, reduces 50% of process water	5	3	1	4	28
Elec	Lamella Pump	Rendering optimisation - Pump efficiency increase for move high viscosity meat/offal/blood	1	3	5	1	28
RE	Pump configurations	supply of 45, 65, and 82 water independently, rather than mixing at PoU	4	4	4	1	28
EE	Boiler blowdown heat recovery	Heat recovery from waste foam ejected from boiler to preheat incoming water	5	2	2	3	27
EE	Hot water automation	Smart Processing Automation	4	3	1	4	27
Elec	Behind-the-meter battery	Battery connected behind the meter to store excess solar/cheap power	2	1	4	2	27
RE	MVR in Rendering	Stick-water evaporation w/ Mechanical Vapor Recompression reduces new steam demand	3	4	3	2	27
EE	Chemical washdown - warm water	Reduces washdown Temperature	3	3	1	4	26
EE	Compressed air heat recovery	Heat Recovery	3	3	1	4	26
EE	Viscera Table Spray Nozzles	Replace copper spray nozzles with high pressure ceramic nozzles	3	3	2	3	26
EE	Front-of-meter/VPP battery	Battery connected to a child NMI to capitalise on spot market price variation	5	4	1	3	25
RE	Shrink Tunnel	Replace old steam tunnels with new electric tunnels	2	3	2	3	25
EE	High efficiency motors	Replace inefficient motors in refrigeration and wastewater	5	4	1	3	25
EE	Compressed air fault management	Compressed Air Audit, monitoring and management to quickly and efficiency fix faults	5	4	1	3	25
EE	Air purges	Refrigeration optimisation - increases concentration of refrigerant in refrigerant line	4	4	1	3	24
Elec	ETES - Steam - Spot market	Thermal energy storage steam generation, exposed to spot electricity market via child NMI	2	2	4	1	24
Elec	ETES - Steam	Thermal energy storage steam generation, supplied by excess solar or cheap energy tariffs	2	2	4	1	24
EE	Disc Dryer (vs continuous)	Rendering optimisation - More efficient MBM dryer - 70-85% efficient vs 45-65% efficient	5	2	1	3	23
EE	Carcass chemical wash	Chemical Cleaning reduces high temperature (~82C) washdown to low temperature (65C)	3	3	1	3	22
EE	Spin Flash Dryer	Rendering optimisation - replaces disc dryer or direct batch dryers	5	3	1	2	20
EE	Electric blood coagulation	Blood coagulation typically done with steam injection, move to electrical, removes steam	3	3	2	1	18
EE	Fat screw press	Rendering optimisation Add-on -Lowers drying loads and increases yield	5	2	1	1	15
EE	Electric hook wash	Replace 82°C continuous water trough with electric coil trough and limited HW supply	3	3	1	1	14

Table 23: TRL definitions, as explained by the International Energy Agency (IEA, 2026).

Category	TRL	Definition	Description	
CONCEPT	1	**Initial idea**	Basic principles have been defined	Beyond the SDS
	2	**Application formulated**	Concept and application of solution have been formulated	
	3	**Concept needs validation**	Solution needs to be prototyped and applied	
SMALL PROTOTYPE	4	**Early prototype**	Prototype proven in test conditions	
LARGE PROTOTYPE	5	**Large prototype**	Components proven in conditions to be deployed	Scope of the SDS
	6	**Full prototype at scale**	Prototype proven at scale in conditions to be deployed	
DEMONSTRATION	7	**Pre-commercial demonstration**	Solution working in expected conditions	
	8	**First-of-a-kind commercial**	Commercial demonstration, full scale deployment in final form	
EARLY ADOPTION	9	**Commercial operation in relevant environment**	Solution is commercially available, needs evolutionary improvement to stay competitive	
	10	**Integration needed at scale**	Solution is commercial and competitive but needs further integration efforts	
MATURE	11	**Proof of stability reached**	Predictable growth	

10.2 Appendix - Technology Breakdown

10.2.1 Rendering and Opportunities

Processes

High Temperature Dry Rendering

High temperature dry rendering combines cooking and drying in a single step, heating raw material directly to approximately 130-140°C to evaporate moisture within the cooker (Rendertech, 2019). Vapour, fat and meal are produced simultaneously, with limited opportunity for intermediate separation, heat recovery, or process control. Steam is typically injected directly, producing dispersed, contaminated vapour streams (Figure 23).

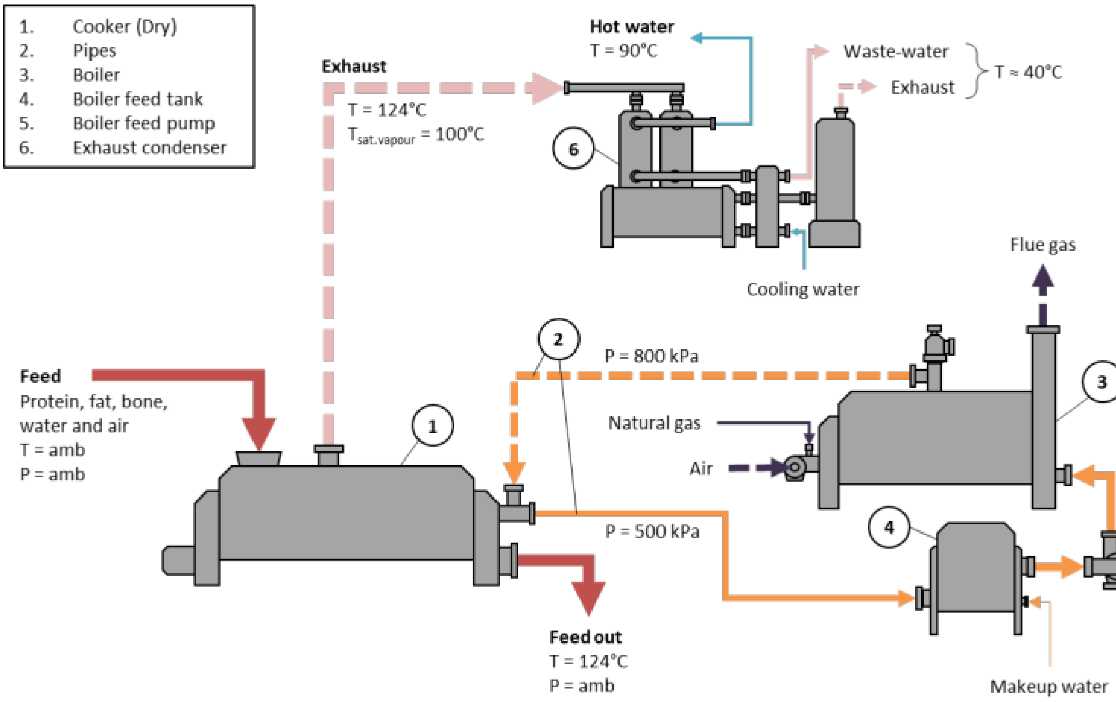

Figure 23: Process flow of high temperature dry rendering (AusIndustry, 2024).

Low-Temperature Continuous Wet Rendering

Low-temperature continuous wet rendering separates cooking, dewatering, and drying into discrete stages. Raw material is heated to approximately 90-100°C to rupture fat cells and coagulate protein, followed by mechanical dewatering using presses or centrifuges (Rendertech, 2019). Stickwater is treated separately through evaporation, enabling recovery of dissolved proteins and fats rather than discharging to wastewater. This staged configuration enables indirect heating, defined vapour streams, and integration of advanced heat recovery (Figure 24).

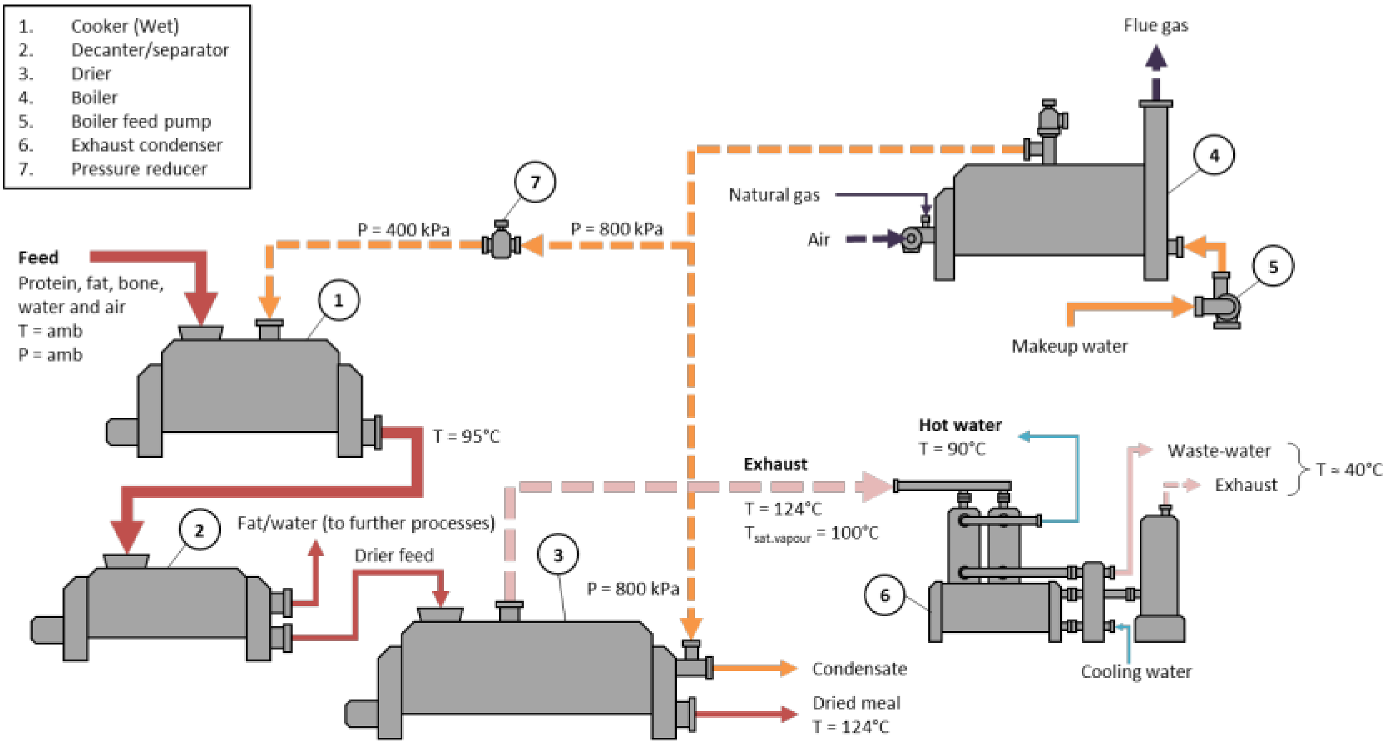

Figure 24: Process flow diagram of steam heated wet rendering with a drier (AusIndustry, 2024).

Low-Temperature Continuous Wet Rendering with Mechanical Vapor Recompression

Mechanical vapour recompression (MVR) can be integrated into wet rendering systems without altering the core process. Low-pressure vapour from the dryer or evaporator is recompressed and reused as process heat rather than being condensed and rejected. This configuration is generally not feasible in dry rendering due to the fragmented and contaminated vapour streams (Figure 25).

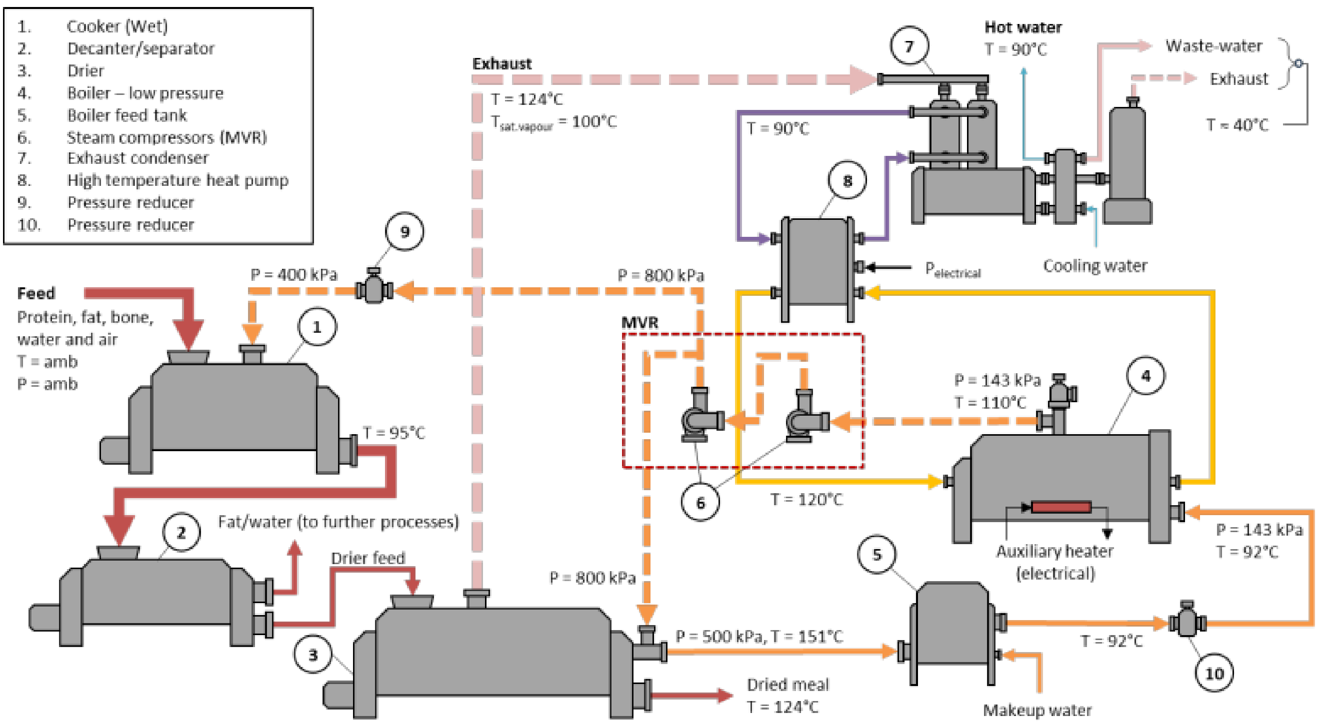

Figure 25: Process flow diagram of wet rendering utilising MVR (AusIndustry, 2024).

Quality of Output

In high temperature dry rendering, prolonged exposure to temperatures above 130°C degrades protein structure and causes pigment fixation in tallow. This often results in reduced meal quality and non-bleachable tallow, limiting access to higher value markets.

Low temperature wet rendering limited exposure to below 100°C prior to separation, preserving protein structure and producing tallow that remains bleachable. Low temperatures also reduce the likelihood of plastic contamination from things like ear tags melting into the product during the tallow phase (Rendertech, 2019).

Energy

Rendering energy performance is primarily driven by how heat is supplied, how evaporation energy is managed, and whether latent heat is recovered or rejected. For red meat rendering operating at approximately 10t/h, baseline steam demand varies materially across rendering configuration, with measured differences in boiler load, recoverable heat, and net thermal energy intensity.

Steam dry rendering requires approximately 0.75 t of steam per tonne of raw material. Most evaporation energy exists the system as low-pressure vapour that is condensed and rejected, resulting in minimal heat recovery and a high reliance on boiler steam. Consequently, this configuration has the largest net thermal demand and the greatest heat rejection to cooling systems (Figure 26).

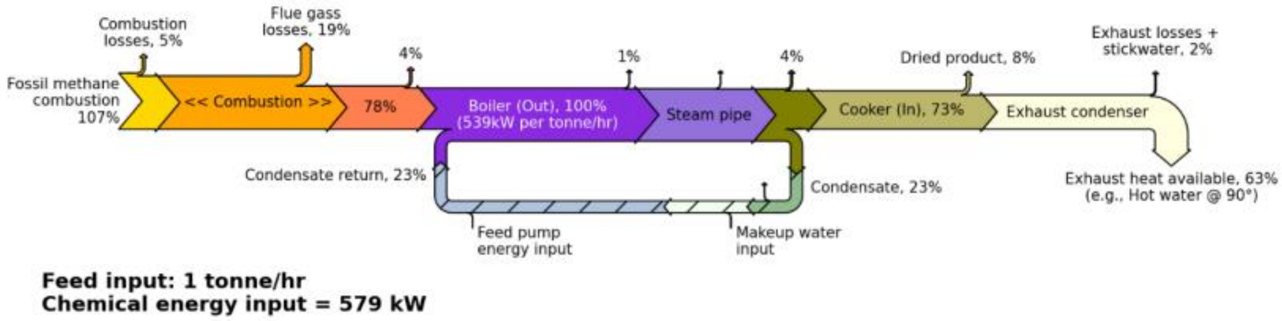

Figure 26: Energy flow through steam heated dry rendering process (AusIndustry, 2024).

Wet rendering reduces steam demand to approximately 0.55 t per tonne of raw material, a reduction of around 27% relative to dry rendering. Energy losses are lower because evaporation is concentrated into defined units, reducing uncontrolled heat rejection. However, the majority of evaporation energy is still supplied by boiler steam, and low-grade vapour in many processing plants are condensed and rejected rather than reused (Figure 27).

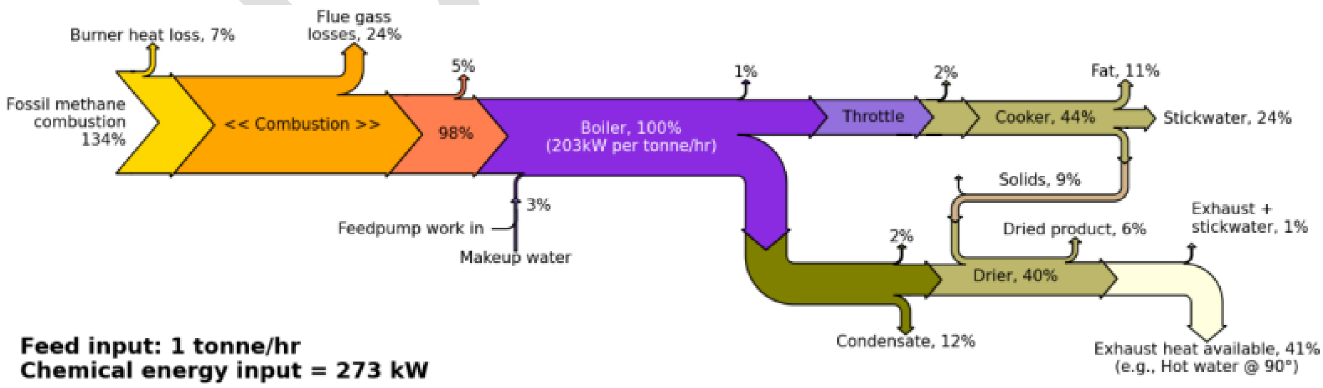

Figure 27: Energy flow through a steam heated wet rendering process (AusIndustry, 2024).

Utilising MVR in wet rendering achieves the lowest net thermal energy demand and is capable of displacing 80-90% of boiler steam, reducing thermal input and shifting energy demand toward electricity for the compressor. Because evaporation occurs in discrete units in wet rendering, vapour quality is more suitable for MVR, allowing substantially higher internal heat reuse than either wet or dry rendering alone, while maintaining the same low-temperature process conditions (Figure 28).

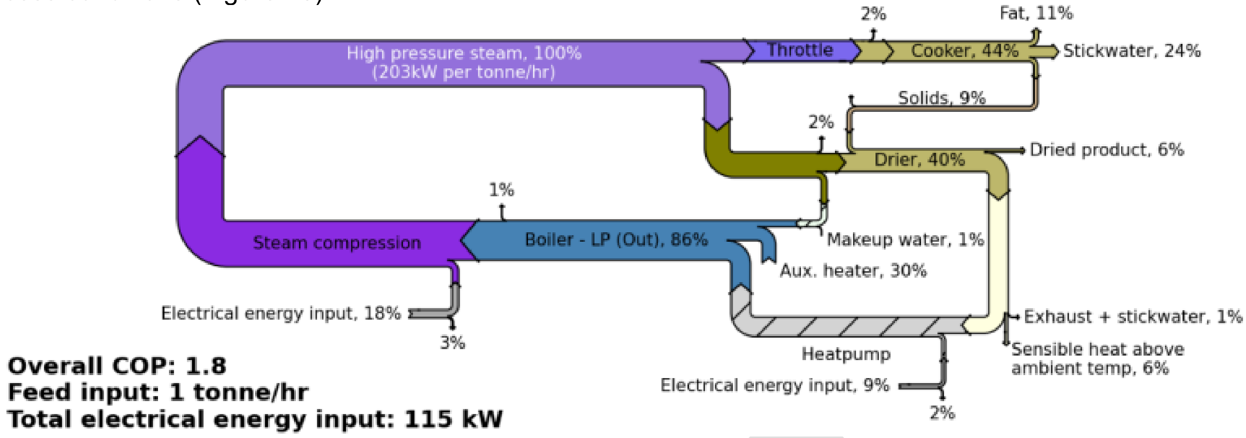

Figure 28: Energy flow through a wet rendering process with heat pump and MVR heat recovery (AusIndustry, 2024).

Overall, converting dry rendering to continuous wet rendering utilising MVR and heat pumps can deliver up to 80% energy savings for rendering operations, equivalent to as much as **30% of a site's total energy use**, while improving product yield and quality. **Estimated payback periods are typically 3–6 years**, with higher savings and faster paybacks.

Fine Crusher

A fine crusher follows a coarse crusher or raw material bin in the rendering line. It further reduces particle size, improving the efficiency of heat transfer in cookers and reduces overall cooking time. This can decrease steam load for rendering by up to 15%, or **site energy use by up to 5%**, and increase fat yield by 1-2 % (Rendertech, 2025). **Estimated payback 2-4 years.**

10.2.2 Energy Efficiency

Energy efficiency is unequivocally the first step in decarbonisation. Its importance in achieving sustainable fuel systems is such that it is commonly referred to as the "first fuel". Focusing on efficiency reduces overall energy demand by lowering energy requirements before new technologies are applied. This reduces the scale and cost of any subsequent renewable technology deployment. The following sections cover specific energy efficiency opportunities.

Insulation

Insulation is one of the most cost-effective efficiency measures for the meat processing industry. On many sites, insulation is damaged, removed, or degraded, and not reinstated because it is not considered production critical. This leads to persistent, normalised heat losses that can account for **0.5-4% of the site's total energy demand**. Energy savings and paybacks vary depending on temperature, pipe/equipment utilisation rates, and existing equipment states. General guidance is as follows:

Steam (120 – 180°)

- **External steam lines**: Severe heat loss due to exposure to wind and rain. Weatherproof lagging offers typical paybacks of less than 1 year.
- **Internal steam lines**: High heat loss due to high pipe surface temperatures. Payback of around ~1 year can be expected, particularly for large diameter pipes, tanks, or steam used in applications like rendering dryers
- Uninsulated valves/flanges/traps are commonly overlooked

Hot Water (45 – 95°C)

- **External hot water lines**: High heat loss due to exposure to wind and rain. Weatherproof lagging offers typical paybacks of 1-2 years.
- **Internal hot water lines:** Payback 1-4 years depending on temperature and flowrates.

Refrigeration (-40 – 5°C)

- Maintenance of lagged refrigeration lines can offer an energy saving however this is highly dependant on refrigerant used on site, the piping routes, pipe runs, exposure to ambient conditions, and existing conditions of the pipework.
    - Improvements to pipe lagging will often reduce load on compressors and save energy.

Heat Recovery from Waste Streams

Rendering

Rendering plants reject large amounts of low-grade heat through stick water, condensers, cooker vapour and wastewater. Capturing this heat through waste heat evaporators, economisers, or direct heat exchangers can offset 5-30% of boiler steam demand load and **reduce site overall energy consumption by 5-10%.** Typical recovered temperatures range from 60 – 85°C depending on the system. **Estimated payback 1-3 years** depending on access to vapour streams, condensate temperature and retrofit complexity. AMPC's report on options to maximise process heat recovery case study D provides an example of cooker vapor heat recovery among other heat recovery opportunities (AMPC, 2015).

Refrigeration

Refrigeration systems reject large amounts of low-grade heat i.e., 25-35°C from the condenser, 40-55°C from the oil coolers, and up to 70°C from the desuperheater. Utilising this heat recovery can reduce 2-5% of the thermal energy demand or **1-5% of overall energy consumption**. Refrigeration heat recovery can be supplemented with heat pump installations that upgrade refrigerant waste heat and produce higher quality hot water. Implementation of direct heat recover would be **expected to have paybacks of 1-2 years** depending on hot water demand profile, refrigeration run hours, water supply temperatures, and ambient outside temperatures. Further information on refrigeration opportunities can be found through AMPC's refrigeration toolkit (AMPC, 2021).

Hot Water Flow Restrictors

Hot water for knife sterilising must be above 82°C. Traditionally knife sterilising is achieved through continuous supply of 82°C in dunk sterilisers (Figure 29 [Left]) which flows directly to drain. More efficient options that reduce flow include spray sterilisers activated by motion sensors (Figure 29 [Middle]), or Econolisers (Figure 29 [Right]. Both systems require a return flow line that returns unused steriliser water back to the hot water tanks. Implementing reduced flow sterilisers can reduce hot water demand for sterilisers by over 70% or **reduce total site energy use by 5-10%.** AMPC completed a case study on the savings of Econolisers and found 99%[17] of steriliser energy and water savings, up to $2,000 per year on water, and over $14,000 per year on energy for each Econolisers installed (AMPC, 2024b). **Estimated payback 0.5-2 years**, depending on the steriliser being replaced and the extend of additional pipework needed (e.g. return lines).

[17] This figure represents the savings from replacing a continuous flow steriliser with an Econoliser in boning or offal rooms where knife sterilisation is less frequent.

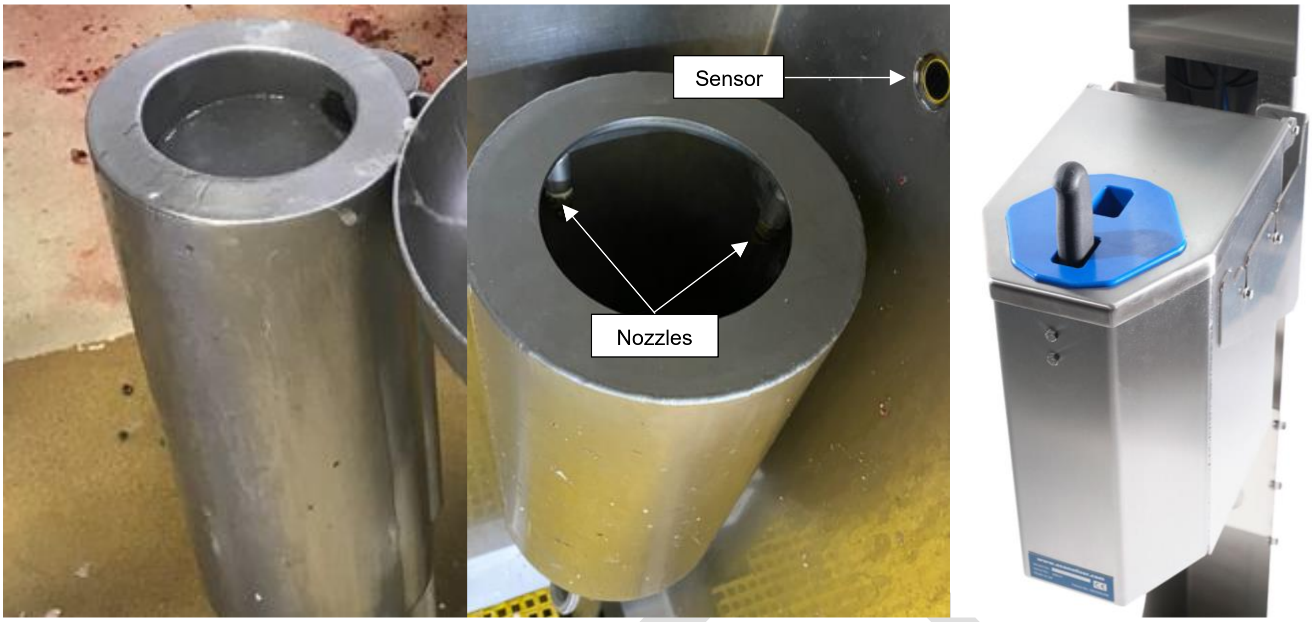

*Figure 29:Steriliser types: [**Left**] Continuous flow dunk steriliser; [**Middle**] Reduced flow sensor activated nozzle spray steriliser; [**Right**] High efficiency Econoliser.*

Refrigeration Upgrades

Several refrigeration opportunities have the potential to reduce electrical load on a site.

EC Fans

Evaporator fans are used to force air across the refrigerant coils and distribute cold air inside the cold store. However, they are typically fixed speed AC fans which leads to unnecessary heat generation inside the cold store. Upgrading to electronically commutated (EC) fans or fitting variable speed drivers allows the fan speeds to be tailored to the load, reducing waste heat loads with a corresponding reduction in compressor electrical duty. This is particularly beneficial during periods of partial loading or refrigeration cycling. For cold stores and chilling operations this can yield up to 40% savings in fan power or **2-5% of total site energy demand**. **Estimated payback 1-2 years** depending on outside climate, and nature of cold store use.

Underfloor heating upgrade

Cold stores require underfloor heating to prevent frost heave – where concrete foundations expand and crack due to the moisture underground freezing and expanding. The underfloor heating occurs in the background and is not often monitored. As a result these systems can be over controlled, run continuously or powered by high-cost energy when waste heat is available. Utilising low grade recovered heat or optimising duty control can reduce **total site energy demand by 0.2-1%. Estimated payback 2-4 years** is dependent on cold store temperature and scale.

Floating Discharge

Many refrigeration plants operate with a conservative control strategy utilising fixed discharge and suction pressures on the compressor, irrespective of the load or ambient conditions. This leads to excessive power demand from the compressors, the largest energy consuming elements of the system. Allowing compressors to "float" the evaporating and discharge pressure (temperatures) according to load and ambient conditions reduces the compressor work markedly. Floating head control is considered best practice.

However, this level of control requires correct sensor setups, stable commissioning and trained operators. As a result, many sites lock in conservative pressure values to protect the processes, even when the floating logic would not affect the refrigeration process. This control change can deliver 5 – 15% refrigeration energy savings or **1-3% of**

total energy demand. Primary costs involve training and commissioning, resulting in a **6-18 month estimated payback.** Combining a floating discharge with a digital twin of the refrigeration system allows for peak performance and control of the refrigeration cycle.

High Efficiency Motors

Although highly cost-effective, high-efficiency (IE3/IE4) motors are rarely installed proactively; replacement usually occurs only when an older motor fails. Purchasing decisions are often driven by upfront cost rather than lifecycle cost, particularly during emergency breakdowns. Embedding efficiency requirements in procurement policy is key to capturing these gains long-term.

Replacing older motors (Figure 30) with modern high-efficiency models reduces electricity consumption across many plant systems — from pumps and fans to conveyors and mixers – and **total energy demand by up to 0.5-1%**. **Estimated payback 2–5 years** depending on run hours and motor size. This is especially effective when timed with planned equipment replacements to avoid duplication of maintenance costs.

Figure 30: Old low efficiency motor being audited before upgrade at a meat works

Lighting

Switching to LED lighting throughout the facility and installing occupancy sensors, especially in cooled rooms significantly reduces lighting energy with minimal operational disruption. Lighting energy can be cut by 50-80% or **0.5-1% of sites total energy demand**. Lighting upgrades are typically implemented as an upgrade policy, replacing legacy fluorescent lighting with LEDs with smart controls. **Estimated payback 1 – 3 years**, typically shorter in areas with long operation hours, or areas with lights left on and minimal usage.

Boiler / Steam Upgrades

Boiler Tuning

Boilers gradually drift out of optimal efficiency as conditions change, however boiler tuning can be a reactive response to faults. Tuning and oxygen trim optimisation will improve combustion efficiency and reduce excess air losses and can improve the efficiency of the boiler by 2-6% or **total energy demand by 0.1-0.5%**. Regular tuning typically only occurs when responsibility is clearly assigned and budgeted. **Estimated payback 3 – 12 months** depending on the frequency of tuning.

Boiler Economiser

Installing a flue-gas economiser to capture waste heat from boiler exhaust and preheat feedwater reduces boiler fuel demand and increases overall efficiency by 5-8% or approximately **1% of total site energy demand**. However, economisers require careful design or redesign and can raise concerns around corrosion maintenance complexity, and downtime risk. As a result, they are often excluded from retrofit projects where facility shutdown periods are short. **Estimated payback 2-4 years** depending on retrofit or new build. Due to the risk and payback of economisers, they are more often installed during major boiler

Condensate Return System

Returning steam condensate back to the boiler is a very effective means of savings energy, as a result any opportunity that can increase the proportion of steam returning to the boiler, as opposed to going to drain will have significant energy savings at comparatively low costs. It is important to identify how much steam is returning as condensate and increase this or prevent steam and condensate from going to drain. It is also important to identify when steam is returned in the condensate line. Condensate returning before the steam can be used in the process is lost energy.

This can be caused by leaks, blockages, and contamination issues. Steam traps improve system efficiency by rapidly removing condensate and non-condensable gases while preventing live steam loss; whereas fail-closed traps primarily reduce heat transfer and disrupt operations. An opportunity for Improving the condensate return system is through yearly steam trap audits, insulation reviews, and flash steam recovery. This can significantly reduce the network losses from steam distribution, saving up to 10% of steam energy or over **1% of total site energy demand**. **Estimated payback 3-12 months** depending on the frequency of audits and reviews completed.

10.2.3 Electrification of Heat

Heat Pump

Heat pumps use a refrigeration system to transfer energy from a lower temperature source (air, water, ground) to a higher temperature process stream. Rather than generating heat, they redistribute it, enabling higher effective energy efficiencies than direct combustion. Their coefficient of performance (COP), or effective energy efficiency typically ranges from 250-600% (COP 2.5 to 6) depending on many factors, including the temperature lift required and heat source availability. This efficiency gain effectively results in a **site wide energy reduction between 15-25%** or higher if the site doesn't operate rendering. Commercially available heat pumps operate at up to 95°C (TRL 11) and typically offer an **under 5-year payback**. Some new models reaching 140°C internationally (TRL 7) operate at a lower efficiency, and are more costly resulting in significantly longer paybacks, while lab demonstrations are showing potential up to 200°C (TRL 4) (Arpagaus, 2023). Heat pumps are an excellent electric technology for baseload heat generation, however, secondary buffering through thermal battery storage, or secondary heating sources such as electric boilers can provide complementary peaking load support. For example, if the site uses low flow sterilisers, come off break at once, there is a peak load on the hot water demand that can be taken by the hot water storage.

Widespread uptake is driven by their high energy efficiency and strong economic performance in continuous, low-temperature applications. Their lower electricity consumption per unit of heat output makes them particularly attractive where energy costs or emissions are tightly managed, such as in regulated or high-volume sectors. When the heat source for a heat pump system is a part of a site production processes, site utilities, or waste outputs, this can increase the complexity of integration especially when retrofitting in brownfield sites, slowing the rate of transition. In these situations, design and integration will require multidisciplinary input from heat pump specialists, process engineers, electrical contractors, refrigeration contractors, and site staff. It may also require a shift in operating philosophy for the site to optimise the system performance. This is different to typical hot water boiler systems (both fossil-fuelled and electric), whose energy source is independent of the site's production, utilities, or waste outputs.

Main Barriers to Adoption

The main barriers for heat pumps are limited load-shifting capability due to the loss in efficiency when operating at partial loads and the long start-up and shutdown time (heat pumps operate most efficiently at continuous steady state loads), high capital cost associated with connecting to waste heat streams and building thermal storage, complex system integration and design, and resistance to changing the operating philosophy of the facility.

The red meat processing sector is not expected to fully transition capable systems to heat pumps by 2050. This is a result of the low cost of fossil fuels, especially coal, which can deliver heat for under $15/GJ compared to more than $16/GJ for heat pumps.

Other Constraints Include:

- **Technical**: Complex design integration increases risk and project duration.
- **Regulatory**: Compliance of refrigerant-related environmental and safety codes are complex and jurisdiction specific.
- **Workforce:** Industrial scale heat pump installation and refrigerant management require specialist training, which is limited in remote regions.
- **Financial:** High capital costs due to the level of design required, as a result, its strongest ROI is during continuous operations, where it is best suited.
- **Legal:** Legacy plant permits may prevent installation or require upgrades and renegotiation.

Figure 31: Mayekawa 90°C Water to Water Heat Pump installed in Food Industry (DETA).

Mechanical Vapour Recompression (MVR)

Similar to heat pumps, MVR transfers and upgrade energy from lower to higher temperatures. However, unlike heat pumps, MVR draws heat directly from the process, avoiding the need for an external medium or refrigerant, resulting in high efficiencies between 600-2,000% (COP 6 to 20). Commercially available systems (TRL 11) are particularly suited to recycling vapour in the rendering process. It can also be applied to blood drying systems to recover heat from exhaust vapours improver overall efficiency. Implementing MVR in these processes can reduce site steam demand by up to 50% **site energy demand by 10-20%.**

Main Barrier to Adoption

MVR has a higher level of complexity for integration even when compared to heat pumps. MVR is particularly hard to retrofit within existing facilities (brownfield) with **paybacks closer to 7-10 years** and is far better suited to new facilities (greenfield) where MVR can be fully integrated into the process and the plant is designed to operate around the MVR resulting in a payback comparing it as an opportunity cost of as low as 2-3 years. This is particularly important for shutdown and start-up. The cost of retrofitting into the process can often exceed five times the cost of the MVR, making it more feasible to new facilities or processes than retrofit applications (Energetics, 2024).

Other Barriers Include:

- **Technical**: Limited expansion of MVR as a technology into other processes due to its complex integration.
- **Workforce:** Requires specialist process engineers familiar with high-efficiency thermal integration.
- **Financial:** High upfront costs without proven savings from existing case studies and high potential for delays in commissioning deter investment (ARENA, 2023).
- **Legal:** Retrofit projects often require renegotiation of existing heat supply agreements adding uncertainty (ACCC, 2023).

Electric Boiler or Electric Thermal Energy Storage (ETES)

Electric boilers and Electric Thermal Energy Storage (ETES) systems both provide combustion-free steam for processing facilities and operate with similar overall energy requirements. While both improve boiler-system efficiency from ~75% (typical gas-fired systems) to 90-100% (**a 5-10% total site energy reduction**), the two technologies differ significantly in design, cost, and operational flexibility.

Electric Boilers

Electric boilers are a mature, commercially available technology (TRL 11) that generate steam or hot water below 300°C using resistive elements or electrode conductivity. They require minimal redesign of piping, controls, or operating practices. This lowers capital costs but also means efficiency gains alone rarely justify investment. **Paybacks typically exceed 8 years** unless the electric boiler is compared to the cost of replacing or rebuilding an ageing fossil boiler.

Adoption is expected to increase before 2030 where in facilities with significant onsite solar generation. By 2030-2035, grid emissions intensity is forecast to fall below that of fossil fuels and consumer supply-chain pressures are expected to accelerate transition. Post 2035, uptake aligns with boiler replacement cycles and corporate emissions commitments.

Electric Thermal Energy Storage (ETES)

High-temperature ETES systems are emerging technologies (TRL 8) that store electrical energy in solid or molten media (e.g., ceramic refractories or molten silicon) at 400-1,200°C and discharge this heat through a heat exchanger to produce steam. ETES operates by charging during low-cost electricity periods such as off-peak grid periods, or surplus onsite solar, and supplying stored heat when the plant requires steam, this results in decreased operating costs compared with electric boilers.

Operating periods of sites are typically during off-peak electricity periods, or up to 24 hours per day. As a result, ETES systems often require significantly higher electrical capacity than electric boilers and capital costs of ETES systems are higher than electric boilers, as a result **payback periods typically exceed 8-10 years.**

Main Barriers to Adoption

Meat processing sector face additional constraints, particularly in securing capital for upgrades. Smaller site scales, narrow margins, and limited grid capacity further reduce the feasibility of investment.

Other Barriers Include:

- **Technical:** High instantaneous demand may create grid complications in industrial zones, especially where boiler capacity exceeds 10 MW, which may occur at sites with rendering (AEMO, 2023).

- **Regulatory:** Complex and time-consuming grid connection approvals for high-load equipment delays deployment (AER, 2024).
- **Workforce:** Limited experienced boiler operators with high-capacity electric steam systems, requiring upskilling of maintenance personnel (AIS, 2021).
- **Financial:** High capital costs when including grid infrastructure upgrades and uncertain electricity price volatility impacts projected ROI, particularly for 24/7 operations (Beyond Zero Emissions, 2020).

Figure 32: High voltage immersion electrode steam and hot water boilers from EPS.

Figure 33: MGA thermal's ETES demonstration plant (MGA Thermal, 2024)

Electric Thermal Energy Storage (ETES) – Spot Market Exposure

High-temperature ETES systems are a relatively new to market technology that is still primarily in the early industrial deployment or commercial stage (TRL 8). They store electrical energy in solid or molten media (e.g. molten aluminium, or ceramic blocks) between 400°C to 1,200°C then discharge heat through a heat exchanger to produce process steam. These systems are designed to use low cost electricity, then store the energy until the plant needs it. This system however is significantly more capital intensive than electric boilers as there is a higher infrastructure demand in electrical supply, takes more space, and the product itself is also significantly more expensive than electric boilers.

With the emergence of low cost and often negatively priced electricity during daylight hours in Australia, high temperature thermal energy storage can provide a low cost replacement to natural gas boiler emissions if the initial capital cost is reduced over time. A thermal energy storage system can access this low cost energy by being supplied by a ‘Child’ NMI. Under this structure, the thermal energy storage system will be connected behind the gate meter but will be exposed to the spot price of electricity via the child NMI, completely independent of the retail electricity contract. The system can then charge (store energy) during low-cost daylight periods and discharge when demand is required. Figure 34 shows the 30 min spot electricity price in February and August 2025 for SA, Qld, Vic and NSW where the price is low or negative for large periods of the day. The average spot price of electricity during 9am-5pm from 01 Dec 2024 to Nov 2025 period was $18/MWh (1.8c/kWh) in SA, $21/MWh (2.1c/kWh) in Qld, $23/MWh (2.3c/kWh) in Vic and $45/MWh (4.5c/kWh) in NSW.

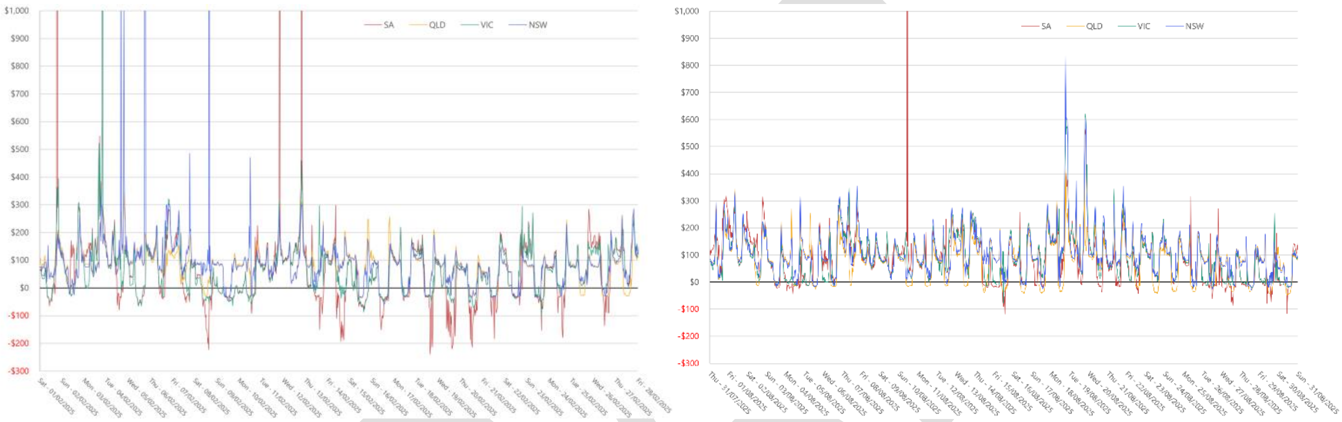

Figure 34: 30min spot electricity price in SA, Qld, Vic and NSW for February and August 2025

The systems can supplement existing steam systems by supplying steam into the steam header, providing redundancy and allowing the thermal energy storage system to be economically sized.

Main Barriers to Adoption

The main barriers to implementing this technology are capital cost of the equipment and capacity of the existing electricity supply at the site. Capital costs are projected to decrease over time and there are financed or ‘Heat as a service’ models being offered to eliminate capex. For most sites, additional electrical capacity will be required from the network/DNSP, which can be technically or cost prohibitive.

Other Barriers Include:

- **Technical:** High instantaneous demand may create grid complications in industrial zones, especially where boiler capacity exceeds 10 MW, which may occur at sites with rendering (AEMO, 2023).
- **Regulatory:** Complex and time-consuming grid connection approvals for high-load equipment delays deployment (AER, 2024).
- **Workforce:** Limited experienced boiler operators with high-capacity electric steam systems, requiring upskilling of maintenance personnel (AIS, 2021).
- **Financial:** High capital costs when including grid infrastructure upgrades and uncertain electricity price volatility impacts projected ROI, particularly for 24/7 operations (Beyond Zero Emissions, 2020).

10.2.4 On-site Renewable Energy

Renewable energy technologies represent a critical pathway for heavy industrial energy users seeking to reduce emissions and achieve decarbonisation targets. The installation of on-site renewable energy generation offers emissions reductions and operational cost savings. The following section covers specific renewable energy opportunities.

Solar

Solar PV remains one of the most effective technologies to help the sector achieve carbon neutrality and support AMPCs strategy to achieve 100% renewable electricity use by 2030. The electricity demand profile of a red meat processing facility is typically well-aligned with the electricity production profile of solar PV. An appropriately sized solar system will typically reduce a site's electricity consumption and emissions by 20-40%. Annual solar yields in Australia range from 1,133 kWh/kWp in Tasmania to 1,545 kWh/kWp in Western Australia, demonstrating a strong potential for solar electricity generation (AMPC, 2023).

Figure 35. Solar yield (kWh/kW), by state.

Rooftop Solar

Rooftop solar involves mounting solar PV panels on to the roof of existing buildings, including industrial factories and sheds. Systems convert solar energy into electricity, with power used immediately on-site to offset electricity consumption from the grid. Panels can be installed flush to the roof surface or tilted to optimise the system's cost and performance potential. Rooftop solar is typically the cheapest form of solar installation at the sub 5MW scale, as the existing roof acts as structural support, and most red meat processing facilities have roof space available to accommodate solar panels without augmentation (AMPC, 2023).

Rooftop solar is an incredibly proven and mature technology, with an estimated payback period of less than 5-years, and a >20% impact in reducing GHG emissions.

Figure 36. Rooftop PV System installed at G & K O'Connor abattoir in Pakenham, Victoria

Ground Mount Solar

Ground-mount solar involves installing solar PV panels on fixed structures mounted on ground-based racking systems, connected behind the meter to offset on-site electricity consumption. Fixed tilt systems are installed at optimal tilt angles of 20-30 degrees to maximise production, and East-West tracking systems follow the sun's movement throughout the day for enhanced yield. Typically, nearby land exists to red-meat processing facilities that could accommodate ground mount solar systems; however, this land often has competing uses such as for wastewater irrigation. Ground-mount systems can co-exist with irrigation and animal grazing; however, it may add complexity and risks to the project. Ground-mount solar is more expensive than rooftop due to additional structural requirements and geotechnical works, however, offers significant opportunities for the industry, with 300MW of ground-mount potential identified (AMPC, 2023).

A case study 2.5 MW of ground-mount solar was installed for red-meat facility Hardwicks of Kyneton, installed in a microgrid alongside 2MWh of battery capacity, enabling the customer to self-generate 65-70% of their electricity demand through local solar generation (Next Generation Electrical, 2022). The ground-mount PV was also integrated with a 1MW heat pump, building economies of scale through decarbonising electricity and hot water production (Hardwick Processors, 2021).

Ground-mount solar is another incredibly proven and mature technology, with an estimated payback period of less than 5-years, and a >20% impact in reducing GHG emissions.

Figure 37. Ground-mount solar array installed for Hardwicks of Kyneton microgrid

Off-site Solar

Off-site solar involves purchasing electricity from ground-mount solar farms located in an off-site/separate location through Power Purchase Agreements (PPAs) or by purchasing Large-Scale Generation Certificates (LGCs) to offset gird electricity consumption. Off-site solar is not an effective solution for red meat processing facilities with suitable space and/or structural capacity to install on-site solar, since they do not provide reductions in electricity costs and represent a continuous expense rather than an on-site asset with a strong payback period.

Main Barriers to Adoption

The most common barriers to adoption for rooftop and ground-mount solar projects stem from high upfront costs, site specific limitations that restrict generation capacity, structural and technical integration challenges and regulatory complexity.

Other Constraints Include:

- **Technical:** Rooftops on older industrial buildings may require strengthening before PV installation, and available roof area is often reduced by vents, pipework and refrigeration equipment. Ground-mount systems may require civil works, fencing and cabling over long distances to reach the plant's switchboard, increasing installation complexity.
- **Regulatory:** Grid-connection approvals, export constraints, and local planning permissions can create long lead times. Variations in state-level policies or network requirements add jurisdiction-specific complexity.
- **Workforce:** Installation requires accredited solar designers and electricians, and regional sites may have limited availability, extending project timelines.
- **Financial:** High upfront capital cost and additional compliance costs may lead to longer paybacks. Additional costs can arise from structural upgrades, grid-connection fees, and transformer or switchboard modifications.
- **Legal:** Ground-mount arrays may require land-use approvals or compete with operational expansion plans. Roof ownership or lease arrangements can also complicate installation on some sites.

Battery Energy Storage Systems (BESS)

Battery energy storage systems (BESS) are a key technology which can be used by heavy industrial energy users to enhance grid resilience and optimise energy management. BESS integrate effectively with on-site solar to perform behind-the-meter energy management, or participate in energy markets through front-of-meter operation. The rapidly falling cost of batteries and increase in subsidies for battery installations mean they are becoming increasingly economically viable for heavy electricity users. The following section covers specific battery energy storage opportunities.

Behind-the-Meter (BTM) BESS

Behind-the-meter (BTM) BESS are installed on the customer side of the utility electricity meter, capturing excess generation from on-site solar PV or storing electricity from the grid during off-peak periods. BTM batteries can discharge stored energy during peak demand periods to reduce grid consumption, lower demand charges and provide backup power for energy resilience. The economic case for BTM batteries is strengthened when paired with on-site solar, maximising self-consumption and reducing demand during high-demand periods (NREL, 2021).

Behind-the-meter BESS is a proven and mature technology, with an estimated payback period of less than 7-years and a 5-10% impact in reducing GHG emissions.

Figure 38. Behind-the-meter BESS installed for Hardwicks of Kyneton microgrid

Front-of-Meter BESS

Front-of-meter (FoM) BESS are physically installed behind the meter but participate directly in wholesale electricity market and FCAS markets through a ‘Child’ NMI. These systems generate revenue through energy arbitrage, capitalising on spot market price variations, and by providing Frequency Control Ancillary Services (FCAS) to maintain grid stability. Figure 39 shows the configuration of a front of meter battery using a child NMI.

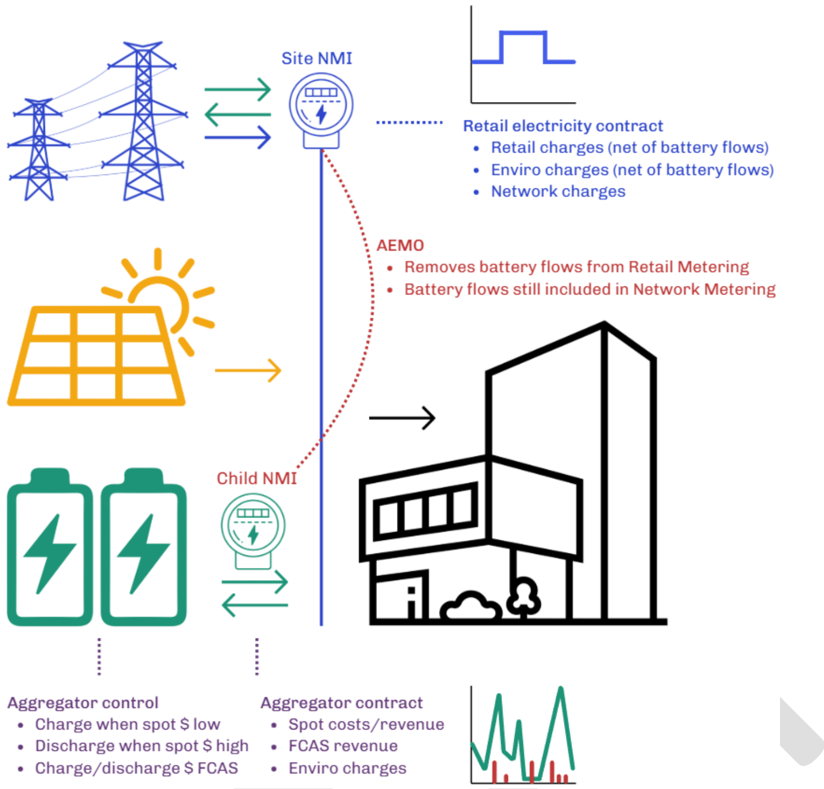

Figure 39: Front of Meter Battery configuration with a Child NMI

FoM BESS can operate within a virtual power plant (VPP), where distributed energy resources are aggregated and coordinated as a dispatchable power plant. Within a VPP, FoM batteries can be networked together, and alongside other assets including on-site solar and demand response programs (AEMO, 2021). Systems are typically operated by battery aggregators, who share a percentage of income with the site owner, such as a meat processing facility.

In addition to spot market and FCAS revenue streams, the battery can reduce network demand charges and can be configured to provide partial or full site backup power. An emerging contract structure is for a third party to own and operate a battery at a customer's site at zero cost to the customer, with the owner retaining all of the front of meter revenue benefit and the customer retaining the network and back-up benefit. In this way an AMPC member can obtain these benefits at no cost.

Main Barriers to Adoption

The most common barriers to adoption for BESS come from high up-front costs and long payback periods, technical complexity in system integration, particularly for high voltage works, and regulatory uncertainty surrounding energy market structures and grid connection requirements.

Other Constraints Include:

- **Technical:** Battery management systems require sophisticated control software and integration with existing electrical infrastructure, including switchboard modifications. Battery degradation over time reduces capacity, requiring replacement after 10-15 years.
- **Regulatory:** Grid connection approvals can be complex, particularly for larger installations. Fire safety regulations and building codes impose strict requirements for battery installation locations and protection systems.
- **Financial:** High upfront capital costs create significant barriers. Battery replacement costs after 10-15 years must be factored into lifecycle analysis, and uncertain electricity price forecasts make business case modelling challenging.

Solar & Battery Configuration Overview

There are multiple solar and battery configurations that can be employed to achieve cost, security and emissions objectives. This section aims to provide a general overview of these options, before they are assessed specifically for your site in the latter sections of the report.

Solar - Behind the Meter

Behind the meter solar is the most common form of solar in businesses and homes throughout Australia. The solar system is made up of solar panels, which produce direct current (DC) electricity, and are connected to one or more inverters which convert the electricity to alternating current (AC) so it can be used at the site. The solar system is installed on the roof, ground or carpark shade and the inverter(s) are connected to the main switchboard or a distribution board at the site, on the customer side of the electricity meter. The system supplies electricity into the site and is consumed by demand at the site. This configuration is shown in Figure 40 with a single rooftop solar system supplying electricity to the site load, which is supplied by a single NMI.

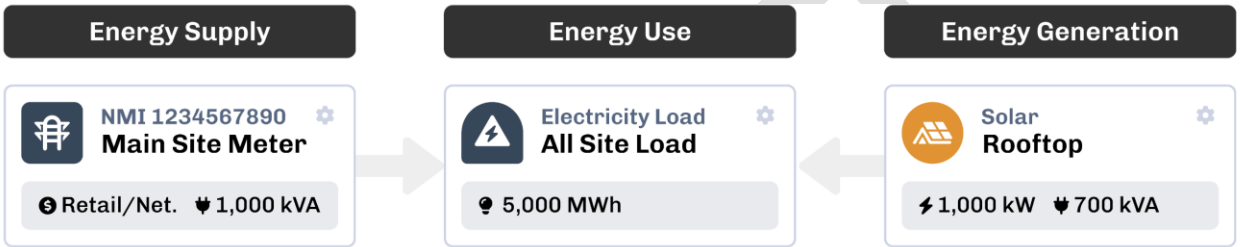

Figure 40: Single behind the meter solar system

Multiple solar systems can be installed at a site, connected to the same or different supply points. Figure 41 shows a site with two supply points with three separate solar systems connected.

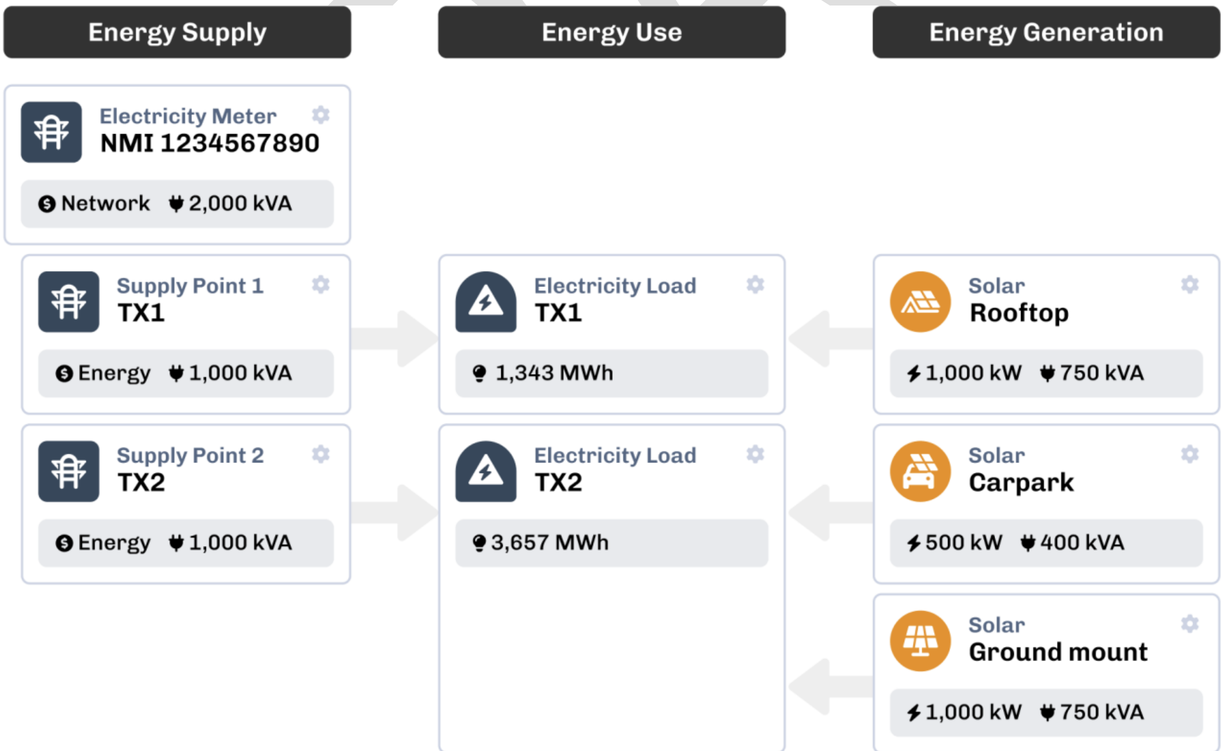

Figure 41: Multiple behind the meter solar systems

The site remains connected to the grid, however electricity consumption from the grid is reduced proportionally by the amount supplied by solar. If there is more electricity able to be generated by the solar than can be consumed at the site, it will be sent out to the grid as exported electricity (if there is no export limitation) or the output of the solar will be curtailed to match the site demand (if it is export limited). Exported electricity from solar has little to no value, so we treat both cases of export limitation the same by valuing the excess electricity produced by solar at $0.

Batteries - Behind the Meter

Batteries installed behind the meter have a similar configuration to solar behind the meter. The battery system is made up of battery cells that charge, store and discharge electricity in DC and a converter that converts electricity from AC to DC for charging, and DC to AC for discharging. Batteries are connected to the main switchboard or distribution board at the site, on the customer side of the electricity meter, and are not directly connected to the solar system.

The battery system typically charges from the site from excess solar generation, from the grid when electricity prices are low, and/or when network demand is low. Conversely, the battery system discharges electricity into the site and is consumed by the electrical demand at the site when grid electricity prices and/or network demand are high. The site remains connected to the grid (unless there is an outage) and the battery in this configuration would not export electricity to the grid. The battery system can typically supply all or parts of the site electricity without interruption, if there is a disruption to supply from the grid. Figure 42 shows a single behind the meter battery connected at a site, supplied by a single NMI.

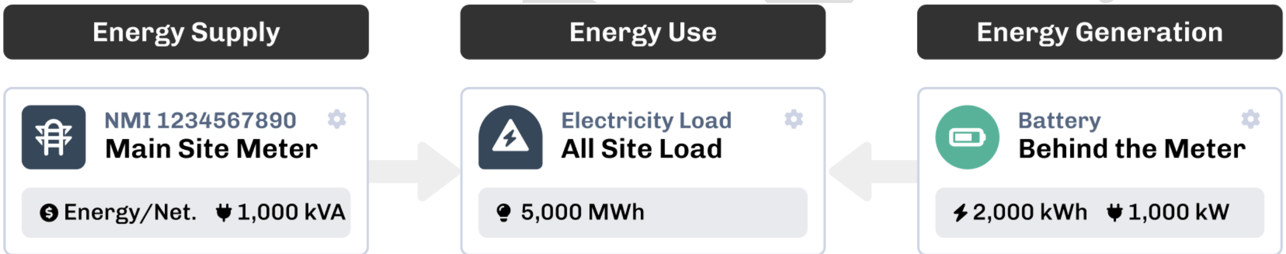

Figure 42: Behind the meter battery

Behind the meter solar and batteries can be combined at a site to provide additional savings from storing excess solar and demand management. Figure 43 shows a single behind the meter battery with a single rooftop solar system supplying electricity to the site load, supplied by a single NMI.

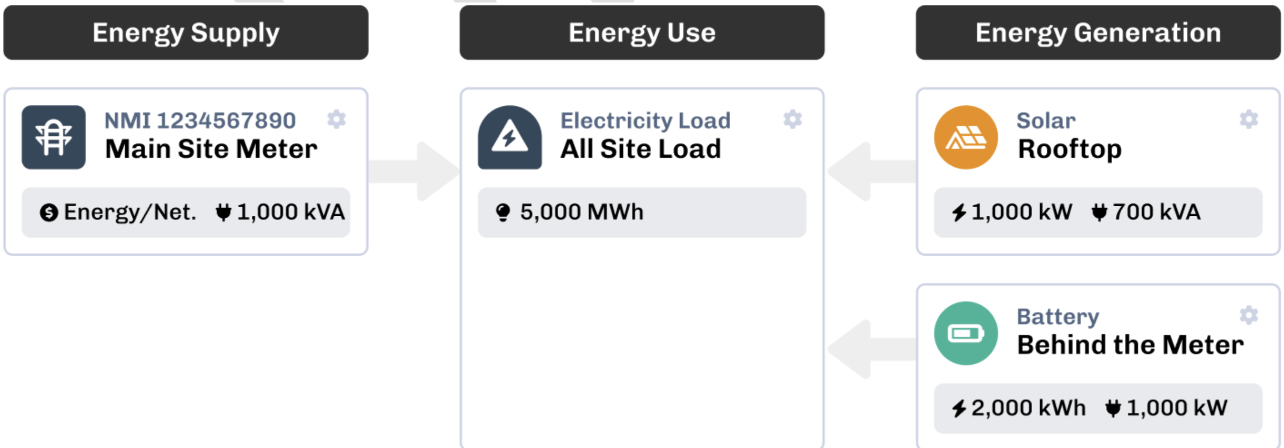

Figure 43: Behind the meter battery and solar

Batteries – Front of Meter

With this configuration, a battery system is installed physically behind the meter, however the battery is metered separately and treated as though it is connected in front of the meter for revenue purposes. This is achieved through the installation of a 'Child' meter or Child NMI which meters energy flows in and out of the battery and nets these off from the site main meter. This metering configuration was devised by the Australian Energy Market Operator (AEMO), with the intent to facilitate batteries and other energy technologies participating in energy markets separate to their retail electricity contract.

Under this mechanism the front of meter battery would charge, and discharge based on market price signals such as the spot electricity price and frequency control and ancillary services (FCAS) markets. The charging and discharging is managed by an aggregator using software that monitors these markets in real time and generates revenue through the management of the battery. The retail electricity contract is not impacted except for the impact on network consumption and demand charges. In this way the front of meter battery can provide additional savings to the customer by minimising these network charges.

Batteries installed in front of the meter have a similar configuration to solar behind the meter. The battery system is made up of battery cells that charge, store and discharge electricity in DC and a converter that converts electricity from AC to DC for charging and DC to AC for discharging. Batteries are connected to the main switchboard or distribution board at the site, downstream of the main meter and are not directly connected to the solar system.

Figure 44 shows a single front of meter battery connected to a new child meter at a site, sitting underneath a single site NMI.

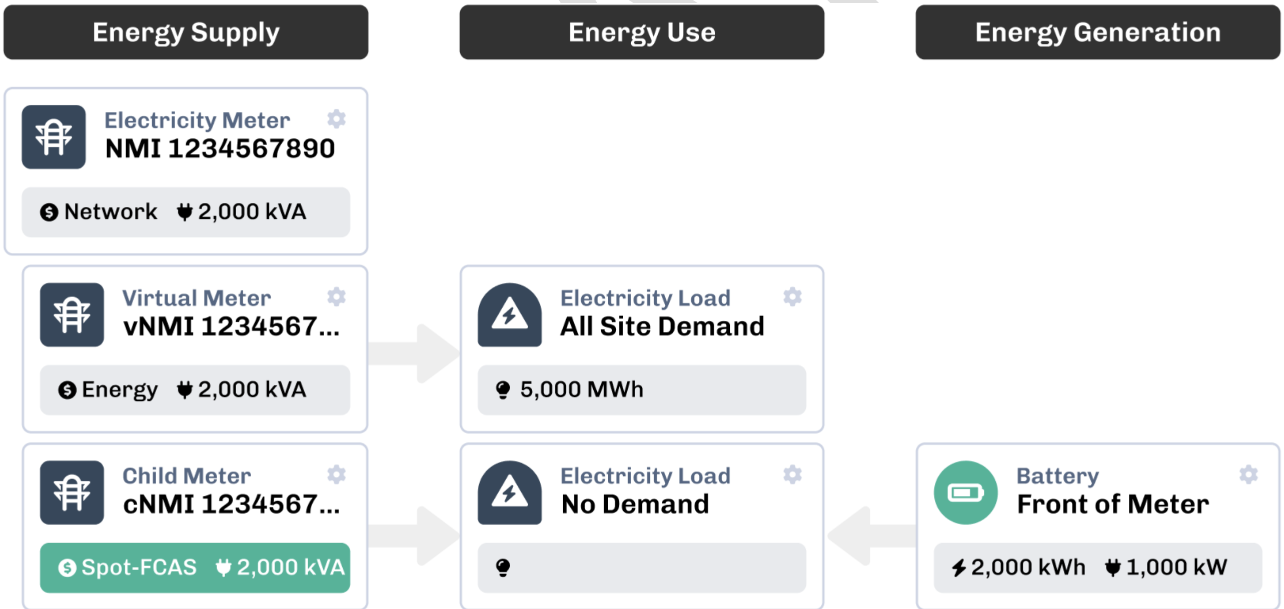

Figure 44: Front of Meter Battery

A Front-of-meter battery can also exist on site with behind the meter solar, however because the systems are separately metered there is no financial interaction beyond the impact of network charges. During the day, solar produced by the solar system would offset electricity from the grid that is consumed by the site, providing cost savings. At the same time, the battery may be charging 'from the grid' at the spot price. Figure 45 shows a solar system connected behind the meter, as well as a single front of meter battery connected to a new child meter at a site, sitting underneath a single site NMI.

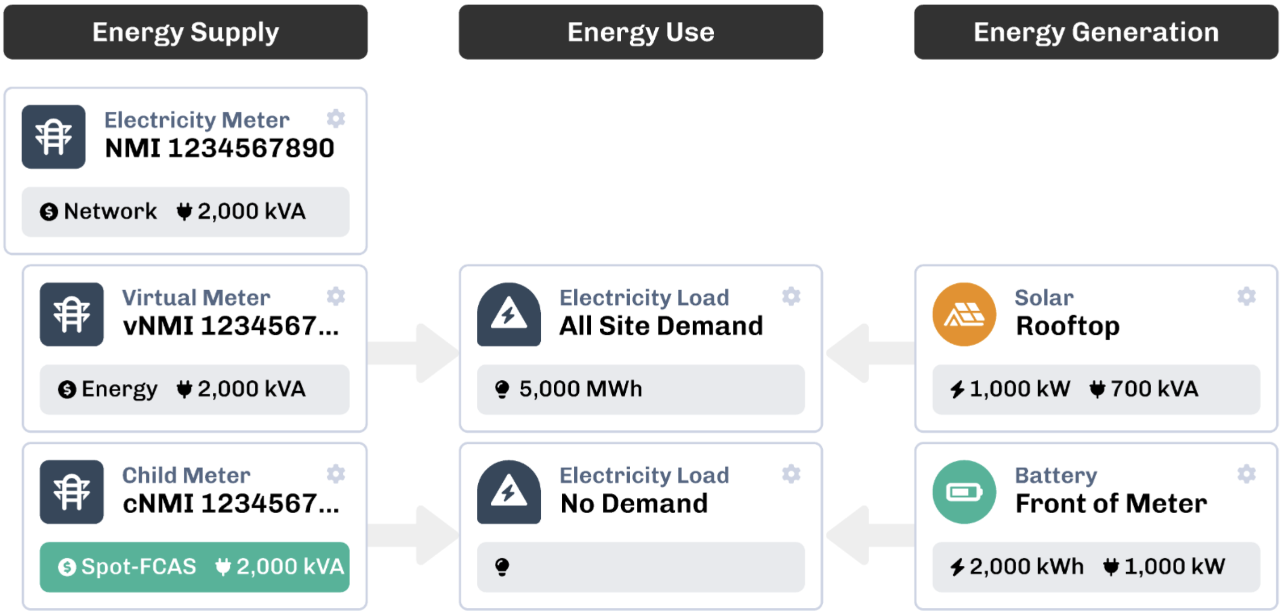

Figure 45: Front of Meter Battery & Behind the Meter Solar

Hybrid Solar & Battery System

Hybrid solar and battery systems or 'DC-coupled' solar and battery system differs from an AC-coupled configuration in that the battery is connected directly to the solar system on the DC side, before the inverter. In this configuration, the solar panels, battery cells, and inverter-charger are integrated into a single system: solar generation flows in DC directly to the battery for storage, and a combined inverter-charger converts DC electricity to AC for use at the site. Because solar energy does not need to be converted to AC before being stored, DC-coupled systems can charge the battery more efficiently than AC-coupled alternatives.

The advantages of the system are a lower capital cost and AC connection capacity with the removal of the inverter as well as increased efficiency as electricity does not need to be converted to AC and back to DC to charge the battery. The main disadvantage of this system is that the total output of the system is capped at the size of the battery inverter rather than having both the solar and battery inverter capacity available in an AC-coupled system. Hybrid solar and battery systems are common in residential installations, are becoming more common at the utility scale and are emerging at the commercial and industrial scale.

As with other behind-the-meter configurations, the DC-coupled system can typically supply all or part of the site's electricity demand without interruption if there is a disruption to supply from the grid. These systems can also be employed in a front of meter scenario configuration, however this is less advantageous and therefore less common. Figure 46 shows a single hybrid/DC-coupled solar and battery connected to a single NMI at a site.

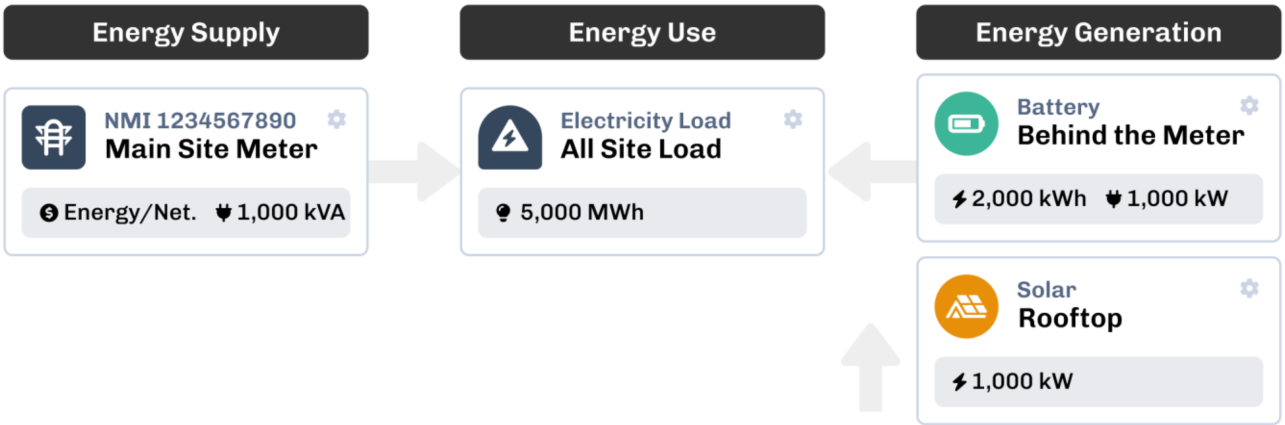

Figure 46: Hybrid/DC-Coupled Solar & Battery System Connected Behind the Meter on a single NMI

Demand Response

Demand response programs involve decreasing site electricity consumption in response to a pricing event such as spot price or FCAS event. A large number of meat processors participate in demand response due to relatively high incentives provided. Although this is lucrative, emissions reductions are immaterial due to the short duration of events, and the need to consume energy to bring equipment or operations back online.

10.2.5 Bioenergy

Biogas

Onsite anaerobic digestion can convert effluent, dissolved air flotation (DAF) sludge, and paunch grass into methane-rich biogas suitable for boilers or blended with natural gas to supply process heat. There are two primarily technologies available for converting waste into methane for meat processing sites: Covered anaerobic lagoons (CALs) and high-rate hydraulic reactors.

Covered anaerobic lagoons (CALs) are primarily installed on multiple AMPC member sites for odour control, however some have been upgraded into low-complexity methane capture ponds (AMPC, 2017). Best practise thermal offset can be up to 50% of natural gas demand, supplying methane for hot water or steam. This is equivalent to up to **30% of total site energy demand.** Figure 47 shows that sites producing biogas are able to offset 10-20% of their total site energy demand, and the site operating best practise is able to offset 33% of their total energy demand with biogas. The primary emissions abatement arises from avoided methane release, making CALs particularly effective as a combined abatement and energy recover measure. Payback for converting existing anaerobic lagoons and installing methane scrubbers to supplement existing natural gas boilers is **less than 3 years.**

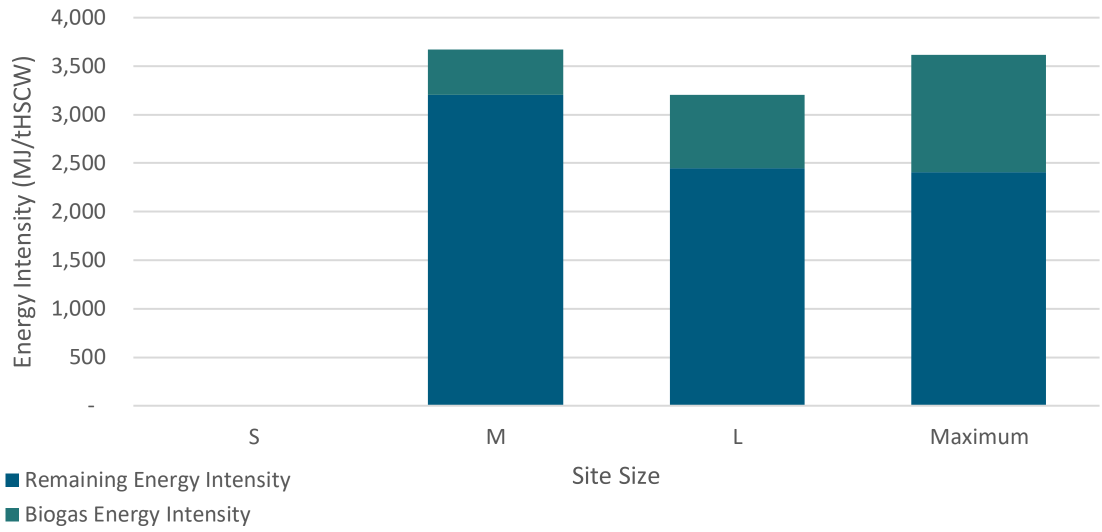

Figure 47: Effect of implementing biogas on energy demand

High-rate hydraulic reactors are designed to process higher-strength organic waste such as paunch material or DAF sludge, which contain significantly higher volatile solids than general effluent, resulting in much higher biogas yields per tonne of feedstock. This enables larger offsets (**Up to 40% of site energy demand**) but are more complex and have higher capital costs, require additional experience in solids handling. AMPC feasibility work and recent integrated bioresource studies describe designs, yields and techno-economic pathways. It shows that the higher energy yield improves economics, however p**aybacks for hydraulic systems are typically greater than 5 years** (AMPC, 2024a).

Barriers to Adoption

Main barriers relate to feedstock variability, capital intensity, and integration complexity. While CALs are relatively simply to deploy, the produce less biogas. High rate reactors can produce more biogas, but use different waste material, require robust operational capability and sustained waste volumes to justify investment.

Other Barriers Include:

- **Technical:** Variable gas production qualities, additional gas cleaning and safety systems required for combustion, but all commercially available.
- **Regulatory:** Environmental licensing, odour management, and biogas safety compliance are jurisdiction specific and can be complex.
- **Workforce:** Operation or anaerobic digesters and biogas systems required specialist skills not commonly available at all meat processing sites.
- **Financial:** High upfront capital costs, particularly for hydraulic reactors, economics are sensitive to site waste volumes, seasonal ambient temperatures, and alternative fuel prices.
- **Legal:** modifications to wastewater treatment or fuel systems may trigger permit amendments or planning approvals.

10.3 Appendix - Decarbonisation

10.3.1 Carbon Market Scheme Overviews

US – eastern states (est. 2009)	
Scheme summary The Regional Greenhouse Gas Initiative is a joint program of 11 Eastern U.S. states[18] that limits GHG emissions from power plants and lowers it over time by auctioning tradable emission permits.[19]	
Sectoral coverage	Power sector
Current exposure of the RMP sector	The RGGI scheme only covers domestic production of power
Projected exposure of the RMP sector	None.

US - California	
Scheme summary The Californian Cap and Invest program covers both domestic emissions and imports from select sectors.[20] The scheme has been extended multiple times since 2018, to expand sectoral coverage and extend the life of the scheme. Regulations require the overall emissions cap to reduce dramatically from 267 to 200m GHG emissions from 2025-2030.	
Established	2013
Sectoral coverage	• Electricity generation (including imports) • Large stationary sources (including refineries, oil and gas production facilities, food processing plants, cement production facilities, and glass manufacturing facilities) that emit more than 25,000 tCO2e annually • Distributors of transportation fuels, natural gas, and other fuels.
Current exposure of the RMP sector	Local food processing plants are covered.
Projected exposure of the RMP sector	The Californian scheme's coverage of imported electricity sets a precedent for potential future coverage of imported emissions. No immediate coverage of the RMP sector anticipated in the near-term.

US – Washington state
Scheme summary The Washington cap-and-invest program covers 70% of state based emissions from almost 100 entities. The emissions cap declines each year to 2030 by 7%, and is scheduled to decline less steeply post-2030. [21]

[18] Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, Virginia
[19] https://www.ieta.org/uploads/wp-content/2025/09/IETA-Business-brief-RGGI-23-Sept25_final.pdf
[20] https://www.ieta.org/uploads/wp-content/2025/09/IETA-Business-brief-California-ETS-September25.pdf
[21] https://icapcarbonaction.com/system/files/ets_pdfs/icap-etsmap-factsheet-85.pdf

A Senate Bill was passed in January 2025 to enable the scheme to link with the schemes in Quebec and California.	
Established	2023
Sectoral coverage	• Mining and extractives • Transport • Buildings • Industry • Power (including imports)
Current exposure of the RMP sector	Not directly exposed
Projected exposure of the RMP sector	The scheme is intended to expand coverage to waste-to-energy facilities and railroads from 2027 and 2031. It is assumed that no additional sectoral inclusions are slated at this stage. The near-to-mid-term exposure to red meat imports is therefore assessed as unlikely.

Japan	
Scheme summary Japan's 'GX-League' is its hallmark carbon market scheme, phased in as a voluntary scheme and then transitioning to mandatory for covered facilities[22][23]. The scheme is set to be the second-largest in Asia, trailing only China, and will cover 400 individual entities and 60% of national emissions from its compliance phase.	
Established	2023 (voluntary), 2026 (compliance)
Sectoral coverage	All sectors and entities with more than 100,000 tons of direct CO_2 emissions
Current exposure of the RMP sector	A number of organisations in the food production and manufacturing industry are currently participating in GX League[24]. No organisations with red meat processing facilities were identified as part of this desktop review.
Projected exposure of the RMP sector	No immediate coverage of the RMP sector anticipated in the near-term.

China

[22] https://www.ieta.org/uploads/wp-content/Resources/Busines-briefs/2025/IETA-Japan-Emissions-Trading-Scheme-_GX-ETS-final-one_July.pdf
[23] https://www.carbon-direct.com/insights/inside-japan-s-gx-ets-carbon-market-and-its-global-climate-impact
[24] Including but not limited to Marubeni Corporation, Mitsui, Agricultural Cooperatives, Maruha Nichiro. https://gx-league.go.jp/member/

Scheme summary China's national ETS covers ~8 billion tCO2-e, regulating more than 3,500 companies from the power, steel, cement, and aluminium smelter sectors with annual emissions in excess of 26,000 tCO2-e. China also launched a national GHG voluntary emission reduction trading market, the Chinese Certified Emission Reduction Scheme (CCER) in January 2024, with most of the participants coming from the technology, transport, industrial, and manufacturing sectors.	
Established	2021 (compliance), 2024 (voluntary)
Sectoral coverage	Power, steel, cement, and aluminium smelter sectors with more than 26,000 tonnes of CO2 emissions.
Current exposure of the RMP sector	No organisations in the food production and manufacturing industry are recorded to participate in both the compliance and voluntary schemes.
Projected exposure of the RMP sector	The scheme is intended to expand coverage to more major industrial sectors by 2027 and gradually transition the ETS towards an absolute cap system by 2030. It is assumed that no additional sectoral inclusions are slated at this stage. The near-to-mid-term exposure to red meat imports is therefore assessed as unlikely.

South Korea	
Scheme summary The Korea Emissions Trading System (K-ETS)[25] covered 79% of Korea's GHG emissions in 2022 and covers 816 (as of 2024) of the country's largest emitters in power, industrial, buildings, waste, transport, domestic aviation and maritime sectors. The K-ETS mandates business entities with annual average GHG emissions of at least 125,000 tCO2-e and individual entities with annual average GHG emissions of at least 25,000 tCO2-e. Smaller entities not covered by the K-ETS would be covered by the mandatory Target Management System.	
Established	2015 (K-ETS), 2012 (TMS)
Sectoral coverage	Maritime, waste, domestic aviation, transport, buildings, industry, power
Current exposure of the RMP sector	The manufacturing industry is covered in the K-ETS. If the manufacturing entity exceeds 25,000 tCO2-e, they will be covered under the K-ETS, and if not, the mandatory Target Management System.
Projected exposure of the RMP sector	No immediate coverage of the RMP sector anticipated in the near-term.

[25] Korea Emissions Trading System (K-ETS) | International Carbon Action Partnership

EU	
Scheme summary The EU ETS [26]is the oldest cap-and-trade system which covers entities in maritime, domestic aviation, industry, and power, with a cap at 1,386 MtCO2-e. The CBAM covers imports of carbon-intensive goods (exceeding the threshold of 50 tonnes) at high risk of carbon leakage such as iron and steel, cement, aluminium, fertilisers, electricity, and hydrogen. CBAM requires importers to buy CBAM certificates which are based on the EU ETS carbon price, representing the embedded emissions in the imported goods.	
Established	2005 (EU ETS), 2023 (CBAM)
Sectoral coverage	Maritime, domestic aviation, industry, power
Current exposure of the RMP sector	Several food production and manufacturing companies participated in EU ETS. Imports of meat/ food is currently not regulated under CBAM.
Projected exposure of the RMP sector	A 2026 mandatory ETS review is expected to examine expansion to additional sectors. The near-to-mid-term exposure to red meat imports is therefore assessed as possible, though highly dependent on a decision to capture red meat under the ETS.

10.3.2 Voluntary Decarbonisation Schemes

SBTi spotlight

The Science Based Targets Initiative (SBTi) is a global sustainability standards body, created to ensure corporate climate targets are scientifically aligned with global climate goals. It is a collaboration between CDP, UN Global Compact, World Resources Institute (WRI), WWF, and the We Mean Business Coalition.

The SBTi has developed sector-specific standards, pathways, and methodologies for setting targets which over 2,000 companies globally have adopted. This includes transport, buildings, and forest, land and agriculture sectors, amongst others.

Food retailers such as Coles and Woolworths are not categorised into a sector with a bespoke standard developed by the SBTi. These types of organisations therefore utilise the SBTi's flagship Corporate Net-Zero Standard[27]. In order to achieve and maintain SBTi certification, retailers are required to meet the rules prescribed within the Standard.

[26] EU Emissions Trading System (EU ETS) | International Carbon Action Partnership
[27] https://files.sciencebasedtargets.org/production/files/Net-Zero-Standard-Criteria.pdf

The Corporate Net-Zero Standard prescribes that if a company's scope 3 emissions are 40% or more of total scope 1, 2, and 3 emissions, they shall be included in near-term science-based targets.

They are then required to:

a. set near-term Scope 3 emissions reduction targets
b. set supplier or customer engagement targets across upstream and/or downstream Scope 3 categories. These must be met within 5 years of the target being set.

If a retailer wishes to obtain or maintain its SBTi certification, it must engage the proportion of its supply chain it has set in its target for the suppliers/customers to drive them to set their own science-based targets in turn.

This recommends but does not require the suppliers/customers to have their own targets validated by the SBTi.

Organisations that process food products must set targets aligned with the SBTi's Forest, Land and Agriculture (FLAG) standard. The FLAG standard allows for decarbonisation targets to be distinguished by commodity and separates FLAG and non-FLAG emissions[28].

Climate Active spotlight

Climate Active is an Australian government-developed sovereign scheme which verifies and certifies organisations as having achieved carbon neutrality. The scheme is undergoing reforms, however, can be considered by meat processing organisations as an option for achieving certified carbon neutrality. This could benefit those AMPC members that are in the supply chains of major retailers that have Scope 3 targets.

The Climate Active program requires disclosure of scopes 1 and 2 emissions, and of Scope 3 emissions if the emissions are of material relevance to the organisation. Most organisations would deem Scope 3 emissions to be of high materiality.

At the time of writing, Kilcoy Pastoral Company Ltd is understood to be the only meat processing organisation in Australia with certification against the Australian government's official carbon neutrality standard, Climate Active[29].

As part of its carbon neutral company certification for FY24, Kilcoy has disclosed a reduction target of 50% by 2026 for Scope 1, 30% by 2027 for Scope 2 and Scope 3 emissions by 30% by 2030 emission sources from a 2022 baseline.

Coles also participates in the Climate Active certification scheme, having had a certified carbon neutral beef product since FY2022[30]. The Coles branded product covers the lifecycle emissions from cradle-to-retail shelf. This includes the emissions associated with the product's:

3. Purchased inputs
4. Primary production on farm
5. Primary and secondary processing, and

[28] https://files.sciencebasedtargets.org/production/files/SBTiFLAGGuidance.pdf
[29] https://www.climateactive.org.au/sites/default/files/2023-12/Kilcoy%20Pastoral%20Company_PDS.pdf
[30] https://www.climateactive.org.au/sites/default/files/2025-07/1711%20-%20Coles%20CN%20Beef%20FY24%20PDS.pdf

6. Distribution centres.

80% of the lifecycle emissions reported are attributable to the meat processing and beef production. This indicates that meat processors could play a material role in supporting the reduction in emissions within the meat production value chain.

Under the Climate Active scheme, all residual emissions must be offset using carbon credits.

Coles offset 100% of the remaining emissions (approximately 15,000t CO_2-equivalent) with Australian Carbon Credit Units, which could have been worth an estimated \$510,000-\$750,000 at the time of purchasing.

This indicates that processing facilities that can demonstrate a lower emissions profile could be seen by retailers as commercially favourable to support the reduction in products' reported lifecycle emissions.

10.4 Appendix - Offsite Grid Decarbonisation

10.4.1 Power Purchase Agreements

The load profiles for AMPC members are noticeably reduced and much flatter compared to the high day time demand loads on weekdays. This distinction is important when considering how much solar or wind should be contracted as there will need to be a balance between sufficiently contracting enough renewables to meet the higher weekday load but to also not over contract for the weekend load unless the spot market price risks are deemed acceptable as this may result in higher or lower cost whether in the PPA cost, which will ultimately impact the firming/exposure cost.

A key concept to understand how to value a PPA is to understand how energy is valued differently throughout the day (evening is more expensive than daytime), as well as the seasonal changes and their impacts on wholesale spot price outcomes (more renewables in summer than in winter). This process is generally what a retailer does when pricing up a customer's load for a retail PPA, albeit it can rely on its own portfolio of assets which can be renewable or non-renewable unless specified.

- **Wholesale PPA:** is where C&I businesses contract directly with project developers, generally for both its energy and LGCs, in a run-of-meter, pay-as-produced basis. At its core, this is a financial hedging instrument for energy, and is a Contract-for-Difference settled against the NEM regional electricity spot market the generator is located in. A wholesale or virtual PPA, does not provide an agreement for the supply of energy to the buyer as a standard retail ESA does and would still need to be procured separately. The wholesale PPA has been generally by organisations as a tool to mitigate their exposure to wholesale market volatility and a way to support renewables and buy LGCs at a discount.

- **Sleeved Wholesale PPA:** due to the virtual nature of a wholesale PPA, in order to connect the wholesale PPA to the supply of electricity to the C&I, a retailer is contracted by the C&I to 'sleeve' the PPA where they act as an intermediary party to manage the trading, market administration and obligations required by the market operator. This tripartite agreement is generally used by large energy users such as smelters or miners may pursue this option where they are able to take on wholesale spot exposure risk for the physical mismatch in energy supply from their wholesale PPA against their actual demand.

- **Sleeved & Firmed Wholesale PPA:** Because of the inherent volatility in the wholesale market, more risk adverse C&Is may request 'firming' in addition to sleeving. A firming contract with an electricity retailer allows them to take on the wholesale exposure risk to meet the C&I's physical balance of supply against the underlying wholesale PPA by utilising its own generation portfolio and financial energy products. The way that the PPA can be firmed is therefore highly bespoke and can have multiple structures to meet the C&I's needs should the retailer be willing to provide it. This approach comes at a premium for the retail services, however, it greatly reduces the internal administrative burden and operational complexity of C&Is.

- **Retail PPA:** are the most common PPA for corporate buyers due to its ability to deliver a simple, project-linked PPA backed ESA. Under this structure, the retailer packages a wholesale PPA of its own to then sleeve and firm it for a more wholistic solution. This provides C&I with small or medium sized loads with an accessible, low-risk product, albeit with a retail service premium. However, there is still ample flexibility as there are different firming price structures that can be negotiated, such as being spot exposed, progressively hedged, give at a fixed price or a combination thereof.

- **24/7 PPA:** is a more recent development where instead of being 100% renewable matched on an annual basis as previous PPAs have been, is to meet all physical energy needs through renewables, i.e. all firming is provided by a renewable energy source and does not rely on non-renewable energy generation technologies, e.g. coal, gas. This is likely to become the future gold standard for being renewable as the newly released Renewable Energy Guarantee of Origin (REGO) scheme allows for the time stamping of green certificates to facilitate the time matching of certificates to bulk energy. This option is reserved only for the most decarbonisation or reputationally ambitious, like tech hyperscalers, who are also able to pay for this materially more expensive solution.

10.4.2 Utility BESS Contracting Structures

- **Physical Toll (PT)** agreements involve the buyer paying a predetermined amount and receiving all market revenues, while also operating the asset. However, this structure can be problematic if the buyer doesn't control all capacity behind the connection point. The buyer must also be capable of becoming a market participant. Additionally, the parties must be aware that Physical Toll agreements are usually considered as leasing agreements for accounting purposes.
- **Virtual Toll – Time Bands** agreements allow the buyer to pay a predetermined amount and nominate when to charge and discharge the asset. Nominations can typically be made up to 15 minutes before the trading interval, with settlement based on actual price outcomes and nominated volumes. While the seller operates the asset and is likely to defend the buyer's nominations, they are not obligated to. Under this model the buyer does not gain access to FCAS markets, and the seller can have multiple contracts per connection point. It's important to note that the offtake may still be valid even if the asset is subject to network curtailment.
- **Virtual Toll – Price Bands** agreements are similar to Time Band Virtual Tolls but involve the buyer nominating charge and discharge quantities over 10 price bands for each trading interval. The buyer pays a predetermined amount, and settlement is based on actual price outcomes and nominated volumes. The seller operates the asset and is likely to defend the buyer's nominations but is not obligated to. Like with Time Band Virtual Tolls, the buyer does not gain access to FCAS markets, and the seller can have multiple contracts per connection point. Likewise, the offtake may still be valid even if the asset is subject to network curtailment.
- **Revenue Swap** agreements involve the buyer paying a predetermined amount and receiving an agreed share of all market revenues. In this structure, the buyer and seller need to agree on how the asset will be operated.

Bespoke Shapes / Times agreements are tailored to specific needs, where the buyer and seller agree on a specific shape to be transacted, such as a 5-9pm flat swap (with or without green certificates). The buyer pays a predetermined amount and receives market revenues for the agreed shape. The seller operates the asset and is likely to defend the agree shape but is not obligated to. Buyers are typically interested in buying a fixed shape during peak periods, and charging the asset is usually outside of such contracts.