RENEWABLE ENERGY OPTIONS FOR AUSTRALIAN INDUSTRIAL GAS USERS

Background Technical Report

Prepared by IT Power for the
Australian Renewable Energy Agency

SEPTEMBER 2015

ARENA

Australian Government

Australian Renewable Energy Agency

About IT Power

The IT Power Group, formed in 1981, is a specialist renewable energy, energy efficiency and carbon markets consulting company. The group has offices and projects throughout the world.

IT Power (Australia) was established in 2003 and has undertaken a wide range of projects, including designing grid-connected renewable power systems, providing advice for government policy, feasibility studies for large, off-grid power systems, developing micro-finance models for community-owned power systems in developing countries and modelling large-scale power systems for industrial use.

The staff at IT Power have backgrounds in renewable energy and energy efficiency, research, development and implementation, managing and reviewing government incentive programs, high level policy analysis and research, including carbon markets, engineering design and project management.

About ARENA

ARENA was established by the Australian Government to make renewable energy technologies more affordable and increase the amount of renewable energy used in Australia. ARENA invests in renewable energy projects, supports research and development activities, boosts job creation and industry development, and increases knowledge about renewable energy. ARENA is currently supporting more than 200 projects and is actively seeking new projects to support.

Report Control Record

Document prepared by:

IT Power (Australia) Pty Limited
Southern Cross House,
6/9 McKay St, Turner, ACT, 2612, Australia

PO Box 6127, O'Connor, ACT, 2602, Australia
Tel. +61 2 6257 3511
Fax. +61 2 6257 3611
E-mail: info@itpau.com.au
http://www.itpau.com.au

Document Control

Report title	Renewable Energy Options for Australian Industrial Gas Users				
Client Contract No.	A0552		**ITP Project Number**	A0142	
File path	general:Work:1Projects:2014:A0142 ARENA Industrial Gas Replacement:Dleiverables: RenewableForGas Master.docx.				
Client	ARENA		**Client Contact**	Joe Ritchie	

Rev	Date	Status	Author/s	Project Manager	Approved
0.1	1 August 2014	Draft	K Lovegrove, H Saddler, J Rutowitz J Jordan, J Peterseim	K Lovegrove	
0.2	21 August 2014	Progress Draft	K Lovegrove, S Edwards, H Saddler, J Rutowitz J Jordan, J Peterseim, J Wyder	K Lovegrove	
1.0	13 October 2014	Draft for client	K Lovegrove, S Edwards, J Jordan J, J Peterseim, Rutowitz, , H Saddler, M Watt, J Wyder	K Lovegrove	J Wyder
1.2	26 March 2015	Revised Draft	K Lovegrove, S Edwards, J Jordan J, J Peterseim, Rutowitz, , H Saddler, M Watt, J Wyder	K Lovegrove	J Wyder
1.3	19 July 2015	Extended Draft	K Lovegrove, S Edwards, N Jacobson, J Jordan J, J Peterseim, Rutowitz, , H Saddler, M Watt, J Wyder	K Lovegrove	J Wyder
2.0	29 September 2015	Final	K Lovegrove, S Edwards, N Jacobson, J Jordan J, J Peterseim, Rutowitz, , H Saddler, M Watt, J Wyder	K Lovegrove	K Lovegrove

LIST OF ABBREVIATIONS

ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AES	Australian Energy Statistics
ANZSIC	Australian and New Zealand Standard Industrial Classification
ARENA	Australian Renewable Energy Agency
AUD	Australian Dollars
BREE	Bureau of Resources and Energy Economics
COP	Coefficient of Performance
CPC	Compound Parabolic Collector
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSP	Concentrated Solar Power
CST	Concentrated Solar Thermal
DNSP	Distribution Network Service Provider
DNI	Direct Normal Irradiation
EEO	Energy efficiency Opportunities
EfB	Energy from Biomass
EU	European Union
GHI	Global Horizontal Irradiation / Irradiance
HTF	Heat Transfer Fluid
IEA	International Energy Agency
IEEDA	Industrial Energy Efficiency Data Analysis
IRR	Internal Rate of Return
ISF	Institute of Sustainable Futures
ITP	IT Power (Australia) Pty Ltd
LCOE	Levelised Cost of Energy
LNG	Liquified Natural Gas
LPG	Liquified Petroleum Gas
NGERS	National Greenhouse and Energy Reporting Scheme
NREL	National Renewable Energy Laboratory (USA)
OECD	Organisation for Economic Cooperation and Development
PV	Photovoltaic
RE	Renewable Energy
SAM	System Advisor Model
UNIDO	United Nations Industrial Development Organisation
USD	US Dollars

Energy unit conversions and prefixes

MW	Megawatt, unit of power equal to 1,000 kW
MWh	Megawatt-hour, unit of energy (1 MW generated/used for 1 hour)
kW	Kilowatt, unit of power equal to 1,000 W
kWh	Kilowatt-hour, unit of energy (1 kW generated/used for 1 hour)
kWp	Kilowatt-peak, unit of power for PV panels tested at STC
EJ	Exajoule, unit of energy equal to 10^{18} J
PJ	Petajoule, unit of energy equal to 10^{15} J
TJ	Terajoule, unit of energy equal to 10^{12}J
GJ	Gigajoule, unit of energy equal to 10^{9}J (1,000 MJ)
MJ	Megajoule, unit of energy equal to 10^{6}J
e	As a subscript on any of above indicates electricity
th	As a s subscript on any of above indicates thermal

Table of Contents

EXECUTIVE SUMMARY

The Australian Renewable Energy Agency (ARENA) has commissioned this study of options for direct (partial or full) substitution of renewables for gas within the boundaries of an existing industrial operation.

The opportunity

Australia consumes around 1,400 PJ of gas each year. More than half of this is for electricity generation plus commercial and residential buildings and upstream internal consumption by gas and oil producers, which are not explicitly considered in this analysis.

Direct industrial use of gas can be divided into four broad categories:

- use at lower output temperatures for steam raising and hot water, and also for various types of drying processes,
- use in high temperature thermal processes, in kilns, furnaces etc,
- as fuel for power generation, and
- use as chemical feedstock, principally for the production of ammonia.

Renewable energy alternatives exist for all these applications.

This study reviews previous studies on the subject, analyses gas use data, summarises stakeholder consultations and establishes the performance plus costs of relevant renewable technologies. This information is used to analyse the relative economic performance and consider the challenges to deployment.

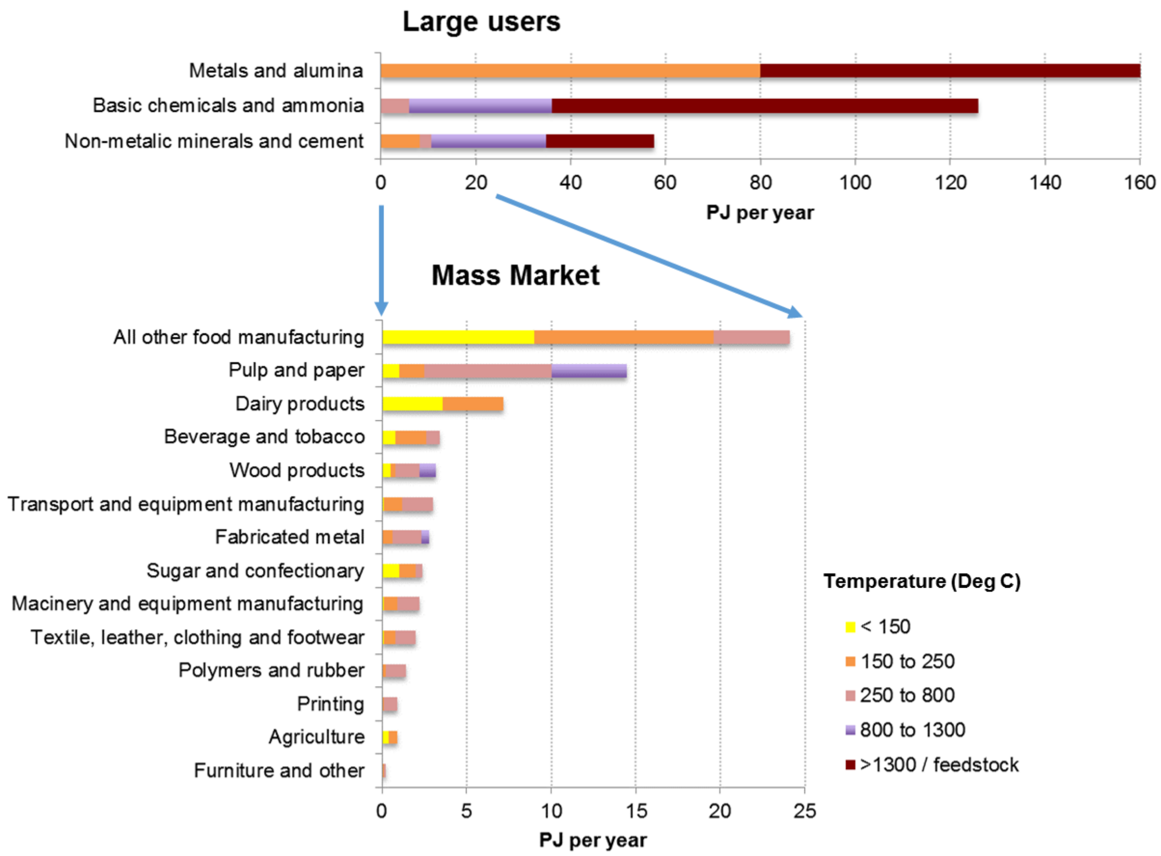
The review of previous studies and the experience of the authors indicates that there are a range of renewable energy technology options that are worth consideration. Those investigated are:

- solar thermal systems for process heat across all temperature ranges,
- biomass combustion for hot water and steam,
- biomass pyrolysis or gasification for chemical feedstocks or for combustion,
- anaerobic digesters for gas for combustion or feedstock,
- direct use geothermal heat for low to medium temperature processes, and
- heat pumps with photovoltaic systems.

This analysis focuses on industrial gas users which are a combination of:

- smaller, mass market customers who are connected to the gas distribution system and, typically, pay significantly more than the wholesale gas price, and
- large users who are connected to the gas transmission system and, typically, pay close to the wholesale gas price.

The specific industry sectors' gas consumption (in PJ/year) have been categorised against application as shown in the following Figure:



The sector breakdowns for the various industrial gas users are for the year 2012 - 13 and the total is 412 PJ per year.

A trend of increasing gas prices in Australia is already in evidence and widely expected to continue as increasing demand for gas for LNG exports pulls the domestic price close to an opportunity cost that is determined by the international market. It is expected that East coast wholesale prices will continue to rise from between $6 -$9/GJ in 2014 to between $9 - $12/ GJ in the next 4 years.

The actual price an individual gas user is or will be paying can vary over a very wide range compared to another user under different circumstances. Factors determining the actual price seen include,

- the amount of gas consumption, consumer's bargaining power,
- the timing of contract negotiation,
- the state the user is located in and
- how far toward the extremities of the distribution system the site is located.

Some gas tariffs are in a block structure of declining cost, which makes measures which reduce but do not eliminate gas use more economically challenging.

Concerns for gas users

Public statements and input from stakeholders indicates that industrial gas users are very concerned by the trend to higher gas prices. However, there are a range of other factors that weigh heavily on an investment decision such as substitution of renewable technologies for gas. These can be categorised as:

- **Business continuity** – maintaining cash flow and presence in the market place is paramount.
- **Market risk** – the risk of losing market share to a competitor due to a disruption.
- **Contractual (supply) risk** – the risk of being let down by a technology supplier.
- **Investment Return** – expectations of internal rates of return can range from 10% to 30% per year, with many smaller companies having limited access to capital and rates of return expectations at the high end of this range.
- **Future fuel prices** – uncertainty around future gas prices drives interest in alternatives, although future biomass prices are also uncertain due to unknown supply and demand pressures.
- **Technology risk** – risk of poor reliability, lack of performance and impact on product quality.

Renewable energy solutions

Technically, a renewable energy solution could in principle be engineered for every single current use of gas by industry. However, there is a dichotomy in technical risk and cost, between solutions that are proven plus commercially available and those that are still in the pilot or even R&D phase (for example solutions for very high temperatures or for chemical feedstocks).

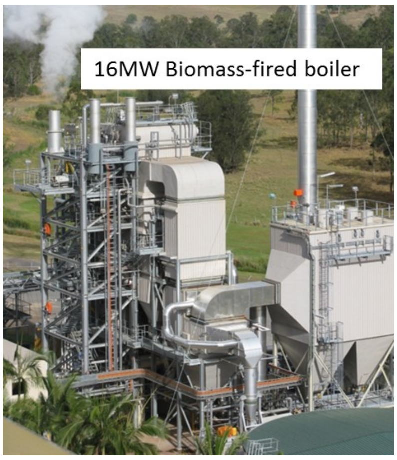
An overview of the various technically viable renewable energy technologies is provided in the following table:

Renewable energy technology	Indicative temp range °C	Status	Comments	Economic viability
Biomass fired boiler	80 - 800	Commercially mature with existing support industries.	Capex higher than gas boiler	Only if low cost locally sourced material.
Biomass gasification and combustion	80 -1000+	Commercially mature with existing support industries.	Capex higher than gas boiler, considerable extra cost to produce pure methane	Only if low cost locally sourced material and for non-sensitive application.
Biomass digestor and combustion	80 -1000+	Commercially mature with existing support industries.	Capex higher than gas boiler, considerable extra cost to produce pure methane	Only if low cost locally sourced material and for non-sensitive application.
Solar thermal Unglazed	30 -60	Commercially mature with existing support industries.	Requires unshaded roof space. Significant seasonal output variation.	Cost competitive for very low grade heat applications.
Solar thermal flat plate	30 - 85	Commercially mature with existing support industries.	Requires unshaded roof space and a structural assessment. Significant seasonal output variation.	Cost competitive for modest temperature heat applications.
Solar thermal evacuated tube	50 - 200	Commercially mature with existing support industries.	Requires unshaded roof space and a structural assessment. Significant seasonal output variation.	Cost competitive for modest temperature heat applications.
Concentrating solar troughs and Fresnel	60 - 450	Commercially available but support industries are mainly overseas.	Design needs to be done by specialists in field.	Maybe cost competitive up to 250°C under good conditions
Concentrating solar heliostats and tower or dish	300 - 1000+	Less commercially available with support industries mainly overseas.	Not applicable at small scales. Thermal storage easily integrated.	Not yet cost competitive
Enhanced Geothermal systems	90 - 250	Still at R&D stage	Most identified resources are remote from gas users	Not yet cost competitive
Geothermal hot sedimentary aquifer	40 - 100	Commercially mature but limited supply chain	Highly site specific.	Can be low cost if resource is not too deep.
Heat pumps with grid electricity	40 - 100	Commercially available but support industries are mainly overseas.	Compare cost of gas to cost of electricity / COP. Some storage may be required.	Cost competitive for modest temperature heat applications.
Heat pumps with photovoltaics	40 - 100	Commercially available but heat pump support industries are mainly overseas.	Appropriate storage may be required to ensure heat pumps do not contribute to monthly peak..	More costly than solar thermal, but could be favoured if a large PV system is planned for electricity supply.

Given the low technical risk appetite of industrial gas users, and the drivers of renewable energy solutions costs, none of the pilot or R&D phase solutions are attractive unless the organisation has a parallel business agenda of engaging in technology development.

These considerations plus the economic analysis lead to the conclusion that it is process heat in the form of steam or hot water and renewable gas for non-quality sensitive combustion that are the most suitable applications at present.

Bioenergy



Biomass can be used in boilers for steam and hot water production. Anaerobic digesters produce alternative gas from wet wastes, as do high temperature gasifiers.

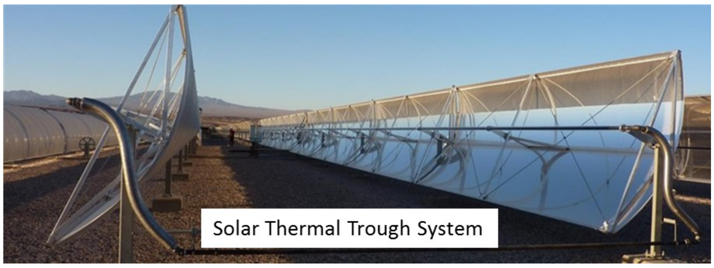
Typically, biomass resources are expensive to transport. Thus the lowest cost resources are extremely localised and typically must be within a few kilometres of the gas users operation to be viable.

Australia does not yet have an established supply chain for material such as wood pellets. This is a possibility for the future and the potential locations plus amounts have been assessed in other studies.

Solar Thermal

Solar thermal systems are available for any desired temperature range. Low temperatures are available from simple flat plate collectors. More complex concentrator systems are needed for higher temperature and these come at a higher capital cost.

Quantifying solar resources is straight forward. For concentrators, direct beam radiation is the key parameter, for non-tracking systems, global (direct plus diffuse) radiation is the input. There are a range of sources and formats for this information.



As is well known, Australian solar resources are progressively better moving inland. Unfortunately this is in reverse correlation to the location of many gas users. Australia's best solar areas are close to the best in the world. However the less favourable solar resources closer to the coast are still above average by world standards[1] and solar thermal solutions should still be considered.

Other Technologies

Hot sedimentary aquifer based geothermal can be effective for low temperature applications however, only a minority of gas users are likely to be able to access a useful sedimentary aquifer resource. Heat pumps are commercially available for temperatures up to around 150ºC although 100ºC represents the upper limit of standard commercial units. For lower temperatures high rations of heat production to electricity consumed are achieved. Coal fired boilers are an alternative fossil fuel choice that can be lower cost.

Economics

Economic performance can be assessed via a comparison of annualised costs, or Levelised Cost of Energy (LCOE)[2]. Results of the LCOE modelling are shown in the following figures.

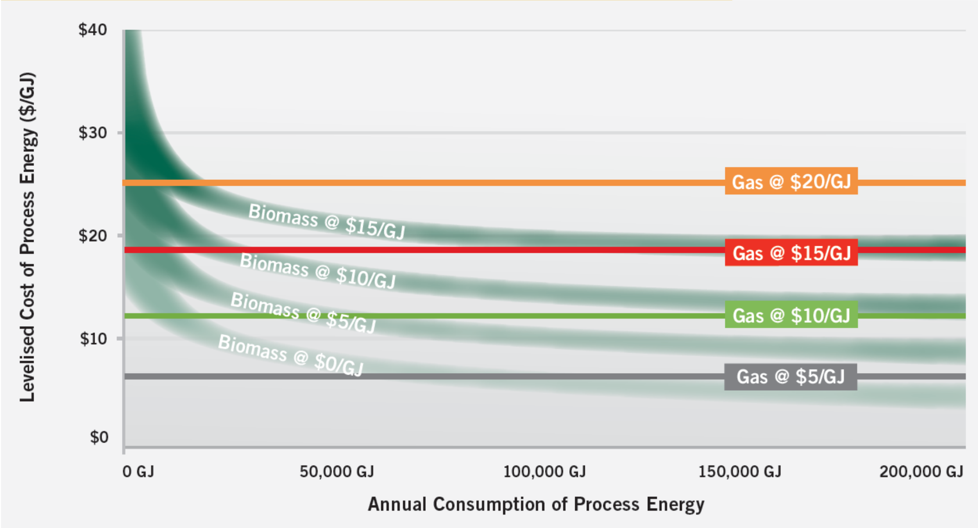
All capital costs have a strong dependence on system size, with larger systems more cost effective. This effect flows through to LCOE directly. Natural gas fired systems also have this attribute. However, for natural gas the capital cost is left out of the analysis on the assumption that an existing gas fired system is the starting point for comparison. Overlaid on this though is the observation that the smaller a gas user is, the higher price they are likely to be paying for gas.

For a biomass resource with a price from zero (waste) up to around $6/GJ, Biomass options appear competitive with gas across the whole range of system sizes.

.

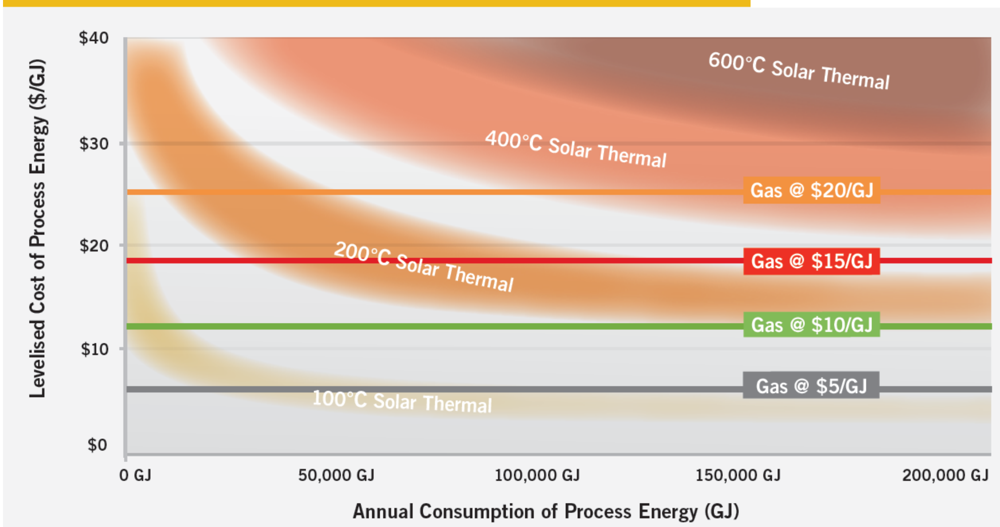
[1] Sydney, for example is as good as many sites in the south of Spain.
[2] Financial parameters used included 60% debt at 7.5%/a interest, 10%/a discount rate for equity, 15 year depreciation plus 20 year system lifetime, tax set to zero, boilers operating at average 70% of full capacity.

Dividing annualised cost by annual energy consumption to compare the levelised cost of process energy from new biomass and existing gas



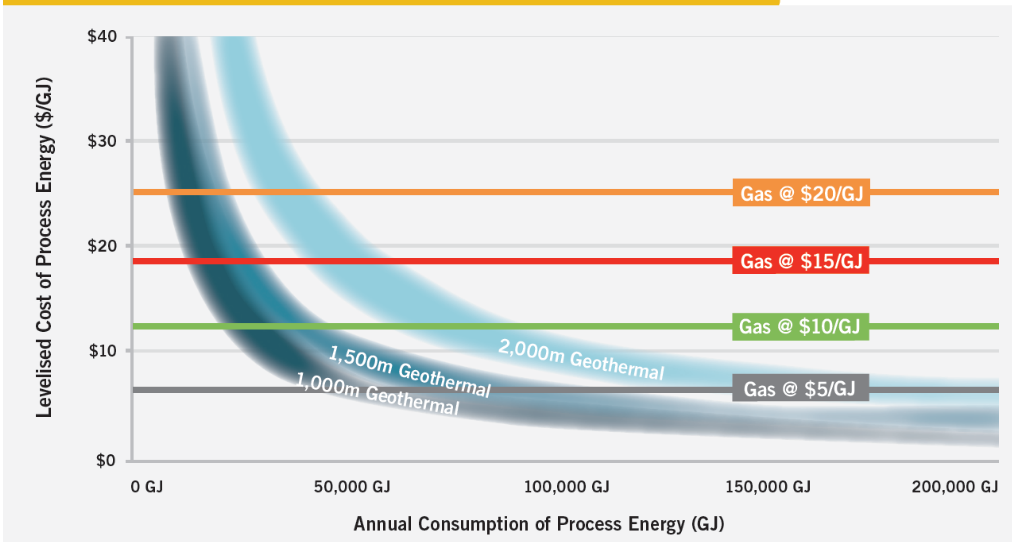
For solar thermal there is no fuel cost to consider. However, the LCOE is dependent on the temperature of application. It also has a high range of variability due to the uncertainty of initial capital cost estimates and the impact of the level of solar resource available. Temperatures up to around 150ºC offer competitive performance, options up to 250ºC are worth detailed investigation, however higher temperature systems require further development of the technology to be competitive.

Dividing annualised cost by annual energy consumption to compare the levelised cost of process energy from new solar thermal and existing gas



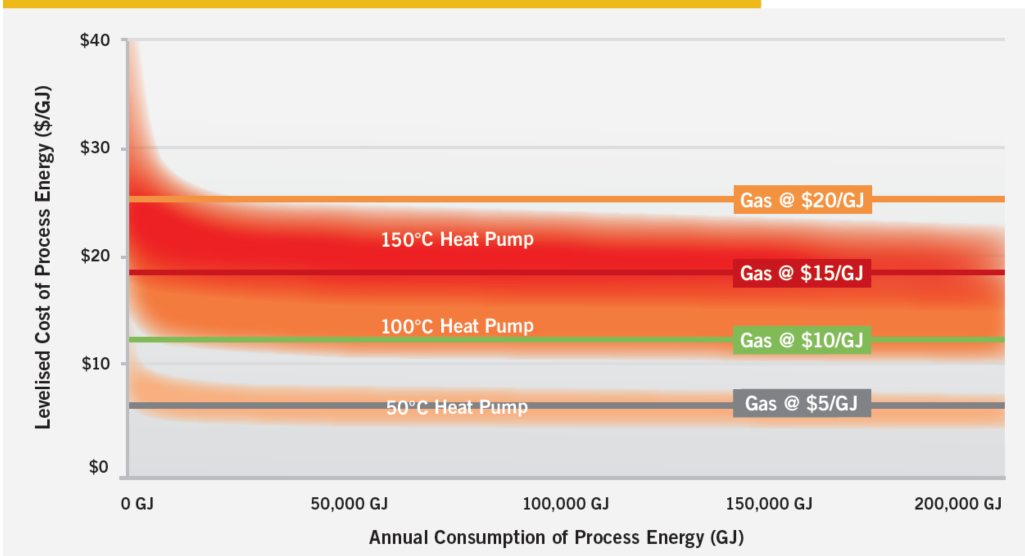
Where a geothermal resource is available it can be quite cost effective. Demand needs to be sufficient to justify the minimum investment in an extraction well plus reinjection well pair and the associated infrastructure.

Dividing annualised cost by annual energy consumption to compare the levelised cost of process energy from new geothermal system and existing gas

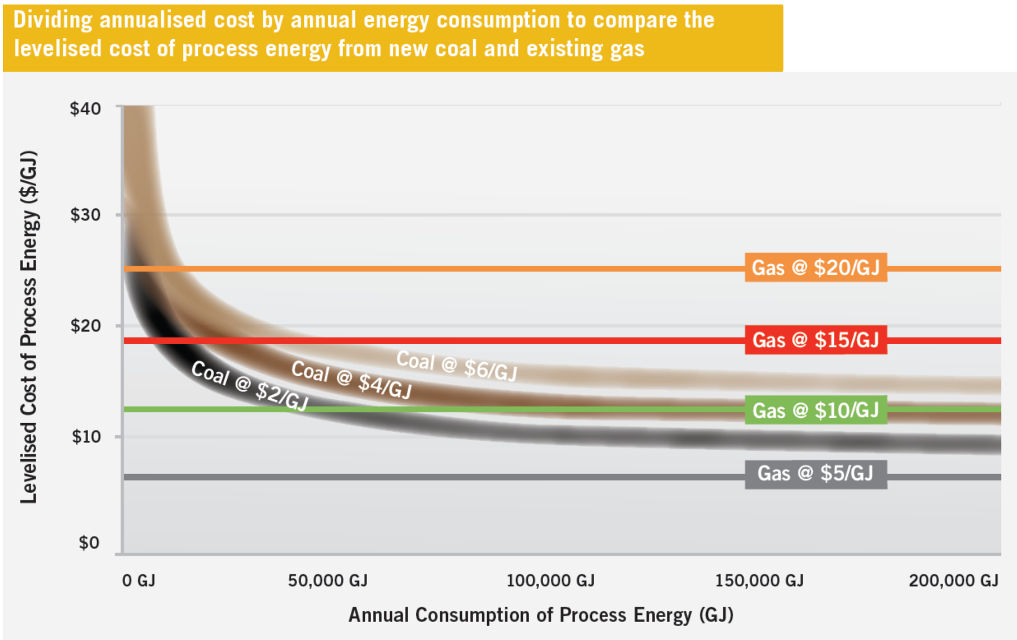


Heat pumps run with a high capacity factor will be economic if the marginal cost of electricity divided by the expected Coefficient of Performance is significantly less than the marginal cost of gas. Directly Photovoltaic driven heat pumps are another option for low temperatures, however in the context of industrial gas users, this option does not appear competitive with a solar thermal solution without grid backup.

Dividing annualised cost by annual energy consumption to compare the levelised cost of process energy from new heat pump and existing gas



Switching to coal combustion is an alternative fossil fuel choice that can be lower cost. A similar investment cost to a biomass boiler is needed and delivered coal prices at between $2 and $4/GJ. While these costs are more than a waste biomass, they are less than most other sources.



.

Conclusion

There are opportunities for renewables to replace gas now. The size of these opportunities will grow as gas prices increase and renewable energy technologies mature. However there are several challenges.

The industrial gas users examined in this study consumed approximately 412 PJ in 2013. The report authors estimate that, based on 2014 gas prices, the potentially viable market for renewable energy technologies is 50 to 100 PJ per year. At an indicative price of $9/GJ this is a potential saving on gas costs of the order of $450 to $900 million per year but with significant upfront investment needs. This potential market is likely to increase as gas prices rise and renewable technologies mature.

There are many examples of renewable energy systems in Australia and around the world, providing energy services that could otherwise be provided by gas. Awareness of the growing market opportunity by solution providers, should result in more pro-active in promotion of renewable energy technologies. However, the level of technical risk perceived by industrial gas users in such solutions remains high. Establishment of some highly visible pilot installations would be a valuable way to assist in reducing perceived technical risk. The supply chain for components in Australia is immature and in many cases, equipment needs to be imported.

In many circumstances industrial gas users, have limited access to capital and expectations of high internal rates of return. There appears to be strong potential and industry preference for third party organisations to make investments and offer to sell renewable sourced energy as a business model.

1. INTRODUCTION

Domestically produced natural gas is a significant part of the primary energy mix for Australia. A trend of increasing gas prices in Australia is already in evidence and widely expected to continue as increasing demand for gas for LNG exports pulls the domestic price close to an opportunity cost that is determined by the international market. Thus, energy substitutions that were previously uneconomic should be re-evaluated in the light of current and future possible gas prices and availability.

Direct industrial use of gas can be divided into four broad categories:

- use at lower output temperatures for steam raising and hot water, and also for various types of drying processes,
- use in high temperature thermal processes, in kilns, furnaces etc,
- as fuel for power generation. and
- use as chemical feedstock, principally for the production of ammonia.

Renewable energy alternatives exist for all these applications.

There is a perception that there are existing cost effective opportunities for renewables to displace gas for such industrial gas users, but that non-technical barriers including a lack of clear enabling information and existing misconceptions may be limiting rates of uptake.

Motivated by these considerations, the Australian Renewable Energy Agency (ARENA) has commissioned this study of options for direct (partial or full) substitution of renewables for gas within the boundaries of an existing industrial operation

This document is a compilation of the technical data and findings of the study. There is also a shorter summary report that captures the key findings. Most of the material in the summary report also appears in this report with different formatting. A spreadsheet is available to assist users in economic screening of options. This spreadsheet uses the same basic calculation method as has been employed to produce the results in Chapter 7.

1.1. Methodology

Identifying the most promising prospects for renewable energy substitution for gas in Australia has required an iterative investigation that has looked at, analysing gas use, considering price of gas to users, identifying technology options, examining relative economic performance and examining non-technical challenges.

The methodology that has been used in this study can be summarised as:

- Review of previous published material on renewables in industry established that the concept of replacement of industrial gas use is technically feasible and can be economically feasible in the right circumstances. These previous studies also pointed to the most likely technologies of interest and the non-technical challenges that can be expected. (Chapter 2)

- A detailed analysis of available gas usage statistics for Australia has been carried out to identify which industry segments use which proportions of gas. This has been mapped to available information on uses and temperature ranges of thermal applications in the various industry sectors to identify energy volumes vs application and temperature in the relevant cases. Previous studies have provided a reasonable guide to the geographical location of these users. (Chapter 3)
- Available information and past experience of the authors has been used to assess the drivers determining current gas prices for users of different types and sizes and to anticipate the likely future changes they may expect. (Chapter 3)
- Following a preliminary analysis of industrial gas user interests and drivers, consultations with key representatives of various gas user segments and industry groups has been used to establish with more clarity, general positions on technical risk, current perceptions, gas price issues, interest in renewables and expectations on economic performance. (Chapter 4)
- The various technically feasible renewable technology solutions have been reviewed and capital cost plus performance information assembled from a combination of review of previously published data, new information from equipment suppliers and industry knowledge. Basic information on a series of Australian and international case studies of the relevant technologies has been collected. (Chapter 5).
- Relevant information on renewable energy resource availability and costs has been assembled, with emphasis on the resources most relevant to the opportunities identified as most prospective (Chapter 6).
- Discounted cashflow analysis has been carried out to compare gas based options to available renewable options using annualised costs, Levelised Cost of Energy and Internal Rate of Return as metrics, and so identify those technologies and applications that appear to be economically favourable under the likely range of current and future gas price scenarios (Chapter 7).
- Knowledge of user sectors, applications, concerns and constraints has been combined with the results of the economic analysis to identify the most likely opportunities for gas replacement (Chapter 7).
- Challenges to implementation and measures that could be taken to encourage implementation have been considered (Chapter 8).

2. PREVIOUS STUDIES OF RENEWABLES FOR INDUSTRY

There have been a number of previous relevant studies in Australia and internationally that look at the general prospects for renewable energy technologies to replace conventional sources of energy for industry. These studies have not targeted gas use exclusively, but have considered areas where gas is often applied. Four key studies are reviewed here.

2.1. Renewable Energy for Industrial applications

Renewable Energy for Industrial Applications is a 2010 assessment from UNIDO (Taibi et al. 2010) projecting out to 2050. It suggests that up to 21% of final energy and feedstock in manufacturing could be renewable by 2050, (30% of final energy plus 14% of feedstock). The study focussed on:

- biomass for process heat,
- biomass for petrochemical feed-stocks,
- solar thermal systems for process heat, and
- heat pumps for process heat.

Other options that are identified as possible potential contributors are:

- conventional geothermal heat – for specialised applications,
- enhanced geothermal systems,
- run of river hydro for motive power, and
- wind for motive power.

The last two options in this list have no particular relevance to existing natural gas use in Australia, the others are relevant.

The biggest future global contribution predicted for a renewable technology type to industry is biomass with up to 37EJ/yr across all sectors. Solar thermal is predicted to reach 5.6EJ/yr. Heat pumps are predicted to offer 4.9EJ/yr presumably limited to lower temperatures. It is noted that the application of concentrating solar technologies in the chemical sector could potentially increase the solar thermal contribution to 8EJ/yr.

The pulp and paper sector is identified as having considerable potential for renewables as is wood processing, with only around one third of final energy use coming from biomass and waste in those sectors at present. It is noted that Brazil currently uses charcoal from eucalyptus forestry on a large scale in the place of coke for iron furnaces, illustrating the potential for areas of substitution that are not considered at a first glance. The cement sector is identified as being capable of utilising any waste or biofuel.

A global biomass world supply curve by region suggests that in OECD countries residue based biomass is available at around 7USD/GJ and energy crops at 10USD/GJ as compared to a natural gas reference price of 7USD/GJ.

The total world biomass potential in 2050 is estimated at 150EJ/yr and up to one third is suggested as the maximum likely to be applied for industrial applications with the rest going to transportation, power generation and the residential sector. Transportation is seen as a very strong competitor for biomass use over other applications.

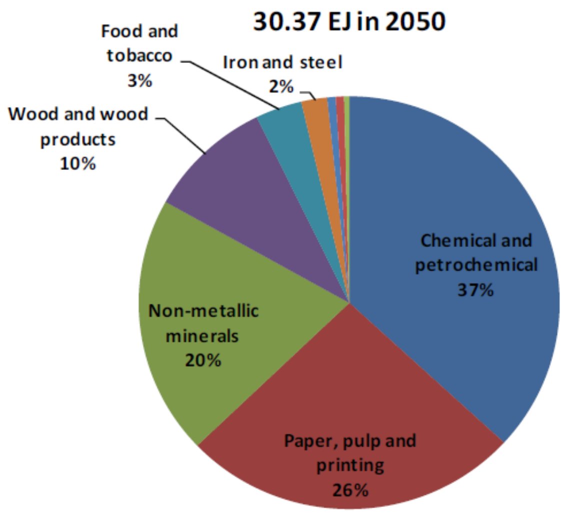


Figure 1. Potential biomass use by sector reproduced from Taibi et al. (2010)

Biomass transport costs can be significant in the initial gathering and centralising phase, however once the biomass is in the form of high energy density product such as pellets, it can potentially be cost effectively shipped over thousands of kilometres in the same way that coal can.

The report suggests the sectoral breakdown of biomass use in 2050 shown in Figure 1. There is an in depth discussion of the options and proven approaches to using biomass as chemical feedstock, with a 2009 listing of applications as shown in Table 1.

An interesting case study involves making tyres from all natural feedstocks and then later using them as renewable fuel in cement kilns once they are discarded.

The predicted sectoral breakdown for solar thermal applications is shown in Figure 2. Unlike biomass, the underlying solar resource vastly exceeds all possible needs. Solar also has an advantage over biomass in not being subject to feedstock price volatility. It is suggested that some solar thermal solutions are very close to being economically viable.

Table 1. Production capacity for bio-based plastics in 2009 reproduced from Taibi et al. (2010)

Production Capacity for Bio-Based Plastics in 2009	kt/year
Cellulose plastics (of which at least 1/3 fully bio-based)	4,000
Partially bio-based thermosets	1,000
Partially bio-based starch plastics	323
Polyactic acid (PLA)	229
Ethylene from bio-based ethanol	200
Polyhydroxyalkanoates (PHA)	80
PUR from bio-based polyol	13
Partially bio-based PTT	10
Bio-based monomers	10
Bio-based Polyamide (PA)	5
Total	5,870

On this basis it is suggested that most of the heat requirement can be met by low cost flat plate collectors or evacuated tubes, with concentrating systems only required at higher temperatures.

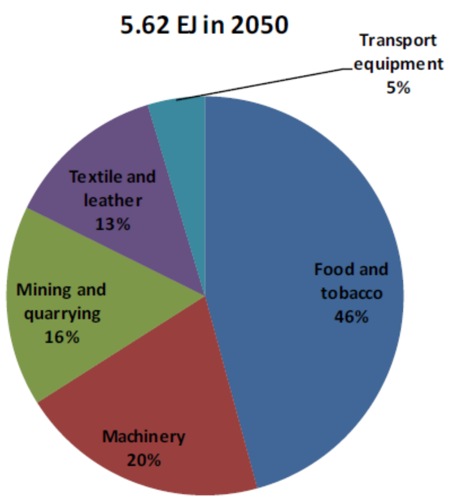


Figure 2. Potential solar thermal use by sector reproduced from (Taibi et al. 2010)

The supply cost curve offered for solar thermal in the food and tobacco sector for 2007, starts at 17USD/GJ and rises to 29USD/GJ which appears high overall and not competitive with gas.

Heat pumps are also singled out for attention, with virtually the same sectoral breakdown of potential application as solar thermal suggested.

Heat pump Coefficient of Performance (COP) decreases with increase in temperature difference as a consequence of the second law of thermodynamics. Heat pumps for temperatures up to 80°C (hot water systems) are known to be readily available. The report also discusses application to higher temperatures above 100˚C. The supply cost curve offered for 2007 suggests a lowest cost for below 60°C where cheap electricity is available at 9USD/GJ Whereas OECD costs for the 60° to100°C range are up to USD35/GJ.

With respect to barriers to renewable energy adoption, the study listed the following:

- lack of information on the potential contribution of renewables and ways of achieving it,
- cheap fossil fuels,
- the absence of appropriate technology supply chains,
- lack of technical capacity,
- the high cost of capital in many developing countries,
- a focus on upfront investment cost instead of full lifecycle cost,
- risks associated with technology transitions and the adoption of early stage technologies,
- restricted access to financial support to cover the extra costs of taxes such as VAT, and
- the lock-in of inefficient, polluting technologies with long lifetimes.

While many of these are related to technology development and economics, they go beyond the issues typically addressed by R&D or market support programs and illustrate the complexity of the challenge in increasing adoption of renewable energy technologies.

2.2. Application of Solar Process Heat to the Commercial and Industrial Sectors

Application of Solar Process Heat to the Commercial and Industrial Sectors, is a June 2005 report for Victoria (Annas et al. 2005). This is the most relevant previous Australian study although it is limited to the state of Victoria and exclusively solar thermal solutions and is now some years old.

The most promising sectors identified are:

- commercial sectors - with relatively large energy needs in suitable ranges and a large number of small players paying higher prices for traditional fuels
- manufacturing – particularly elements of;
    - food, beverage and tobacco manufacturing – especially dairy, beverage & malt, meat, fruit and vegetable, and to a lesser extent bakery products,
    - wood and paper product, and to a lesser extent;
        - petroleum, coal, chemicals & associated,
        - machinery & equipment; and
        - textiles,
- also to a lesser extent, parts of sectors;
    - agriculture – timber & crop drying, aquaculture,
    - electricity, gas and water – sludge drying, desalination.

The report analyses relative levelised costs of energy in considerable detail. It is suggested that in evaluating competitiveness, the capital cost of conventional equipment is not that relevant as it would be required as backup in the majority of cases. It is also small relative to fuel cost.

Their key conclusions around potential cost effectiveness of solar thermal options for Victoria in 2005 are illustrated in Figure 3.

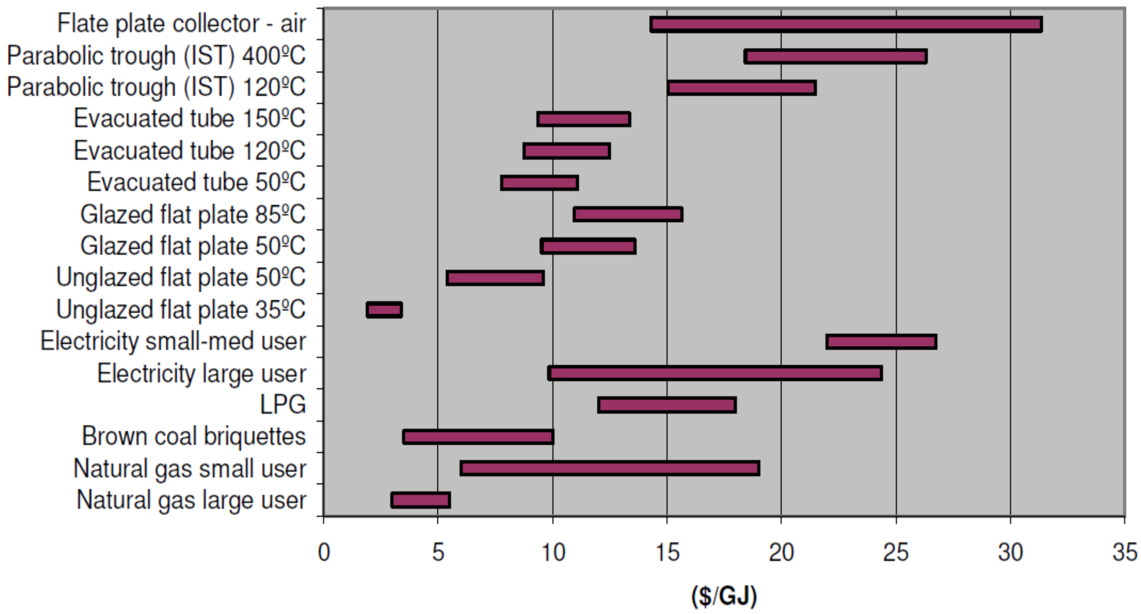


Figure 3. Cost of solar thermal process heat by source, compared to fossil sources, for Victoria in 2005, reproduced from (Annas et al. 2005).

2.3. Potential for Solar Heat in Industrial Processes

Potential for Solar Heat in Industrial Processes, is a report from Task 33 of the IEA Solar Heating and Cooling program (Vannoni et al. 2008).

The report summarises the findings from various national studies that were not identical in terms of their methodologies and assumptions and so country to country comparisons need to be treated with care.

At the time, solar process heat installed capacity varied by country from negligible levels to a maximum on 10 MW_{th} in the USA. Other countries that had more than 1 MW_{th} installed included Austria, Egypt, Greece, Netherlands and Spain. This grouping includes countries with good solar resources and countries with poor ones. Many other good solar countries had negligible installed capacity. Clearly other factors such as the cost of other energy sources and government policy measures were the main drivers.

A very pertinent observation is that quite often industrial processes exploit medium temperature heat by using steam as a heat carrier even though lower working temperatures would be sufficient (eg for drying).

The identified potential for Austria, Spain, Portugal, Italy and the Netherlands was compared and it is suggested that it is about 3 to 4% of total primary energy in all the countries considered.

2.4. Achieving Deployment of Renewable Heat

Achieving Deployment of Renewable Heat (Dolman et al. 2011) examines barriers to a range of technology options and presented various international case studies on support policies. They found that barriers could be classified under:

Technical suitability

- Can the renewable technology actually provide the service needed? Does the basic resource have time or capacity constraints? Is there space to accommodate the equipment needed? etc.

Supply capacity

- This is supply capacity for providing the renewable technology solution, ie the whole chain from manufacture through to installation. This will be particularly pertinent in Australia given that much of the technology is from overseas.

Time discounting

- This might be better described as a financing barrier, the issue is the high upfront capital cost of a renewable solution. The unstated effective discount rate on future energy savings may be very high.

Institutional factors

- Hidden subsidies or market failures that favour the status quo gas solution.

Hidden and missing costs

- A key example is the opportunity cost of deploying a renewable solution that may not be captured in the upfront economic analysis.

Regulatory and administrative costs

- Costs for approvals and development and accessing incentive schemes may be higher than the gas based status quo.

Risk and confidence

- Flowing from the early stage in commercial maturity
  - Uncertainty around key performance and cost parameters as well as the general lack of confidence in less proven technology.
- Awareness
  - Purchasing decisions for replacement can be urgent and hence not allow adequate investigation of new options.

A useful graphical interpretation of these barriers is reproduced in Figure 4.

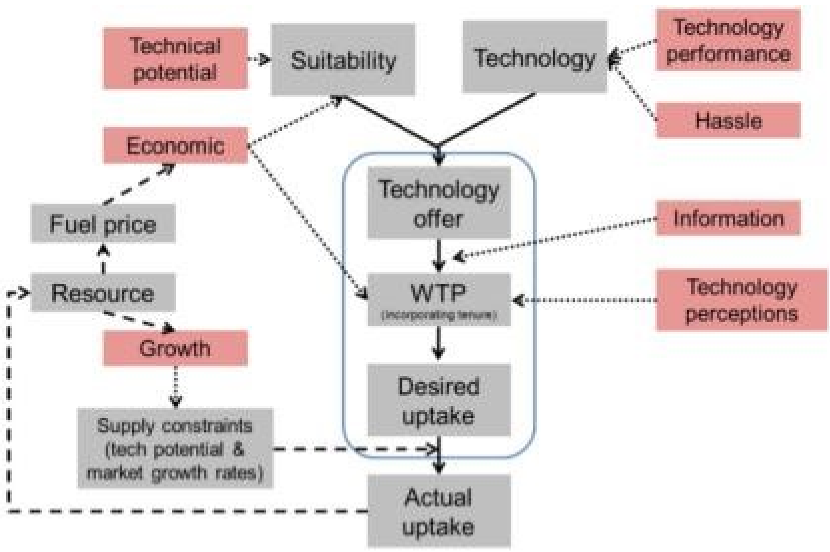


Figure 4. Barriers to technology uptake (Dolman et al. 2011)

The concept of a 'Willingness to Pay' (WTP) as a precursor to the development of customer demand, as well as its relationship to the wider issues of technology, economics and societal acceptance is of interest when developing policy.

For the non-domestic sector in the UK they offer a graph, based on survey data, of Willingness to Pay which is a straight line appearing to reflect expectations of internal rate of return.

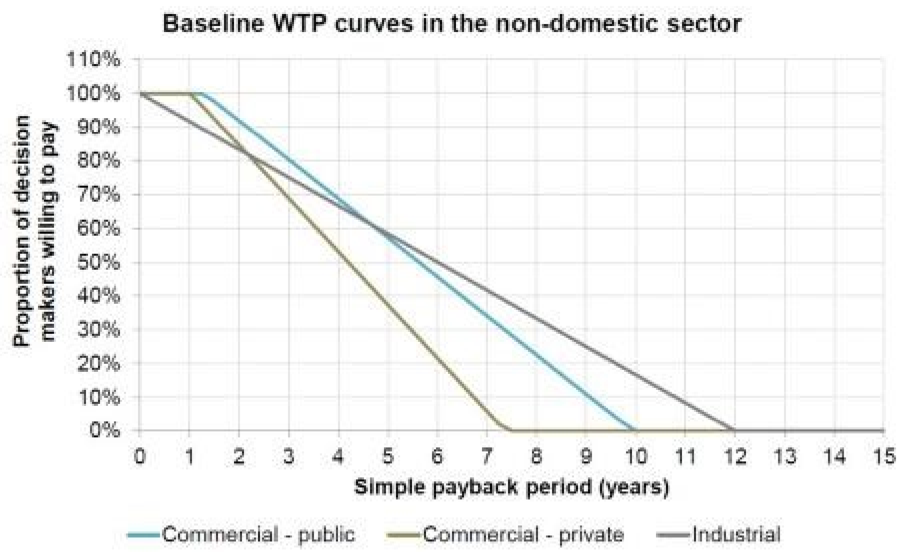


Figure 5. Willingness to pay - UK, commercial/industrial (Dolman et al. 2011)

The report summarises specific barriers to biomass boilers, reproduced in Table 2.

Table 2. Barriers to biomass boiler uptake, reproduced from (Dolman et al. 2011)

Barrier	Description
Lack of trained designers/installers	Specialist skills are needed to specify and install biomass heating systems
Resource availability	There is a limit to the quantity of biomass fuel that can be supplied from domestic sources. Imports will be required when demand for fuel exceeds a certain level.
Lack of national fuel supply chain	No well-developed national supply chain for biomass fuel. This could lead to supply restrictions in some areas.
Fueling and de-ashing hassle factor	Biomass boilers require regular refueling and de-ashing.
Space requirements	Biomass heating systems require significantly more space than fossil fuel alternatives. Installation at sites with limited space may therefore not be possible
Air quality issues	The combustion of biomass leads to higher particulate and Nitrous Oxide emissions relative to fossil fuels. This can be an issue in areas where air quality is a concern.

The report also provides a specific list of barriers for solar thermal and biogas technologies and a presentation of international case studies on support policies.

2.5. Summary

There have been previous investigations of the use of renewable energy to provide energy services that are often delivered by natural gas. There are clearly technologies available and working projects that demonstrate the technical feasibility to do this. Previous studies suggest that economic viability is achievable in some cases.

Moving from these earlier international studies to the Australian context now and in the near future; renewable solutions are more commercially mature and gas costs increased so that the case for action should be stronger.

The studies reviewed support the original working hypothesis of the present study, that bioenergy and solar thermal solutions appear likely to play a central role. Other less obvious areas for investigation that are flagged as technically and economic possibilities include:

- Use of biomass derived pyrolysis or gasification products as chemical feedstock.
- Injection of biogas of gasification products into existing gas lines or use in existing gas combustion systems.
- Use of heat pumps for process heat, potentially powered in whole or part by behind the meter photovoltaic systems.
- Geothermal systems.

3. NATURAL GAS USAGE IN AUSTRALIA

3.1. Introduction

The 2014 edition of *Australian Energy Statistics* (*AES*) (Ball et al. 2014), compiled by the Bureau of Resource and Energy Economics (BREE), is the most complete current source of data on energy use by economic sector. It reports that the total consumption of gas in Australia in 2012 - 13 was 1,387 PJ distributed as shown in Figure 6.

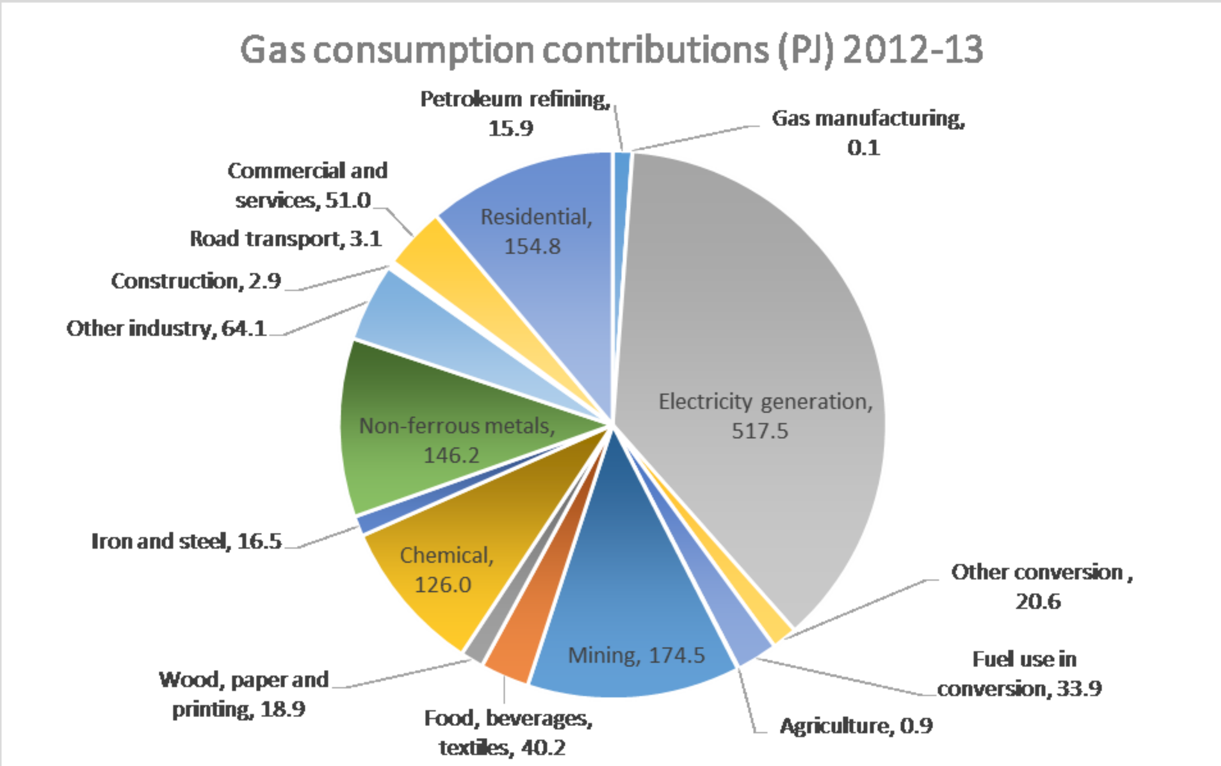


Figure 6. Gas consumption in Australia (2012-13). Data from AES (Ball et al. 2014)

This chapter analyses this gas consumption by the various industry segments that use it, what they use it for and where they are located. The range of prices that these users currently pay for gas and the future prices they are likely to pay are also discussed.

Together this information provides the foundation for the analysis of the prospects for renewable energy substitution for gas usage that makes up the remainder of this report.

The view of Figure 6 appears comprehensive until one attempts to create a more detailed analysis of the data to identify segments of use for this report. At that point there is a need to look not only at *AES* data but also at data from a number of other sources in order to create the most meaningful analysis. Each data set differs from others in the purpose for which it was collected, the limitations on that collection and in the way in which the data is categorised, collated, cleaned and ultimately analysed before public dissemination. It is most important to note that the summary totals and individual numbers from each dataset often do not precisely agree. It is important to focus on the broader messages from the various datasets and not to expect each set of numbers to exactly equal another.

3.2. Available gas consumption data

The *AES* reports energy consumption by fuel and by ANZSIC sector[3]. The most recent annual edition of *AES* published in July 2014 contains data up to 2012-13.

In the *AES*, sectoral disaggregation is at the 2-digit level for most (but not all) sectors of manufacturing and at the 3-digit level for a few sectors for national level data. *AES* also includes state level data, but with considerably less sectoral disaggregation, mainly because of data confidentiality constraints. The major source of input information to *AES* for the manufacturing industry sectors is the National Greenhouse and Energy Reporting Scheme (NGERS) reports submitted by large energy users. BREE has limited data from smaller individual users, which means that the quality of the published consumption figures for sectors with large numbers of small users is sometimes questionable. There is no comprehensive public data on consumption by location below the state level.

Reports submitted by businesses participating in the Energy Efficiency Opportunity (EEO) scheme are another potential source of energy consumption data. However, public reports, including those prepared by Climate Works under the Industrial Energy Efficiency Data Analysis (IEEDA) project (Climateworks 2012) provide only total energy consumption, i.e. all fuels combined, and are therefore of limited use to this study. Other confidential data which disaggregates energy consumption by fuel may exist but has not been made available for this study. A limited quantity of IEEDA data on gas use in a few sectors has been provided by ARENA for this project and is summarised in Table 5.

An Australian Bureau of Statistics (ABS) survey conducted in 2009[4], provides national level gas consumption, in 2008-09 only, for selected sectors at a greater level of sectoral disaggregation than *AES*.

The annual statistical publication of the Energy Supply Association of Australia, entitled *Electricity Gas Australia* (ESAA 2014), provides data on gas consumption and customer numbers at the retail level, i.e. gas supplied through distribution networks, segregated into only two groups: large commercial and industrial, defined as consumers drawing more than 10 TJ per year (but not including very large consumers connected directly to transmission

---

[3] *"The Australian and New Zealand Standard Industrial Classification (ANZSIC) is a classification that provides a framework for organising data about businesses by grouping business units carrying out similar productive activities.... ANZSIC is a hierarchical classification with four levels, namely divisions (the broadest level), subdivisions, groups and classes (the finest level). At the divisional level, the main purpose is to provide a limited number of categories which will provide a broad overall picture of the economy. The subdivision, group and class levels provide increasingly detailed dissections of the broad categories."* The ANZSIC system complete listing is in Appendix A.

[4] ABS, 2010. Energy, Water and Environment Management, 2008-09, cat. No. 4660.0 http://www.abs.gov.au/AUSSTATS/abs@.nsf/Lookup/4660.0Main+Features12008-09

pipelines) and residential and small commercial and industrial, defined as customers drawing less than 10 TJ per year. However, this disaggregation is not available for NSW or Tasmania.

The Australian Energy Market Operator (AEMO) is responsible for operating wholesale gas markets in eastern Australia. It is currently engaged in developing in-house capability to prepare forecasts of future gas supply and demand. Such forecasts are a key input to fulfilling its responsibility to provide the market with the data needed to inform decisions by gas industry participants about opportunities for new investments. A report on forecasting methodology, prepared by consultants ACIL Allen and commissioned and published by AEMO as part of this process, contains the following observation (Balfe & Kelp 2014):

"To meet its objectives for gas consumption forecasts, AEMO will require consumption data that are disaggregated by customer type and location. While these data may exist (within DNSPs and/or AEMO's retail systems) ACIL Allen has not assumed that they would be available to AEMO."

This quotation confirms the difficulty of obtaining detailed, disaggregated data about gas consumption.

This Chapter draws variously on all of these sources together with the experience of the authors, in seeking to construct the best possible overall picture of gas consumption by industry for Australia in 2014.

3.3. Gas use by industry segments

Cumulative assessment of the gas market breakdown and analysis is shown diagrammatically in Figure 7.

The gas industry classifies customers into three groups: electricity generators, other large industrial consumers connected at the transmission level, and 'mass market' or distribution network connected customers. This classification is however not applied with complete consistency across the country; in some market regions, i.e. essentially, some states, many very large consumers are connected at the distribution network level, whereas in others, particularly Queensland, most are connected at the transmission level. Each group has a different pricing and market structure and tends to exist in very different business size groupings and be exposed differently to national and international forces. The mass market customers are much of the focus of the following discussion, although of the large industrial consumers, we believe there may be pilot project opportunities for renewable energy substitution in the non-metallic minerals and basic chemicals sectors.

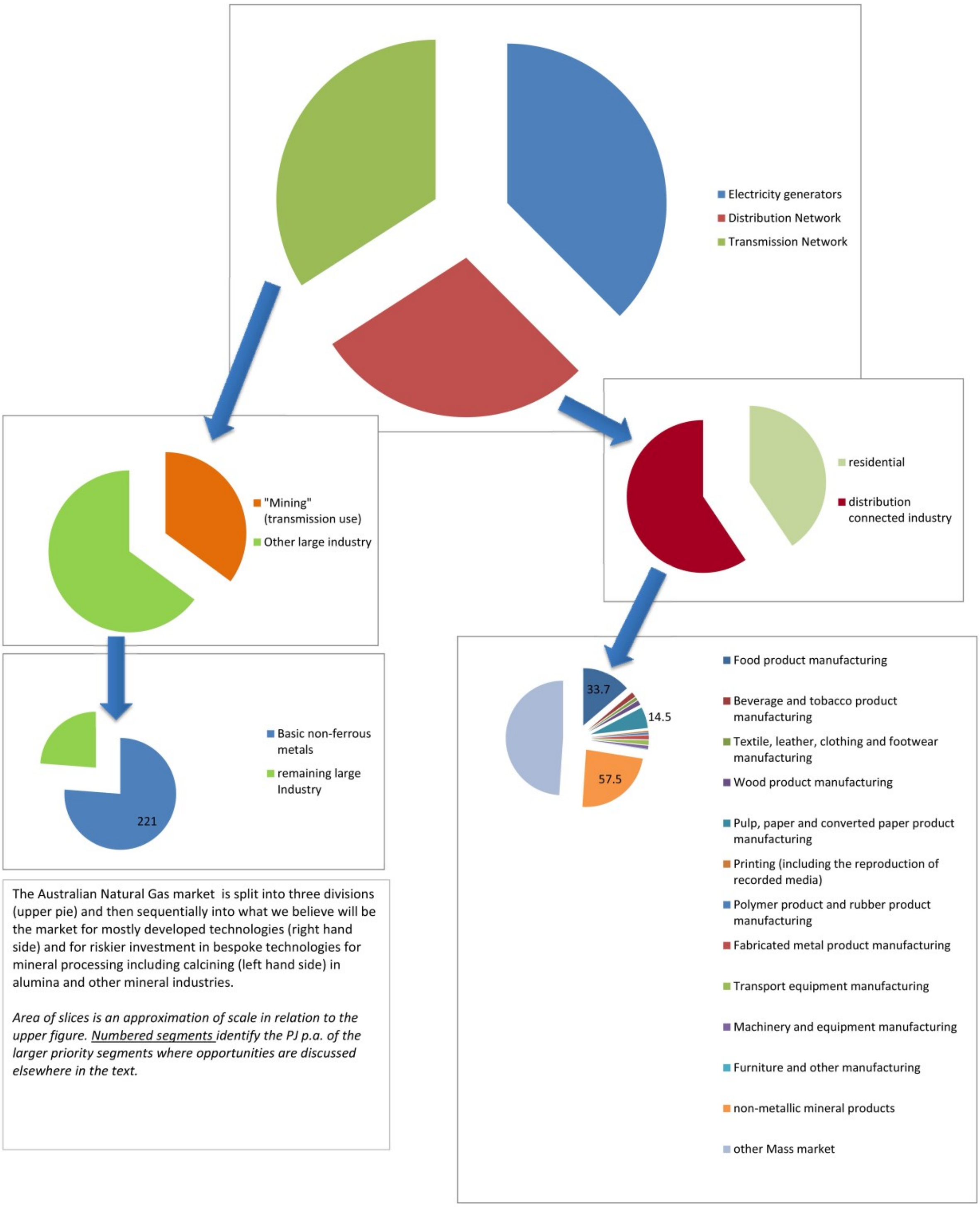


Figure 7. Natural gas market and breakdown to target sectors

The breakdown of the gas consumption between these three sectors in the National Energy Market is:

- Electricity generators 492 PJ (38%)
- Transmission 447 PJ (34%)
- Mass market (Distribution) 372 PJ (28%)

The mass market segment includes domestic (household) consumption as well as the vast proportion (numerically) of Australian businesses who obtain their gas through distribution system. Combustion of gas is by far the most important source of thermal energy (heat) for the agriculture, mining and manufacturing sectors as a whole. Other fuels used to provide heat include coal, LPG and various biofuels. Significant use of biofuels is confined to three manufacturing sectors, it is discussed later in this Chapter and shown in Table 7. In the past, brown coal briquettes were quite important, particularly in Victoria, but their consumption has been falling for many years[5] and in late July the owner of the factory, at Morwell, announced that it would close at the end of August 2014. However this closure has not eventuated.

Table 3 provides an overview of thermal fuel use by industry (excluding power generation) in 2012-13, excluding biofuels, using data taken from *AES*. Energy use is shown by fuel by sector. While gas is by far the most important fuel overall, the special circumstances of a few individual industry sub-sectors mean that either coal or biofuels are more important.

Three of the sectors notably use very large volumes of natural gas and each has special features.

Mining: The great majority of the reported natural gas consumption in the mining category, is used by the upstream oil and gas industry to process natural gas for both domestic use (as in Victoria) and to convert it to LNG (as in WA). Some large mining operations in WA are remote from the grid and use gas to generate electricity, but AES reports this gas use under Electricity generation, not under Mining.

For the oil and gas industry, the use of their own resource to drive processing can be extremely cost efficient. It is provided at very low marginal cost and as such this sector is unlikely to be a realistic target for renewables substitution in the near term.

Basic Chemical and Chemical, Polymer and Rubber Product Manufacturing: A small number of large petrochemical and ammonia manufacturing establishments use gas in large volumes, both as a source of energy and as a feedstock. The feedstock use includes both natural gas as normally understood, i.e. methane, and ethane, which BREE also classifies as natural gas. Methane is used as feedstock for the manufacture of ammonia at six plants located in Queensland, NSW and WA.

[5] BREE, 2014. Australian Energy Statistics Update http://industry.gov.au/industry/Office-of-the-Chief-Economist/Publications/Pages/Australian-energy-statistics.aspx#

Table 3. Annual consumption of fuels used to provide thermal energy, sourced from AES (Ball et al. 2014)

	Natural Gas (PJ)	**Other thermal energy fuels, excl. biofuels (PJ)**			
		LPG	*Black coal*	*Briquette*	*Other fuels*
Div. A Agriculture, forestry and fishing	0.9	1.9			1.9
Div. B Mining	174.5	1.7	3.1		4.8
Div. C Manufacturing					
11-12 Total Food, beverages and tobacco	35.1	1.8	9.0	1.9	12.7
13 Textile, clothing, footwear and leather	5.1	0.2	0.4	0.2	0.8
14 Wood and wood products	1.9	0.6	0.1		0.7
15-16 Pulp, paper and printing	14.8	0.1	4.3		4.4
18-19 Basic Chemical and Chemical, Polymer and Rubber Product Manufacturing	126.0	13.9	6.7		20.6
20 Total Non-metallic mineral products	57.5	4.9	22.8		27.7
20.1 Glass and glass products	*11.5*	*0.2*	*0*		*0.2*
20.2 Ceramics	*16.5*	*0.4*	*0.6*		*1.0*
20.3 Cement, lime, plaster and concrete	*23.9*	*4.3*	*22.2*		*26.5*
20.9 Other non-metallic mineral products	*5.6*	*0.1*			*0.1*
21 Primary Metal and Metal Product Manufacturing					
21.1-21.2 Iron and steel	18.6		120.0		120.0
21.3-21.4 Basic non-ferrous metals	146.2	0.1	51.7		51.8
22 Fabricated metal products	2.3	0.6			0.6
23-24 Machinery and equipment	4.2	0.8			0.8
25 Furniture and other manufacturing	0.1	0.1	0.6		0.7
Totals (excluding subsections which are incorporated in their above sections)	**587.2**	**26.7**	**218.7**	**2.1**	**247.5**

Ethane is used at plants in Sydney and Melbourne to make polyethylene. Together these eight plants are the only major chemical plants in Australian which use gas as a feedstock (several others use petroleum refinery by-products) and hence they account for the great majority of the reported consumption of natural gas in this sector. There are a much larger number of ‘downstream’ chemical product manufacturers which use gas in much smaller quantities for a variety of purposes, but the statistics do not allow their consumption to be separated from that of the large users.

The majority of use is as chemical feedstock, with high temperature heat for reactors much of the remainder. The nature of chemical synthetic industries is such that substitution of feedstock requires high levels of purity and an associated high capital investment in process development to meet stringent modern quality standards. The mixed and variable product streams from biomass gas technologies, for example, would face considerable challenges for this use.

Basic non-ferrous metals: Most of the gas use reported by this industry sector occurs at five very large alumina plants, three in WA and two in Queensland. Alumina production at scale involves the consumption of enormous quantities of energy for steam raising and further enormous quantities at higher temperature for calcining. One plant in WA and one in Queensland use coal for steam raising and gas for calcining; the other three use gas for both processes.

The second application, calcining, has a high temperature requirement and this excludes it from all except the more experimental renewable energy technologies. The lower temperature steam could be considered for renewable substitution. However it faces the challenges of very gas large volumes and competition with gas supply that currently, and for the foreseeable future, has the lowest prices of any industry sector because it has by far the largest consumption, both collectively and as five individual sites.

After the above three largest sectors, various aspects of manufacturing industry are of greatest interest. Table 4provides data for natural gas only at a greater level of detail for these and other sectors from the Australian Bureau of Statistics (ABS). In general, the figures reconcile reasonably closely with the BREE numbers, but note that the grouping of the sectors does not precisely align because BREE uses, in part, an earlier version of the ANZSIC. The judgment of the authors of this study, is that the ABS numbers are more reliable for the lower consuming sectors than the BREE numbers. The numbers in both Table 3 and Table 4 show that after the three very large sectors listed above, three other sectors account from the majority of gas use in manufacturing, these are:

- food product manufacturing,
- paper manufacturing, and
- non-metallic mineral products.

The remaining consumption is fairly evenly spread across a larger number of sectors, including agriculture, each having relatively small consumption (and a large number of establishments).

Table 4. Annual consumption of natural gas by selected sectors of manufacturing, sourced from ABS.

Industry sector	Natural gas consumption (PJ)
Food product manufacturing	33.7
Dairy product manufacturing	7.2
Sugar and confectionery manufacturing	2.4
All other food product manufacturing (by subtraction)	24.1
Beverage and tobacco product manufacturing	3.4
Textile, leather, clothing and footwear manufacturing	2.0
Wood product manufacturing	3.2
Pulp, paper and converted paper product manufacturing	14.5
Printing (including the reproduction of recorded media)	0.9
Polymer product and rubber product manufacturing	1.4
Fabricated metal product manufacturing	2.8
Transport equipment manufacturing	3.0
Machinery and equipment manufacturing	2.2
Furniture and other manufacturing	0.2
Total (excluding the subsections which are incorporated in their above sections) ***Total is slightly different from the same sectors totalled in Table 3 for BREE data. Sectors are not identical and accounting for the different inclusion of Basic Chemicals in the Polymer section the equivalent total is 64.9 for BREE data.*	**67.3****

Table 5 summarises data from the EEO program, compiled by Climate Works under the Industrial Energy Efficiency Data Analysis (IEEDA) project, and provided by ARENA. The data show the applications for which gas is used in the food, paper and non-metallic mineral product sectors. The numbers are for an indeterminate year, but are almost certainly a year or two earlier than the *AES* data. This discrepancy should make no difference to the general conclusions which can be drawn from the data.

It will be noted that the data is disaggregated to the sub-sector (ANZSIC 3-digit) level for some parts of Food, beverages and tobacco, but there is no disaggregation for Non-metallic mineral products. However, most thermal energy use in this latter sector is at very high temperature in kilns and furnaces used to produce cement, glass, bricks and other ceramic products. Some cement kilns use coal and some gas, but the other industries use only gas. Most energy use by the other two industry sectors is in boilers and dryers (which in fact are often heated by steam). No application data is available for the other sectors listed in Table 4. Data is also lacking for Agriculture, where some gas is used for space heating glass houses and the sheds used in intensive livestock production. The data is compared to the BREE sector data (close to the ABS data) for the latter two categories and the remainder shown in the last column – while the data of Table 5 may be useful in the food industry sub-sectors it is clearly missing the detail required to assist with broader analysis.

Table 6 shows data from *AES* on gas use by sector by state. It can be seen that, according to the *AES* data, Victoria uses far more gas than other states – more in fact than all the others combined – in the industry sectors for which state data are available. The next largest users are NSW and SA. Data are not published for sectors where gas use is dominated by one or two very large individual users. The separate state figures for some sectors do not sum fully to the national total because of data withheld for commercial in-confidence reasons and also gas use in the NT.

Table 5. Gas use by application and economic sector comparing AES and IEEDA. (PJ per year)

Economic sector	**Total natural gas use (AES)**	**End uses of natural gas and other gaseous fuels, excluding LPG (from IEEDA)**							
		Boiler systems	*Dryers*	*Steam systems*	*Furnace/ Kilns*	*Ovens*	*Other process heating*	***IEEDA Total***	*AES and IEEDA Discrepancy*
111 Meat and Meat Product Manufacturing		1.66		0.47			2.38	**4.5**	
113 Dairy Product Manufacturing		1.00	4.33				1.33	**6.7**	
Other Food product manufacturing		0.86	0.52			0.72	0.80	**2.9**	
15-16 Pulp, paper and printing	**14.8**	9.91	8.59					**18.5**	-3.7
20 Total Non-metallic mineral products	**57.5**				9.45		4.93	**14.4**	43.1

Table 6. Gas use by state and economic sector AES (Ball et al. 2014) (0.0 indicates less than 0.05, 0 is (none)) Units are PJ per year.

ANZSIC Sector	NSW	VIC	QLD	WA	SA	TAS	BREE Totals
Div. A Agriculture, forestry and fishing	0.2	0.5	0.0	0.0	0.1	0.0	0.9
Div. B Mining	0.0	23.0	19.1	96.0	17.1	0	174.5
Div. C Manufacturing							
11-12 Food, beverages and tobacco	9.6	16.3	3.5	1.8	3.2	0.7	35.1
13 Textile, clothing, footwear and leather	0.8	3.5	0.0	0	0.8	0	5.1
14 Wood and wood products	0	0.5	0.0	0.7	0	0.0	1.9
15-16 Pulp, paper and printing	0	11.9	0.5	0.1	0	0.0	14.8
18-19 Basic Chemical & Chemical, Polymer & Rubber Product Manufacturing	*Not published*						
20 Non-metallic mineral products	12.0	11.1	5.4	15.8	13.2	0	57.5
211-212 Iron and steel	*Not published*						
213-214 Basic non-ferrous metals	*Not published*						
22 Fabricated metal products	*Not published*						
23-24 Machinery and equipment	0.4	2.0	0	0	1.8	0	4.2
25 Furniture and other manufacturing	0.0	0	0.0	0.0	0	0	0.1
Totals excluding Mining and Non-metallic mineral products	**11.0**	**34.7**	**4.0**	**2.6**	**5.9**	**0.7**	**236.6**

Page intentionally blank

3.4. Application of Gas Use Relevant to Renewable Substitution

In general, renewable thermal energy supply technologies are more technically and commercially mature in applications requiring hot water and steam. Much of the mass market sector needs fall into this category. The non-metallic mineral products, metallic products and basic chemicals sectors are larger, usually transmission connected and likely to require alternative less proven technologies. The reliable data from the tables above has been collated into a summary in Table 7 for the mass market sectors. Table 7 essentially presents the same data as Table 4, but with non-metallic minerals excluded and agriculture added. It shows that the various food processing industries account for 51% of total gas consumption in the mass market sectors listed in the table. Paper and wood products account for a further 26% of natural gas use.

Table 7. Annual natural gas and biofuel consumption in mass market sectors

Industry sector	Natural gas use (PJ)	Share of total gas use	Biofuel use (PJ)
Agriculture	0.9	1.3%	
Dairy product manufacturing	7.2	10.7%	
Sugar and confectionery manufacturing	2.4	3.6%	
All other food product manufacturing (by subtraction)	24.1	35.8%	87.2
Beverage and tobacco product manufacturing	3.4	5.1%	
Textile, leather, clothing and footwear manufacturing	2.0	3.0%	
Wood product manufacturing	3.2	4.8%	11.6
Pulp, paper and converted paper product manufacturing	14.5	21.5%	15.2
Printing (including the reproduction of recorded media)	0.9	1.3%	
Polymer product and rubber product manufacturing	1.4	2.1%	
Fabricated metal product manufacturing	2.8	4.2%	
Transport equipment manufacturing	3.0	4.5%	
Machinery and equipment manufacturing	2.2	3.3%	
Furniture and other manufacturing	0.2	0.3%	
TOTAL Mass market	**68.2**	**100%**	**114**

Table 7 also shows biofuel consumption in the food (sugar milling), wood product and paper industries. It can be seen that each of these three industries already uses more biofuel than natural gas, even though they also use large amounts of natural gas. There is a distinction in that very few sugar mills use natural gas for the limited amount of non biomass firing required, coal is the preferred supplementary source of boiler fuel. Gas is more widely used for co-firing and other processes in the paper industry. At most sugar and paper mills, biofuels from waste products are used for production of steam and for co-generation of electricity.

Less information is available about gas use in the remaining sectors listed in Table 7, accounting for the remaining 23% of gas consumption in the mass market sectors.

The ESAA (ESAA 2014) gas customer number data provide a useful insight into the number of establishments with significant gas use. Annual consumption of more than 10 TJ[6] implies, assuming an average price of $15 per GJ, an annual gas bill of more than $150,000. The numbers of establishments with consumption above this level is reported as follows in 2011-12:

- Victoria 779
- NSW and ACT 476
- WA 185
- Queensland 177
- SA 160
- Tasmania no data reported

Replacement of gas usage requires a viable alternative. The temperature ranges relevant to the identified industry sectors are analysed and grouped by other authors in different fashions but, like the gas use data, the similarities make broad sense. The categories used in this report are as shown in Table 8.

Table 8. Heat categories

Hot water	**Low temp (steam / drying)**	**High temp (steam / drying)**	**High temp (direct heat / steam**	**Specialist / feedstock or**
<150°	150° – 250°	250° - 800°	800° - 1300°	>1300°

The well-established renewable technologies are able to provide energy in the first three usage categories. These are well suited to the aim of this study - *to examine direct (partial or full) substitution of renewables for gas within the boundaries of an existing industrial operation*. These more established technologies have a lower technical risk and are thus more likely to be implemented. The specific applications of the larger and/or less established technologies for categories on the right (>800°C) carry a higher level of project risk due to both the technology risk and the large size of the investments required.

[6] An annual consumption of 10TJ (1/100PJ), corresponds to a continuous average instantaneous consumption at a power level of approximately 300kW, more likely it could represent varying consumption ranging up to the order of around 1MW peak.

3.4.1. Views of other authors

The industry experience of the authors of this study is in agreement with a number of authors who have reviewed the heating requirements of various industries by the temperature range. Some of these are summarised here.

"Potential for Solar Heat in Industrial Processes" - a report from Task 33 of the IEA Solar Heating and Cooling program (Vannoni et al. 2008), emphasises the lower temperature ranges. They suggest the share of energy use in industrial processes (Note – not just gas use) shown in Figure 8.

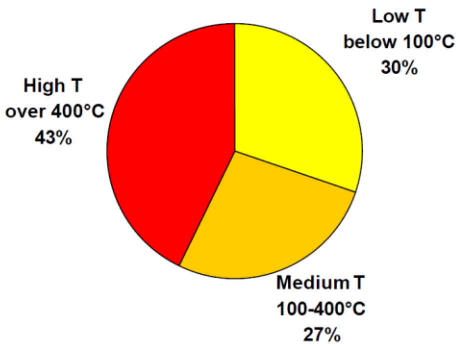


Figure 8. "Share of industrial heat demand by temperature level. Data for 2003, 32 European countries: (Vannoni et al. 2008). Reproduced from (ECOHEATCOOL 2005)

Taibi et al.(2010) provides a global breakdown by temperature range by general industry sector as shown in Figure 9. Here again emphasising the lower temperature ranges of our categorisation and again not limited to gas use.

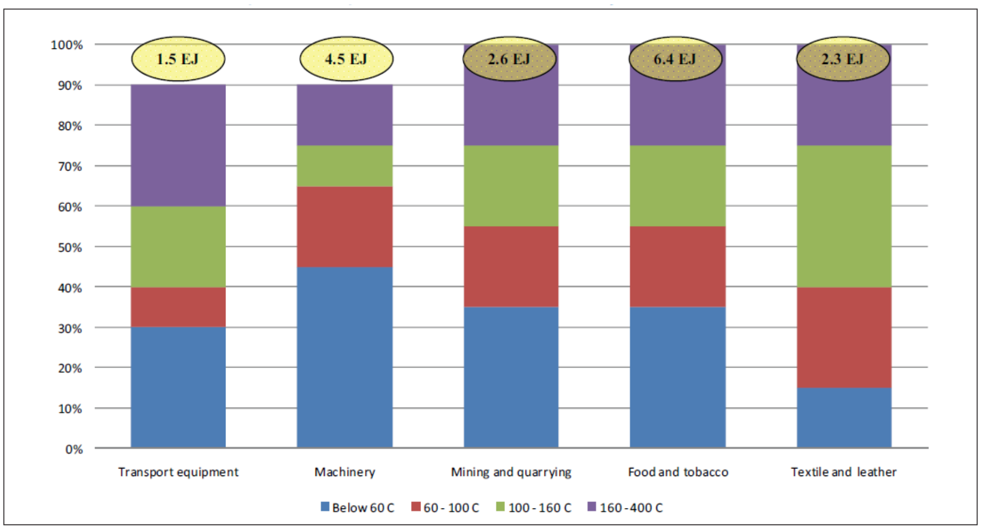


Figure 9. Heat grade and demand by sector (Taibi et al. 2010)

Vannoni et al. (2008) gives a similar global summary of heat applications, it is reported that 31% of heat demand in the EU is from industry, with the breakdown by temperature and application in Figure 10 (again not just gas use).

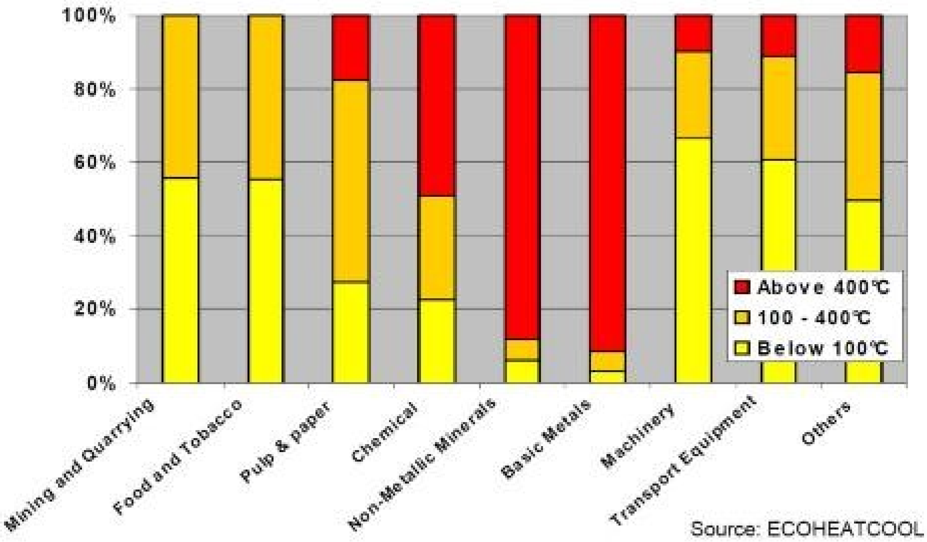


Figure 10. Global heat demand by industry (Vannoni et al. 2008) reproduced from (ECOHEATCOOL 2005)

Weiss (2010) also offers the explicit identification, shown in Table 9 of the actual uses that cause various industry sectors to require heat at specific temperatures.

The collations of the above authors indicate the drivers for low temperature applications where energy is supplied by a variety of technologies and sources. Gas usage however allows a broader application to higher temperature processes and these processes are not covered in the above references. In particular they are all mass market usages and do not extend to bespoke or less established technologies at higher temperature ranges that also considered in this report.

The distribution of energy use between these various forms and the higher temperature ranges cannot be determined from the data. The possibility of further disaggregating the data on gas consumption has been discussed above but it needs to be made clear that the data is patchy and disaggregating the energy use in each of these priority sectors into the thermal ranges suggested needs to be interpreted with caution. While historical data doesn't necessarily apply, there is an opportunity for predictive analysis - the Energetics study (Annas et al. 2005) on the potential for applying solar process heat in Victoria, presented energy use for various relevant industry segments with a detailed breakdown by temperature range. This data is more representative of broader usage including some higher temperature gas usage and has been summarised in Table 10. The fractional split amongst specific subdivisions may be to some extent Victorian specific and also vary slightly over time. Note that although these data are now more than ten years old, practices in the industries covered have been essentially unchanged over that period.

Table 9. Uses for heat grades in select industries reproduced from (Weiss 2010)

Industrial Sector	Process	Temperature Level (°C)
Food & Beverage	Drying	30° - 90°
	Washing	40° - 80°
	Pasteurizing	80° - 110°
	Boiling	95° - 105°
	Sterilizing	140° - 150°
	Heat Treatment	40° - 60°
Textile Industry	Washing	40° - 80°
	Bleaching	60° - 100°
	Dyeing	100° - 160°
Chemical Industry	Boiling	95° - 105°
	Distilling	110° - 300°
	Various chemical processes	120° - 180°
All Sectors	Pre-heating of boiler feedwater	30° - 100°
	Heating of factory buildings	30° - 80°

Table 10. Temperature distribution of energy use for mass market sectors (Annas et al. 2005)

Meat industry	**Temp**	**%**
Hot water	40 to 60°	14%
Rendering/Fat Melting - Gas	50 to 140°	40%
Hot water: eg Cutting, Deboning, Sterilisation - Gas	80 to 90°	29%
Other - Gas	Various	16%
Dairy industry	**Temp**	**%**
Evaporation - Gas	60°	47%
Pasteurisation - Gas	72°	24%
Drying - Gas	120°	29%
Fruit & Vegetable	**Temp**	**%**
Boilers - Gas	40 to 60°	12%
Hot Water Low Temp - Gas	40 to 60°	13%
Hot water Med Temp - Gas	60 to 80°	19%
Steam High Temp - Gas	80 to 200°	28%
Ovens - Gas	250 to 400°	25%
Other - Gas	Various	3%
Beverage & Malt Manufacturing	**Temp**	**%**
Malt Germination - Gas	15°	4%
Malt Kilning Curing - Gas	30 to 40°	13%
Hot Water - eg Cleaning, Heating, Warming - Gas	40 to 60°	7%
Pastuerisation - Gas	60 to 90°	10%
Hot Water - eg CIP, Cleaning, Sterilisation - Gas	60 to 100°	20%
Beer Brewing - Gas	140 to 210°	21%
Malt Kilning - Drying - Gas	180 to 200°	25%
Pulp, Paper & Other Wood Product Industries	**Temp**	**%**
Low Temp Process	20-60°	10%
Medium Tem Process	60-100°	20%
Direct Fired Process	100°+	31%

Chemical industries	Temp	%
Space Heating - Gas	60 to 120°	7%
Hot Water - Gas	60 to 120°	8%
Steam Processes - Gas	70 to 400°	85%
Metal Industries	**Temp**	**%**
Various - Gas	100 to 800°	23%
Furnace - Gas	450 to 500°	49%
Furnace - Gas	500 to 600°	11%
Furnace - Gas	1,200°	18%
Machinery & Equipment	**Temp**	**%**
Boilers - Gas	50 to 150°	5%
Boilers - Gas	150°+	15%
Direct Fired Processes - Gas	200°+	20%
Furnace - Gas	500°+	60%

3.4.2. Application by sectors for Australia

Table 11 applies the gas only component of this sector breakdown, moderated by the other available information and experience of the authors, to the known usage of mass market sectors in Table 7. Table 12 extends the analysis to the larger transmission connected sectors. The information is also shown graphically in Figure 11.

Table 11. Energy / temperature usage distribution for mass market sectors by temperature of conversion.

Industry sector (units are in PJ)	Hot water	Low temp (steam / drying)	High temp (steam / drying)	High temp (direct heat / steam	Specialist
	<150°	150–250°	250-800°	800-1300°	>1300°
Agriculture	0.4	0.5			
Dairy product manufacturing	3.6	3.6			
Sugar and confectionery manufacturing	1.0	1.0	0.4		
All other food product manufacturing	9	10.6	4.5		
Beverage and tobacco product manufacturing	0.8	1.8	0.8		
Textile, leather, clothing and footwear manufacturing	0.1	0.7	1.2		
Wood product manufacturing	0.5	0.3	1.4	1.0	
Pulp, paper and converted paper product manufacturing	1.0	1.5	7.5	4.5	
Printing (including the reproduction of recorded media)		0.1	0.8		
Polymer product and rubber product manufacturing		0.2	1.2		
Fabricated metal product manufacturing		0.6	1.7	0.5	
Transport equipment manufacturing	0.1	1.1	1.8		
Machinery and equipment manufacturing	0.1	0.8	1.3		
Furniture and other manufacturing	0.0	0.1	0.1		
Relevant technologies	Mass market solar Small Biomass Boiler, heat pumps, geothermal	Evacuated tube bespoke solar, Concentrating solar, Biomass Boiler	Biomass Boiler, Concentrating solar parabolic troughs and fresnel	Concentrating solar – heliostats and parabolic troughs biomass gasification and combustion	Concentrating solar – heliostats and tower. Biomass gasification
Total Mass market Opportunity	**16.6**	**22.9**	**22.7**	**6**	**0**

Table 12. Energy / temperature usage distribution for larger transmission connected sectors, classified by temperature of conversion.

Industry sector (units are in PJ)	Hot water	Low temp (steam / drying)	High temp (steam / drying)	High temp (direct heat / steam	Specialist
	<150°	150–250°	250-800°	800-1300°	>1300°
Metals (includes Alumina)		80			80
Non metalic Minerals processing (includes cement)		8.1	2.6	24.2	22.6
Basic Chemicals (includes ammonia)			6	30	90
Relevant technologies	Mass market solar Small Biomass Boiler, , heat pumps, geothermal	Evacuated tube bespoke solar, Concentrating solar, Biomass Boiler	Biomass Boiler, Concentrating solar parabolic troughs and fresnel	Concentrating solar – heliostats and parabolic troughs biomass gasification and combustion	Concentrating solar – heliostats and tower. Biomass gasification
Total Large Industrial Opportunity	**0**	**88.1**	**8.6**	**54.2**	**192.6**

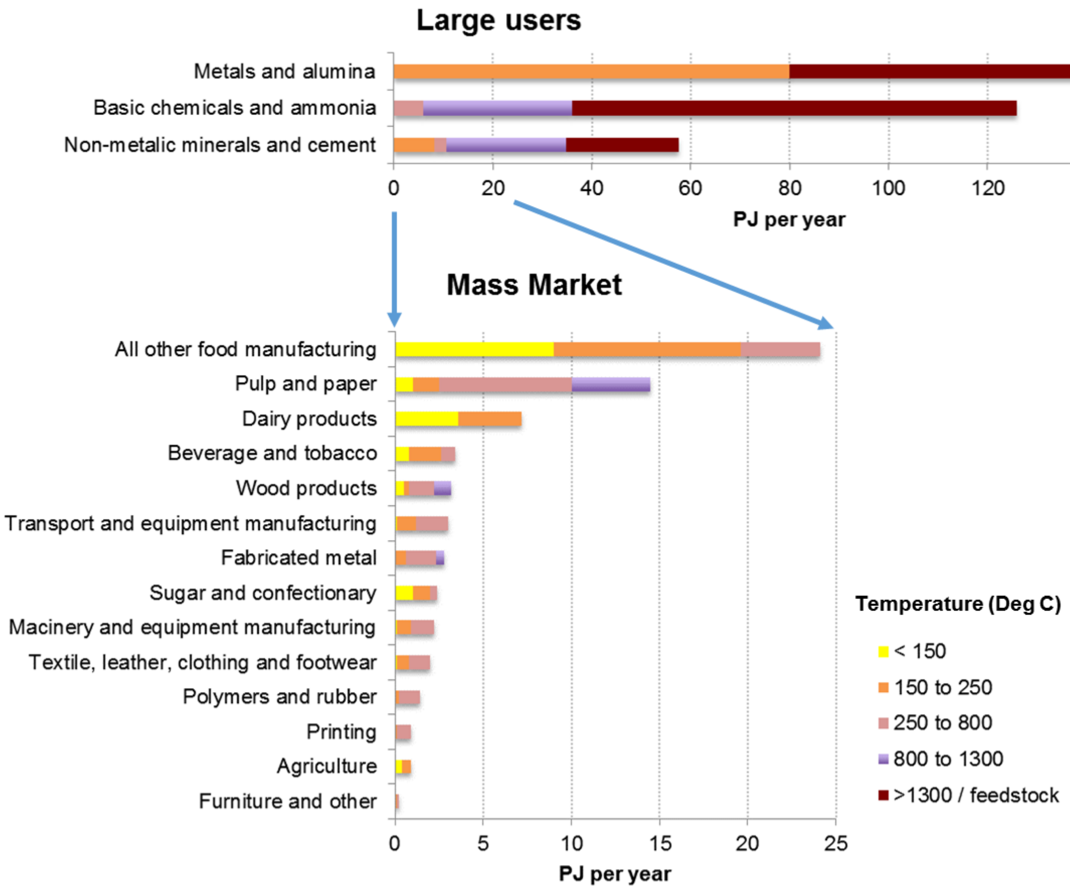


Figure 11. Energy / temperature usage distribution for all relevant sectors, classified by temperature of conversion.

This gas usage analysis has been done with some cross sector approximations (eg the use of the "Machinery and equipment" values for all of the equipment production categories of Table 7). While there are uncertainties with this assessment, with the data available, it is the most representative estimate at this time.

Examining the large users, it is notable that a very large amount of gas that is consumed in making alumina. Much of this is for production of steam by the Bayer process in the temperature range of 150°C – 250°C. This is the lowest temperature opportunity in the large user category.

Within the mass market users, it is notable that the various food related sectors are very significant. Their requirements span the temperature spectrum but also have the largest fraction at the lower temperature end.

The food sector is a growth area for Australia and an increasing source of exports. Recent projections (Lineham et al 2012) have forecast a 77% increase in the value of Australian agri-food exports (meat, dairy, fruit) by 2050. These increases are due to increasing demand from developing markets, primarily in Asia. Such growth has already being witnessed in the dairy products manufacturing industry, where milk production in Australia to the decade ending 2011 increased by around 41(Food Processing Industry Strategy Group 2012). Such increases in production will increase the demand for energy.

Quality and environmental credentials are seen as important considerations for the food sector in particular, above and beyond the price of energy.

Within the food sector, many specific operations such as abattoirs have issues of disposal of wet biomass waste. This can cost money to deal with, but also lead to methane emissions (a strong greenhouse gas) from decomposition if not flared or utilised for energy.

In contrast to the food sector, many other aspects of manufacturing have been declining in Australia and an increasing cost of gas would clearly add pressure in this regard.

These results are interpreted as temperature of the water / steam working heat transfer fluid rather than the necessarily lower temperature of the end use. Traditionally, gas fired systems allow a comfortable margin between temperature of steam raising and temperature of use. This makes heat exchange surfaces smaller and allow reduced fluid flow rates and since gas boilers have only a small performance penalty with temperature, it comes at little cost. The least risk technical approach is to maintain the same steam / water temperature conditions when switching to renewable sources. Revising it downward would require modification to the heat exchangers at point of use. This approach as greatest impact on solar thermal solutions as requiring a higher temperature could require a more complex and expensive system. A full systems based investigation would be recommended to an individual user, however the conservative approach is more appropriate for initial screening.

It can also be observed that for the higher temperature categories, steam must be heated progressively from a low feedwater temperature to its final temperature. It is possible to consider doing such heating in stages. In such an interpretation much of the heat requirement identified in higher temperature categories could be provided at lower temperatures. Technologies could be mixed such that cheaper simpler approaches were used for preheating with the more expensive technologies reserved for the highest temperature stage.

3.5. Locational distribution of gas users

The location of a gas user is the major determinant in the level of renewable resource that is likely to be available and hence whether a renewable energy solution is going to be cost effective.

A key study by CSIRO (supported by the Australian Solar Institute) has examined the locational distribution of energy use by industry and process temperature. *Industrial Energy Usage in Australia and the Potential for Implementation of Solar Thermal Heat and Power* (Beath 2012). The study examined 2,498 sites by location, industrial activity and characteristic process temperature. Key observations included:

"Relatively few industrial sites were present in areas of high insolation that could utilise higher temperature heat directly, but some potential opportunities were identified involving bauxite and laterite ore processing, ammonia production, oil refining and natural gas processing. In areas with moderate insolation, outside major cities, there are numerous sites in the food processing, building products, textiles and wood products industries that could utilise low to moderate temperature solar heat."

In the sites using process heat in the range 50 – 300°C, shown in Figure 12, the large mineral processing / chemicals sites are the Alumina refineries that have been discussed previously. A large number of smaller sites in the textiles / timber / paper or food processing can be seen in regional areas where solar or biomass resources could be sufficient to make a viable contribution.

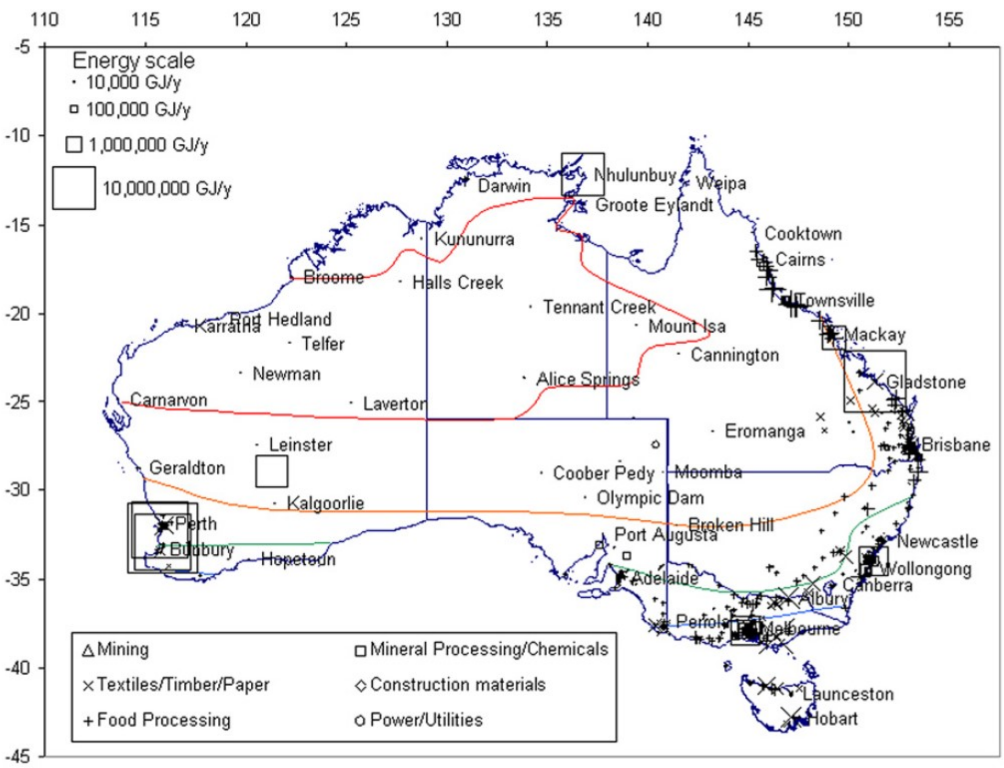


Figure 12. Industrial sites using process heat between 50°-300°C (Beath 2012)

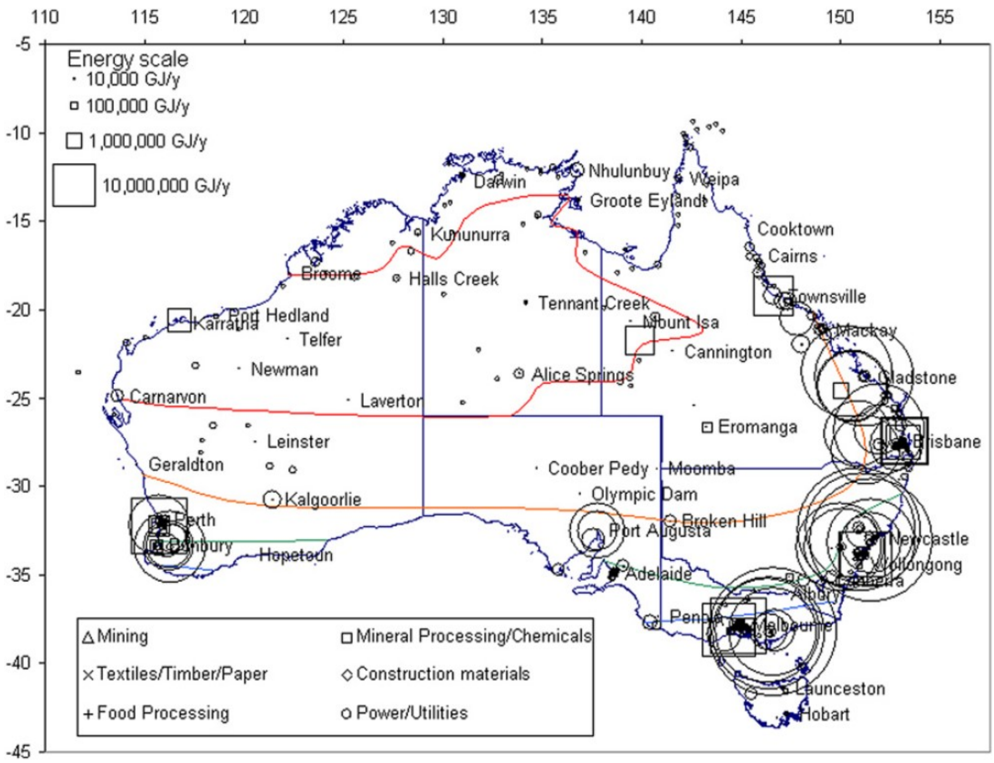


Figure 13. Industrial sites using process heat between 300°-800°C (Beath 2012)

In the 300 – 800°C range, shown in Figure 13, most of the large power generation sites are coal fired power stations that are not relevant to the present study. The smaller / medium sized power generation sites would be gas based (eg Kalgoorlie and Alice Springs). Many of the mineral processing / chemicals sites are current gas users and include both the large alumina refineries and ammonia plants.

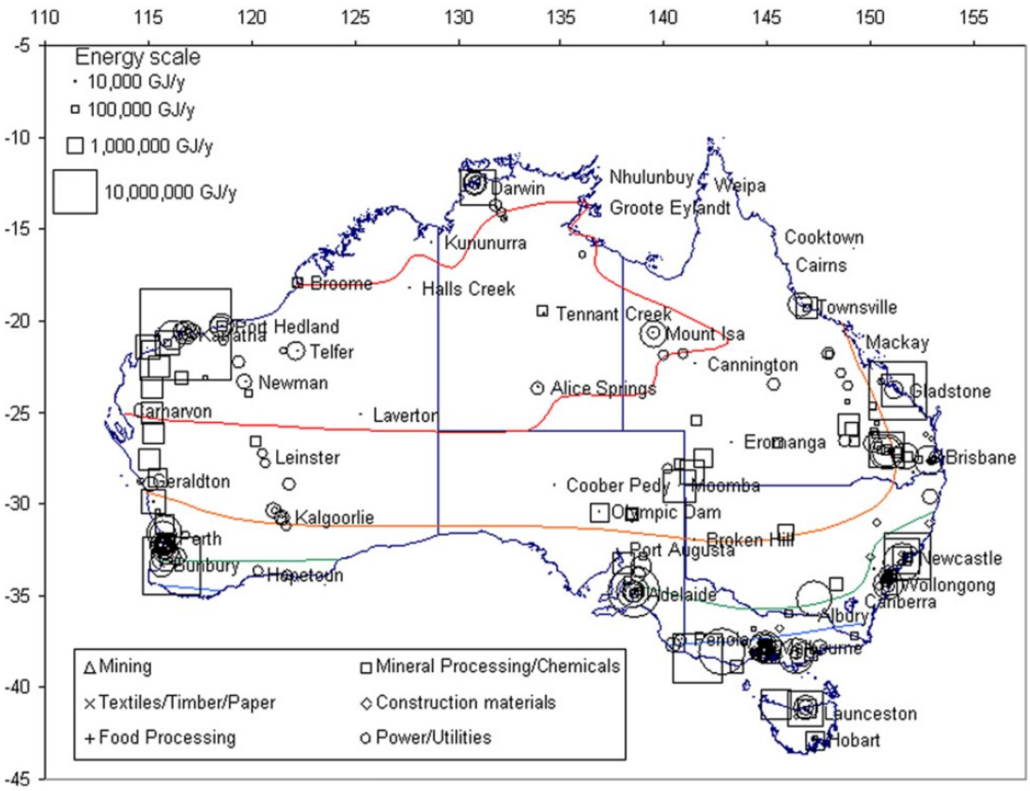


Figure 14. Industrial sites using process heat between 800°-1300°C (Beath 2012)

In the 800 -1300°C range illustrated in Figure 14, a combination of Alumina calcining, large chemical plants and upstream oil and gas processing are largely responsible.

3.6. Present and future cost of gas by user

The prices which users pay for gas vary widely, depending on consumption level. A classification commonly used by the gas industry divides customers into three groups: electricity generators, large industrial, and 'mass market'. Mass market is usually defined as consumers using less than 10 TJ per year, which includes all residential consumers and many small business consumers. Large industrial consumers can be separated into those which are supplied through distribution networks and those which are directly connected to a transmission pipeline. As a generalisation, this last group includes the very largest users, but the separation between the two groups of large consumers is somewhat arbitrary, because it also depends on the extent of the transmission pipeline system in each state. Most electricity generators are connected directly to the transmission pipeline system. Overall, electricity generation currently accounts for just under a third of total gas consumption in eastern Australia, but has been excluded from the scope of this study.

Prices paid by all consumers include the wholesale or commodity cost, i.e. the 'wellhead' price, including processing costs, and the transmission cost. Customers connected to distribution networks also pay for distribution and smaller customers also pay a retailing cost. The larger the volume consumed, the smaller the $/GJ contributions paid for distribution, all else being equal. The majority of distribution network costs are borne by mass market customers, who therefore face much higher total prices per GJ than electricity generation and large industrial customers.

The inclusion of distribution costs means that the structure of prices for mass market customers is markedly different from the structure of prices for large industrial customers. The latter typically pay a flat rate per GJ consumed, under a contract with several years duration, negotiated between buyer and seller. The (relatively small) transmission and distribution cost component is location specific, it depends on how much of the total network is being used to transport gas from the wellhead/processing plant to the user.

Mass market customers, by contrast, pay against tariffs which have the following structure:

- A supply charge, specified in $/day and typically set at levels which equate to an annual cost of between $200 and $300.
- A variable (per MJ consumed) component separated into several blocks or tranches, with a decreasing price per MJ at higher consumption levels.

Residential consumers are typically billed quarterly and business consumers monthly. The total price paid in each bill is based on the consumption level during the period covered by the bill. This block structure is set by the various network businesses and applies to customers supplied through each business' particular network. Consequently there is considerable variation around Australia in both the consumption volumes covered by each block, and the relative prices applying. Invariably, however, the first block price is higher, sometimes much higher, than the prices of subsequent blocks. This complex structure means that the marginal cost of gas consumption can vary widely between customers, depending on their level of consumption. For all residential customers, though probably not for the majority of small business (commercial and industrial) customers, the marginal cost will vary between summer and winter, because of the marked seasonality of demand for space heating, which is the major residential use of gas. This block structure is one of the major challenges for renewable energy substitution. A situation where a renewable solution only provided partial substitution may be competing with only the lowest marginal cost of gas rather than the overall (higher) average cost of gas to the customer.

There is much less transparent public data about the structure of gas prices than there is about the structure of electricity prices. There is no equivalent of the AEMC reports on residential price trends, NSW and WA are the only jurisdictions which continue to regulate retail gas prices, and only NSW does so in a transparent manner.

The wholesale gas market in eastern Australia is undergoing a somewhat turbulent transition from price levels set by the balance of supply and demand within the purely domestic market to levels aligned with export parity netback levels at the new LNG plants at Gladstone in Queensland, aligned to opportunity cost. In other words, prices at gas processing facilities in eastern Australia are likely rise to levels equal to the price being paid at input to the LNG plants in Gladstone, less the cost of transmission from the processing plant to Gladstone. At present there is a relatively small number of gas processing locations in eastern Australia outside the coal seam gas areas of Queensland. There are three locations in eastern Victoria, the original Exxon-BHP plant at Longford (by far the largest), and two in south west Victoria. There is one at Moomba in far north east SA and six small plants in south west Queensland, some of which are not currently operating. As the LNG plants come on stream from 2015, much of the gas produced through Moomba and the south west Queensland plants will flow either to Gladstone or to large domestic consumers in Queensland. Wholesale prices in the four south east states will therefore largely be set by the producers in Victoria. In other words, the wholesale component of a consumer price will tend to equal the price ex-Longford (the major Gippsland gas processing plant) plus the cost of transmission to the bulk supply point. A separate issue for gas users will be the willingness of gas producers to retain gas for the domestic market, if secure high price contracts are available for exports. This will be an issue especially if exporters are faced with shortages of gas to meet contracts.

Domestic market wholesale prices underwent a similar transition in WA several years ago, but are constrained by the domestic market gas reservation policy of the state government. This is now being re-considered. Data on the current levels and likely future trends of wholesale prices were obtained from various sources, including the *State of the Energy Market* (AER 2013), the *Gas Market Report* (BREE 2013) and the *Scoping Study on the Economic Impact of High Gas Prices* (Marsden Jacob Associates 2014). There is considerable variation between the various reports and projections in both the precise timing of the expected price increase and the level ultimately reached. In general terms, however, wholesale prices are projected to rise markedly over the next few years to a new higher but stable level. Each report projects modest differences in both the rate of increase and the final level, related, for the reasons explained above, to distance from Gladstone: faster and higher in Queensland than in Victoria, with NSW and SA in between. However, the differences between each report are greater than the differences between markets in each report.

Another important feature of gas pricing is that large consumers normally enter into contracts of several years duration and usually also have several different contracts, with different start and end dates, to cover their whole requirements. When over the next few years, and to what extent, large consumers are exposed to the new higher prices will depend on the details of their individual contracts. Some, whose former contracts have all recently expired, are already paying much higher prices, while others, whose contracts mostly have a year or two to run, are still paying quite low prices.

For smaller commercial and industrial consumers, the wholesale cost forms a smaller proportion of their total price than it does for large consumers, because they also pay distribution costs. Analysis of the standard tariffs, which most gas retailers offer for residential and small business mass market customers, was used, together with more detailed information provided by the NSW Independent Pricing and Regulatory Tribunal (IPART), to estimate the approximate size of network and other cost components faced by smaller consumers. For both small business and residential consumers, distribution costs equal half or more of the total price paid in every state. Gas distribution costs have been increasing steadily for over a decade. Further significant increases were passed through in regulated distribution cost changes in new prices introduced from 1 July 2014 in most states (distribution costs in Victoria change on 1 January). For small consumers, therefore, the wholesale cost increases have a much smaller relative impact on the total price paid. Distribution costs are less for larger business consumers, as are retail costs, so that wholesale prices are therefore a proportionately larger share of lower total prices. In other words, this group of large consumers, are more exposed to wholesale price increases than small consumers, but less than the very large consumers. It is the views of the very large transmission connected consumers which have tended to dominate the recent public discussion of gas prices.

In this context, finally, it is relevant to note that the general expectation, with which the author's concur, is that gas network cost increases are likely to moderate substantially from now on. This will vary geographically, however, depending on the business strategies pursued by individual gas network businesses. The overall expectation is that residential and small business gas prices will increase further over the next few years, driven by the steady increase in wholesale prices, but little or no further increases in distribution costs. No significant price decline is expected in the short to medium term. Perhaps after 2020, these small consumers may see modest price declines, after wholesale prices have stabilised and distribution costs start to slowly decrease as the high capital expenditures incurred over the last few years gradually move out of the regulatory asset base.

For larger consumers, paying a smaller distribution cost component, the impact will be smaller in both absolute and relative terms, because wholesale costs are a larger proportion of the total price. For very large consumers, the wholesale opportunity cost will dominate, and this will be driven by international LNG prices and the particular circumstances of the contractual relationships between the LNG plants and their customers in Japan, Korea, China and elsewhere. These factors are, of course, extremely difficult to predict.

Relative to 2014 price levels (excluding the now removed carbon price component), the projections are for average gas prices to increase as shown in Table 13. In 2018, as in 2014, the overall level of prices is highest in NSW and lowest in Victoria, with SA in between. These trends are broadly consistent with a reference in the recent Deloitte Access Economics report (Deloitte 2014) of contracted wholesale prices currently at levels around $8.70 per GJ

Table 13. Suggested near term gas price increases.

State	Medium size consumers			Large transmission connected consumers		
	2014	2018	Increase	2014	2018	Increase
NSW	$13/GJ	$15 - $16/GJ	18%	$9/GJ	$11 - $12/GJ	30%
VIC	$7.50/GJ	$10 - $11/GJ	40%	$5.9/GJ	$9 - $10/GJ	52%
SA	$11/GJ	$13 - $14/GJ	23%	$8.9/GJ	$11 - $12/GJ	27%

There is insufficient detailed data about the makeup of current prices in the other states to prepare equivalent projections for Queensland, Western Australia and Tasmania. BREE data suggest that in Queensland black coal is relatively more important, and gas less important than in other states as a source of thermal energy for medium size manufacturing businesses. Finally, it is important to appreciate that 2014 price levels already incorporate levels of wholesale costs appreciably higher than two or three years ago.

The discussion needs to end with the caveat that the only certainty around future gas prices will be increased uncertainty. During the period of this study international oil prices have unexpectedly fallen by half. Most commentators do not expect them to stay at such low levels however there does not appear to be any consensus on when they will rise again to early 2014 levels. International LNG prices are linked to oil prices both indirectly via demand and also directly via contract terms in some cases. The low price of oil is having a major impact on the oil and gas shale fracking sector in the US, the extent to which the US will be a player in LNG exports in coming years and the effect that would have on prices is another source of uncertainty.

3.7. Summary

Australia's consumption of gas in 2012-13 was approximately 1,400PJ. Of this slightly under half was consumed by the industry sectors which are in the scope of the present study. The industrial users can be categorised between mass market consumers, being those connected to the gas distribution system and large users being those that are directly connected to transmission pipelines. The mass market users pay considerably more for their gas than the large users who see close to the wholesale price. Small mass market users can pay similar prices to residential customers.

Food related sectors dominate in the mass market users, the large user segment is dominated by metals, minerals processing and chemical production.

Gas is used largely as a source of process heat, frequently via water / steam as a heat transfer mechanism. Direct heating in ovens also occurs and chemical industries use it as a feedstock as well as a heat source. Classification of use by temperature shows a spread between temperatures less than 150°C to over 1000°C. If the actual end use temperature is considered rather than the temperature of conversion in boilers, the fraction of energy used at lower temperatures increases.

Many industrial gas users are in regional areas. Whilst there is not a perfect correlation with the location of renewable resources, it is sufficient to suggest there is a strong technical potential for renewables to replace gas.

The increased capacity of LNG export facilities in Australia is driving demand for gas and is widely expected to lead to domestic prices that are the 'net back' value from the international price. This is predicted to be around $11/GJ by 2018 for large customers and more for smaller customers. There is a great deal of uncertainty around this due to unknown future developments in oil price and the level of international LNG supply from other producers.

Many user's gas contracts are structured with a supply charge and energy tariffs on a sliding scale that reduces with consumption. This can work to make the business case for a renewables solution more challenging.

4. PERSPECTIVES OF GAS USER STAKEHOLDERS

4.1. Manufacturing sector view of gas price impact

This section summarises informative alternative views on the future of gas pricing, with the end result closely consistent the position identified in Chapter 3.

A recently released study for Australia under the prospect of rising gas prices *Gas market transformations – economic consequences for the manufacturing sector* (Deloitte 2014) is very relevant to the present study.

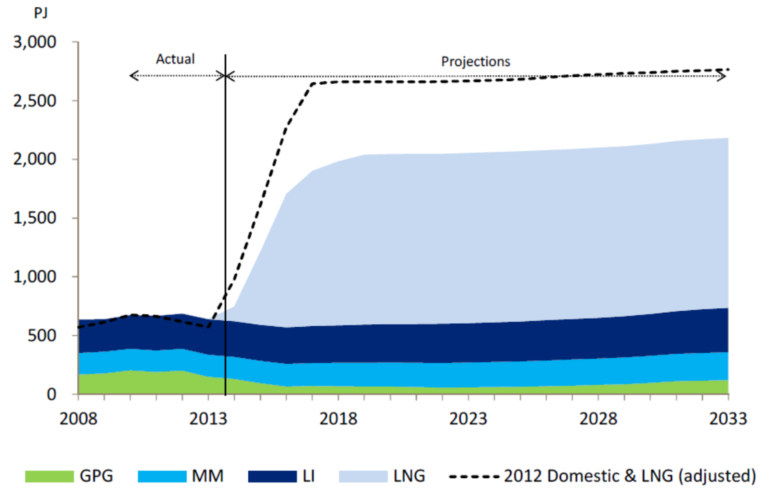
The project consortium comprised:

- The Australian Industry Group
- The Australian Aluminium Council
- The Australian Food and Grocery Council
- The Australian Steel Institute
- The Energy Users Association of Australia
- The Plastics and Chemicals Industries Association

The transformations in the gas markets are described differently in terms of the East and West coasts. On the East coast it is the development of new LNG export facilities in Gladstone which will cause gas prices rising to international levels also driven by a constrained gas supply. In the West the LNG export industry is well established however there is reference to *"…expected to rise strongly to oil-linked LNG netback parity as long term legacy contracts under the NWS State Agreement expire"*.

Previously East coast gas averaged $3-$4/GJ. Oil linked international LNG contracts for customers such as Japan are reported to be $14 -$16/GJ and the 'netback' price implied by this, ie the implied feed price to the LNG plant is $10 -$12/GJ. Effectively this is the current opportunity cost for gas that is already impacting supply contracts domestically. AI group is quoted as surveying gas using businesses on the East coast and indicating current contracting prices average $8.72/GJ.

It is not simply the presence of an export LNG facility that drives prices up but the relative supply versus the demand level that the facility adds. It is apparent that East coast supply will struggle to meet the combined demand (see Figure 15) and hence close to full international netback prices might be expected. The actual level of supply will be strongly determined by the ongoing development of unconventional / coal seam gas resources.



Source: AEMO 2013, Gas Statement of Opportunities
NB: AEMO's 2013 projections do include Arrow Energy
GPG refers to Gas Powered Generation, MM refers to Mass Market (residential and commercial)_LI refers to Large Industrial

Figure 15. Projected domestic and LNG demand for East Coast (Deloitte 2014) (AEMO 2013)

It is reported that in the AI group's survey of gas using businesses, of those looking for new supply contracts:

- Nearly 10% could not get an offer at all,
- One third could not get a serious offer and
- One quarter could get an offer from only one supplier

In the West, LNG exports have run for some time, however state government arrangements for domestic gas reserves have protected WA consumers from international prices. These date from 1979 when the North West Shelf was developed and was underpinned by state government contracts to buy gas, with additional amounts reserved for domestic use. The result has been low gas prices in that state and consequently it is now the most gas use intensive state. Historically prices in the West have averaged $2-$3/GJ but with many legacy contracts now coming to an end and government policy around domestic reservation uncertain, future prices in WA are likely to be much higher but are very uncertain.

As noted in the previous section, modelling of future east coast gas prices by both SKM and IES is discussed, and vary considerably but do agree on prices rising rapidly by 2015 - 16 and getting to the order of $10/GJ. The IES analysis is interesting as it suggests major variation between states with Brisbane and Adelaide experiencing the highest prices. For the West a more progressive price increase is projected and it could fall between a low price scenario of around $8/GJ in 2015 to nearly $11 if full net back pricing is reached.

Five company case studies are presented:

- Orica Australia – uses gas as a chemical feedstock to produce ammonia (used in explosives and fertilisers) and sodium cyanide (used in gold extraction)
- Rio Tinto Alcan – uses gas for heat and steam to produce alumina, which is the key input into aluminium
- Goodman Fielder – uses gas for heat and steam in its bakeries to produce bread and baked products
- Australian Paper – uses gas for heat and steam in its pulp and paper mill
- GB Galvanizing – uses gas for heating in its 'hot dip galvanizing' process, which is used to protect steel from corrosion

Ammonia production is claimed to become unprofitable at a $9.50/GJ gas price and an existing plant would be shut down (ie not even the marginal cost of production can be covered).

For Rio Tinto it is claimed that Alumina production will be uneconomic for a gas price greater than $7 - $8/GJ. Alcoa's alumina activities are also referenced. In an Alumina refinery, gas is used for the Bayer process (steam driven), Calcination (1100°C) and electricity generation.

Goodman Fielder' bakeries use gas 49% for ovens, 38% for steam and 13% other uses.

Maryvale pulp and paper mill is discussed and it is noted that more than half of its energy needs are met through onsite generation using black liquor. The mill still needs 6.6PJ/yr of gas for boilers and 1PJ/yr for a lime kiln. The combined 7.5PJ/yr makes the mill one of the largest gas consumers in Victoria. Fuel switching to coal for the boilers is discussed but against that is a suggested high capital expenditure and 6.5 fold increase in GHG emissions (although with no carbon price currently applicable in Australia, this may no longer be a consideration).

A much earlier study by Energetics (Annas et al. 2005) deals with industrial process heat and incorporates views on pricing.

The observation is made that the actual cost of energy to a business is strongly linked to the size of the business and that there is a correlation within industry divisions as some are characterised by a few large businesses but others by many small businesses. Specific cases are listed in Table 14.

Whilst gas prices have changed considerably since then and vary from state to state, it is likely that this relative variation from sector to sector is indicatively reasonable.

A useful observation is made about gas prices relative to remoteness, the example offered is that gas prices in Mildura were at least twice that of most other areas in Victoria.

Overall in Victoria they suggested that (in 2005) 11PJ out of 92PJ of gas was supplied at $6 - $19/GJ, compared to the remaining 81 PJ at $3 - $5.50/GJ.

Table 14. Energy unit costs by sector (Annas et al. 2005)

Industry Sector	Electricity	Natural Gas
Food, Beverage & Tobacco Manufacturing	$24.35/GJ	$4.86/GJ
Wood & Paper Product Manufacturing, Printing, Publishing & Recorded Media	$19.59/GJ	$3.48/GJ
Petroleum, Coal & Chemical	$17.82/GJ	$2.91/GJ
Non-metallic Mineral Product Manufacturing	$17.73/GJ	$3.75/GJ
Metal Product Manufacturing	$9.85/GJ	$4.48/GJ
Machinery & Equipment	$23.24/GJ	$4.60/GJ
Commercial – includes FGHJKLMN	$26.73/GJ	$6.08/GJ

4.2. Considerations driving gas users

Technology switching is an inherently risky business. While it is dangerous to apply generalisations to the situation any individual business may find itself in, it is possible to identify a series of risk factors and to consider in general terms the nature of the businesses that are swayed more by one factor than another. Decisions of any consequence are assessed by the business based on their individual situation in what can be a complex and highly dynamic environment.

The risk factors considered either consciously or unconsciously by decision makers can be categorised in many different ways. For the purposes of this discussion they are categorised as:

- Business continuity
- Market
- Contractual (supply) risk
- Investment Return
- Future fuel prices
- Technology risk

This represents an approximate ranking from highest importance down. This list is not intended to be exhaustive, nor is it intended to replicate full listing of due diligence categories, which can be quite extensive. The list will be used to outline considerations for businesses in different categories.

Businesses can be categorised into large, medium, small and micro. Various government agencies categorise small businesses as having less than 100 (or 200) employees and large businesses above this. For this discussion we also add the micro category - those with less than

10 employees. It is the general relationship of the business size to the state of planning sophistication, capitalisation, succession planning and access to capital that makes the size of the business a useful indicator of how they may react to a particular opportunity. Small businesses tend to have many competitors, lower business valuations, less access to capital and fewer staff to smooth out year to year and generational succession planning. This limits the level of experimental capital that they can or will employ.

The first three of these risk factors – business continuity, market and technology – are generally considered equally by businesses of all sizes.

Business continuity

Business continuity is fundamental to all businesses. Businesses operate within finite cash flow limits and any interruption to sales creates a critical financial risk which must be planned for. If the planned energy replacement is part of an operation that is central to the business operations, or pivotal for production of a major (perhaps iconic) brand within the business, or even pivotal for a newly developing line of budget products with a promising (or even future reliant) profitable return to the business – then any interruption to this operation may have devastating effects for the future of the business.

Market risk

Market risk is deeply entwined with business continuity; If a product is missing from the supermarket shelves for a few weeks then the previously loyal customer base may gain a taste for the competitor's product. For businesses with less developed marketing plans or brands, loss of continuity of supply in a competitive market may mean that they lose a single major customer forever, and this can be lethal. Thus the potential of a change to production methods to alter the nature of the product they produce and the potential interruption will be carefully assessed by businesses of all sizes.

Contractual risk

Once a business has decided to move on a technology option the choice of partner and the correct choice of contractual arrangement is exceedingly important. No realistically achievable amount of damages, withheld payments or consequential loss suits will substitute for the seamless performance of an installation contract. Early exit or contract default is not a satisfactory option either as this leaves the business behind time, cash poor and with resources stretched as they battle the old supplier and try to engage new ones. Questions asked include; *Is the technology supply company well known and trustworthy with a history of good on-time applications in this space? Do they have a culture which matches and integrates with yours?* Large businesses may have a greater capacity to explore these questions but they are equally important to both categories where a major project is involved.

Investment return, future fuel price and technology risk factors are treated differently by small and large businesses. Businesses tend to be valued on a multiple of future years earnings. The multiple reflects the observer's view of how long they can trust in the stability of that earnings potential. This attitude is clearly reflected in stock market pricing. Blue chip companies with long histories and attractive future risk factor analysis command a low earnings per share, interpreted by some as an indication that the business is viewed as having say a greater than 20 year assured lifetime. Publicly listed companies in a more volatile condition may be estimated as a 10 year assured lifetime etc. This fairly simplistic view continues into the small business arena – but the judgements are often more harsh. A recent review of small business pricing in Australia indicates that business sale prices for micro businesses are usually at a 1-3 year earnings multiple. This much lower multiple reflects the realities of the business environment for micro and small businesses.

Investment return

The allocation of resources to change for the future is highly likely to follow this valuation / assured lifetime time constraint. There are few small businesses in Australia that will invest in a major alteration to energy systems that will not pay back in one or two years (excluding end of life replacements). Energy auditors commonly look for >30% IRR before promoting opportunities to clients and notably this translates to payback in this < 3 year time frame. Large businesses on the other hand will sometimes consider changes that command only a 20% IRR - or even as low as 5%, where that change has other synergies with their operations (increased production levels or additional labour savings in other areas) or corporate aims (such as a 'GHG neutral' marketing decision). A small business will seldom entertain a major technology change with an IRR as low as 20% and almost never 5% unless there are other mission critical factors involved. If they can obtain access to capital they will often get a greater return from investing in increased marketing or by placing funds elsewhere.

Future fuel prices

Future fuel prices affect the ability of the investment to deliver the anticipated investment return. An adverse move in pricing may mean an increase in costs that may not be borne by competitors and cannot be passed onto the customer. This risk could work for or against renewable energy options.

Technology risk

Technology risk is essentially filtered through the same lens from a whole of business perspective (market and continuity effects) but it also falls under a number of factory floor, production cost and supplier trust considerations. Questions asked include:

How well known is the technology? How has it functioned for others? How likely is it that the two months installation time will turn into 6 months? Did you hear about company X who put one of *these in and could only get their production ovens to 87 when we all know that you must have 89 for good quality control on this process (and what's more they struggled to get to 87, losing two hours warm up time in the process every time they start a new machine up)? Can we leave our existing system intact until the new one is commissioned to mitigate these risks?*

These are all examples of client questions based on actual experiences in technology replacements. No business small or large wants to be on the bad end of a problematic technology experience.

These last two factors also promote a different consideration for large businesses generally. Businesses with greater future planning capability, alternative business lines with cash flow of sufficient size to help get over hurdles, with longer histories to underpin capital raising and investor confidence for unexpected events and with a diverse and competent workforce can take on more risk in this area than a smaller business.

Combining these last three risk factors indicates why larger businesses will take on more ambitious projects if it fits with their long term plans. A major Australian business with a stable market may be tempted to look at a new technology even though there are uncertainties around its application and a low(ish) rate of return where it has other synergies with its long term plans. It might be expected to have the workforce, or be able to hire the workforce, that will enable detailed management of technology assessment and supplier relationships, to have the capacity and long term planning to undertake pilot trials and to otherwise mitigate risks, and to have the capital and strength and diversity of cash flow to enable it to make this happen and to ride the storm if the project does not proceed. A small business will generally not be able to raise the capital in its own right for such a venture. It will seek more established technologies (even though they may be 'new' they would be expected to have a longer track record), lower risk and faster payback.

The sectors of Table 11 include almost entirely users in the manufacturing sector. These will be composed of businesses stretching across both the large and small categories noted above.

4.3. Engagement with users and stakeholders

Consultations were held with representatives of two national industry associations, the Australian Industry Group (AIG) and the Gas Users Association.

For the AIG, brief background material was provided and two of their senior executives with significant experience with their members along with broader industry experience were interviewed. For the Gas Users Association three direct industry contacts at CEO or senior level were interviewed. These industry participants were major Australian energy users. Some had made significant and thorough investigations into renewable and other alternative energy sources – biomass, wind, solar PV, concentrating solar and gasification.

Following introductory material delivery all participants were invited to lead the discussion in identifying the major issues involved in such decisions from their own perspective. Discussion was then targeted to ensure coverage of at least the issues noted above.

Broadly – the points raised in our own discussion above were confirmed by the stakeholders along with a number of useful additional points which are discussed below.

Technology risk and return on investment were the most frequently identified points.

Technology Risk

There was a requirement that the technology to be used is trialled and tested, proven in not just a few but a significant number of other installations. Twenty to thirty functional installations of the technology being considered (worldwide) was seen as necessary by one of the business interviewees. This was seen as significant for businesses at all levels.

The concept of redundancy was the most notable addition to technology risk discussions. Retaining the existing energy source during installation of the new and being able to cut back and forth during the commissioning period and beyond was seen as one way to achieve this. Gasification was noted as one example where the original gas supply needed to be kept alongside the gasification plant. Alternatively where there are multiple production setups or multiple product lines there was an opportunity to test one line first, hence reducing overall risk. Keeping the old energy source as a backup has significant cost implications – especially in regards to the cost of major gas pipelines.

Large systems were seen as more difficult because of the lack of flexibility to experiment.

Intermittent energy producers (wind and solar) were seen as particularly problematic for larger energy users.

Business continuity

Notwithstanding the points on redundancy above (used to ensure continuity) process continuity was high on the list of factors for all interviewees. One particularly powerful example was of a glass furnace, subject to a $100m cost and 6 month recovery time from failure.

An example of unseen risk, even following technology proving, was given as the waste to energy plants in Germany where their technical success (alongside improvements in recycling) has led to a shortage of waste in the market – leading to increased energy costs from the need to transport waste much greater distances.

The ability to continue in the face of environmental challenges was another point noted by business interviewees. Proven technologies with a strong history helped, however this was tempered with a recognition that new technologies may be part of future competitive industries and at some point risks may need to be taken to remain in business.

Market

For another of the business interviewees a strong reliance on rapid supply was a key element in competing with overseas imports. Any risk to process continuity was a risk to their strong market position.

Contractual (supply) risk

Business interviewees had little risk appetite in engaging providers directly for energy technology supply. There was a general desire not to own and not to manage energy supplies, expressed quite strongly. They did not want the problems of capital, procurement, management and employment and preferred to engage others to take on these risks supplying them with steam, heat etc at the appropriate conditions. High levels of confidence were required (see above note re 20 to 30 prior plant experiences).

Investment Return

All real world examples were in agreement with the principles outlined above. Maximum payback terms of 4 to 5 years (20% IRR) were suggested with most requiring a 2 to 3 year payback (30-50% IRR). Special industries and their suppliers were provided as an example requiring one year payback. Longer payback terms were associated with also achieving other strategic objectives (both national and international companies).

Two examples of long paybacks being acceptable, were given by business interviewees – one where there was a perceived requirement from a global parent to maintain operations (hypothetical) the other where a payback of 10-15 years had been accepted on a major equipment commission. Digging deeper on this second example identified the centrality of the commission to the business as well as increased reliability as driving factors. In this instance it was also significant that they had contracted the operating risk and the capitalisation out as an energy supply agreement to another party – so they had not in reality accepted an internal investment at this rate of return.

Future fuel prices

The issue of future fuel prices was raised by all interviewees – both affecting new equipment and some established equipment. There were some who had invested in cogeneration, for instance, but who could not see the cogeneration installation continuing beyond the life of the current gas contract. Interviewees covered a spectrum of those who had successfully established new gas contracts at acceptable prices for the near future and those who were unable to at this time and were deeply concerned about the effect of rising gas prices on the future of their business. Interviewees noted that significant bargaining strength issues were associated with energy pricing – although of course not all had this power.

Impact of gas supply contracts

Section 3.6 has discussed in general terms the nature of gas contracts with connection charges and tariffs that vary by blocks of energy consumed and a range of other factors that mean that a reduction in gas usage may see a much smaller marginal cost of gas saved than the average cost of all gas delivered. A key stakeholder has provided the commentary in Table 15 on other complicating factors flowing from gas contract terms for large users (Thong 2015).

Table 15. Possible impacts of changing gas use flowing from contract structures (Thong 2015).

Typical (relevant) gas contract term	Impact of change of gas use
Supply conditions - firm/interruptible	Industrial users will likely seek gas on-demand in case of failure or intermittent supply from alternative.
Gas price	Gas supply price will be affected by the volume and 'firmness' required.
Price redetermination	Current contract needs to be re-opened and may allow supplier to re-price higher and industrial user loses the balance of contract benefit if they have a favourable price negotiated some years ago.
Annual contract quantity	Annual contract quantity will be reduced.
Take or pay (TOP) component	Take or pay component will need to be reduced, lowering certainty of demand profile for supplier.
Banked gas (TOP not taken)	If banked gas is a term in current contract, industrial user could bank unused gas instead of opening TOP terms but would expect a maximum volume allowable.
Maximum daily quantity	Maximum daily quantity will be reduced, presumably impacting gas price.
On sell rights	Relates to bankability of gas and whether availability to on sell banked gas. This could be helpful to an industrial user if favourable conditions prevailed.

Commentary on forward gas price assumptions

There are also strong suggestions that high prices will contribute to the closure of some large manufacturing operations, which would reduce demand and possibly limit the price rise seen by other users. High prices and unmet demand do of course incentivise gas producers to expand production, however even if it were practical, there is no incentive for gas producers to increase production to a point that a surplus of domestic supply drove prices down below export parity. Over the months that have elapsed since the first consultations of this study, it appears that there has been some easing in the manner in which users see the future situation. Possibly some consensus is forming that the combination of market forces will see a levelling of the wholesale price at around $10/GJ.

Other matters noted by stakeholders

- Often the motivating factor for technology change around energy source was “90% around flexibility and features of new machines” rather than the energy efficiency per se.
- Two of the large energy users saw themselves as well informed and had no perceived requirement for industry guides, while one could see benefits in them for staff at all levels.

4.4. Summary

Public statements and studies from large gas users confirm considerable concern at the trend to higher gas prices driven by the expanding LNG export market. Beyond this it is reported that many are having difficulty even finalising gas supply contracts.

At face value this situation does make the business case for renewable energy options stronger. Possibly the biggest advantage that renewables can offer is the removal of uncertainty. If the high capital cost can be financed and risk of equipment failure mitigated, the uncertainty in annual operating costs should be largely removed.

The risk factors considered either consciously or unconsciously by decision makers can be categorised as:

- Business continuity
- Market
- Contractual (supply) risk
- Investment Return
- Future fuel prices
- Technology risk

These must all be addressed if a renewable energy option is to prove the preferred choice.

5. TECHNOLOGY OPTIONS

5.1. Overview

The technically possible routes to direct substitution of renewables for gas within the boundaries of an existing industrial operation are summarised as follows.

5.1.1. Process heat

Process heat is clearly the main current use of natural gas that can be targeted for replacement by renewables. Process heat can be provided by:

- Solar thermal technologies, with the technology solution optimised for the temperature range needed. For example temperatures in the range 80° to 150˚C can be provided by simple arrays of evacuated tube collectors. At the other extreme, temperatures of over 1000°C are only possible with point focus concentrators, ie tower systems or dishes. In between a range of options are available including trough and linear Fresnel concentrators.
- Combustion of biomass or solid waste. Combustors are typically combined with steam boilers and could so substitute for any gas use for process heat in the range 100° to 350°C.
- Gasification of biomass or solid waste, to produce a renewable gas mixture that can directly replace natural gas in appropriately retuned gas combustion systems.
- Solar thermal driven gasification of solid materials provides an identical product to conventional gasification, but with the final gas being partly solar derived and partly derived from the original solid in energy content.
- Landfill / digestor gas can provide a direct replacement of methane from natural gas. Landfill gas capture for gas engine power generation is now almost ubiquitous on significant landfill sites in Australia. In addition current gas engine systems offer the potential for conversion to capture exhaust waste heat and so operate in co-generation mode. Anaerobic digestion in tanks or covered ponds is a proven approach and can be fed with wastes such as sewerage, effluent from operations such as feedlots or abattoirs.
- Direct renewable electricity generation (via for example solar PV or wind systems) can be used to operate electric heaters or heat pumps. Electric resistance heaters are simple and effective up to very high temperatures however the overall economics are limited by the efficiency / cost of initial electricity production. On thermodynamic grounds, a better use of electricity when heat is desired, is a heat pump.
- Use of renewable electricity to produce hydrogen by electrolysis that is then substituted for natural gas use for combustion. This approach is unlikely to be economic because of the overall low efficiency and high capital intensity. It is however worth considering in

situations where a renewable generation technology designed for electricity production, is periodically curtailed due to lack of demand or unfavourable instantaneous tariffs. In such instances, diversion to hydrogen production may be a rational operating response.

- Geothermal heat sources. There are a range of interesting geothermal prospects under investigation. Most attention has been paid to applications in renewable electricity production. However, underground resources range from temperatures around 100°C up to 250°C. A significant number of process heat applications may be addressed within this range.

5.1.2. Fuel for power generation

Gas fuel replacement. As for process heat, any process that produces a suitable combustible gas could in principle be used to substitute either whole or in part, for the natural gas fuel used in gas engines or turbines. This includes

- Gasification of solid biomass or waste or
- Landfill gas
- Digestor gas
- Gasification driven by high temperature solar thermal heat

Direct hybridisation is well established and involves combining renewable sources of heat into what would otherwise be gas fired power generation. Gas fired combined cycle plants that accept extra solar heat into the steam cycle are a well-established approach.

5.1.3. Chemical feedstocks

Chemical feedstocks from gas are either pure hydrogen or a mixture of carbon monoxide and hydrogen (syngas). Options in these regards are; biomass gasification; solar thermal assisted processing of biomass or fossil fuel; and direct renewable hydrogen production.

5.2. Natural gas for process heat

With the process heat application so dominant in the opportunities for renewable substitution, it is of value to briefly summarise the features of the natural gas fired approach to heating water or steam.

Gas fired boilers can be categorised as water tube or fire tube boilers. In the case of water tube boilers, as the name implies, water flows in tubes that exchange heat with the hot combustion products. In fire tube boilers, the combustion gases are directed through tubes that pass through a large drum containing water, in a shell and tube heat exchanger arrangement.

While water tube boiler systems can cover all industrial process heat plant requirements lower cost fire tube boilers are typically used for low pressure and temperature applications. Figure 16 shows examples for natural gas fired water and fire tube boilers.

Figure 16: Natural gas fired water tube (left) and fire tube boiler systems (right) courtesy of Weismann Group

The term ‘boiler’ is applied even if the product is simply heated water rather than steam.

With gas combustion able to generate product temperatures of over 1000°C, the temperature (and pressure) of the water / steam produced has little effect on efficiency of the unit.

Efficiencies range from around 80% to 90% depending on the level of sophistication. More efficient boilers have a slightly higher cost. Cost is not very dependent on the temperature and pressure specifications. This is because they essentially only determine the specifications of the tubing, whereas most of the cost is determined by the fabrication process.

For comparison with renewable energy options, costs have been determined as shown in Figure 17 and Table 16. The three data points in yellow are from Pitt and Sherry’s direct project experience and are the basis of the detailed breakdown in Table 16. The data from other reports show a similar size dependence but lower costs.

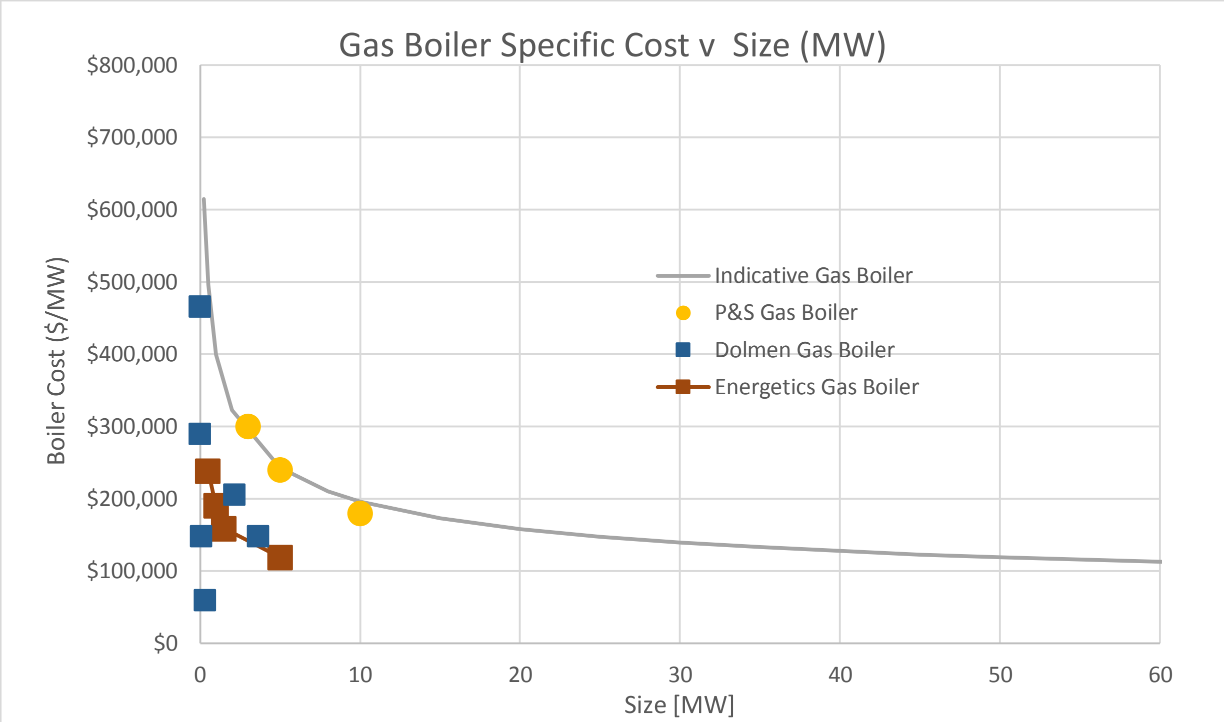


Figure 17. Gas Boiler Specific Cost versus Size

Table 16. Gas boiler capital costs

Size	3 MW	5 MW	10 MW
Steam boiler up to 400°C	$265k	$370k	$550k
Additional for superheated steam	$80k	$111k	$165k
Additional for feed, tanks, pumps, etc.	$65k	$70k	$120k
Boiler Total	**$410k**	**$551k**	**$835k**
Approvals, services, engineering & other installation & reticulation	$492k	$661k	$1,002k
Rounded Total	**$900k**	**$1,200k**	**$1,800k**
Specific Cost	**$300/kW**	**$240/kW**	**$180/kW**

A curve fit of capital cost with a power law dependence on size with an exponent of 0.7 has been fitted to the more conservative directly obtained data of Pitt and Sherry. This curve is used as the basis for economic analysis of biomass options.

5.3. Bioenergy

5.3.1. Technologies

A variety of thermochemical, physiochemical and biochemical technologies are available to convert biomass feedstocks to thermal energy (Figure 18).

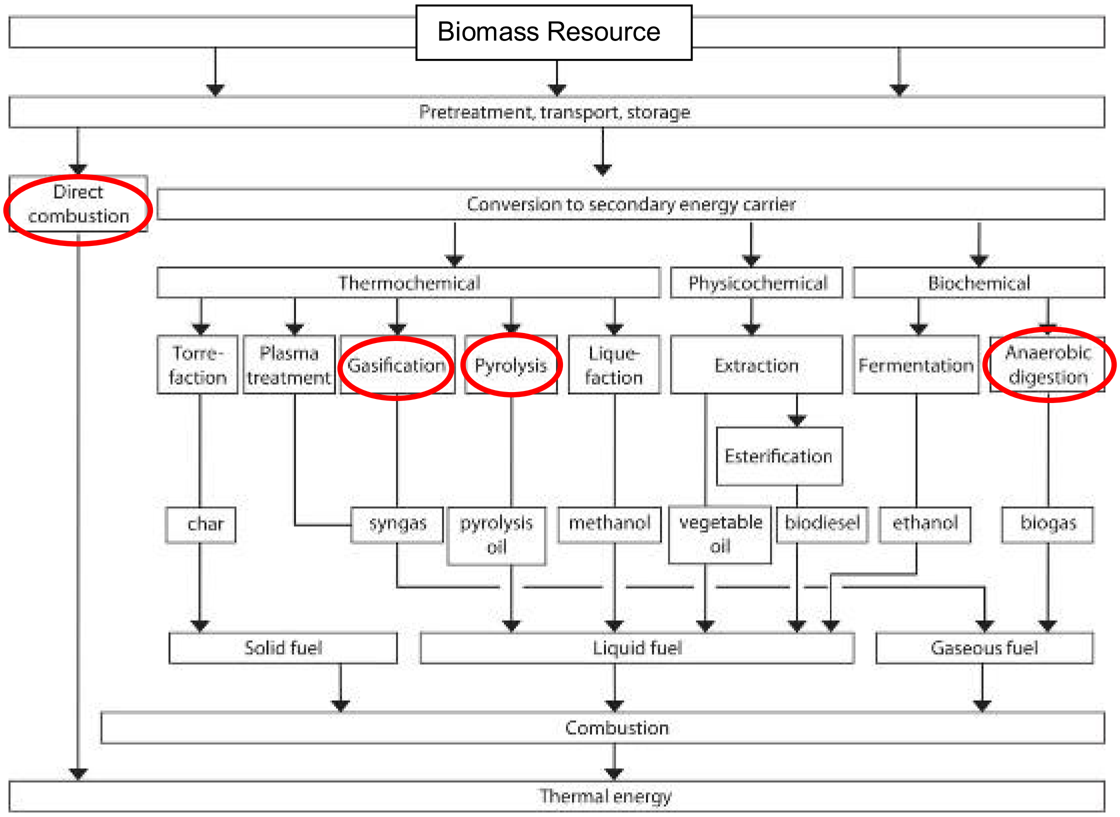


Figure 18: Energy from waste conversion technologies (Kaltschmitt 1998)

The most commonly used technology options to produce process heat from biomass and waste feedstocks are direct combustion, gasification, pyrolysis and anaerobic digestion.

The main technologies which are considered here are:

- Combustion, including
  - grate combustion, and
  - fluidised bed combustion.
- Gasification, including
  - gasification/ combustion for heat and
  - gasification for a combustible gas.
- Pyrolysis.
- Anaerobic digestion.

Feedstocks for energy from biomass (EfB) are varied, and the specific feedstock will affect the overall cycle efficiency as well as the type of technology used. Feedstocks can be solid or liquid, and include wood, bark, bagasse, agricultural crops (eg straw and rice husk), energy crops (eg mallee), and waste products (eg wood or paper waste, black liquor, sewage sludge). Depending on the biomass feedstock, the plant capacity, and the conversion technology, cycle efficiencies for current EfB plants generating electricity vary from 15–35% (Stucley et al. 2012). However, cycle efficiencies for process heat are higher, and range from around 80% to up to 90%.

The capacities of EfB plants range from small industrial heating systems with capacities in the tens of kW, to the world's largest plant, the Polaniec power plant in Poland, which has an electrical output of 205 MW_e, corresponding to a thermal capacity of around 600MW_{th} (GDF SUEZ 2013). However, the comparatively low calorific value of biomass compared to black coal or natural gas leads to relatively high transport costs. Plants larger than 100 MW_{th} are generally only found when co-located with processing facilities which themselves create the feedstock, such as sawmills, paper or sugar production. In such situations cogeneration is common, with much of the electricity used on site, which tends to increase the economic viability of the bioenergy plant. In some case the biomass is densified to increase its calorific value, such as drying and compression into pellets or briquettes. This can assist with transport and handling and the biomass' suitability for existing feed handling systems (such as those set up for pulverised coal). However such densification comes at a significant cost and it is not always an ideal solution for biomass use.

Combustion

Co-firing biomass in fossil fuel plants is of increasing interest worldwide as it is a low-cost option for the integration of renewable energy (Lempp 2013). Depending on the power plant design different biomass integration options are possible, including blending coal and biomass, a biomass boiler in parallel to the coal boiler, designated biomass burners or biomass gasification (Tadros et al. 2009). Worldwide, several reference plants exist that blend solid biomass and coal prior to combustion, such as in the 590 MW_e[7] Avedore power station in Denmark (Stucley et al. 2012), or gasify biomass and burn the raw gas in parallel to the main fuel, such as in the 560 MW_e Vaskiluodon Voima Oy power station in Finland (Metso Corporation 2011). The choice of the co-firing system depends on the feedstock quantity and quality as well as the design of the host plant (Tadros et al. 2009; Lempp 2013). Case studies at utility scale have already been investigated in Australia (Meehan 2013) but while some trials have occurred, co-firing has not been used in Australia at anything like the uptake in Europe.

Currently, grate combustion systems combined with water tube boilers are the most established in the EfB market (Spliethoff 2010) with many thousand operational systems worldwide, and plant capacities ranging from a few hundred kW_{th} to above 300 MW_{th}. There is significant experience with these plants, and a variety of technology suppliers. Some systems have been hybridised with

[7] Note that such a system involves a boiler with a thermal output that is around three times larger than this electrical output.

natural gas to raise feedstock conversion efficiency in plants generating electricity and to improve feedstock flexibility, such as the 28 MW_e Holstebro plant in Denmark (Andersen et al. 1992; Babcock & Wilcox Vølund A/S 2008).

Grate combustion systems

Figure 19: Biomass combustion type boiler during installation and view of the furnace showing a water-cooled grate with ash outlet at the bottom during assembly[8]

Figure 19 shows a conventional grate combustion system. The biomass feedstock is fed onto the grate and primary air is supplied through it to enable the combustion process. During combustion the feedstock moves from the fuel supply side to the ash extraction side of the furnace. The high temperature flue gas generated passes through the furnace and in many cases secondary air is injected above the furnace to increase combustion efficiency. Subsequently the flue gas enters the convective heat transfer area where most of the heat is transferred from the flue gas to the working fluid, dominantly water-steam but also thermal oils. Depending on the boiler design and the process criteria the convective heat transfer area includes economisers to preheat the working fluid, evaporators to turn water into saturated steam, and super-heaters to increase the steam temperature. Radiative heat transfer occurs in the furnace. Many biomass systems have air preheaters downstream economisers increase the temperature of the combustion air and increase cycle efficiency.

Following the air preheater the flue gas passes through the gas cleaning systems, typically a bag-house or electrostatic precipitator and is subsequently released into the atmosphere through the stack. When using contaminated biomass feedstocks, additional flue gas cleaning equipment can

[8] Image courtesy ERK Eckrohrkessel GmbH, Germany

be required, eg flue gas scrubbers, to ensure compliance with emission standards. A variety of wood wastes are used as feed in both Europe and North America.

Two boiler technologies exist, water and fire tube boilers. In water tube boilers the working fluid is inside the tubes and the flue gas outside. Such boilers are dominant in biomass plants as the heat transfer tubes can be easily cleaned and withstand high operating pressures. Fire tube boiler systems operate at lower pressures and typically with low ash fuels. The flue gas and any particles passes through the tubes while the water is in a shell surrounding all heat transfer tubes. Typically, fire tube systems have slightly lower cost due to a more automated manufacturing process but have limitations in regards to fuel composition, fuel flexibility, ash loads, limited steam temperature and pressure, and plant capacity.

Fluidised bed combustion systems

Fluidised bed combustion systems burn the feedstock in suspension by injecting air from the bottom of the furnace. In addition to the feedstock and air an inert material, such as sand, is added. Bubbling and circulating systems exist and they differ in the height of the fluidised bed. In a bubbling fluidised bed system the fluidisation is limited to the lower part of the combustion chamber while in a circulating fluidised bed the feedstock and inert material is distributed throughout the combustion chamber. Unburnt feedstock and inert materials are collected in a cyclone and returned to the combustion chamber inlet. The air velocity is more than 2m/s higher than in grate combustion systems in order to fluidise the fuel. These systems were developed to improve efficiency and lower emissions. The combustion arrangement differs considerably from the grate technology, but the boiler system in which the fluidised bed is integrated is very similar. Various reference plants with capacities exceeding 100 MW_{th} are in operation using a variety of feedstocks, but despite the size of these plants and their technical benefits, they are less mature than grate systems. Fluidised bed technology is suitable for process heating plants with inherently smaller capacities, typically below 50 MW_{th}, and such facilities already exist in Australia, eg 16 MW_{th} plant at a Nestle processing plant in Queensland[9] and three multi-megawatt cogeneration plants at the paper recycling plant on Gibson Island in Queensland, and sugar mills in Condong and Broadwater in New South Wales[10]

[9] http://ecogeneration.com.au/news/gympie_fluidised_bed_boiler/034462/
[10] http://www.northernstar.com.au/news/broadwater-and-condong-cogeneration-plants-sold/2078372/

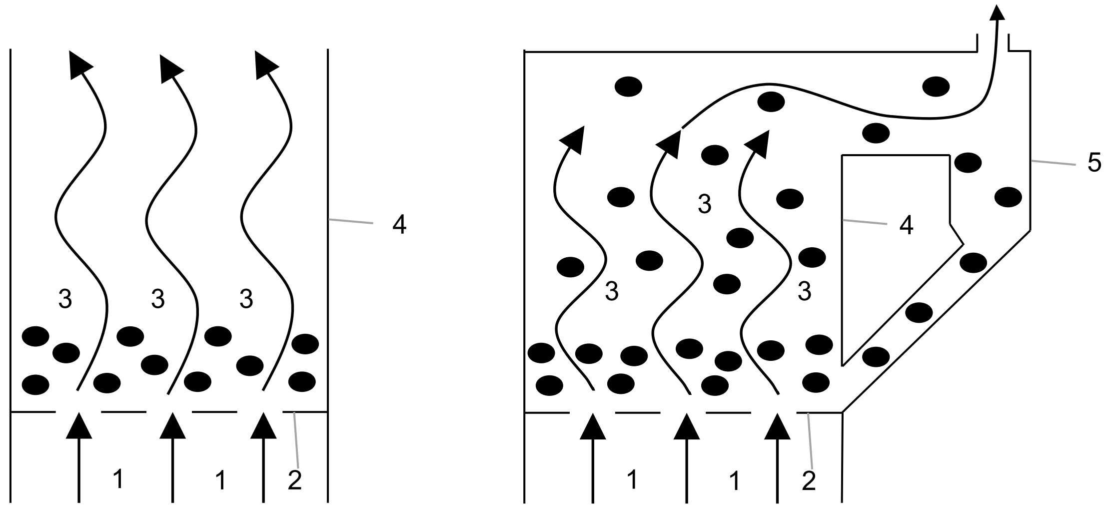


Figure 20: Schematic of a bubbling (left) and a circulating fluidised bed system (right) with air (1) flowing through the injection nozzles (2) fluidising the feedstock and inert materials (3), Furnace walls (4) and cyclone (5) shown indicatively only

Gasification systems

Gasification systems can offer technical benefits over combustion systems, as they produce a synthesis gas that, after suitable cleaning, is compliant with standard gas engines and gas turbine specifications, thus allowing the use of highly efficient electricity generation. Co- and trigeneration is also possible but the overall cycle efficiency would not be higher than in a conventional combustion type plant. Gasification syngas has also been trialled in turbines and combined cycle systems for electricity generation but while several demonstration facilities have been built in Europe and North America no organisation has pursued such pathways into commercial applications.

Gasification technologies are further separated into gasification/combustion and gasification technologies (Lamers et al. 2013).

Gasification/combustion, also known as staged combustion or close coupled combustion, uses gasifiers to produce a raw gas that is burnt in a water tube boiler. The water tube boiler has a similar design to the boilers for grate combustion or fluidised bed systems, (see Figure 21). In the gasifiers solid feedstock is heated and converted at oxygen poor conditions into a raw gas, consisting dominantly of carbon monoxide and hydrogen. Later in the process the raw gas is burnt in a boiler (see 2 in in Figure 20) with additional air to achieve a stoichiometric combustion. A variety of commercial gasification/combustion plants operate worldwide, such as the 140 MW_{th} plant in Vaasa in Finland (Metso Corporation 2011) and the 20 MW_e Weyerhauser cogeneration plant in Uruguay using wood waste[11] as well as the 20 MW_e Fukuyama plant in Japan using refuse derived fuels (JFE Engineering 2011).

Figure 21: Boiler systems with two gasifiers (left) and three gasifiers (right)[12]. Gasifiers; 1, boilers; 2.

Other gasification plants include equipment to clean the produced raw gas to a quality suitable for high efficiency conversion in gas engines and gas turbines. The high efficiency for electricity generation is promising but the technology has not seen much commercial use over the past twenty years, largely due to the complexities involved in cleaning a biomass derived raw gas, eg tar condensation. Only a few gasification plants operate in combination with gas engines or turbines. the 6 MW_e Skive demonstration plant in Denmark using biomass (Spectrum Magazine 2009) as well as the 1.5 MW_e Chiba and the Mizushima plants in Japan using waste feedstocks (Sumio et al. 2004). The Mizushima plant provides synthesis gas to an adjacent processing plant. Smaller gasifier/engine combinations are found in India and China where several hundred small downdraft gasifiers have been built for heat and power applications. For process heat applications the additional effort of cleaning the raw gas to a synthesis gas is unlikely to be rewarded as the raw gas is of sufficient quality to be burnt in a boiler system. However, it is a technology option for retrofitting existing natural gas fired boilers if the prospective owner is comfortable with the financing risk or can work with a third party that takes on the bioenergy plant.

Pyrolysis Plants

In pyrolysis plants the feedstock is heated to above 300°C in the absence of oxygen and converts to synthesis gas, oil and char.

[11] http://www.berkes.com.uy/eng/tallermetalurgico/antecedentes.php?aux=21
[12] Images courtesy ERK Eckrohrkessel GmbH, Germany

- Slow pyrolysis makes char and syngas.
- Fast pyrolysis makes up to 70% w/w oil, with the balance of the feed converted to char and gas.

If made to a suitable quality, the oil and synthesis gas may be used as fuel for high efficiency power generation in gas engine and turbine plants. Both pathways have been demonstrated but at present there are no commercial plants operating this way anywhere in the world. The production of char is an important development as it can be used as biochar for carbon sequestration, for soil enhancement, and potentially as a renewable feedstock for metallurgical processes subject to carbon content and impurities (Sohi et al. 2009; Garcia-Perez et al. 2010). A variety of demonstration plants exist, such as the Somersby facility in Australia which is capable of processing 300 kg of feedstock per hour to produce biochar and 200 kW electricity (Pacific Pyrolysis 2010). No commercial slow pyrolysis plants are operational yet, but a number of fast pyrolysis plants have operated in North America over the past twenty years, focusing on oil production for chemicals and furnace fuel. Moreover charcoal production (without syngas or oil) is routinely practised at large scale worldwide for metallurgical and cooking applications.

Anaerobic Digestion

The production of biogas from biodegradable materials using anaerobic digestion is well established in Europe and growing globally due to the availability of feedstocks, the versatile uses of biogas and the ability to recover useful energy from what is essentially a waste disposal exercise. Anaerobic digestion is a biochemical process using bacteria to decompose organic matter without the presence of oxygen. Such systems can convert various feedstocks into biogas and a digestate, eg sewage sludge, municipal solid waste, and organic industrial, commercial, farm and residential waste streams. An example for a plant using sewage effluent from a piggery is shown in Figure 22. The biogas can be used to provide process heat and/or electricity generation or be cleaned to yield a pure methane stream. The digestate is nutrient rich and can be sold as a fertiliser. Depending on the feedstock the anaerobic digestion system configuration differs in regards to feedstock supply, eg batch or continuous supply, feedstock quality, eg dry or wet, process temperature, eg mesophilic or thermophilic, and complexity, eg single or multi-stage. The biogas methane content ranges from 50-75% with the remainder being carbon dioxide and some trace gases.

Figure 22: Anaerobic digestion plant using the sewage effluent from a piggery in Utah, U.S.[13]

Energy from Waste

The future for EfB strongly depends on the sustainability and cost of biomass feedstock production. Alternative uses for feedstocks usually exist, and energy production is often the lowest value use.

In addition to the use of 100% renewable biomass feedstocks organic waste materials are suitable feedstocks to provide process heat and electricity. Prior to using waste materials for energy recovery, priority has to be given to waste prevention, reuse and material recycling. Despite debates about the competition of waste recycling with energy from waste (EfW) it has been demonstrated that typically countries with EfW facilities have higher recycling rates than countries without (EEA 2007).

Feedstocks used predominantly in current EfW facilities include municipal solid waste (MSW), refuse derived fuel (RDF, recovered from municipal solid waste), sewage sludge, tyres and wood waste. In Europe these plants have to comply with very stringent emission limits set by the European Union (European Parliament and Council 2010). Some states in Australia are making specific reference to waste to energy plants (EPA VIC 2013; EPA NSW 2013) in addition to the well-established emission controls that already apply to combustion plants .

[13] http://www.abc.net.au/news/2014-03-11/pig-effluent-methane-digester/5313540

While MSW streams can have a biogenic content of up to 50% (Gohlke & Spliethoff 2007), the use of RDF derived from that MSW is of particular interest as it complements recycling efforts, has a significant renewable component and is more consistent than MSW. This has positive flow-on effects in the power plant including better combustion performance, higher efficiency and simplified flue gas cleaning (Chang et al. 1998). The recovery of wood waste and RDF from municipal, commercial and industrial waste streams is well established with many units in commercial operation, including a large operation in Adelaide, SA.

Since the commissioning of the first EfW plants in the late 19th century, see example in Figure 23a, technologies have improved significantly in regards to cycle efficiency, from 15–21% in the 1980s to over 30% in recent units (Gohlke 2008). Emissions (eg dioxin and furan emissions fell by 99% between 1990 and 2005 (Stevenson 2007). These improvements were possible through a variety of technologies including feed management, optimised combustion, high efficiency bag-house filters and flue gas scrubbing.

Figure 23: a: Waste incineration plant Bullerdeich in Hamburg in 1896 (Vehlow 2004) *and b: modern Energy from Waste plant in Tokyo, Japan (right)*[14]

Today almost 2,200 commercial EfW plants operate worldwide (ECOPROG 2013) many of them in the middle of densely populated cities, such as Paris, London, Berlin, and Tokyo (as shown in Figure 23b), where waste materials are created and electricity and process heat is needed. In 2006 EfW plants produced 46 TWh of electricity and an equal amount of process heat worldwide (Themelis 2006) and by 2017 another 180 plants are expected to be operational (ECOPROG 2013).

5.3.2. Capital Costs

Technologies to convert biomass feedstocks into process heat or electricity are available but have different levels of maturity.

[14] Image courtesy Logan Mirto

To identify a cost curve for the most relevant technologies, biomass combustion, gasification/combustion and anaerobic digestion, publicly available cost data for complete process heat plants and information on boiler costs provided by ERK Eckrohrkessel GmbH were collected. To scale the available cost data a thermodynamic model was developed and validated with the cost information obtained to match publicly available industry prices, such as AU$11m investment for the recent Australian Tartaric biomass plant[15]. With the model verified a range of plant capacities were modelled to obtain cost data points. Based on the various data points power law curves were created to estimate the cost for various plant capacities and biomass feedstocks, see Figure 24. The costs provided in Figure 24 reflect the complete process heat plant cost using water tube boiler systems, including plant equipment, civil works, installation, piping, 14 day fuels storage and plant commissioning. Some cheaper fire tube boiler systems exist for biomass feedstocks but these are limited in fuel type, steam temperature and pressure.

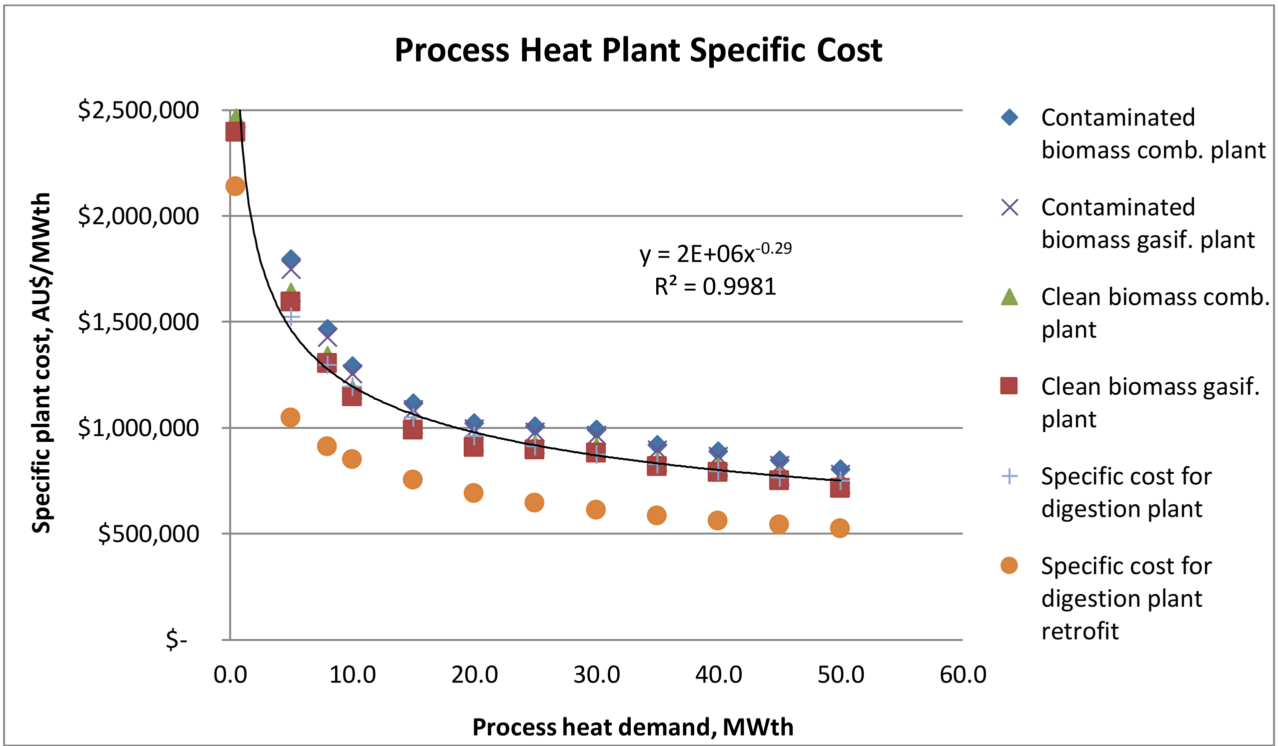


Figure 24: Cost curves for the various biomass technologies assessed and natural gas

Various plant capacities were considered ranging from 0.5-50 MW_{th} for clean biomass combustion, gasification/combustion and anaerobic digestion plants, and 5-50 MW_{th} for plants using contaminated biomass feedstocks, such as RDF. The inherently higher complexity of plants using contaminated biomass requires a minimum size of several megawatts thermal to justify not only the technical complexity but also administrative complexity, eg environmental approvals.

[15] http://www.sunraysiadaily.com.au/story/2333293/new-11m-biomass-plant-environmentally-friendly-carbon-cut/

To compare the cost for a biomass feedstock based process heat plant with a natural gas alternative cost curves for natural gas fired water tube and fired tube boiler plants were created with industry information and the developed thermodynamic model.

Figure 24 clearly shows capital cost differences between process heat plants using various biomass feedstocks, eg clean and contaminated, and conversion technologies, eg combustion, gasification/combustion and anaerobic digestion. Also the significantly lower capital cost of natural gas fired process heat plants is apparent.

The cost difference between combustion and gasification/combustion plants results mainly from the lower amount of excess air a combustion/gasification plant requires. Converting the solid feedstock at sub-stoichiometric conditions into a raw gas and then burning the raw gas at stoichiometric conditions requires less air than the stoichiometric combustion of a solid biomass feedstock. The smaller amount of excess air results in a smaller flue gas volume and hence smaller boiler and flue gas cleaning components. However, the overall impact is marginal, as this affects two cost components only, and does not affect efficiency in a process heat plant. This is different in plants generating only electricity where gasification systems can lead to higher Rankine cycle efficiencies and hence more significant specific plant cost reductions. It is also important to remember that gasification plants generally have much stricter feed requirements than combustion plants, with tight limits on moisture content, average particle size and particle size distribution, which helps to explain why combustion plants account for the great majority of EfB systems worldwide.

The cost difference between clean and contaminated biomass feedstocks derives mainly from the additional flue gas cleaning equipment contaminated fuel plants require, eg flue gas scrubbing systems. Also the boiler design differ as in plants using contaminated feedstocks an additional gas paths might be required to maintain the minimum flue gas temperature and the convective heating surface arrangement is different due to the presence of chlorine and higher particle loads.

The specific capital cost curve for retrofitting an anaerobic digestion plant is generally significantly lower than the other biomass alternatives. However, this requires the existing boilers to be able to burn biogas without adverse effects on the boiler lifetime and some contaminants in biogas can have an adverse effect on boilers if they are not removed. If a new biogas fired boiler is required with the anaerobic digestion plant the specific costs may be similar to clean biomass combustion plants, depending on the relative costs of gas collection and cleaning and solid biomass feed handling. A noticeable difference is that the specific cost of a digestion plant exceeds the cost of a thermochemical plant at capacities <5MW$_{th}$. The cost of small biogas plants increases significantly because of the higher cost of small tanks. Small biomass boilers can be provided as modular units with minimal on-site installation.

To provide a reference point for biomass plants the cost for natural gas fired plants using water and fire tube boilers are shown in Figure 24. It is apparent that the specific capital cost for a natural gas plant is significantly lower as these do not require flue gas cleaning, fuel storage equipment, compiles combustion zones and ash handling, and the boiler is more compact due to a smaller combustion chamber and the absence of particles allowing the use of finned tubes. These factors also lead to quick and low cost on-site installation. The cost for natural gas fired process heat systems could be even lower when using a fire tube boiler. However, this design is not suitable for all applications due to limitation relating to steam temperature, pressure and capacity. Two natural gas fired boiler examples are shown in Figure 16.

5.3.3. Case Studies

The case studies presented here are of technology applications that are either in whole or part relevant to natural gas usage replacement, even if they did not actually involve natural gas replacement in their implementation.

B1 Case Study - Biomass boiler - Australian Tartaric Products, Victoria

Summary

Resource	Biomass 90,000 tonnes per year of grape marc
Investment	$7.5m for a 8MW$_{th}$ boiler, 600 kWe Organic Rankine Cycle generator and associated balance of systems
Construction	Commissioned in November 2013
Designed to deliver	Process steam at 180°C and electricity
Energy saved	2,900MWh per year of electricity, 73,450GJ of fuel oil per year and 40,760GJ of LPG per year
Simple payback	About 5 years
Implementation	European boiler manufacturer with experience in burning grape marc chosen so that best practice was integrated into design.
Other aspects	Received $1.8m grant from the Victorian Government's Regional Infrastructure Development Fund and $1.7m from the Australian Government's Clean Technology Investment Program.

Description

Due to the rising cost of boiler fuels, Australian Tartaric Products (ATP) investigated alternative boiler options for its facility at Colignan, Victoria. In 2013, ATP commissioned an 8MW$_{th}$ biomass boiler using grape marc. The boiler provides steam for process heat and for a 600kW$_{e}$ Organic Rankine Cycle generator. This biomass waste-to-energy project reduces carbon dioxide emissions by about 10,000 tonnes per year. In 2013, this project won the Lever Award for Innovative Processes.

Figure 25: Automatic feed handling and 8MW$_{th}$ boiler using grape marc, photos Australian Tartaric Products

B2 Case Study - Fluidised bed boiler - Coffee processing, Nestle Australia, Queensland

Resource	Biomass, coffee grounds and sawdust
Investment	About $9m for a 16MW$_{th}$ boiler
Construction	Commissioned in May 2009
Designed to deliver	24 tonnes per hour of process steam
Energy saved	Onsite energy consumption from renewable sources is reported as 70%
Simple payback	Not published, thermal boiler operates at 75% efficiency and saves 4,000 tonnes per year of greenhouse gas emissions
Implementation	Minimal gas consumption for start-up only
Other aspects	Old gas boiler was decommissioned.

The Nescafe factory at Gympie is Australia's largest coffee manufacturer producing nearly 10,000 tonnes of instant plus roast and ground coffee per year. In 2009, Nestlé Australia installed a 16MW$_{th}$ bubbling, fluidised bed boiler capable of using coffee grounds, a process waste product, and sawdust. The boiler is optimised for high moisture and finely ground organic materials and supplies all the process steam requirements of the site. The project lowered greenhouse gas emissions by 4,000 tonnes per year and avoids 5,400 tonnes of waste going to landfill annually.

Figure 26. Installation of the new 45m stack and the Fluidised bed boiler at the Nescafe factory

B3 Case Study - Co-firing – Cement manufacture, Adelaide Brighton, SA

Resource	Biomass, 70,000 tonnes per year of recycled construction and demolition timber, approximately 17 MJ/kg
Investment	Plant upgrade
Construction	2003
Designed to deliver	Process heat above 1,450°C
Energy saved	20% of annual natural gas consumption
Simple payback	Not published
Other aspects	Cement kilns operate with flame temperatures up to 2000°C

Adelaide Brighton's Birkenhead gas-fired kiln has the capacity to produce 1.3 million tonnes of cement products per year. In 2003, the cement kiln commenced using more than 70,000 tonnes of recycled construction and demolition timber per year as a supplement to natural gas at their Birkenhead cement kiln in South Australia. The receival, storage and feed system was upgraded in 2005.

To provide the recycled timber a designated processing plant was built in the vicinity of the cement plant. The plant was built by SITA-ResourceCo and is capable of converting up to 350,000 tonnes of raw material into 150,000 to 200,000 tonnes of alternative fuel each year.

Figure 27. Construction and demolition timber processing and supply to the Birkenhead cement plant, photos Adelaide Brighton

B4 Case Study - Biogas - Berrybank piggery, Victoria

Resource	Piggery sewage effluent
Investment	$2.3m for a two stage anaerobic digestion plant and biogas cogeneration plant
Construction	1991
Designed to deliver	About 1,700m^3 biogas per day
Energy saved	190MWh of electricity and 440MWh_{th} of heat per year
Simple payback	About 7 years
Implementation	Biogas is purified to remove corrosive hydrogen sulfide.
Other aspects	To recover the waste products, the farm modified the existing drainage system.

In 1991, Berrybank Farm had about 15,000 pigs and commenced using its sewage effluent to produce biogas. The two-stage, anaerobic digestion plant produces about 1,700m^3 of biogas per day, which is used to fuel biogas engine generators.

Most of the electricity from the biogas generators is used on site with some excess exported to the main-grid. Heat from the engines is recovered and used in the digestion plant and for other purposes. The biogas plant lowers annual electricity, gas, water and fertiliser costs and a seven year payback period was forecast.

Figure 28. Part of the biogas plant and the primary and secondary digestors with the biogas generator shed. Photos Berrybank Farm

B5 Case Study - Biomethane – Arnburg agricultural waste plant, Germany

Resource	Maize silage, whole-plant grain, sugar beets, chicken manure and other liquid manure
Investment	Four digesters of 4,900m^3 and six digestate storage units of 5,000m^3
Construction	2012
Designed to deliver	1,650m^3 biogas per hour
Energy saved	Biomethane is sold
Simple payback	Not published
Implementation	Biomethane plants are widespread in Europe
Other aspects	Uses amine scrubbing

Biogas can be upgraded to biomethane, through amine or water washing processes. This enables it to be injected into an existing natural gas pipeline or used in processes requiring methane.

The Arnburg plant consists of four digesters of 4,900m^3 and six digestate storage units of 5,000m^3. The plant is capable of producing 1,650m^3 biogas per hour. About 250m^3 of this is used for onsite process heating. The remaining biogas is scrubbed to produce biomethane of sufficient quality to be sold. The plant requires a feedstock supply of about 70,000 tonnes per year, consisting of a mix of maize silage, whole-plant grain, sugar beets, chicken manure and other liquid manure.

Figure 29 Altmark biomethane plant in Germany. Photos Nordmethan

5.4. Solar Thermal

5.4.1. Technologies

Solar thermal technologies convert solar radiation into heat. Their efficiency is limited by heat losses from the hot collector surfaces that increase with temperature and with the area of the hot surface. Solar thermal technology solutions must be optimised for the temperature range needed. Various approaches are used to reduce thermal losses and so improve efficiencies and these increase the complexity and cost of the system. Low temperature heat (eg for pool heating) can be provided by black, uninsulated rubber or PVC tubes laid flush on a rooftop. At the other extreme, temperatures of over 1,000°C are possible with point focus concentrators such as heliostat tower systems or paraboloidal dishes. The range of options available is summarised in Table 17.

Table 17. Solar thermal technologies & key characteristics

Collector Technology	Tracking	Concentration Ratio[16]	Temperature Range	Usual heat transfer fluid
Unglazed	Nil	1	20 - 40°	Water, air
Glazed Flat Plate	Nil	1	30-85°	Water, air, glycol
Evacuated Tube	Nil	1	50-150°	Water, glycol
Compound Parabolic with evacuated tube	Nil	1-5	60-200°	Water, glycol
Linear Fresnel	Single axis	10- 40	100-450°	Water, steam, HT oil
Parabolic Trough	Single axis	15-50	100-450°	Water, steam, HT oil
Paraboloidal Dish	Double axis	500-2,000	300-2,000°	Steam, chemical process
Heliostat Power Tower	Double axis	500-1,500	300-2,000°	Steam, molten salt

Non concentrating systems are mounted to rigid frames and convert the radiation that is incident on them, whether it is direct beam or diffused by clouds or dust. Concentrating systems use mirrors to concentrate only the direct beam component of solar radiation. The greater the concentration ratio, the smaller the hot area that is subject to thermal losses and hence the higher the achievable operating temperature. Concentrators must track the sun, those that focus on a linear receiver only need to track on a single axis, point focus concentrators need to track in two axes.

[16] Concentration ration is the ratio of the intensity of radiation after concentration compared to incident sunlight.

With very few exceptions, a fluid medium is required to pass through the collector and absorb the heat. This Heat Transfer Fluid (HTF) can then be transported to a point of use where some form of heat exchanger is applied to extract useful heat. The boiling and freezing points, the heat capacity, and the chemical stability of the material are major factors in HTF selection.

Solar heat can be stored in tanks of heated HTF, or via heat exchangers to other thermal energy storage mediums. New approaches to HTF, solar collectors and storage mechanisms are the subject of ongoing research and development.

The following sections provide more detail on the solar collector types.

Unglazed Collector

Unglazed collectors are simple panels of black material containing channels for heat transfer fluid, usually water (see Figure 30).

Figure 30. Unglazed Collector for an indoor pool at the Australian Institute of Sport, Canberra [17]

Unglazed collectors are suitable for temperatures of around 20°C above ambient temperature and are often used for swimming pool heating. For this application, they are typically fabricated from EPDM rubber or PVC. The simple design results in high thermal losses for a given temperature, however their low cost makes them an attractive option in low temperature applications like pool heating. Unglazed panels made from sheet steel have been demonstrated for air heating, however such products are not readily available commercially.

[17] http://sunbather.com.au/portfolio/ais-canberra/ (Accessed 18-08-14)

Glazed Flat Plate Collector

Addition of a sheet of glass in front of a flat panel solar collector plus an insulating material behind it, are simple ways for reducing convection and conduction heat losses. Flat plate glazed collectors are the dominant technology in the Australian domestic solar hot water market. They are a mature technology. Traditionally confined to the domestic market, rising energy prices are now stimulating demand for commercial systems, where the technology easily scales via the assembly of standard panels in arrays as illustrated in Figure 31. Annual output will be maximised if the collector is tilted toward the equator at an angle equal to the latitude of the site.

Figure 31. Commercial flat plate collector array[18]

The construction details of a typical panel are shown in Figure 32. Tubes carrying a HTF are welded to a flat, black coloured, sheet metal absorber plate. The absorber plate heats with incident radiation and then conducts heat to the tubes containing the HTF. The absorber tube 'black' coating is often a selective surface, meaning it is a material that has been formulated to have high absorptivity across the solar spectrum, whilst having a low emissivity in the infrared wavelengths associated with the sub 100°C operating temperatures, thus further reducing radiation losses.

[18] http://www.solarproductcn.com/4-3-commercial-hot-water-system.html (Accessed 18-08-14)

Figure 32. Cross sectional view of a flat plate collector[19]

Thermosiphon collectors dominate the Australian domestic market. In this case the storage tank is mounted above the panels and as the name implies, the hot fluid from the panels circulates naturally to transfer heat to the water in the storage tank. This design although simple, adds significantly to the loading of the roof. In commercial systems, a split-system comprising a ground mounted tank and roof-mounted collectors is normally preferred due to the larger tanks employed. Circulation pumps and controls are needed to circulate water or HTF through the panels and to the tank. Figure 33 illustrates a possible installation arrangement. This figure is included as an example of a number of possible arrangements. Arrangements with top and bottom headers and parallel flow paths are also used. Array layout deign needs to consider avoiding the potential for stagnation in some panels and airlocks.

Flat plate systems often require frost protection in cooler climates where ambient temperatures drop below zero. This may be in the form of a HTF with antifreeze properties, or via a pump which circulates water from the tank when system sensors detect sub-zero temperatures.

[19] www.solapac.co.nz [Accessed 19-08-14)

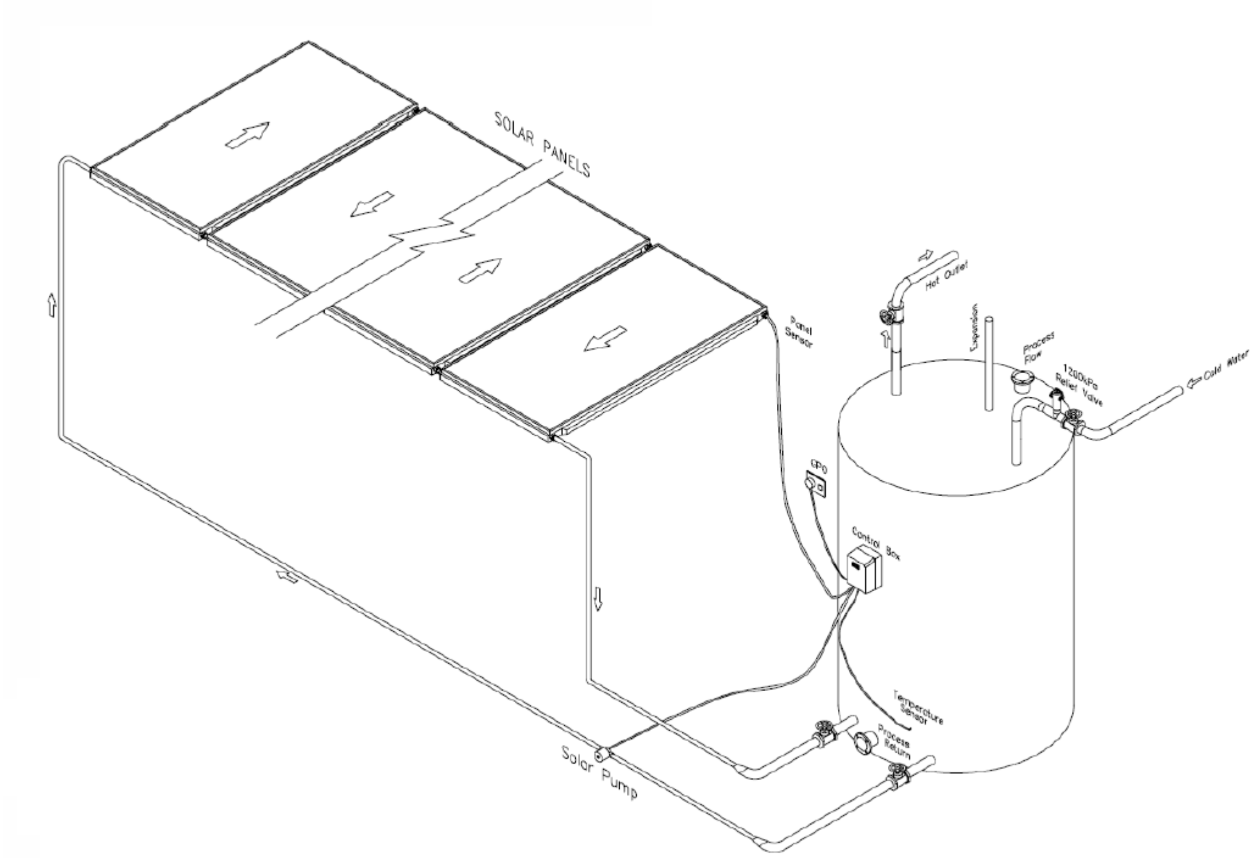


Figure 33. Solar hot water system arrangement[20]

Evacuated Tube Collectors

Evacuated tube collectors are the competing solar technology for domestic and commercial solar hot water. A series of individual tubes are mounted together in panels as shown in Figure 34. They are a less mature technology than flat plate collectors and systems tend to cost more, but are typically recommended over flat plate collectors in cooler or less sunny locations where thermal losses become more significant relative to the amount of solar radiation absorbed. As with flat plate collectors, commercial-scale systems utilise the same components as domestic systems, and scale easily.

[20] Edwards Solar

Figure 34. Evacuated tube collector array[21]

A single evacuated tube is constructed in similar manner to a thermos flask, as shown in Figure 35 and Figure 36. An inner and outer glass tube are fabricated as a continuous unit with one open end and the annular space between them evacuated. The inner tube is coated with a selective surface for preferentially absorbing solar radiation. Inside the inner tube a heat transfer mechanism is installed to collect the heat by conduction from the hot inner tube surface. Figure 35 shows one method employed which is a sealed heat pipe based on a standard refrigerant material that boils and moves the heat by natural convection and then condensation to the inside of a storage tank or water heat exchanger. Figure 36 shows an alternative of a basic ‘U’ tube HTF heat exchange unit that sits within the tube. Direct heating of the HTF within a tube is also possible.

[21] www.sustainablebuildingconstruction.blogspot.com (Accessed 01-09-14)

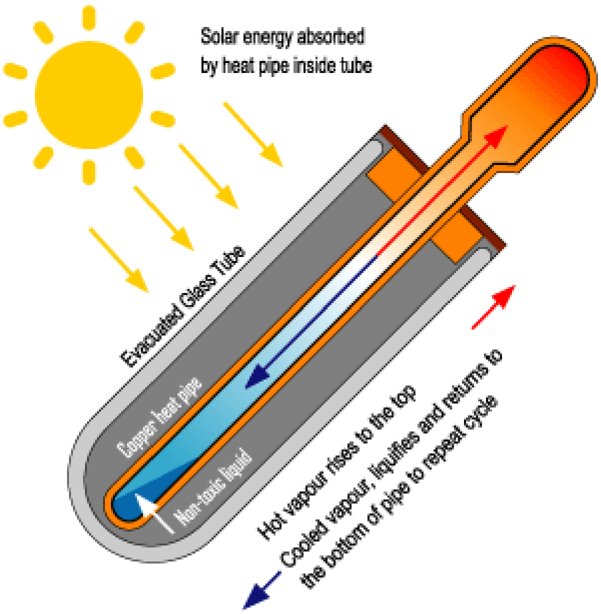


Figure 35. Working principle of an evacuated tube with heat pipe based heat transfer[22]

Figure 36. Exploded view of an evacuated tube with internal u-tube heat exchanger[23]

As with flat plate collectors, annual output will be maximised if the collector is tilted toward the equator at an angle equal to the latitude of the site. However, in Australia, the low thermal losses of evacuated tube collectors make them prone to summer overheating. To mitigate this risk, collectors will often be mounted at greater angles, levelling seasonal output by increasing winter output at the expense of summer output. Increased tilt angles will also increase hail resistance of the tubes, which are typically designed to withstand 25mm diameter hail stones incident at

[22] www.reuk.co.uk (Accessed 19-08-14)
[23] www.andyschroder.com (Accessed 19-08-14)

90km/h. Frost protection is not commonly required owing to the same insulating properties which allow the collector to generate high temperatures.

CPC Collectors

Compound Parabolic Concentrators (CPC) are an example of a non-tracking concentrator. They utilise evacuated tube receivers with an arrangement of stationary mirrors to gather more radiation than is directly incident on the tube. The optical principles are illustrated in Figure 37. Concentration levels of around two times are possible and so have the effect of boosting operating temperatures up to around 150°C.

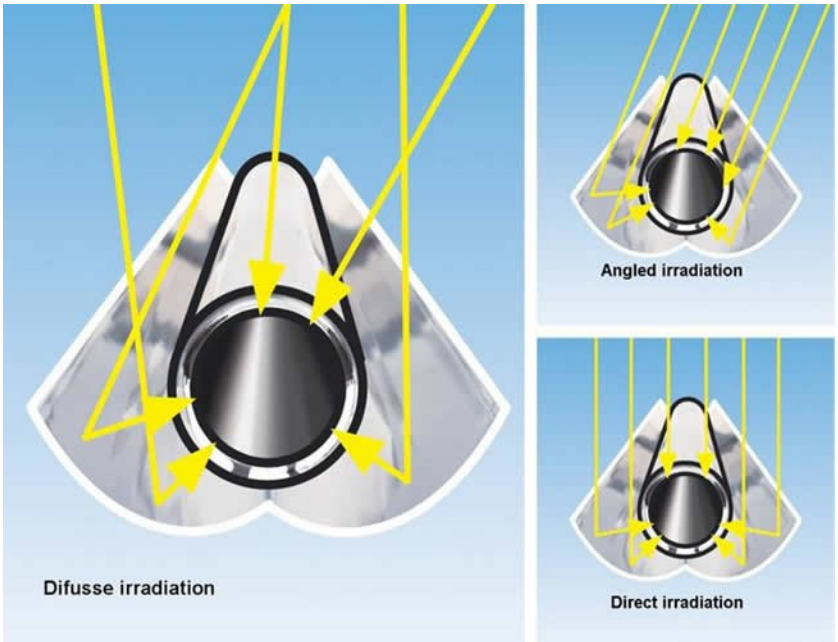


Figure 37. Working principle of a CPC[24]

Multiple tubes are again arranged in panels as illustrated in Figure 38.

[24] www.jrsolar.co.za (Accessed 19-08-14)

Figure 38. A CPC collector[25]

Parabolic Trough Collectors

The focal properties of the parabola are utilised in trough concentrator systems. The tubular receiver is fixed to the focal line of the array of mirrors, which track the sun along one axis throughout the day. Trough systems can heat a HTF such as synthetic oil, or generate steam for process heat or power generation. Modern systems are capable of reaching up to 500°C but are typically used for temperatures between 150 to 400°C.

Key components are illustrated in Figure 39. As tracking occurs, the receiver at the focal point of the trough must also move. This creates the necessity for dynamic joints through which the HTF must be circulated, adding complexity.

The receiver tubes can be simple metal tubes. Adding a glass tube cover to limit convection losses improves performance or alternatively using an evacuated tube as the receiver gives the best possible performance. The evacuated tube receivers differ from those used in panels in that they are usually direct flow through units made from a central metal tube with a surrounding glass tube joined by a bellows unit to maintain the sealed evacuated space.

[25] www.andyschroder.com (Accessed 18-08-14)

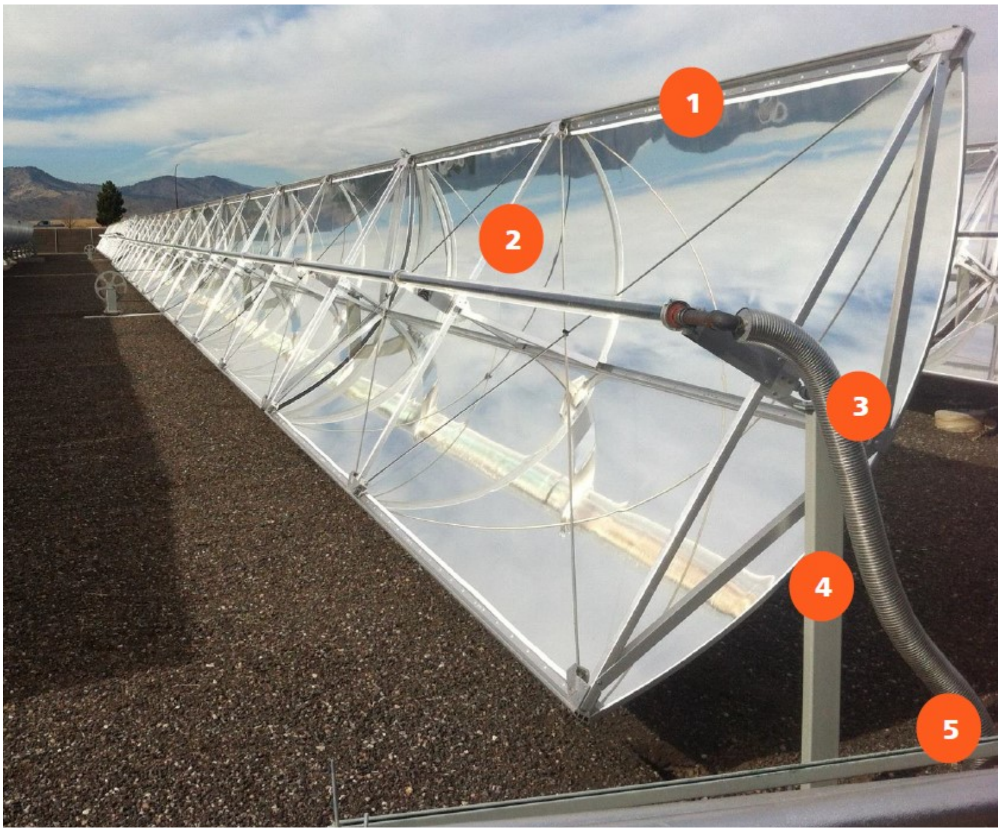


Figure 39. Parabolic trough collector construction, 1 Concentrator with aluminium or glass mirror, 2 Receiver tube, 3 Flexible coupling, 4 Pylons, 5 Header piping (picture from Abengoa).

Whilst parabolic troughs could be made in any length and aperture width, there has been an evolution in commercially available products in two directions, large aperture units for solar thermal power generation and smaller systems for process heat.

Use of large troughs with aperture widths of around 5.8m and high quality evacuated tube receivers has become standard practice for concentrated solar power generation. These large trough arrays use heat transfer oil in the receivers and collect heat at around 400°C. Arrays with peak thermal capacities between $30MW_{th}$ to $1GW_{th}$ have become a mature technology, with the hot oil used to raise steam for power generation, (Figure 40).

Large trough collectors can also be used for process heat. Arrays down to $1MW_{th}$ are technically feasible, however large trough suppliers typically have less interest in such small systems. Globally there are a number of companies who offer small aperture, lightweight troughs specifically for mid-range process heat, as illustrated in Figure 41.

Figure 40. Parabolic trough field in a large CSP plant (picture K. Lovegrove)

Figure 41. Small aperture parabolic trough collector (picture from NEP)

Linear Fresnel Reflectors

A Linear Fresnel system is an analogue of a trough concentrator and provides heat over the same temperature range. Long semi flat mirror strips laid out in parallel rows are each tracked independently so as to focus direct beam radiation on a linear focus that is fixed on a non-moving tower (Figure 42). Manufacturers of LFR systems claim that they offer advantages over trough concentrators via having reduced structural costs, mirrors that are easier to manufacture and clean plus the benefits of a fixed focus that does not require flexible coupling for the HTF. Against these advantages their overall average optical efficiency is lower.

As with troughs, receivers can be evacuated or non-evacuated. Whilst less commercially mature than troughs, the split of commercial offerings into large scale units used for power generation (but also available for process heat) and smaller units particularly aimed at medium temperature process heat can be observed.

The fixed receiver and the low profile of the mirrors does work to make the smaller LFR systems suitable for roof top integration as shown in Figure 42 and Figure 43.

Figure 42. Linear Fresnel Collector (courtesy of Industrial Solar)

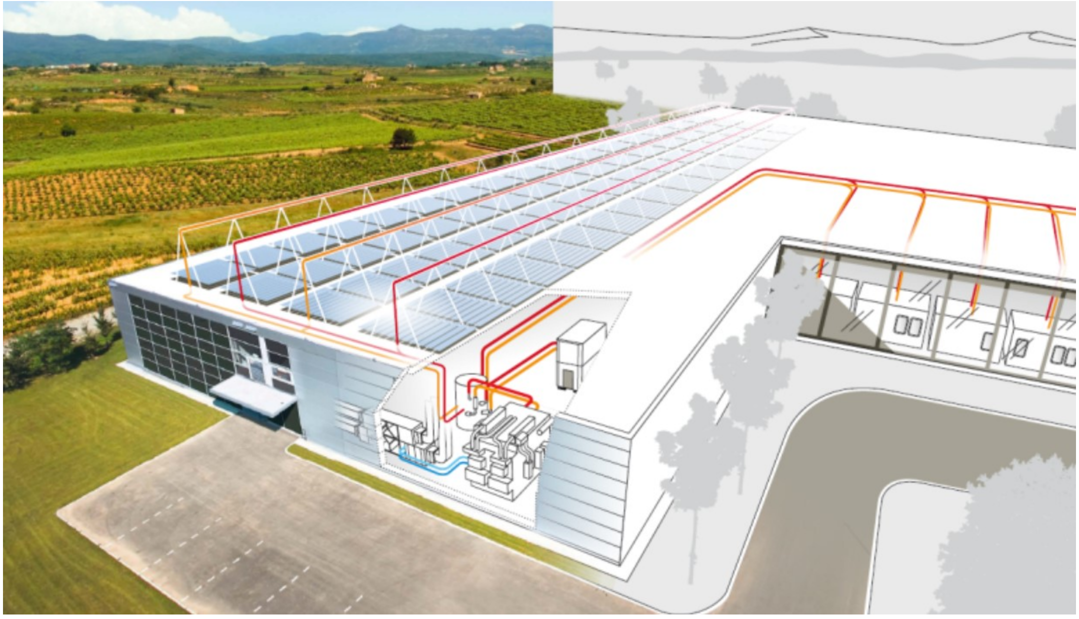


Figure 43. Linear Fresnel system configuration (courtesy of Industrial Solar)

Heliostat Power Tower Concentrators

In the concentrated solar power sector, the heliostat field / central receiver approach is gaining wider support. It offers higher temperatures (matching any available steam technology) and can also utilise the molten salt energy storage solution more effectively because of the higher temperature difference.

The most commercially mature systems are large in thermal capacity (Over $50MW_{th}$). However there are also commercial players developing smaller systems down to a few MW_{th} in size. For a process heat application the use of molten salt as both a HTF and thermal storage medium is readily adaptable and offers heat at temperatures up to 580°C.

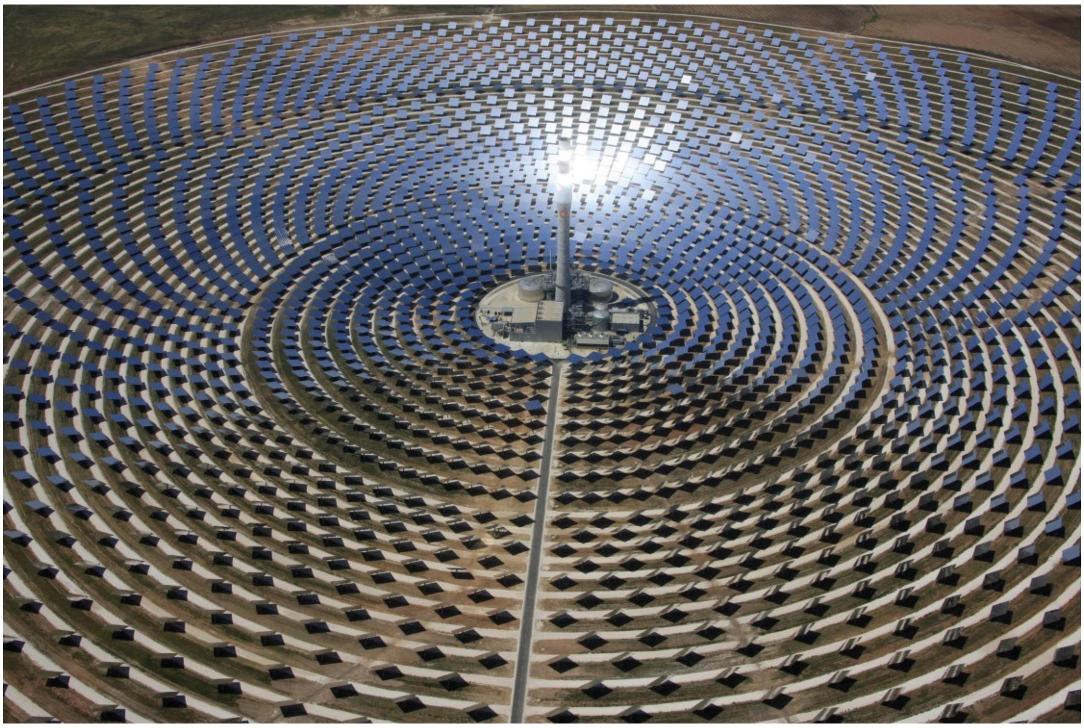


Figure 44. Arial view of the Gemasolar Heliostat power tower plant in Spain, thermal capacity 400MW$_{th}$ (courtesy of Torresol Energy).

There is ongoing work at the pilot stage on applying tower systems to directly drive high temperature chemical processes. A key relevant example is the solar driven steam reforming of methane to produce hydrogen or syngas mixtures. The CSIRO solar group in Newcastle is a pioneer in this area.

Paraboidal Dish Concentrators

Paraboidal dishes are the least mature of the large scale solar thermal technologies but also provide high concentration ratios and low thermal losses. Dishes are double axis tracking and have the highest concentration levels and efficiencies of the concentrator system options. Dishes are also modular and have the capacity to be mass manufactured to minimise project engineering costs. They are mentioned here for completeness as there is no real commercial provider in a position to offer solutions for immediate application to industry for process heat as yet.

Figure 45. Australian National University's prototype 500m^2 paraboidal dish concentrator (picture K Lovegrove)..

5.4.2. Global status

The International Energy Agency (IEA) has a program devoted to Solar Heating and Cooling (SHC) that is directly concerned with solar heat, with much of its activity at lower temperatures. A separate IEA program, SolarPACES (Power and Chemical Energy Systems) is concerned with high temperature concentrating systems primarily for power production but also for direct solar thermal driven chemical processes. The two programs combine for a shared task to promote small concentrators for the medium temperature range process heat applications.

Figure 46 is reproduced from *Solar Heat Worldwide* (Mauthner & Weiss 2014), an annual status report from the IEA SHC program. It compares the relative magnitudes in installed capacity and energy production of several high profile renewable energy approaches including solar thermal heat. It can be seen that the solar thermal heat category is very significant in basic energy terms compared to the more high profile wind and PV sectors. Within the renewable electricity section of the figure, the solar thermal electricity generation segment is small. However it is worth noting that in terms of thermal contribution, the 3GW$_e$ of installed generation capacity[26] represents approximately 15GW$_{th}$ of installed capacity in solar concentrating fields and the 5 TWh$_e$ produced is derived from around 20TWh$_{th}$ of high temperature thermal heat production.

[26] This capacity has grown to 4.5GW$_e$ at the end of 2014, corresponding to 22.5GW$_{th}$

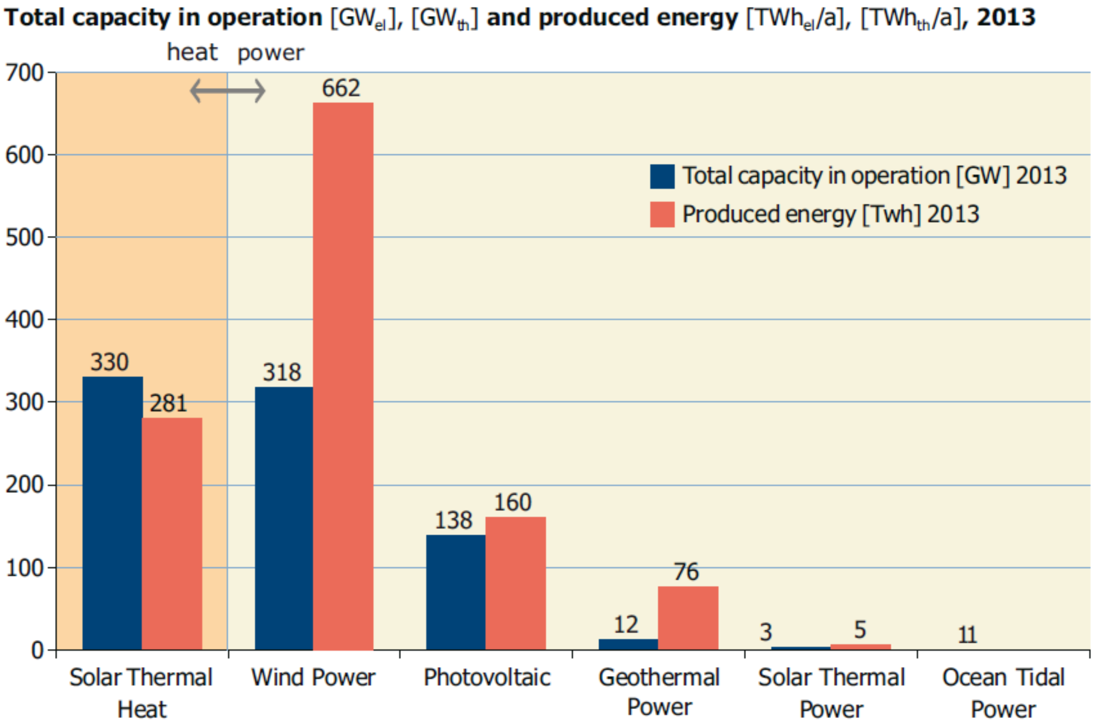


Figure 46. Worldwide renewable capacity and generation, thermal and electric reproduced from (Mauthner & Weiss 2014).

Much of the solar thermal heat contribution comes from domestic hot water systems, however industrial use is significant. In an earlier report, Weiss (2010) gives a global summary of Solar heat applications reporting that there were 200 operating solar thermal plants for process heat with a total capacity of $42MW_{th}$ ($60,000m^2$) globally. The market has grown since 2010. For the 200 hundred plants totalling $42MW_{th}$, this gives an average process heat plant size of $210kW_{th}$.

The small scale concentrator systems operating in the range 150 - 250°C are virtually invisible in these statistics. Whilst the technology has been thoroughly proven and commercial installations exist, they are still in very small numbers, reflecting the fact that traditionally gas in particular has offered a cheaper solution.

The solar thermal power systems are all constructed in large arrays in the 10s or 100s of MW_{th} capacity. The learnings are however applicable for larger higher temperature process heat applications.

It is reported that globally there were 460,000 jobs in the field in 2013. It is instructive that China dominates the installed capacity for solar heat as illustrated in Figure 47.

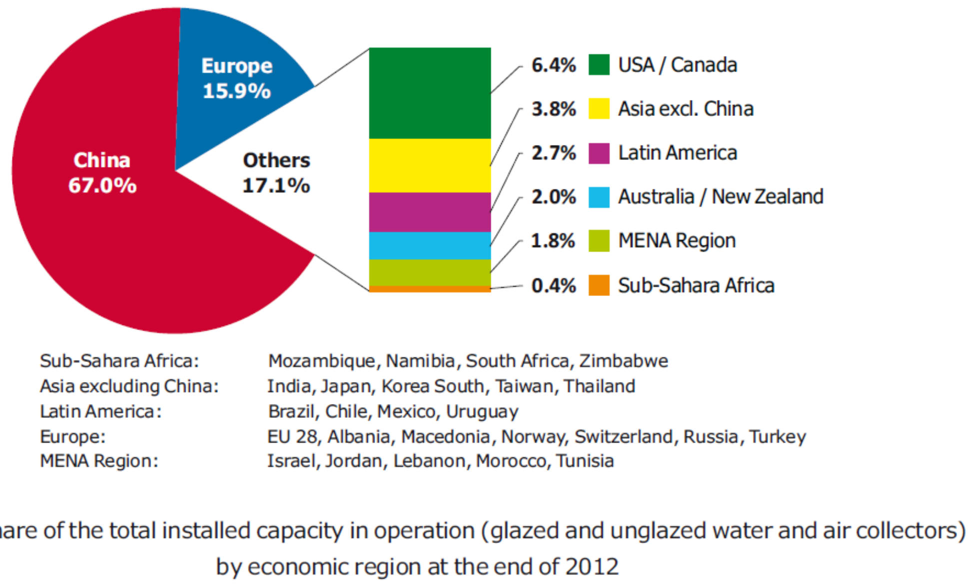


Figure 47. Solar hot water breakdown by country (Mauthner & Weiss 2014)

Overall, evacuated tube collectors dominate as shown in Figure 48, with China the major manufacturer and consumer.

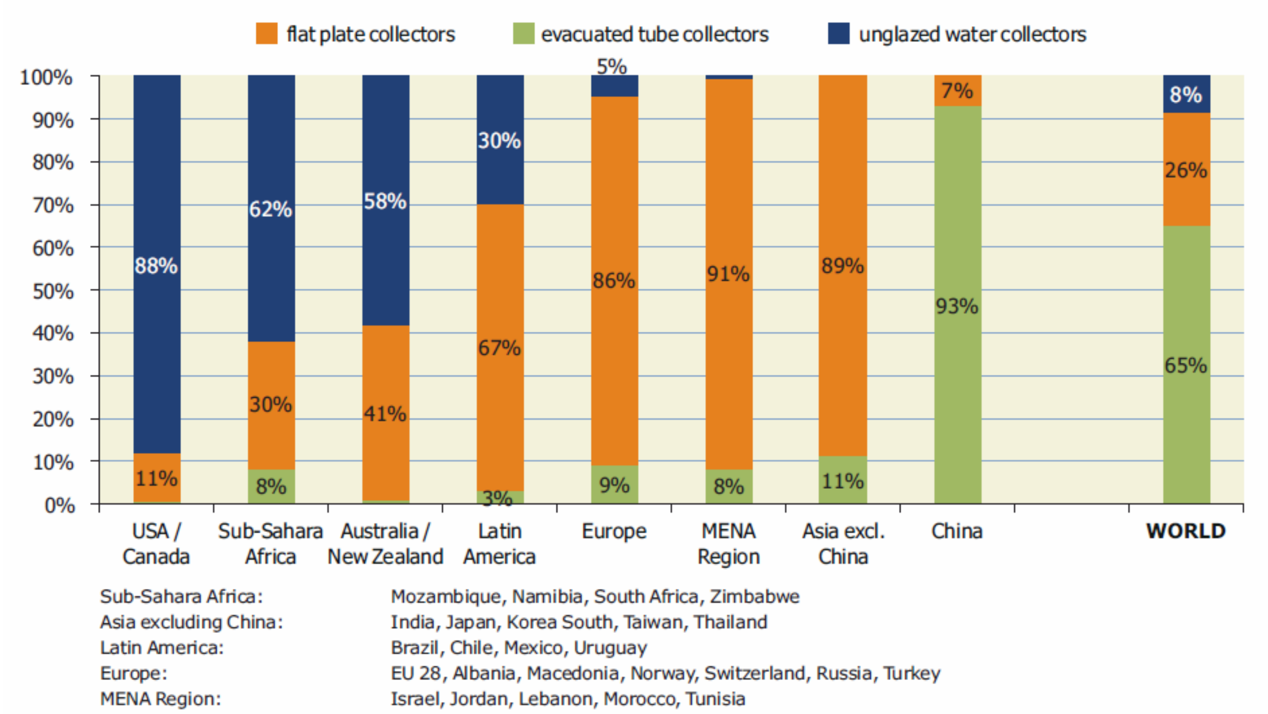


Figure 48. Solar thermal technology share by region and technology as at the end of 2012 (Mauthner & Weiss 2014)

5.4.3. Solar Thermal equipment suppliers

Whilst the solar thermal technologies are all well progressed into commercialisation, it is only the evacuated tube and flat plate systems that can be described as commercially mature. In Australia, the supply chain and market for systems operating below 100°C is strong however for operation above 100°C the supply chain is not strong. Nonetheless technology providers either local or from overseas can be found for industrial gas users seeking alternative energy sources.

Table 18 contains a non-exhaustive list of technology suppliers both within Australia and, where necessary, internationally, for each of the technologies.

Table 18. Solar thermal technology suppliers

Technology supplier	Country of origin	Website	Notes
Non glazed			
Sunbather	Australia	www.sunbather.com.au/commercial/	HiPEC PVC
Glazed flat plate			
Rheem	Australia	http://www.rheem.com.au/commercialsolarwaterheaters	Major flat plate vendor in Australia. Standard efficiency (NPT200) or high-efficiency (Bt Series) flat plate collectors. A number of commercial systems completed.
Rinnai	Australia	http://www.rinnai.com.au/commercial/	Commercial flat plate and evacuated tube systems with instantaneous gas boosters.
Edwards	Australia	http://www.rheem.com.au/solar-edwards	A long term provider of domestic systems featuring stainless steel tanks. They are now also part of the Rheem group
Solahart	Australia	http://www.solahart.com.au	Solahart is more focused on the domestic sector where it is a leading player. The company is owned by Rheem
Chromagen	Europe / Australia	www.chromagen.com.au	Australian distributors of a brand with presence around the world. Domestic and commercial systems.
Evacuated tube			
Apricus	Australia	http://www.apricus.com.au/commercial-hot-water/	Has the majority market share in Australian evacuated tube systems. Tubes manufactured in China, and a number of commercial systems have been completed. Gas or electric boosting.
SolarArk	Australia	http://www.solarark.com.au/commercial/	As above, components manufactured in China and assembled locally. A number of commercial systems completed.
Endless Solar	Australia	http://endless-solar.com.au/commercial-	Evacuated tube system vendor with instantaneous gas boosting.

		solar-hot-water/	
CPC plus tube			
Ritter Solar	New Zealand	http://xlsolar.co.nz/large-scale-solar-systems	Linuo Paradigma are a major manufacturer in China, who trade under the brand name Ritter Solar and Ritter XL internationally. The Australasian office is headquartered in NZ. They have advised that no commercial-scale projects are happening at present, nor are any in the pipeline.
Solfex	UK	http://www.solfex.co.uk/Product/1-cpc-inox/	Manufactured Ritter Solar GmbH in Baden-Württemberg-Germany
Evergreen Energy Solar	Europe	http://www.evergreenenergy.ie/cpc6.htm	On line retailer of wide range of renewable heat systems.
Small Parabolic Trough			
New Energy Partners	Australia / Switzerland	http://www.nep-solar.com/	NEP are originally Australian based and have developed a small trough product for process heat with demonstration systems in Newcastle.
Solitem	Germany	http://www.solitem.de/	Coated aluminium troughs in a range of aperture widths to maximum 4m.
Smiro	Germany	http://smirro.de/smirro/index.php/de/solare-konzepte/produkt-smirro	3.4m^2 collector modules using lightweight aerofoil like structure.
Abengoa	Spain / USA	http://www.abengoasolar.com/	As well as its major role in large scale CSP systems, Abengoa Solar has smaller light weight trough systems for industrial process heat applications.
Large Parabolic Trough			
Abengoa	Spain	http://www.abengoasolar.com/	Market leader in large (5.8m aperture) glass reflector based trough systems operating with evacuated tube receivers and oil HTF
Sener	Spain	http://www.sener-power-process.com/ENERGIA/solar-power/en	A large Spanish engineering company that has featured prominently in the CSP industry globally.
Skyfuel	USA	http://www.skyfuel.com/home.shtml	Offering a large lightweight trough product using their propriety ‘Reflectec’ film for mirror surfaces.
Small Linear Fresnel			
Industrial solar	Germany	www.industrial-solar.de	A small LFR system targeted at process heat. 12 sites around the world are identified as reference installations
Chromasun	USA	http://chromasun.com/index.	Package roof mounted micro Fresnel

		html	systems
Large Linear Fresnel			
Novatec		http://www.novatecsolar.com/	Global leader in large LFR systems for CSP plants.
Heliostat Tower			
Abengoa	Spain	http://www.abengoasolar.com/	A major player in commercial CSP power station projects
Solar Reserve	USA	http://www.solarreserve.com/	Large tower salt receiver systems
Torresol Energy	Spain	http://www.torresolenergy.com/TORRESOL/home/en	Responsible for Gemasolar 20MWe first ever commercial salt tower system
Brightsource	Israel / USA	http://www.brightsourceenergy.com/	Developer of large tower based CSP systems
E solar	USA	http://www.esolar.com/	Offering a more modular small tower based approach
Vast Solar	Australia	http://www.vastsolar.com/	A start up company offering modular small tower systems, currently building first demonstration system
Helios Towers	Australia	www.heliostowers.com	A start up company looking at heliostat manufacture
Paraboidal Dish			
Solar Systems	Australia	http://solarsystems.com.au/	Primarily a dish concentrated PV product, but offer low temp heat as by byproduct and dishes could be adapted for high temperatures.

5.4.4. Capital Costs

Solar thermal costs and performance vary strongly with temperature. At higher temperatures specialised collector technology is required to mitigate the increased thermal losses associated with high temperatures. Each technology provided by a given supplier will have a certain cost per unit area. At the same time, as discussed further in Section 5.4.5, the efficiency will be very dependent on operating temperature, starting at a high value at low temperatures and dropping off to zero at some maximum temperature for the technology in question. The cost per m^2 must be divided by the efficiency to determine an installed cost per unit capacity for a particular temperature. Since each technology can operate over a range of temperatures, the result is a series of curves of installed cost per unit capacity versus temperature that is indicatively as shown in Figure 49.

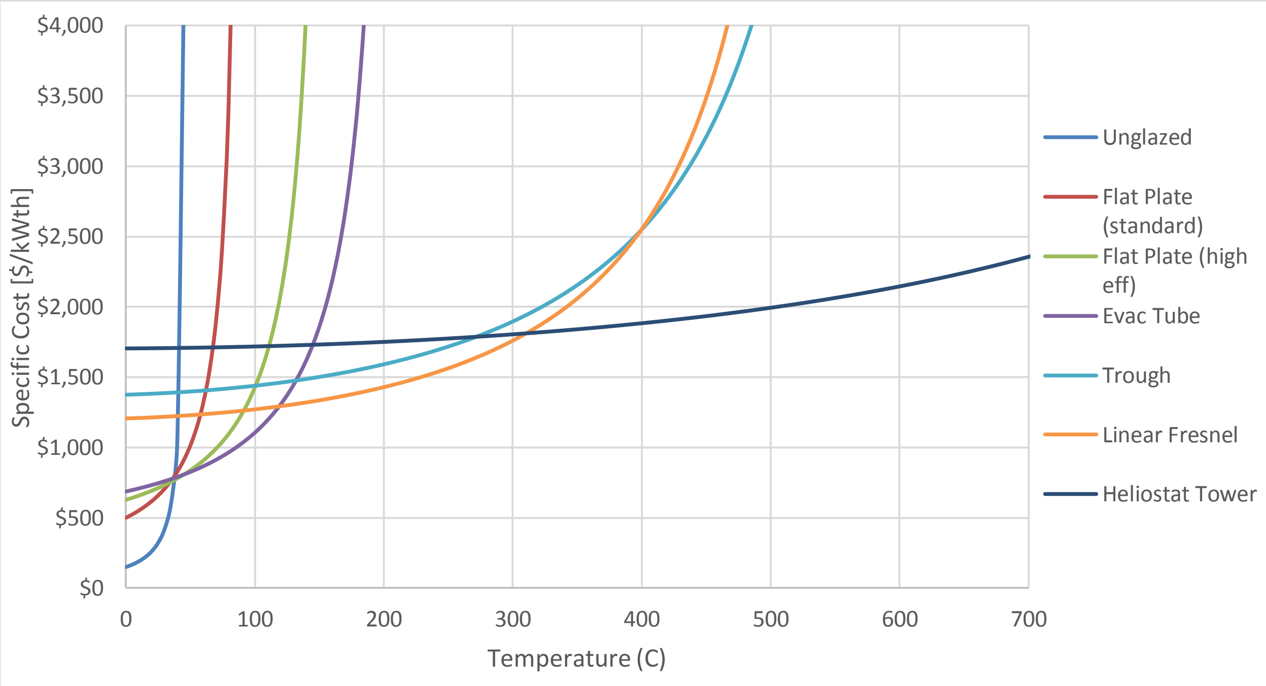


Figure 49. Indicative capital costs with temperature

Establishing reliable cost data points for as-built systems is challenging in solar thermal owing to the extensive balance of plant costs and the different amounts of storage required. Systems have cost contributions from the collector array and the storage system (if any) and the overall cost is strongly dependant on the amount of storage chosen.

Ideally a costing basis of cost per unit area for each collector type plus cost per unit capacity for thermal energy storage would be established together with a size dependency. However it is apparent that the supply chain and the number of relevant projects for supply temperatures above 100°C is low, particularly in Australia. The information that is available is rather in the form of cost per unit capacity for particular systems with 'typical' levels of thermal storage, with 'typical' equated to approximately one day of thermal load.

As well as storage medium, storage cost will depend on the size of the tanks employed, and storage size will depend on the needs of the customer. A hypothetical customer whose heat demand matched the solar resource exactly would require no storage. An industrial gas user considering a system as a partial fuel saver, that could be covered within the turndown ratio of an existing gas fired system could also consider having no storage.

Installation costs per unit capacity, will decrease with increasing system size, but will also depend on issues such as site access, remoteness, height etc. The procurement process will also impact this component significantly, as this is often where contractors will apply their margin. For an industrial customer, a competitive tender process is slower, but it is more likely to result in lower installation costs than simply selecting a supplier and requesting a design and quote.

The information that has been obtained for solar, biomass and natural gas technologies appears to be consistent with an accepted power law fit to costs with an exponent of 0.7 (Perry & Green 1999), ie:

$$Cost(capacity\ x) = Cost(capacity\ y)\left[\frac{x}{y}\right]^n$$

Where: *x* = plant capacity of interest

y= base case plant capacity

n = exponent less than 1

What has been done is to collect cost data points from a combination of; information from suppliers, previously published reports and known system case studies. All these cost data points incorporate "typical" amounts of thermal storage which could be interpreted as approximately 1 day of thermal load. Published data from previous years has been escalated at 2.5%/a. Overseas data has been converted at current exchange rates. The power law size cost scaling discussed above has been assumed to be valid and all data points normalised in system size to 1MWth on that basis. The results are shown in Table 19 and plotted as a function of operating temperature in Figure 50.

It is apparent that a linear fit to this data is a reasonable approximation for the purposes of a rule of thumb approach to assessing economics at an initial screening stage. The indication of an approximate linear fit, suggests that the hypothetical cost versus temperature relationships suggested in Figure 49 do arrange in such a way that the locus of most cost effective choices line up in such a manner. It can be concluded that however, that the linear fit is only valid out to about 600°C and from that point must steepen to vertical as it follows the trajectory of the relationship for towers or dishes.

The fact that data from disparate sources and times can be normalised in a reasonable manner to 1MWth supports the proposed power law relationship with size. The data set is however too limited to draw any firm conclusions around the value of the exponent other than to say it is not incompatible with a commonly suggested value of 0.7.

Based on this fit to the 1 MW_{th} case, the power law size dependence can be re-applied to generate the family of cost estimation curves shown in Figure 51.

Table 19. Solar thermal system costs normalised to $1MW_{th}$ and AUD 2014

Source	Collector only 2014 ($/m^2)	BOP, storage & install 2014 ($/m^2)	Total cost ($/m^2)	Cost per kW 2014	Size (kWth)	Temp	Cost per kW at $1MW_{th}$ base capacity
Trough Plant, South America			$750	$1,500	8,000	260°C	$2,799
Taibi et al. 2010	$286		$286	$572	1,000	80°C	$572
Flat plate, Dolman, 2011	$967	$645	$1,612	$3,224	3	80°C	$541
Flat plate,Dolman, 2011	$782	$521	$1,303	$2,605	32	80°C	$928
Trough,Spanish Feasibility Study	$525	$133	$657	$1,166	1,000	200°C	$1,166
NEP small trough system estimate	$800	$560	$1,360	$2,473	200	200°C	$1,526
NEP larger trough system estimate	$600	$420	$1,020	$1,855	1,000	200°C	$1,855
Tubes plus CPC				$1,600	200	150°C	$987
Domestic SHW				$4,000	2	70°C	$594
CPC website data	$165	$659	$824	$1,904	147	150°C	$1,072
Queanbeyan NSW Pool flat plate			$2,573	$5,642	13	70°C	$1,528
Tubes, De Bortoli Winery Griffiths NSW			$1,170	$3,407	143	95°C	$1,901
Australian Institute of Sport		$60	$173	$361	720	40°C	$327
Tower Estimate from CSP in Australia study				$1,047	100,00 0	600°C	$4,168
Domestic (10m^2) Pool Heating	$300	$300	$600	$1,250	5	40°C	$252
Quenbeyan Pool Heating unglazed (340m^2)	$120	$120	$240	$500	282	40°C	$342
Industrial Solar estimate				$1,335	1,000	250°C	$1,335
Annas et al. 2005 Unglazed @ 35°	$140	$140	$280	$560	200	35°C	$346
Annas et al. 2005 Unglazed @ 50°	$140	$140	$280	$800	200	50°C	$494
Energetics Flat Plate 1	$349	$349	$699	$1,205	200	80°C	$744

Annas et al. 2005 s Flat 2	$604	$357	$960	$1,455	200	80°C	$898
Annas et al. 2005 Flat Plate 3)	$418	$357	$775	$1,292	200	80°C	$797
Annas et al. 2005 Evac Tube @ 85°	$418	$357	$775	$1,409	200	85°C	$869
Annas et al. 2005 s Troughs @50-150Deg	$667	$238	$905	$1,292	200	100°C	$797
Large troughs @400Deg from CSP in Austarlai study				$1,047	100,000	400°C	$4,168

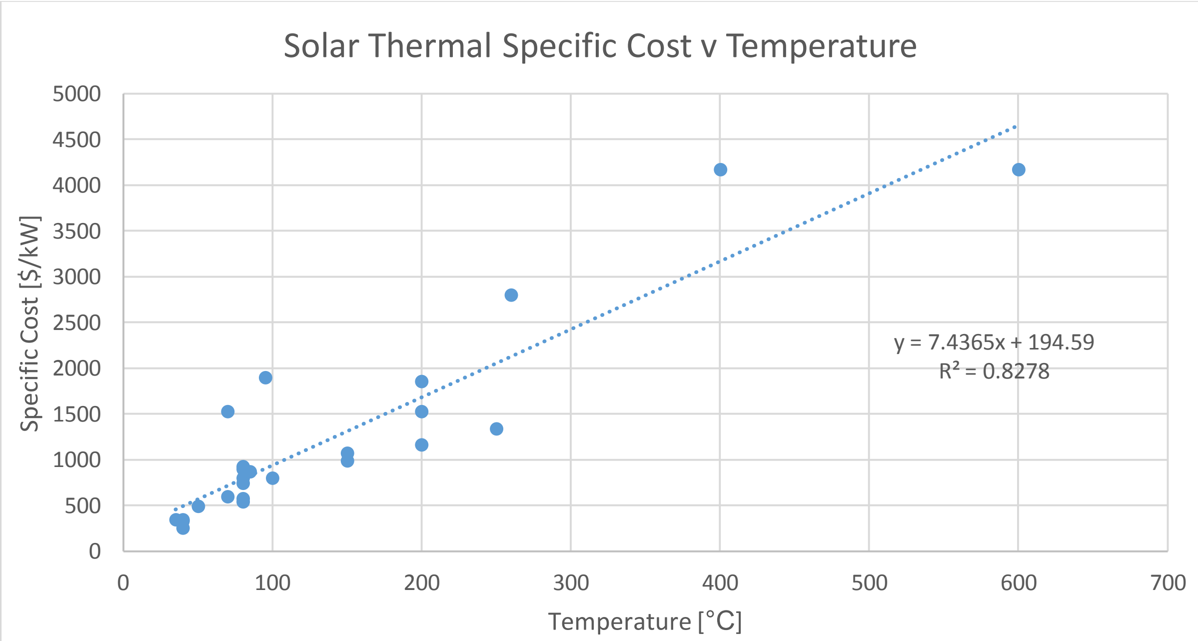


Figure 50. Solar Thermal specific cost versus temperature, normalised to a 1 MW_{th} system and expressed in AUD 2014.

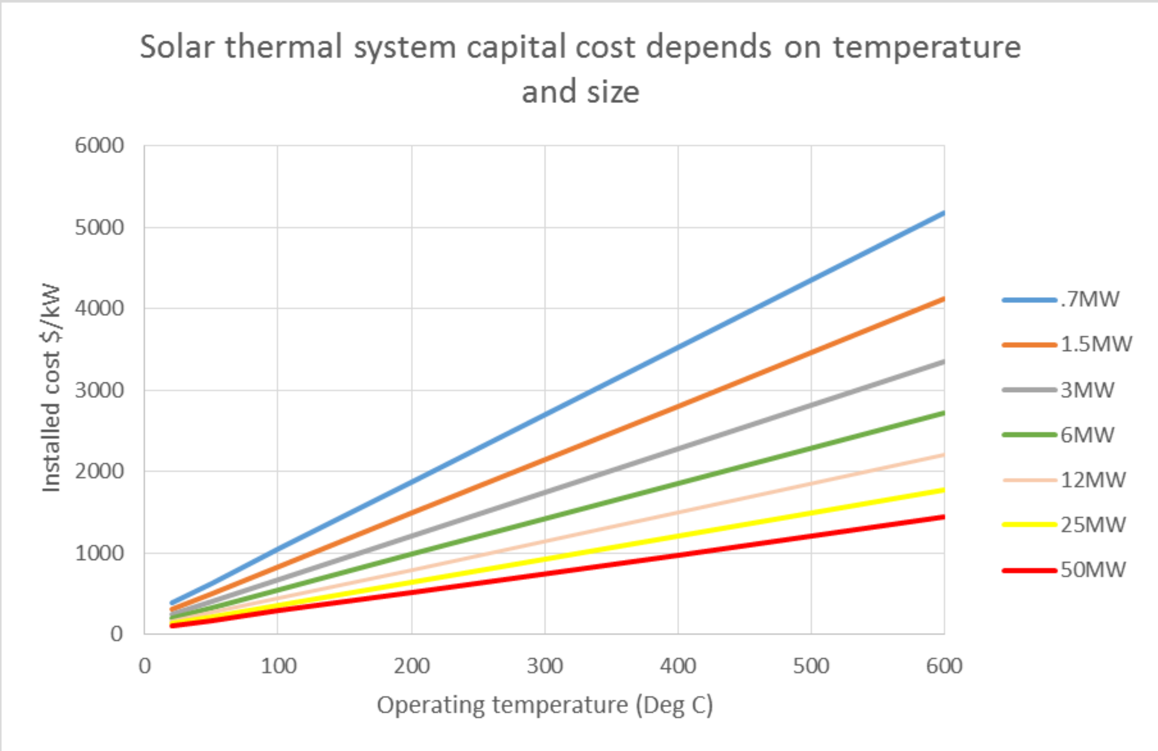


Figure 51. Solar Thermal specific cost versus temperature, for a range of system capacities, in AUD 2014.

5.4.5. Performance analysis of solar thermal systems

Solar Thermal systems are subject to the variability of solar input, through the diurnal cycle, cloud variability and seasonal variations. Predicting their performance is a more complex process than it is for other technology options. Overall analysis of economic potential requires an estimate of annual output. Assessing the integration issues associated with matching production to load requires prediction of output on an hour by hour basis.

The determinants of instantaneous energy production can be summarised as:

- The thermal losses that are directly linked to the instantaneous temperature of the system. These are largely independent of the level of solar radiation absorbed, as a consequence, at low solar input, efficiency drops.
- The level of solar radiation absorbed, which is determined by both the instantaneous intensity of radiation and the angle at which it strikes the collector aperture. The output of a fixed collector will be at a maximum when the sun rays are perpendicular to the surface of the collector (typically around midday). At lower sun angles the solar gain will be reduced due to the lower projected area presented to the sun. Tracking collectors also experience

incidence angle effects. For a single axis concentrator, seasonal sun movement away from perpendicular to the tracking axis reduce output[27].

- Dynamic effects such as lags due to the thermal capacity of components and minimum operational thresholds.

The following sections examine, firstly, the determination of peak efficiencies for the various collector types, followed by an examination of the modelling of the semi-dynamic behaviour of the systems over a full year, leading to some indicative results that best inform further economic comparisons for this study.

Peak Performance

The efficiency of a solar collector refers to the heat output for a given heat input and can be defined as:

$$\eta = Q_{out}/Q_{in}$$

AS/NZS 2535, ISO 9806 and the IEA SHC use the following second-order equation to model collector efficiency.

$$\eta = \eta_0 - a_1(T_m^*) - a_2 G (T_m^*)^2$$

where:
η = collector thermal efficiency
η_0 = "optical efficiency" - collector thermal efficiency at $T_m^* = 0$
a_1 = first order loss coefficient ($W/m^2/°C$)
a_2 = second order loss coefficient ($W/m^2/°C$)
T_m^* = reduced temperature difference = $(t_{fluid} - t_{ambient})/G$
G = solar irradiation (W/m^2)

The constant η_0 is indicative of the optical efficiency of the collector under direct normal irradiance, while the two coefficients a_1 and a_2 describe the increasing thermal losses of the collector with increasing temperature.

Derivation of the coefficients for this equation is addressed by many collector testing laboratories around the world and, if the area of the collector is known, the equation can be used to determine the output of the collector at a particular irradiance and temperature.

Representative coefficients for Unglazed, Glazed Flat Plate, and Evacuated Tube solar thermal technologies are listed in Table 20.

[27] Angle effects are often quantified by a scale factor on peak efficiency called the Incidence Angle Modifier (IAM), this can be plotted as a function of time of day or be quoted as an annual average.

Table 20. Efficiency coefficients for various solar thermal technologies (for gross area)

Collector Type	η_0	a_1	a_2	Source
Unglazed	0.840	18.00000	0.00000	IEA SHC via Energetics
Flat Plate	0.608	5.47000	0.01260	SRCC – Solahart L Series
Evac Tube	0.456	1.35000	0.00380	SRCC – Apricus AP-20
CPC	0.554	0.81180	0.00307	SRCC – Ritter 18 OEM[28]
Trough	0.720	0.15000	0.00170	SANDIA via Energetics

The efficiency curves which result from the efficiency equation and the coefficients provided in Table 20 are shown in Figure 52.

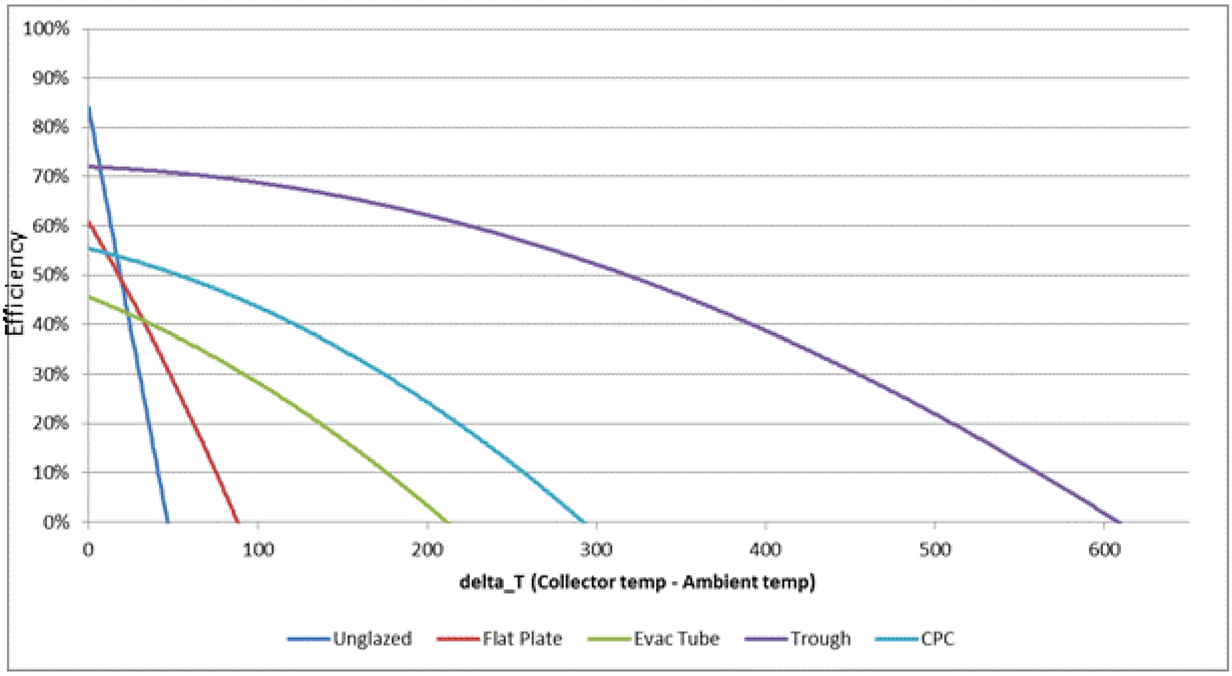


Figure 52. Peak efficiency at 1000/W/m² irradiance (GHI or DNI as appropriate) vs temperature.

As the temperature of the fluid increases, so too do the losses, until the efficiency drops to zero for some limiting temperature. This limit is low for unglazed collectors, restricting them to low temperature applications such as pool heating. Unglazed collectors can be seen to have the highest optical efficiency, but also the highest thermal losses for a given temperature.

A glazed flat plate collector has lower optical efficiency than an unglazed collector due to the small amount of radiation reflected by the glass. However, this glass prevents losses to the ambient air and also reduces re-radiative losses, with the glass transmitting high wavelength solar

[28] http://www.andyschroder.com/ (Accessed 19-08-14)

radiation, but blocking low wavelength thermal radiation (the greenhouse effect). Lower thermal losses are the result, and higher temperatures are thus attainable.

Evacuated tube collectors will tend to have lower optical efficiency (based on gross collector area) than flat plate collectors on account of the spacing between tubes. The spacing plus the curved surface of the absorber tubes however means that they maintain their performance at close to peak levels for longer hours of the day.

The efficiencies considered in this study are based on gross area of the collector. There can often be confusion, particularly in the comparison between flat plate systems and evacuated tubes, between efficiencies defined around the gross area of the collector, the aperture area, or the absorber area. Gross area refers to the footprint of the collector, and so includes the frame and manifold of the collector. Aperture area refers to the glazed area of a flat plate collector, and to the diameter multiplied by length of the glass tubes in an evacuated tube collector. Absorber area is the exposed absorber area of a flat plate collector, and the total diameter multiplied by length of the cylindrical absorbers within an evacuated tube collector.

When gross area is considered, evacuated tube collectors will tend to appear less efficient than flat plate collectors at low temperatures (low thermal losses), owing to spacing between tubes and the evacuated space within each tube collecting no energy from incident radiation. When absorber or aperture area is considered, the efficiency of tube systems will appear relatively higher.

Annual Performance Analysis

To assess collector performance in different locations around Australia, the System Advisor Model (SAM[29]) developed by the U.S Department of Energy's National Renewable Energy Laboratory (NREL) has been used. SAM models the hourly performance of a solar thermal system using a range of parameters specified by the user, alongside a solar data file which includes hourly irradiance and ambient temperature information for a specific location.

SAM contains a range of default models for different solar thermal technologies. A solar hot water model can be configured for glazed and unglazed flat plates and evacuated tube systems. High temperature concentrator system thermal performance can be considered by examining solar field output in separate models for, parabolic trough, linear Fresnel and heliostat tower based concentrating solar thermal power systems.

The solar data files used represent mean years from the Australian Climatic Data based and downloaded from the Energy Plus website[30].

In the solar hot water model, the collector can be specified according to the area and the efficiency parameters described previously. Default values were used in this study, including

[29] https://sam.nrel.gov/
[30] http://apps1.eere.energy.gov/buildings/energyplus/weatherdata_about.cfm

levels of thermal storage and assumed load profiles. Collector and system performance for unglazed, glazed flat plate, and evacuated tube collectors at various locations around Australia within this model (see Appendix B).

SAM results are in the form of hourly time series data over the course of a year. An excerpt from the flat plate collector modelling is depicted in Figure 53. The graph shows three consecutive days with different irradiance conditions (above), and the resulting collector output (below).

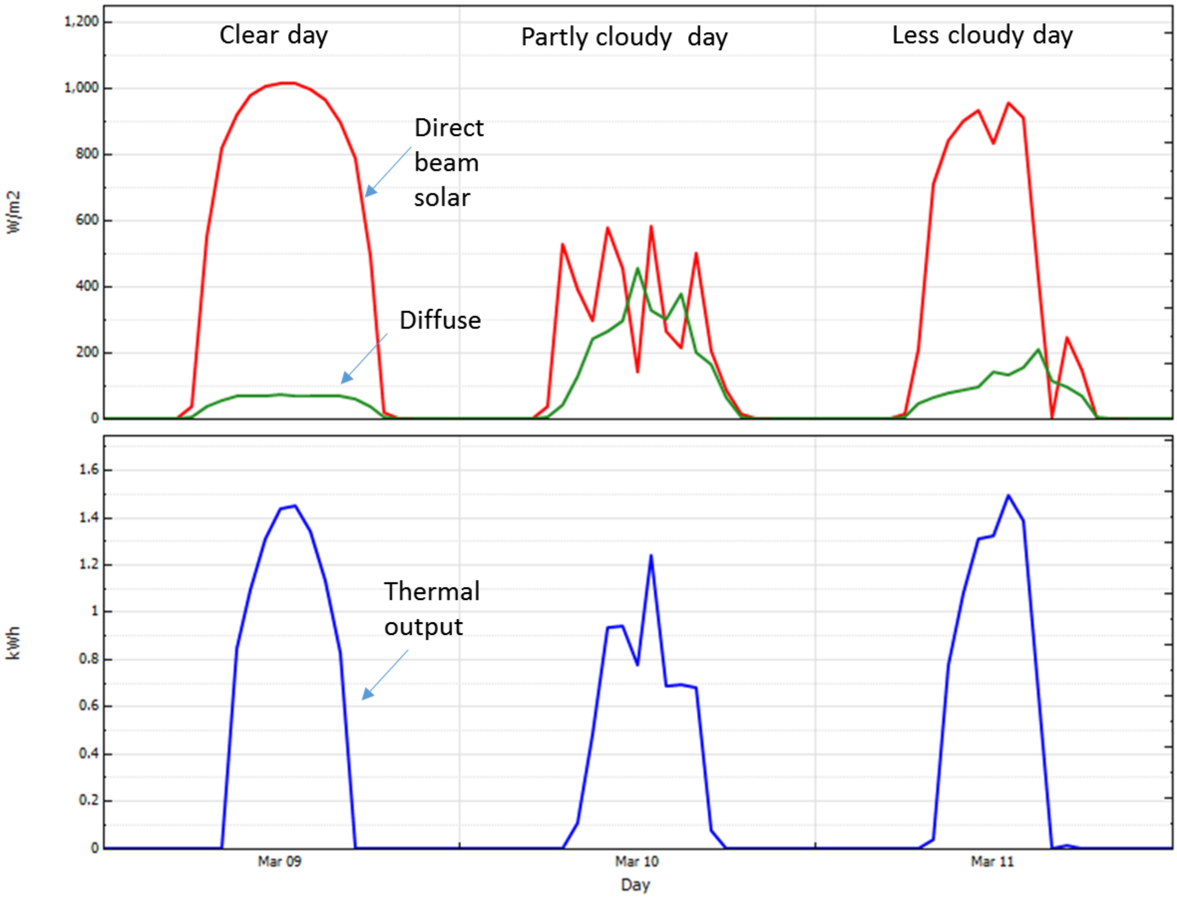


Figure 53. SAM time series results for a flat plate hot water system for three representative days.

Seasonal variation is deduced from the time series results, as per Figure 54. This excerpt from the flat plate modelling shows the impact that reduced irradiance and ambient temperatures have on collector performance from month to month.

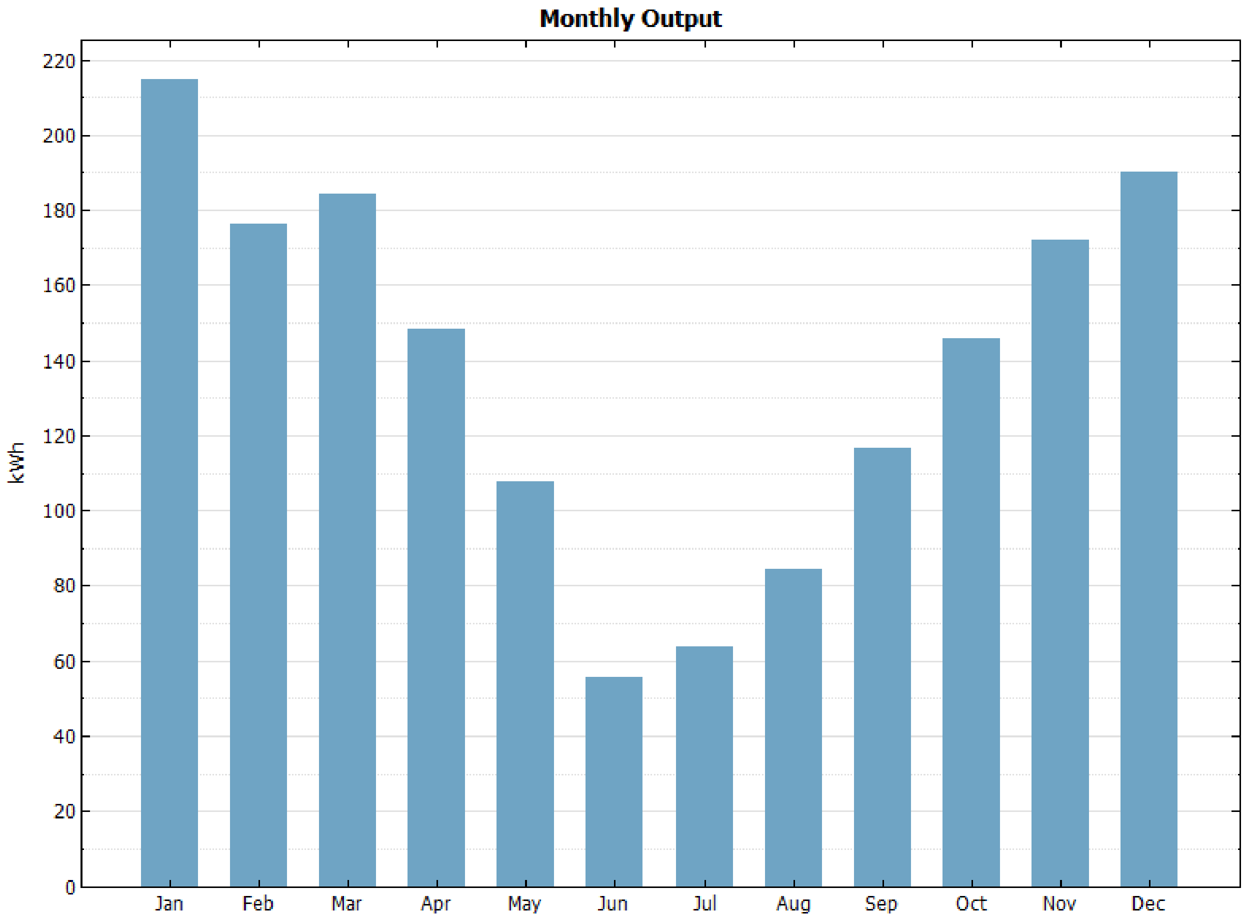


Figure 54. SAM monthly results

The performance of a $10m^2$ North-facing unglazed collector at raising water to 25°C was modelled. The collector tilt was set to 20°, which was assumed to be the typical roof pitch. This was not altered between locations owing to the inability to frame-mount non-rigid unglazed collectors. Storage parameters were set up to model a pool such that volume and thermal losses are high.

For the flat plate and evacuated tube models, the performance of $2.96m^2$ collectors at raising water to 55°C was assessed. The collectors were oriented due North and tilted at the latitude of the site. A typical 300L hot water tank was assumed for storage, and the ambient temperature surrounding the storage tank was set to the average annual ambient temperature of the location.

It should be noted that SAM modelling of solar water heaters is simple. The default settings do not include seasonal variation of load but rather a constant 200L/day, and modelling assumptions such as a mixed tank can result in understatement of performance for the type of solar water heaters that are used in Australia.

Whilst these example are sized for domestic applications, the predictions of output per unit area are equally valid for larger commercially sized systems.

The collector efficiency parameters that were used in the modelling are those shown in Table 20. The results in terms of annual output per square metre are depicted in Table 21 and Figure 55.

Table 21. Collector annual output by location

Location	GHI [kWh/m²/yr]	Average Ambient Temp [°C]	Unglazed [kWh/m2/yr]	Flat Plate [kWh/m2/yr]	Evac Tube [kWh/m2/yr]
Hobart, TAS	1,389	12.5°	1,038	541	838
Melbourne, VIC	1,469	15.0°	1,105	551	861
Albany, WA	1,582	14.7°	1,155	600	981
Sydney, NSW	1,773	18.4°	1,270	668	1,076
Brisbane, QLD	1,828	19.8°	1,341	699	1,096
Perth, WA	1,913	18.0°	1,419	736	1,084
Rockhampton, QLD	2,012	22.1°	1,440	762	1,215
Darwin, NT	2,114	27.3°	1,370	750	1,262
Alice Springs, NT	2,256	21.2°	1,706	877	1,256

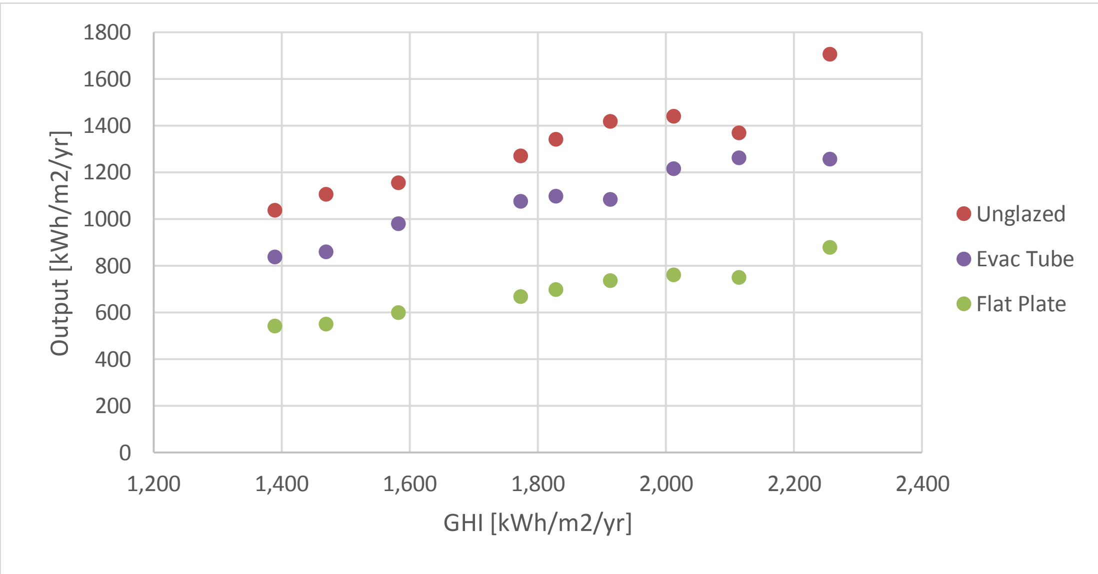


Figure 55. Collector output v GHI by location

As expected, the annual output for these three technologies shows strong dependence on annual GHI. Due to varying thermal losses in collectors, variation could be expected on account of ambient temperatures and other localised meteorological characteristics. Such effects are responsible for the scatter that is observed, however it is apparent that for a good rule of thumb, output is linear in the GHI.

If annual output is compared to the output expected at a design point GHI of 1000W/m^2 if it were maintained 24 hours a day, 365 days per year, the result is the relationship of capacity factor to GHI shown in Figure 56. These linear fits are used to support the economic analysis in Chapter 7.

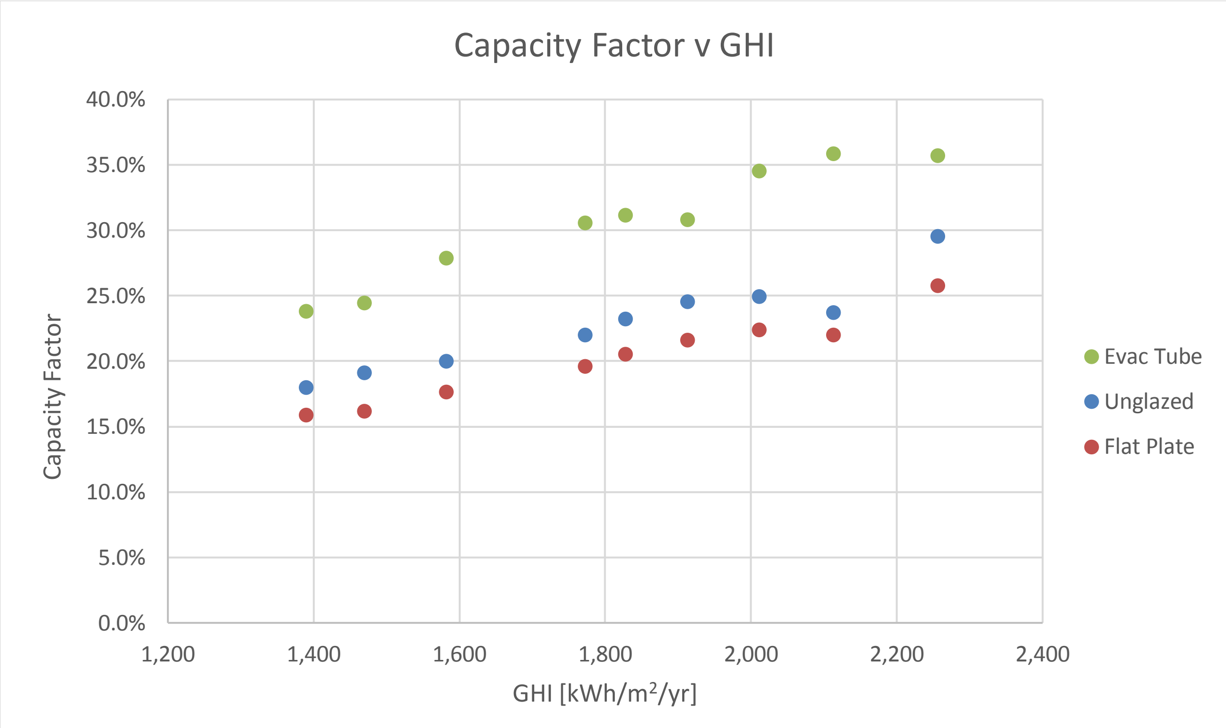


Figure 56. Collector capacity factor v GHI by location

Parabolic Trough

The 'physical trough' parabolic trough CSP plant model within SAM was also used to estimate capacity factor at various locations around Australia. SAM's trough model does not define the collector according to efficiency coefficients, but rather a range of physical parameters which can be specified by the user. The result of this is that determining a rating of the system is more complicated than the method used above.

The output of the system at all instances when direct normal irradiance was at or near 1,000W/m^2 was collated. Although there is some variation in output, it was most often small enough to derive a typical maximum output, which was used as the peak rating of the system. The annual heat output of the system could then be compared to this peak output to derive capacity factors as described previously (Figure 57).

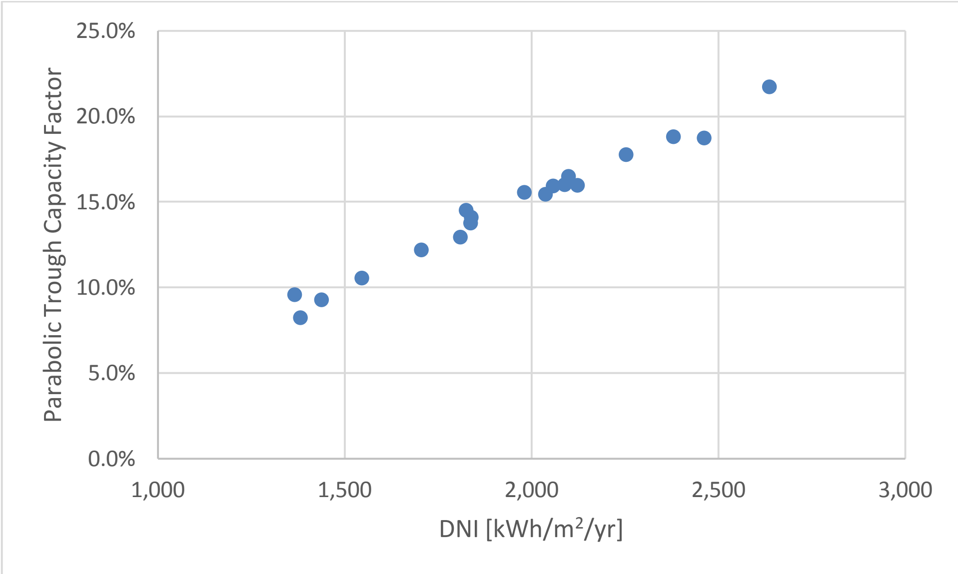


Figure 57. Trough capacity factor v DNI by location

Again a strong correlation can be observed against solar resource (in this case measured with DNI).

It has been assumed that trough capacity factors are a good approximation for Fresnel systems and also to a lesser extent heliostat systems. Although the performance of a trough system is strongly temperature dependant, it is assumed that the capacity factor is not.

5.4.6. Case Studies

The following pages contain a series of solar thermal case studies covering examples of the various technology types and their typical application. These are examples where solar thermal systems are being employed in cases where gas could also be applied.

S1 Case Study - Unglazed collector - Australian Institute of Sport, ACT

Summary

Resource	Canberra averages a global horizontal irradiation of about 18MJ/m^2/day
Investment	1,500m^2 of PVC strip collector
Construction	2011
Designed to deliver	Hot water to keep three indoor pools at 30°C, pumps are capable of moving 3.4 tonnes of water per minute
Energy saved	About $105,000 in first year of operation
Simple payback	Less than two years
Implementation	Original 585m^2 system installed in 1983 was removed.
Other aspects	Site has flat roof areas that are multi-tiered.

Description

The Australian Institute of Sport is located in Canberra. Its Swimming Centre has a variety of indoor pools heated to 30°C.

In 2011, Sunbather installed 1,500m^2 of PVC strip collector via HIPEC Commercial. Sunbather worked out the optimal collector area and pumping system for this project using a swimming pool thermal analysis program developed by the University of NSW. The software utilised a climatic data file for Canberra to perform an hour-by-hour thermal simulation of the pools' heat losses and heat inputs from gas and solar.

Figure 58. Aquatic Centre roof areas showing solar collector photos Sunbather

S2 Case Study - Glazed flat-plate collector - Marstal district heating, Denmark

Resource	Marstal averages a global horizontal irradiation of about 10MJ/m^2/day, (Marstal is at latitude 55°N)
Investment	33,000m^2 flat-plate solar collector orientated for optimal winter performance with hot water storage
Construction	In 2012, the existing 18,000m^2 collector field was expanded and the hot water storage was also significantly expanded
Designed to deliver	About half the annual district heating hot water requirements
Energy saved	46,540 to 55,440GJ per year
Simple payback	Not published, the storage system has received grant funding
Implementation	Integration with existing fossil fuel boilers has recently been supplemented with a new biomass boiler
Other aspects	District heating is common in Denmark

Marstal is a town on a Danish island with a population of about 2,300. It has a large flat-plate solar collector field that is used to reduce the amount of fossil fuels burnt over the year for domestic heating. The system also has a large hot water storage capacity.

The hot water is stored at 70°to 75°C but can reach 95°C in sunny periods. Next to the storage is a plant room that contains heat exchangers, control systems and the back-up fossil fuel boilers. The boilers are used to supplement the solar field when there is insufficient heat to meet the load.

The back-up system has recently been upgraded with the aim of making it completely renewable. Additional infrastructure installed included a 4MW wood chip boiler with a 750kW$_e$ Organic Rankin Cycle generator operating off the boiler's flue gas and a 1.5MW$_{th}$ heat pump. The wood chips are sourced from locally produced willow crops.

Marstal solar flat-plate collector field,
photos Sunstore and Erik Christensen

S3 Case Study - Evacuated Tube - De Bortoli Winery, NSW

Resource	Griffith averages a global horizontal irradiation of about 20MJ/m^2/day
Investment	One hundred 30 tube collectors, about 200kW$_{th}$ with two 6,000 litre storage tanks and two 350kW condensing boilers
Construction	Start May 2013, commissioned August 2013, further control system optimisation Oct 2013
Designed to deliver	About 12,000 litres of 95°C water per day as a pre-heater
Energy saved	More than 80% of annual hot water load, around 1,120GJ per year
Simple payback	About 6 years, before grant funding
Implementation	Roof needed to be strengthened
Other aspects	The solar thermal project was a small part of a larger energy efficiency upgrade project across multiple sites.

As part of a bottling line expansion, De Bortoli Winery installed a large solar thermal evacuated tube collector at its Griffith winery in 2013. This system was designed to reduce gas consumption for hot water by more than 80% over the year.

The evacuated tube collectors are mounted at a tilt angle of 37 degrees to optimise performance in high demand periods and two 6,000 litre stainless steel storage tanks are used to store the hot water. Two high-efficiency, 350kW gas-fired boilers were also installed to ensure bottling can be scheduled as required. A programmable smart control system was installed by De Bortoli Wines which maximises daily gas savings.

The winery also installed a 230kW photovoltaic system which was forecast to produce about 349MWh per year, (1,586kWh/kW$_p$/year). The simple payback on the photovoltaic system was estimated to be about three years. De Bortoli Winery received a $4.8m Clean Technology Food and Foundries Investment Program grant to contribute to the plant upgrade and expansion that was forecast to cost $14.5m.

Figure 59. Evacuated tube collectors and storage tanks, photos Apricus

S4 Case Study - Small solar parabolic trough - Cheese manufacturer, Switzerland

Solar resource	The site in Saignelegier averages a direct normal irradiation of about 12MJ/m^2/day
Investment	627m^2 trough solar collector field
Construction time	About 2 months
Designed to deliver	Process heat for cheese manufacture
Energy saved	50% of the daily heat demand on sunny days
Simple payback	Not published
Other aspects	Factory had a flat roof

NEP Solar have installed a 627m^2 trough solar collector field on the roof of the Emmis Tete de Moine cheese manufacturing plant in Switzerland. This system produces over 50 per cent of the daily heat demand of the dairy process on sunny days.

In Australia, NEP Solar have installed a 330m^2 trough collector field in Newcastle. This field can reach temperatures of 330ºC. The Newcastle Granite Power project received funding from ARENA and generates 30kW$_e$ and produces over 150kW$_{th}$ of heat for the Wallsend swimming complex.

Figure 60. Parabolic trough collector in Switzerland and a ground-mounted system in Newcastle, photos NEP Solar

S5 Case Study - Large solar parabolic trough - Minera El Tesoro copper mine, Chile

Resource	The Atacama Desert averages a direct normal irradiation of more than 30MJ/m^2/day
Investment	USD $12m for 10MW$_{th}$ trough solar collector field
Construction	Commissioned November 2012
Designed to deliver	Reduction in annual diesel use by 55% for the solution heating process
Energy saved	Reduces annual emissions by about 10,000 tonnes
Simple payback	Not published
Implementation	Installation workforce peaked at 180 people
Other aspects	Thermal storage allows for provision of heat outside of daylight hours

Abengoa Solar have installed 1,280 parabolic trough modules on six hectares of land adjacent to a copper mine in the Atacama Desert. The plant cost USD $12m and supplies heat to the copper refining process. The maximum operating temperature is 260ºC.

A heat transfer fluid (water with a corrosion inhibitor) is circulated through the solar collectors and a heat exchanger is used to deliver this heat to the storage tanks and the electro-extraction process used to produce copper.

The solar thermal system is designed so that it can store energy in the form of pressurised hot water. This allows the system to support operation after sunset and on partially cloudy days. The system controls automatically select the solar field, or the thermal tanks, or both as the sources of heat for the electro-winning process.

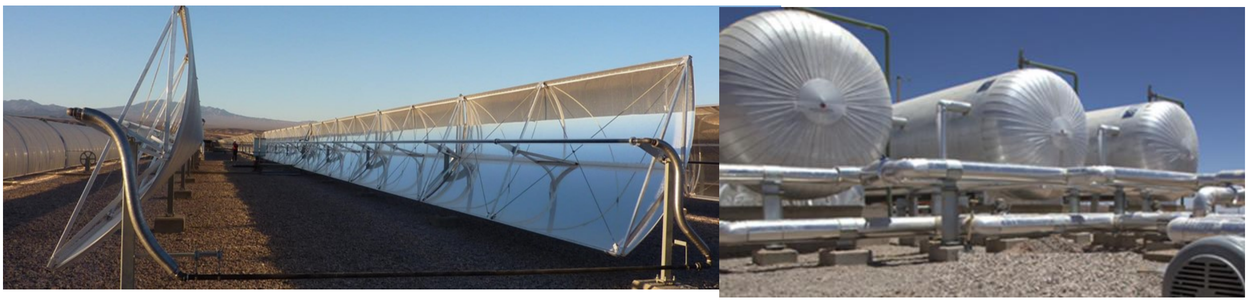


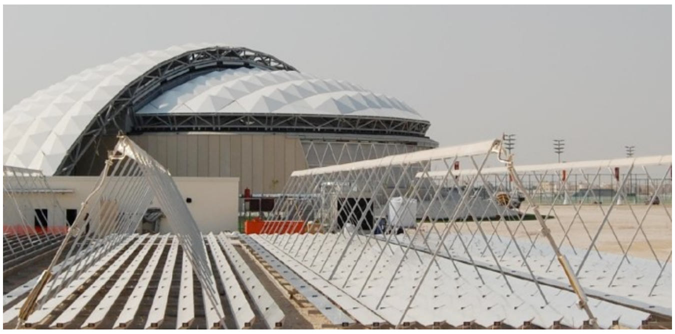
Figure 61. Parabolic trough collectors and thermal storage tanks at Minera El Tesoro, photos Abengoa Solar

S6 Case Study - Linear Fresnel collectors - Doha Football Showcase Stadium, Qatar

Resource	Doha averages a direct normal irradiation of about 20MJ/m^2/day
Investment	1,408m^2 Fresnel collector, rated at 700kW$_{th}$
Construction	2010
Designed to deliver	Water to 200°C to run chiller to cool football stadium
Energy saved	Demonstration project
Simple payback	Not published
Other aspects	Includes a 40m^3 hot storage tank and a 100m^3 phase change cold storage

The Doha Showcase Football stadium is typically used for a few hours at a time in the evening and is not used on successive days. To continuously cool the stadium, a large amount of power would be required. However, due to the intermittent nature of its use, an innovative cooling solution was implemented that uses a smaller air-conditioning system, which is predominantly solar powered. It is operated several days ahead of a game and relies on the thermal inertia of the building and eutectic tanks beneath the stadium to maintain conditions during use.

Due to the high ambient temperature and humidity during the daytime, the double-effect lithium bromide absorption chiller is operated in the evenings. The Fresnel collector field heats water to up to 200°C which is stored in the pressurised hot water storage tank. The tank is used to store approximately 2.5MWh of thermal energy. This is used to provide energy to the chiller which has a nominal cooling capacity of 750kW. The evaporator of the chiller is connected via a cold water circuit to a phase change material cold storage with a volume of 100m^3. The cold storage has a capacity of 5.8MWh thermal and is located beneath the stadium.



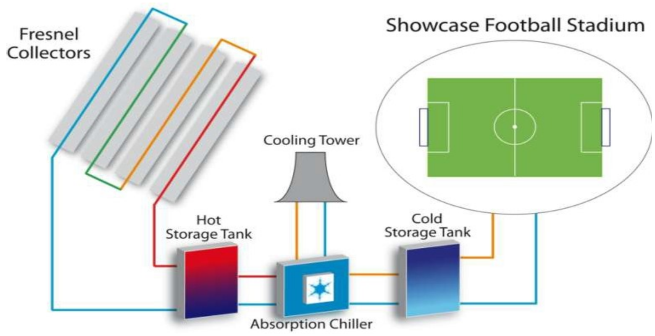


Figure 62. Fresnel collector field in Doha and diagram of cooling system, images Industrial Solar

5.5. Geothermal

Geothermal heat resources have a long history of use through natural hot springs. Geothermal energy systems rely on drilled wells to access heat sources of various types and temperatures within the earth’s crust. The two most important advantages of geothermal solutions are that the footprint at ground level is very small and once developed, wells can produce heat 24 hours per day on demand.

ARENA has recently examined the potential for geothermal energy in Australia in a comprehensive manner[31]. Three major reports have been released;

- *Barriers, Risks and Rewards of the Australian Geothermal Sector to 2020 and 2030*, a report for ARENA by the International Geothermal Expert Group Members, (ARENA 2014),
- *Competitive Role of Geothermal Energy near Hydrocarbon Fields*, a report by Evans & Peck (2014), and
- *Geothermal Energy in Australia*, a report produced by CSIRO (Huddlestone-Holmes 2014)

Although the focus of these reports is largely directed at the potential for power generation relevant material from these reports is reviewed here.

5.5.1. Resource types

In Australia, geothermal heat largely originates from radionuclide decay in deeply buried granites. Where an overlying rock strata has low thermal conductivity, it forms an insulating cap and allows rock temperatures to rise significantly as a consequence of the heat generated over long time periods. As a rough rule of thumb, temperatures increase between 20°- 35°C per km in depth, in Australia (Rockwater, 2015). Accessing this heat depends on the circulation of water to the hot rock, either naturally occurring or by artificially injecting it. In other countries water can be naturally in contact with heat sources that are connected with seismic or volcanic activity.

Huddlestone-Holmes (2014) provides a categorisation into three basic situations as illustrated in Figure 65.

[31] http://arena.gov.au/about-renewable-energy/geothermal-energy/expert-group/

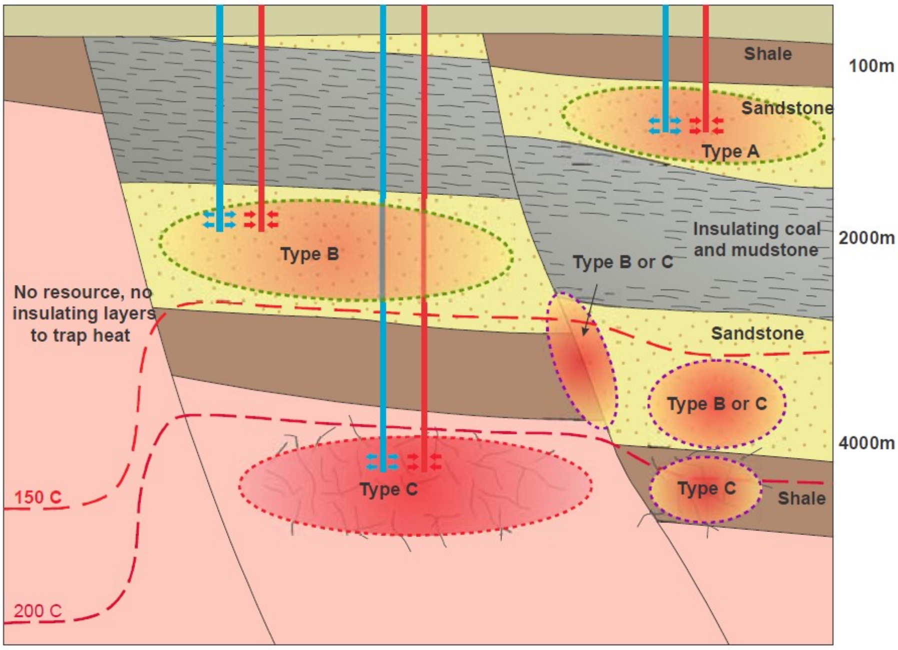


Figure 63. Geothermal resources, A) Shallow direct use,
B) Deep, natural reservoirs, and
C) Enhanced geothermal systems.
Reproduced from CSIRO, (Huddlestone-Holmes 2014)

The distinction made between the three types is based on depth and the temperatures available.

Shallow direct use and deep natural reservoirs, (together referred to as hot sedimentary aquifers) require establishing boreholes for water extraction. Shallow direct use and deep natural reservoirs have been exploited to a limited degree in Australia but to a much greater extent in other countries, eg New Zealand. They typically offer temperatures between 60 and 110°C.

The deeper, enhanced geological systems[32] can access higher temperatures between 200 and 250°C. To achieve this requires drilling bores to in excess of 4,000m, close to technically achievable limits. Drilling is then followed by artificial fracturing of the rock (Fracking) to establish a high surface area permeable region between injection and extraction wells

5.5.2. Technical approaches for hot sedimentary aquifers

Enhanced geological systems offer the greatest long term potential but are still in the R&D phase. It is hot sedimentary aquifers that could potentially represent a renewable energy alternative for industrial gas users in the near term.

Harnessing a hot sedimentary aquifer resource requires drilling bore holes. This is a standard practice with an established industry that is usually targeted at constructing bore holes to provide

[32] Sometimes referred to as Hot Dry Rock geothermal.

water resources. Holes are drilled at chosen diameters. Steel casings are then lowered in sections, with each section screwed to the next. The gap between casing and the side of the hole is filled with cement grout pumped in under pressure. A perforated screen is lowered into the bottom of the hole in the active part of the aquifer to allow water to flow but keeping rocks and sediment out.

The water in an aquifer is typically under some pressure, which will cause it to rise up the bore hole to an equilibrium at 50 or 100m below the surface. Consequently a submersible pump is lowered down to this level to produce the flows needed.

Bores holes can be drilled and cased in a range of diameters. Holes are often initially drilled at a small size and then ‘reemed’ to a larger size. For deeper holes, a hole may be drilled and cased to an intermediate depth and then continued further in a smaller diameter.

If the goal is to provide process heat, then the approach that offers the most sustainable use of a resource is to have two boreholes, one for extraction and one for reinjection. Aquifer water is brought to the surface and heat extracted via a heat-exchanger for the process, it is then reinjected to the aquifer as illustrated in Figure 64.

The alternative is to simply extract the water from one bore, extract the heat and dispose of it. This is clearly cheaper and there are geothermal heat projects which have done this and simply discharged water into a river or drain. If the water is needed for a town supply or irrigation purposes, then there is a stronger argument for the single bore approach.

The extraction rate achievable is limited by the ability of the aquifer to replace the extracted flow, determined by both the permeability/porosity and the thickness of the reservoir. Pumping requirements will also increase with increasing well depth and decreasing well diameter. Extraction rates and pumping loads have a significant impact on project economics.

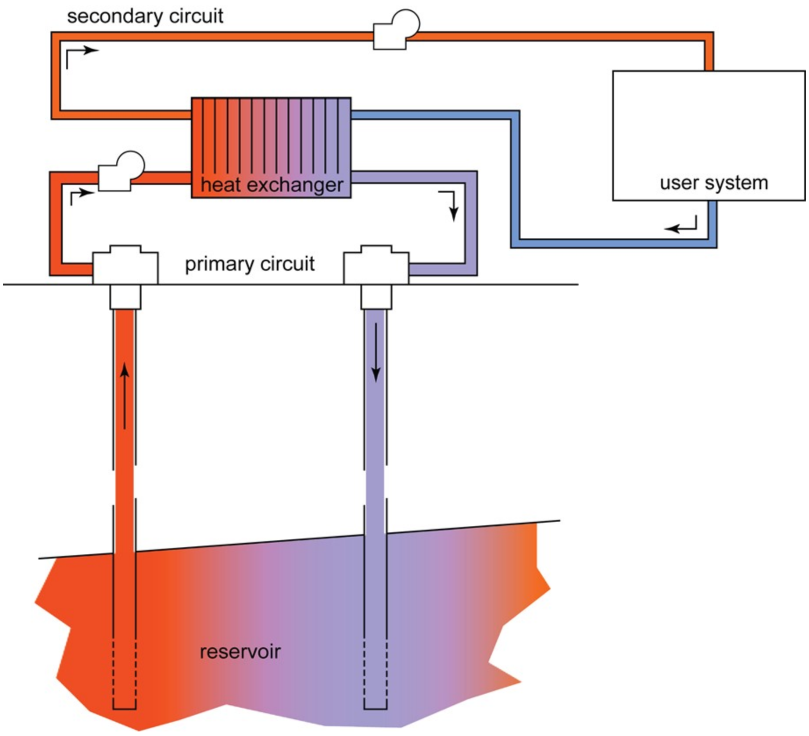


Figure 64. Typical geothermal 'doublet ' (Pujol & Bolton 2015)

Significant uncertainty exists during geothermal project development regarding the temperatures that exist at depth and the achieveable water flow rates from a well. As a result, geothermal project development involves probabilistic resource assessment by hydrogeological consultants.

Together with the temperature of the resource, the flow rate determines the thermal power which can be extracted.

Power (MWth) = mass flow rate (kg/s) x specific heat (kJ/kg/°C) x ΔT (°C)

where the specific heat of water is 4.186 kJ/kg/°C and ΔT (°C) is the temperature difference between the extracted groundwater at the inlet and outlet of the heat exchanger.

It can be seen that thermal power increases linearly with temperature and flow rate, and that even a “small” geothermal project with a flow rate of 10 L/s and ΔT = 10°C gives thermal power of 420kW. While increasing well depth (and hence cost) is most often required to attain higher temperatures (and hence thermal power), the flow rate achievable is mostly a property of the aquifer although higher flow rates can be achieved at the expense of increased pumping power requirements. Where the thermal load exceeds that which can be met by a single pair of wells, further wells can be added however they must be suitably separated to avoid locally lowering the temperature of the aquifer. The result is that project economics are highly dependent on flow rate.

5.5.3. Costs and opportunities

The *Competitive Role of Geothermal Energy Near Hydrocarbon Fields* report (Evans & Peck 2014) provides the following cost forecasts:

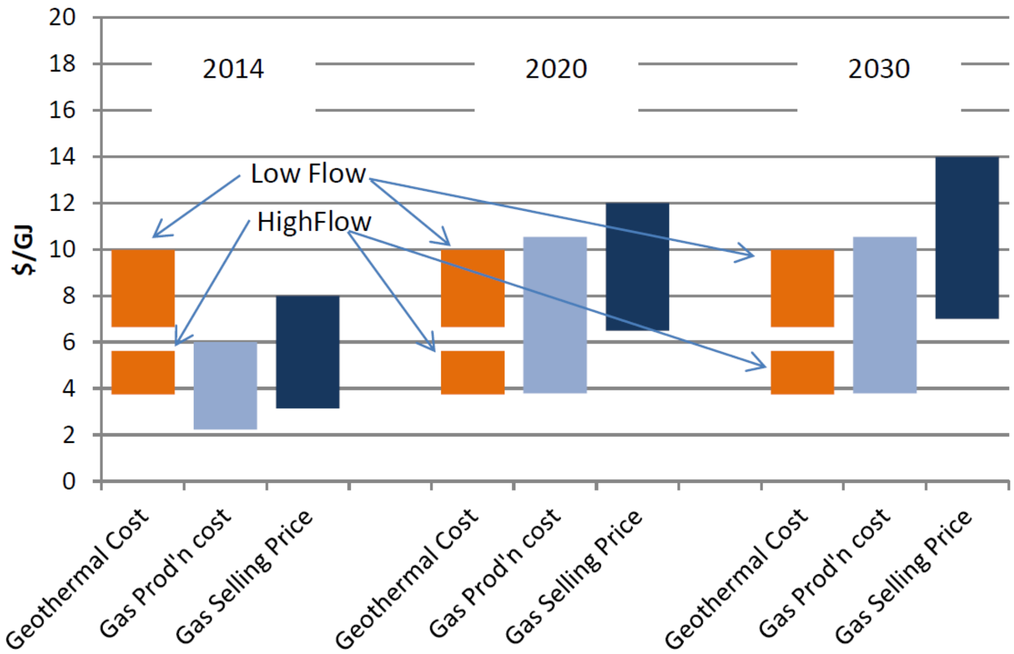


Figure 65. Comparison of geothermal energy cost, gas production cost and gas selling price at Moomba. Reproduced from (Evans & Peck 2014)

Evans and Peck conclude that by 2020, enhanced oil and gas recovery, processing facilities and various utilities could cost effectively be run with geothermal direct heat. Urea production and carbon capture processes are hypothetical new processes that could be viable by 2020 in Moomba.

The report identifies alumina production as a potential application and indicates that an enhanced geothermal system in the Cooper Basin that is remote from the bauxite is not a viable way to reducing energy costs. However, it is noted that there is an ongoing investigation of applying geothermal heat near the Gove alumina refinery in the Northern Territory.

The Evans & Peck report indicates that pulp and paper production is an application that might be suitable for regions that have the feedstocks in proximity to geothermal resources. There is an example of a major direct geothermal heat application in New Zealand's pulp and paper sector (see Section 5.5.4).

Table 22 quotes geothermal heat costs before allowing for a heat exchanger and injection costs to sustain circulation. However, Evans & Peck claim that this provides a valid comparison to the gas fuel price, as this does not include the cost of a gas fired boiler system. Evans & Peck conclude that even in a high flow scenario, geothermal heat would be too risky an investment in 2014 but should be viable by 2020.

Table 22. Geothermal heat production costs, from Evans & Peck, June 2014.

	Low Flow (40kg/s/well pair) $/GJ heat	High Flow (80kg/s/well pair) $/GJ heat
Optimistic well cost	6.66	3.75
Optimistic well cost + 50%	9.99	5.62

In the Cooper Basin, 2020 could mark a turning point for considering geothermal solutions as many existing facilities will come to the end of their working life and need to be replaced.

The analysis of the potential for use of geothermal heat for assisting gas production at Moomba notes that 8 per cent of gas is needed to provide the energy for production plant operations

The *Barriers, Risk and Rewards of the Australian Geothermal Sector to 2020 and 2030* report indicates that the most prospective markets for geothermal energy in Australia out to 2030 are in remote locations that are off the grid, and where there are commercial-scale applications for either electricity or direct heat. It also notes that where an identified geothermal resource is co-located with gas processing and recovery facilities, there may be opportunities for use of geothermal heat. The report provides detail on costs, including those reproduced in Table 23.

Table 23. Cost parameters for geothermal systems, from (ARENA 2014).

Parameter	Enhanced Geological Systems	Hot Sedimentary Aquifer
Capacity MW	50 MW	50 MW
Production wells	12	13
Injection wells	6	7
Resources depth km	5km	4km
Resources temperature ºC	250ºC	150ºC
Rejection temperature ºC	70ºC	70ºC
Flow rate kg/s	60 kg/s	100 kg/s
Production well costs $m	$281m	$120m
Cost per production well $m	$23.4m including stimulation	$9.3m
Injection well costs $m	$128m	$65m
Cost per injection well $m	$20.3m	$7.3m
Power plant costs $m	$100m	$125m
Power plant costs $/kW	$2,000/kW	$2,500/kW
Power plant efficiency (net of all parasitic loads)	9%	12%
Brine reticulation costs $m	$15m	$20m
Geology and permitting costs $m	$15m	$20m
Fixed O&M costs	2% of total capital cost	3% of total capital cost
Thermal draw down	none	none
Project life years	30 years	30 years
Electricity LCOE $/MWh	$222/MWh	$161/MWh

The cost parameters can be used to deduce the capital investment required for industrial heat applications. The thermal capacity of systems can be calculated from the power plant conversion efficiencies and their rated electrical power output.

For Table 24, the costs of the power plant have been removed for thermal applications. Instead an allowance for balance of plant aspects at 10 per cent of the quoted power plant cost is used to produce the specific cost estimates.

Table 24. Cost estimates for thermal energy developed from figures in ARENA 2014.

Parameter	Enhanced Geological Systems	Hot Sedimentary Aquifer
Thermal Capacity	550 MW_{th}	420 MW_{th}
Total Cost $m	$450m	$240m
Fixed O&M costs	2% of total capital costs	3% of total capital costs
Specific coat	$818/$kW_{th}$	$571/$kW_{th}$

An internal report provided by Rockwater Consultant Hydrogeologists (Pujol & Bolton 2015) gave the following capital cost estimates:

> "*For recent geothermal projects undertaken in the Perth Basin of Western Australia at depths ranging from 500 to 1500 m, the total capital costs ranged from $1350/m to $1850/m (average $1700/m). These costs exclude Heat exchanger and circulation pumps in the secondary circuit that would be required regardless of the chosen heating method. Costs include insurance (typically 1%), supervision, testing and control (13%), pipework (5%), headworks and submersible pump (10%) and all drilling related costs (71%).*" "*… for projects deeper than 1500 m heavy duty oil and gas drill rig will be required. It is estimated that these costs might be in the order of $2500/m ± $500.*"

The latter figure is consistent with the figure of $9.3million per 4,000m deep production well given in Table 23. In the economic modelling provided in Section 7.2.5, ITP have used $1,700/m capex for wells up to 1,500m in depth, and $2,500/m beyond that. An injection well is assumed to be 60% of the depth of the production well, and a cost-size scaling relationship has been assumed for drilling of multiple wells on one site.

5.5.4. Examples and Case studies

The *Geothermal Energy in Australia* report (Huddlestone-Holmes 2014) includes the following case studies.

- Two fish farms in South Australia and Victoria.
- A meat processing plant, owned by the Midfield Group in Victoria, uses 42ºC groundwater from an 800m deep bore. It is boosted to 82ºC for use in sterilisation.
- Two spas in Rye and the Mornington Peninsular use 43°C water from 700m.
- Various pool heating projects in Perth as listed in the following table.

Table 25. Direct use geothermal for pool heating in Perth, reproduced from (Huddlestone-Holmes 2014).

Installation	Year	Maximum Ground Water Flow (l/s)	Production Depth (m)	Injection Depth (m)	Thermal Power	Produced Ground Water Temp (°C)	Injected Ground Water Temp (°C)
Bicton	1997	18	750	n/a	400	40	n/a
Christchurch Grammar	2001	12	757	628	625	42	30
Challenge Stadium	2004	50	750	650	2,000	43	35
Claremont Aquatic	2004	14	864	608	775	43.5	31.5
Craigie Leisure	2006	21	802	452	400	40	34
St Hilda School	2011	20.5	1,007	682	1,275	49	34
Canning Leisure	2012	26	1,165	588	975	47	38
Beatty Park Leisure	2013	35	1,156	799	1,925	49	35
Hale School	2014	26	1,006	496	1,725	45.5	30
Mandurah Aquatic	*2015*	37	1,100	700	1,575	45.5	35.5

G1 Case Study - Geothermal - Kawerau timber processing plant, New Zealand

Resource	Geothermal fluids at 270°C
Investment	Production wells 950m to 2,100m deep
Construction	Built in 1957
Designed to deliver	5,000,000GJ per year
Energy saved	A range of users benefit from the resource
Simple payback	Not published
Implementation	Production wells tend to suffer rapid run-down due to mineral deposition and cold water inflow
Other aspects	Various measures are used to maintain output

The timber processing plant at Kawerau is one of the largest geothermal heat users in the world. The direct use is more than 5 PJ per year spread over three separate owners with supply from a fourth party. The geothermal field has been providing steam since 1957 and is the cheapest energy source at Kawerau.

The production wells range between 950m and 2,100m while the wells for reinjection range from between 300m and 3,000m. The resource temperature is 270ºC and about 9 to 12 million tonnes of brine fluid are extracted annually by the timber processing plant. This hot fluid is directed to several uses:

- the Bay of Plenty TG1 power station generating 2.6MW and rejecting fluid at 109ºC,
- the TG2 power station generating 3.8MW and rejecting fluid at 85ºC,
- to supply 2.7Mt per year of steam for Norske Skog Tasman (NST) for its 8MW geothermal turbo alternator, and
- for use by NST, Carter Holt Harvey and SCA Hygiene in their pre-evaporators, boiler feedwater heating, timber drying kilns and paper drying.

Figure 66. Kawerau timber mill site and 8.3MW binary cycle plant installed in 2008, photos NZ Geothermal Association

5.6. Heat Pumps

Heat pumps are systems that use a small amount of high grade energy to upgrade low temperature heat to a higher, useful temperature. Heat pumps generally use a compression and expansion cycle of a working fluid to transfer low temperature heat from a source to useful heat where it is required. They can provide multiple units of useful thermal energy for each unit of electrical energy consumed and are classified as harvesting renewable energy by some stakeholders, given that the bulk of the energy is provided by the environment. If the electrical energy is provided by an onsite photovoltaic system, then the operation is completely renewable and in keeping with the terms of reference of the present study. Alternatively, or in addition they can be driven by grid electricity which may or may not be renewable in origin. Either way, heat pumps can be used to replace gas for industrial processes

The basic concept of a closed cycle vapour compression heat pump is illustrated in Figure 67. In heating mode, the working fluid gas is compressed such that its temperature increases, and then passes through a heat exchanger to deliver heat to the application as it condenses to liquid form. The working fluid is then expanded to lower its temperature below that of the source heat temperature (eg. ambient air or waste heat). The fluid can then travel through another heat exchanger to collect heat from the source to evaporate it.

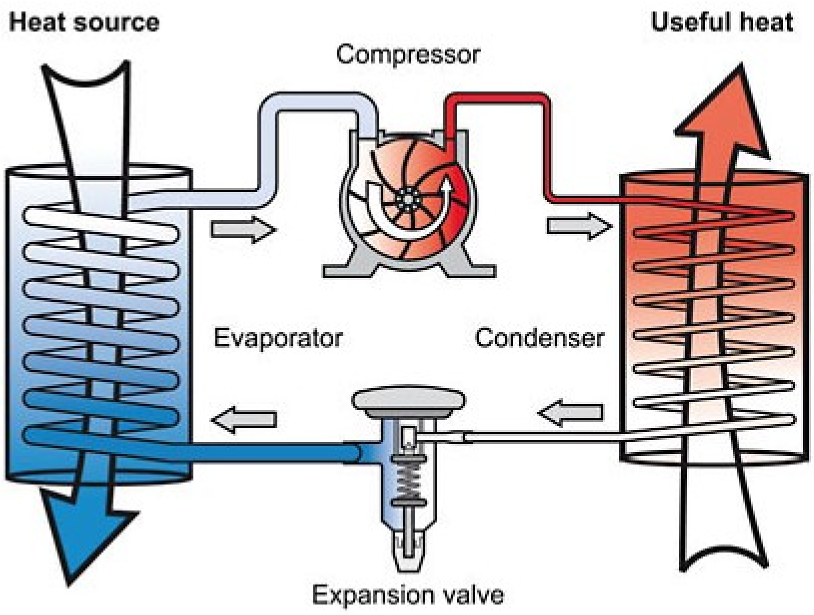


Figure 67. Components of closed cycle vapour compression heat pumps[33]

Heat pumps can be used in a wide range of applications as illustrated in Figure 68. Based on the Japanese analysis presented in Figure 68, the industrial use of heat pumps is dominated by cooling processes and space heating and cooling using low (-100 ºC to 50ºC) temperatures.

[33] http://www.veoliawater2energy.com/en/references/heat-pumps/

Steam generation by a vapour recompression (VRC) heat pump is shown as a high temperature (up to 165ºC) industrial application. A further guide to the range of sink temperatures, and the temperature lift ranges is given in Table 27, below.

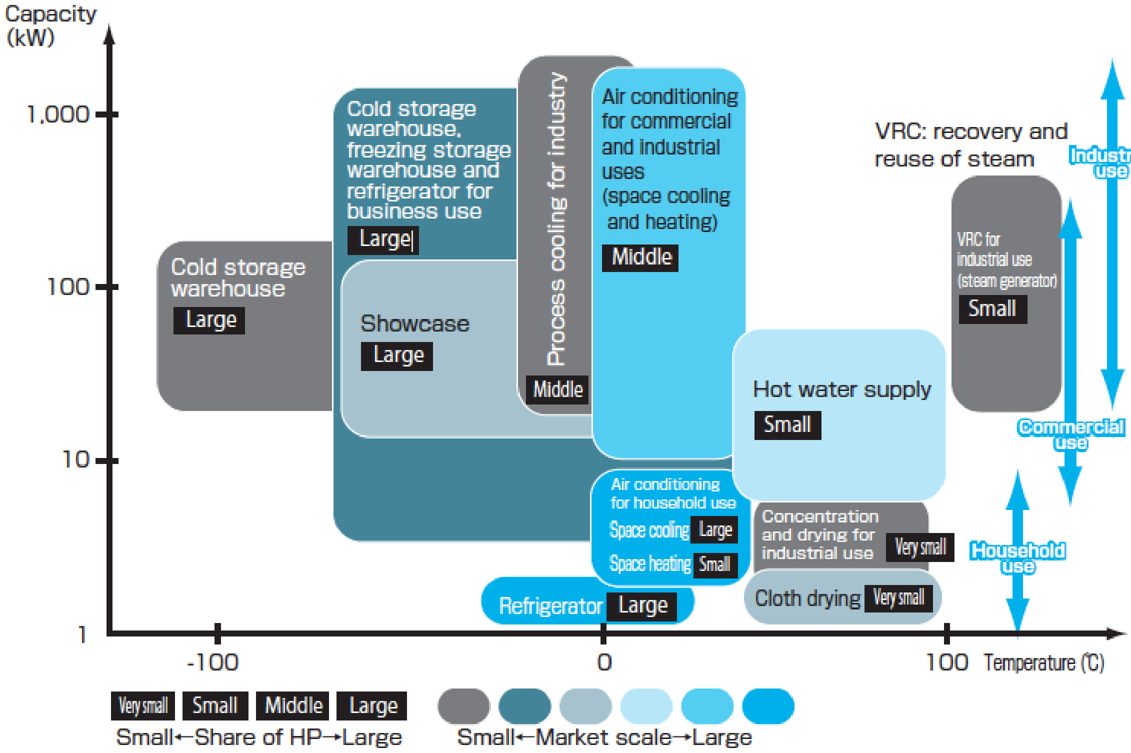


Figure 68. Heat pump applications (Heat Pump & Thermal Storage Centre of Japan 2011)

Sites where heating, cooling, water heating and drying are required simultaneously offer opportunities to improve efficiencies by minimising waste heat and coolth. The introduction of heat pumps delivering water at temperatures below 100°C is relatively straight forward as a range of heat pump units are commercially available.

SPECIFICATION (for reference)	
Description	Water Heat Source CO_2 Heat Pump Hot Air Heater
Heating Capacity	125KW
Rated Brake kW	25KW
Refrigerant	R744(CO_2)
Compressor Model	Semi-hermetic Reciprocating 2-cylinder type model: C2HT
Main Motor	3φ×AC200V
Rated Cooling Capacity	9.0 ton
Operating range	Hot air outlet temp. below 120°C Heat source water outlet temp. -10°C~25°C
Note: Capacity in above table is based on 20°C intake air temp., 100°C hot air leaving temp. and 20 °C evaporating temp.	

Figure 69. Example of a commercial heat pump for hot air at 100ºC[34].

Figure 69 shows an example of a small scale industrial heat pump for process heat applications. Typically, higher temperature applications are more complex requiring integration with existing processes and waste heat sources.

Temperature lifts of 30-100ºC are seen as necessary to enable the widespread use of heat pumps in industrial processes. Above 100°C, there are few commercially available heat pumps that can deliver these temperatures and it is generally considered that these applications *still require additional R&D activities for the development of high temperature heat pumps, integration of heat pumps into industrial processes and development of high temperature refrigerants* (IEA Heat Pump Centre 2014a).

Despite the need for R&D there are manufacturers with heat pumps that can deliver temperatures up to 165 ºC. In 2013, Kobelco announced the development of two heat pump models capable of delivering steam at 120ºC and 165ºC. The Kobelco high temperature heat pumps are only available in Japan. Thermo-acoustic heat pumps are also being developed for high temperature use with temperatures up to 180ºC achievable (IEA Heat Pump Centre 2014a).

5.6.1. Technology

Heat pumps can be categorised by the source of the energy and also by the process used within the heat pump.

- **Air-source** heat pumps are used widely for air-conditioning. They can be used for both heating and cooling, when they are referred to as reverse-cycle. Air-source heat pumps tend to be smaller, modular and mass produced products.

[34] Heat Pump & Thermal Storage Technology Centre of Japan, Survey of availability of Heat Pumps in the Food and Beverage Fields, March 2010,from http://www.hptcj.or.jp/Portals/0/data0/e/publication/pdf/survey.pdf

- **Ground-source** heat pumps have lower running costs but are more expensive to install due to the need to bury heat exchanger pipes underground. The lower running costs are due to the use of the ground as the energy source/sink and the grounds higher conductivity and capacity to accept and provide energy.
- **Water-source** heat pumps are similar to Ground-source heat pumps and may be less expensive to install. They use a large body of water, such as a lake or the ocean, as the energy source/sink.
- **Waste-energy** source heat pumps use an otherwise unwanted or unutilised energy from and industrial process as the source/sink. This can be the waste energy from a heating or a cooling process. Industrial scale heat pumps use a waste heat source to increase efficiency and optimise project economics. Heat pumps could be particularly beneficial to gas users who have waste heat streams and or simultaneous needs for cooling and heating.

The different thermodynamic processes used in heat pump systems are (IEA Heat Pump Centre 2014b):

- **Closed cycle compression** heat pumps operate in the same way as the heat pumps used in refrigerators and air-conditioners. This is the dominant approach in commercial operation. There are four different types of compressors used: scroll, reciprocating, screw and turbo compressors. The different types are commonly used at different sizes: scroll compressors are used in heat pumps up to 100 kW heat output; reciprocating compressors up to 500 kW; screw compressors up to 5 MW and turbo compressors in systems above 2 MW; and, oil-free turbo compressors above 250 kW.
- **Vapour injection** heat pumps are similar to closed cycle compression systems. The economizer vapour injection (EVI) cycle uses an additional heat exchanger to sub-cool the refrigerant before it enters the evaporator, increasing the capacity gain measured in the system. In the sub-cooling process, a proportion of the refrigerant is evaporated and injected into the compressor providing additional cooling at higher compression ratios.
- **Mechanical vapour recompression** heat pumps increase the pressure of waste gases and this increases the temperature at the same time, allowing the heat to be re-used. Steam is the most common type of vapour compressed by MVR. The most common MVR system, often used in evaporation applications, is a semi-open type where the vapour is compressed directly. Following compression, the vapour is condensed in a heat exchanger where it is delivered to the target process. The other type of semi-open MVR system uses and evaporator instead of a condenser. This type is used to vaporize and increase the temperature of a process flow using mechanical work and a lower temperature heat source.
- **Thermal vapour recompression** systems achieve heat pumping through the use of an ejector and high pressure vapour. It is often referred to as an ejector. A TVR heat pump is

driven by heat, not mechanical energy, therefore it can be applied in situations where there is a large difference between fuel and electricity prices.

- **Absorption** heat pumps use a mixture of volatile and non-volatile working fluids. The boiling point of the fluid mixture is higher than the corresponding boiling point of volatile fluid, allowing for the volatile fluid to be evaporated and condensed from the mixture. In industrial applications, the most common mixtures are lithium bromide solution and water (LiBr/H2O) and ammonia and water (NH3/H2O). The absorption cycle has two possible configurations: Type 1, absorption heat pump and Type 2, heat transformer. The types operate at different pressure levels, and therefore at different temperatures, in the four main heat exchangers: evaporator, absorber, desorber and condenser. Absorption systems are dominantly used for cooling purposes.
- **Absorption-compression hybrid** heat pumps combine absorption and compression technologies. They utilize a mixture of absorbent and refrigerant and a compressor. There is an important difference between hybrid and absorption cycle. In the hybrid heat pump the absorber and desorber are placed in reversed order to an absorption machine, i.e. desorption in the hybrid cycle occurs under low temperatures and pressures and absorption under high temperatures and pressures.
- **Thermo acoustic** (TA) heat pumps are still in the development phase. They use acoustic energy to upgrade waste heat to usable process heat at the required temperature. (Spoelstra & Tijani 2005).

The key descriptor for the performance of a heat pump is the coefficient of performance (COP) which is the ratio of heat energy delivered or extracted to the energy input. The expression for the COP of a heat pump is:

$$COP = \eta \times \frac{T_d}{T_d - T_s}$$

Where: Td is the delivery temperature

Ts is the source temperature

η is the system efficiency. Efficiencies between 0.4 and 0.7 are typical.

Two main factors influence the COP, the temperature of the available (source) heat and the delivery temperature and the system efficiency. The COP is increases as the temperature difference between the source and the delivered heat (sink) decreases. Also as the delivery temperature increases the COP decreases. These temperature relationships are shown in Figure 70.

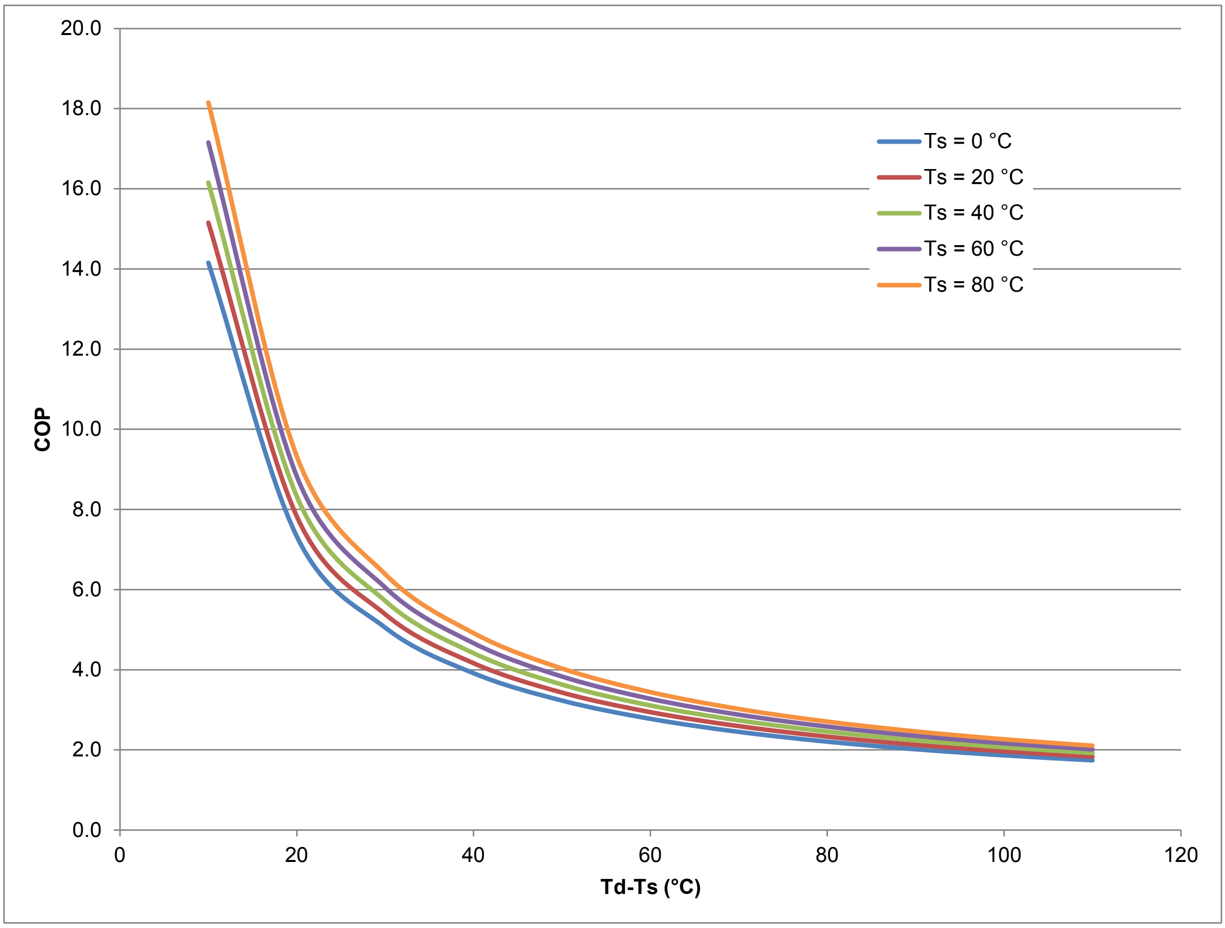


Figure 70 COP for different source temperatures and system efficiency η = 0.5.

The system efficiency can be estimated from the manufacturers COP and temperature information. The efficiency for several heat pumps is given in Table 26, indicating a typical range of between 0.5 and 0.7. The COP values from the manufacturers are shown against the curve for a theoretical heat pump of η = 0.6 and for source temperature of 40°C in Figure 71.

Table 26 Heat pump performance figures. [35]

Model	T_s (°C)	T_d (°C)	COP	η
Vilter-SC-291-300	35	55.7	9.91	0.62
Vilter-SC-291-300	29.4	56.2	8.25	0.67
Vilter-SC-291-300	23.9	56.8	7.07	0.71
Vilter-SC-291-300	35	61.9	7.92	0.64
Vilter-SC-291-300	29.4	62.6	6.79	0.67
Vilter-SC-291-300	23.9	62.9	6.03	0.70
Vilter-SC-601-600	35	61.1	8.36	0.65
Vilter-SC-601-600	29.4	61.7	7.22	0.70
Vilter-SC-601-600	23.9	62	6.43	0.73
Vilter-SC-601-600	35	64.8	7.53	0.66
Vilter-SC-601-600	29.4	65.8	6.59	0.71
Vilter-SC-601-600	23.9	65.2	5.82	0.71
Vilter-SC-601-600	35	68.6	6.81	0.67
Vilter-SC-601-600	29.4	69.3	6.02	0.70
Vilter-SC-601-600	23.9	70.2	5.4	0.73
Mayekawa PH-W85	40	65	6.5	0.48
Mayekawa PH-W105	40	70	5.7	0.50
Mayekawa PH-W105	40	75	5	0.50
Mayekawa PH-W125	40	75	4.8	0.48
Mayekawa PH-W125	45	85	4.5	0.50
Kobelco SGH120	120	65	3.2	0.52

[35] ITP analysis, Mayekawa information from http://www.mayekawa.com.au/wordpress/wp-content/uploads/2013/02/Plus-Heat-Water-Heat-Source-Heat-Pump.pdf, Vilter information from http://www.emersonclimate.com/Documents/Vilter/Product_Brochures/Heat-Pump-2011VM-43-R4.pdf, Kobelco information from http://www.chuden.co.jp/english/corporate/ecor_releases/erel_pressreleases/__icsFiles/afieldfile/2011/03/03/2.pdf

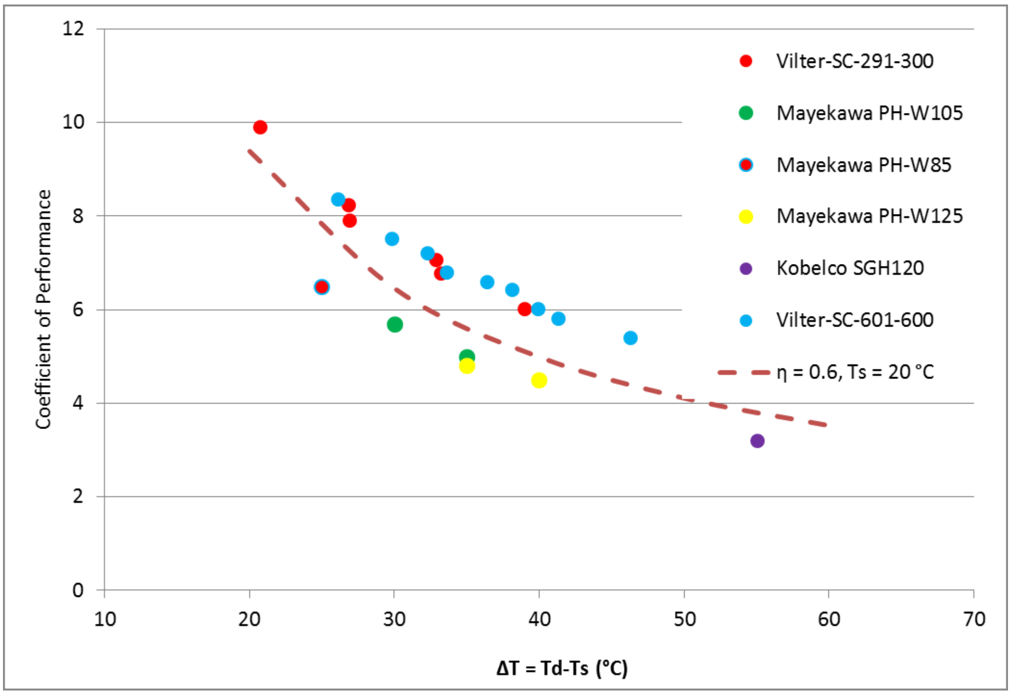


Figure 71 Manufacturer COP figures compared to COP for η = 60% and T_s = 20°C

In Figure 71, the COP of heat pumps from several manufacturers is shown by the point data. The COPs of the heat pumps are given for different source temperatures (T_S). The Vilter heat pumps have efficiencies of around 0.7 and the Mayekawa heat pumps around 0.5. Both use ammonia as refrigerant. The Vilter units use a single screw compressor and the Mayekawa units a reciprocating compressor. The Kobelco SGH120 is a high temperature heat pump using a screw compressor and a specially selected refrigerant.

5.6.2. Capital Costs

There is limited published information available on the capital and maintenance costs of industrial scale heat pumps. Australia currently has few large scale industrial heat pump systems in operation other than conventional HVAC and refrigeration applications and suppliers were unable to provide cost information. However, they advised that the industrial heat pumps installed in recent years have achieved pay back periods of less than 3 years. This is supported by IEA findings from European, Korean and Japanese heat pump projects across a range of industries with payback periods between 2 and 7 years (IEA Heat Pump Centre 2014b). Table 27 is sourced from (Becker 2009) and reproduces information published in a 1997 book (Berntsson & Franck 1997) using the Marshall-Swift equipment cost index.

Table 27. Wholesale equipment costs of industrial scale heat pumps (Becker 2009)

Type	Max Delivery Temp °C	Max Temp Lift °C	Installation Cost (2009 USD[36]) per kW Rated Output					
			500kW	*500kW*	*1MW*	*1MW*	*4MW*	*4MW*
			Lower	*Upper*	*Lower*	*Upper*	*Lower*	*Upper*
Closed compression cycle, electric	120	80	629	979	447	769	336	587
Closed compression cycle, engine	130	90	727	1,077	545	867	419	685
Mechanical Vapour Recompression (MVR)	190	90			531	629	189	308
Thermal Vapour Recompression (TVR)	150	40			294	378	140	168
Absorption Heat Pump type 1	100	50	475	545	419	489	350	406
Heat Transformer type 2	150	60	1,119	1,258	1,007	1,161	825	951

Based on the 1MW reference case above, adjusted to 2015 AUD, a specific cost curve ($/kWe) was developed for ITP's economic analysis using a cost-size scaling relationship. This cost curve was then validated against cost data from case studies of projects from Germany and Austria (IEA Heat Pump Centre 2014b). A comparison is provided in Figure 72.

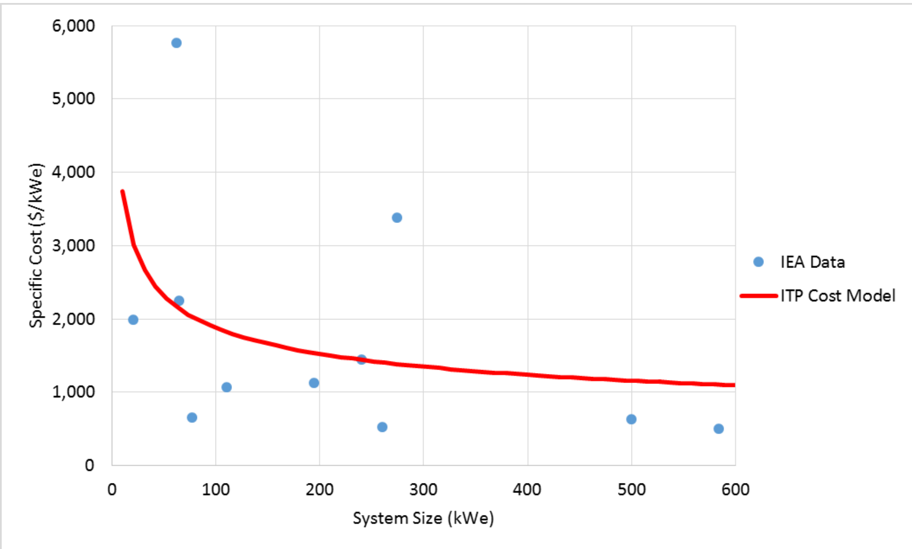


Figure 72. ITP cost model against IEA case study data for heat pump capex

Suppliers of industrial heat pumps in the Australian market include:

[36] Based on a Euro to USD exchange rate of 1.4

- Emerson Climate Technologies http://www.emersonclimate.com/
- Amertec Pty Ltd, www.amertec.com.au (agent for Emerson)
- Mayekawa (Mycom) http://www.mayekawa.com.au/

Typically, converting from a gas-fired boiler to an industrial heat pump involves changing the input energy to electricity, a more expensive energy source per unit. However, the higher COP can compensate for this.

5.6.3. Photovoltaics for powering heat pumps

Rooftop PV system costs vary, but installed costs between $2/W and $2.50/W are typical, excluding all subsidies. For every kWp of PV installed, annual generation of 1,000 – 1,850 kWh can be expected in Australia, depending mostly on the solar resource at the location, and the quality of the design/installation. These generation values equate to capacity factors of 11-21%.

The technology exists to install a heat pump and restrict its daytime electricity consumption to the output of a PV array and incorporate sufficient thermal storage so as to avoid production curtailment. However, it is more likely that sites will install PV systems according to available roof space and overall site loads. Replacing gas boilers with electric heat pumps will increase the site load able to be displaced by the cheaper PV electricity.

If a heat pump were to be powered directly by PV only, the capacity factor of the heat pump (relative to its electrical capacity – kWe) would be limited to the capacity factor of the PV system. For this reason, if the price of PV and grid electricity is assumed to be equal (rooftop PV LCOE's are typically between $0.10 - 0.20/kWh or $28 - 56/GJ in Australia), then the LCOE of PV-powered heat pumps will be higher than the LCOE of grid-powered heat pumps which can run at higher capacity factors.

5.6.4. Case Study

H1 Case Study - Heat Pump - Tree Top Food Processing, USA

Summary

Resource	Ambient air, not a PV with heat pump system
Investment	USD $1.25m industrial heat pump
Construction	2009
Designed to deliver	Heat for apple drying
Energy saved	About 94,300GJ of natural gas per year while electricity consumption increased by 8,580MWh per year
Simple payback	Less than 3 years
Implementation	Heat pumps can be installed to harvest waste heat from chiller condensers
Other aspects	The warm water reclaimed from the heat pump will be used for freezer defrost

Description

Tree Top Food Processing is one of the largest providers of dried apple products to the food manufacturing industry. The Wenatchee facility produces dehydrated apple products with moisture levels below 2.5 per cent. During harvesting periods, the plant can receive up to 900 tonnes of apples per day.

An industrial heat pump was installed in 2009 to provide heat to the conveyor for drying apples. The existing natural gas burners remain as auxiliary heat. It was estimated that the heat pump would save 94,300GJ of natural gas per year while increasing electricity consumption by 8,580MWh per year. The estimated energy bill savings were USD $463,000 per year.

Figure 73. Tree Top apple processing factory, photos Food Manufacturing Magazine

5.7. Other Fossil fuel options

A gas user considering a substitution of gas use by a renewable energy solution, will also inevitably consider other fossil fuel based options that may be available as part of an overall strategic review. The following section examines supplying process heat from coal or LPG.

The 2014 Australian Energy Statistics report that about 216PJ of coal, 23PJ of LPG and 2PJ of coal briquettes are used each year to raise process heat in Australia's manufacturing sector. It also reports 241PJ of other fuels used each year for thermal energy by manufacturers.

In regards LPG or fuel oil, they are effectively fuels than can directly substitute for natural gas. Indeed they can use essentially the same burners / boilers with retuning. However there is no realistic scenario where an existing natural gas user would find that LPG or fuel oil would ever offer a cheaper option. Rather those users who are using LPG or fuel oil are doing so because they are simply too far from a natural gas pipeline and those are the only options for fuel delivery.

Companies reliant on LPG or fuel oil can be regarded as an additional sector which might consider a renewable energy option. All the analysis carried out in the study applies equally to those users, they simply represent users facing input fuel costs that are at the high end of the range modelled here and thus will see proportionately better rates of return on a renewable energy option.

Coal is an alternative to natural gas for raising process heat through steam. It may not be a viable alternative for all heat requirements, eg glass manufacture, unless it is gasified first. Coal is a very low cost fuel source as provided to Australia's power stations.

5.7.1. Coal

The quality of coal varies depending on where it is sourced from and if it has been washed. The location of Australia's coal resources and mines is shown in Figure 74.

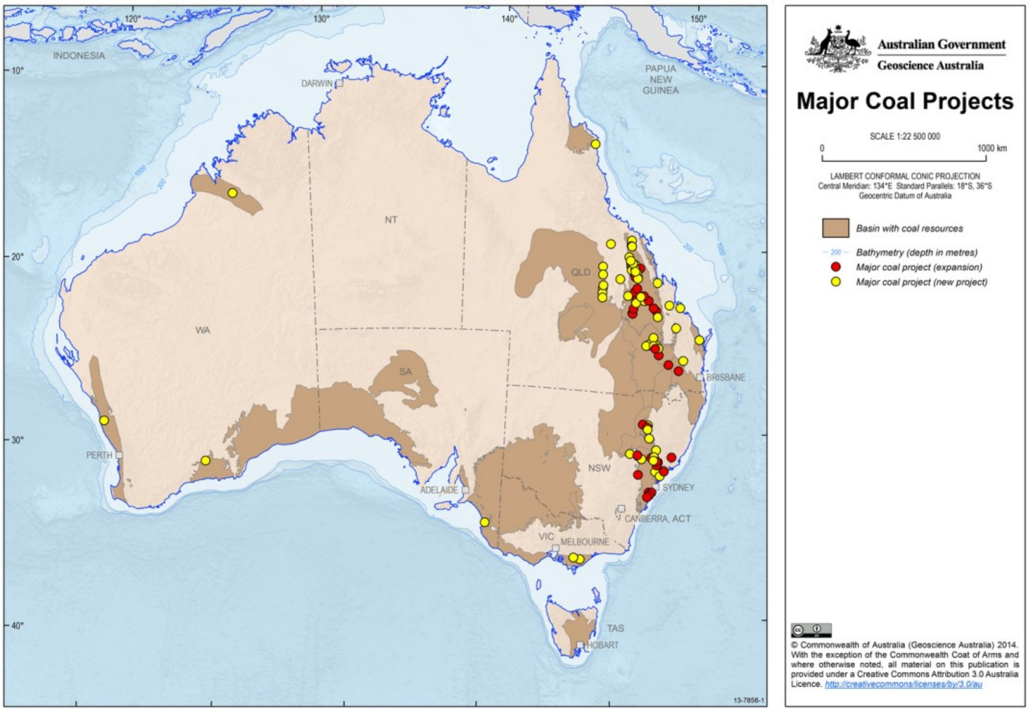


Figure 74. Major coal projects in Australia, (Image from: www.minerals.org.au/resources/coal/coal_mines_by_state)

More detailed maps of the mine site locations and their size by State is available from the Minerals Council of Australia website.

In 2014, BREE[37] reported the '*gross energy content*' of coal as per the following table.

Table 28. Gross energy content of coal

coal	Qld	NSW	Vic	Tas	SA	WA	NT
GJ/tonne	27	27	10.3	22	12.4	19.7	na
unwashed GJ/tonne	21	23					

[37] www.industry.gov.au/industry/Office-of-the-Chief-Economist/Publications/Documents/energy-in-aust/bree-energyinaustralia-2014.pdf

BREE's 2013 publication, *Energy in Australia* had different figures for Tasmanian plus SA coal and also for the unwashed coal. Thus when converting $/tonne figures to $/GJ for coal, care needs to be taken on the coal quality specification, moisture content and whether it is the lower heating value or the higher heating value that is being quoted.

As a comparison to the low energy density of SA and Victorian coal, BREE reports the gross energy content for wood chips is between 10 and 16 GJ/tonne depending on moisture content.

Coal price

The cost of extracting thermal export coal in Australia has been reported[38] as between $40 and $90/tonne, with the majority of mines producing at costs below $60/tonne. The historical price available for Australian thermal coal delivered to a port is shown in Figure 75.

Figure 75. Australian coal prices (Image from: www.indexmundi.com/commodities/?commodity=coal-australian&months=120&currency=aud).

The cost of coal delivered to an industrial site will vary significantly depending on the supply mine and the distance the fuel has to be trucked or railed. In 2006, the Productivity Commission[39] estimated that rail freight costs were around $0.025 to $0.032 per tonne km while road transport costs were around $0.045 to $0.064 per tonne km. A more recent estimate from a WA government website[40], indicates that in 2013 a B-Double truck would cost more than $400 per hour to operate which gives an indicative, GST exclusive, road freight cost of $0.09 per tonne km.

[38] www.treasury.gov.au/PublicationsAndMedia/Publications/2014/Long-run-forecasts-of-Australias-terms-of-trade/HTML-Publication-Import/5-Exports-of-nonrural-bulk-commodities-thermal-coal

[39] www.pc.gov.au/__data/assets/pdf_file/0007/48373/sub041attachmentb.pdf

[40] www.transport.wa.gov.au/mediaFiles/rail-freight/Freight_GuidelineRates.pdf

Truck-delivered coal prices as low as $55/tonne have been reported. This is equivalent to $2/GJ. In another example a business in mid NSW currently using LPG has been offered coal delivered at $125/ t, equivalent to $4.60/GJ.

Victorian and SA brown coal resources are not suitable for export and mine gate prices could be expected to be lower for these fuels. However, transporting brown coal will be more costly per GJ due to the much lower energy content. Dried coal briquettes (~$9/GJ and 22GJ/tonne) are available in Victoria. This plant was due to be closed in 2014 but apparently its life has been extended.

Estimates of mine gate coal prices and indicative truck transport costs by State are shown in Table 29.

Table 29. Indicative coal prices.[41]

$/GJ	Qld	NSW	Vic	Tas	SA	WA	NT
mine gate coal price low	2.2	2.1	0.7	2.2	1.2	2.4	na
mine gate coal price high	2.6	2.5	1.0	2.6	1.6	2.8	na
truck transport 200km	0.9	0.8	1.9	0.9	1.6	1.0	
delivered indicative price	3.3	3.1	2.8	3.3	3.0	3.6	na

While Queensland coal could be trucked to the NT, the long distance makes this not viable.

Boiler and ancillaries pricing

The cost of coal-fired boilers is significantly higher than gas-fired boilers due to fuel handling requirements. A coal fired boiler system with all its associated fuel handling and storage systems has a capital cost that is the same or slightly less than that of a biomass boiler. However, coal is significantly cheaper than gas. Thus obtaining process heat from coal is likely to be highly competitive with gas for many industrial sites.

Burning a GJ of NSW coal emits around 90kg of CO_2e. Thus factoring in a carbon price of $30/tonne roughly doubles the fuel cost for process heat supply. However, investors are likely to expect grandfathering of permits and exemptions for trade exposed industries for any future carbon price, so are unlikely to weight this risk highly, unless they have an internal carbon reduction strategy.

[41] Low price is based on ACIL Tasman 2012 fuel price estimates published in BREE's Australian Energy Technology Assessment, except WA where low price is from: au.news.yahoo.com/thewest/a/23844456/premier-begs-for-higher-coal-price/

5.7.2. LPG

LPG and natural gas are substitutable for most processes and equipment. Some industrial sites also rely on LNG that is trucked in if cheaper reticulated natural gas is not available.

LPG is also an internationally traded commodity (Figure 76) and the Australian suppliers claim the price is influenced by the international contract price. LPG pricing will also vary by location and the distance from the source.

Figure 76. International LPG prices[42]

A delivered to port cost of $1/Gallon is equivalent to about 26.4c/litre or about $10/GJ. Removing the GST and the current fuel excise (10.2c/litre) from Australian capital city, February 2015, bowser prices gives an Australian cost of around 42c to 62c/litre ($16 to $25/GJ). Why the Australian bowser price, minus tax and excise, is significantly higher than the international traded price is beyond the scope of this analysis. Prices change relative to import and export volumes, size plus locations of suppliers and the relevant government policy settings.

LPG boilers are similar to natural gas boilers. However, costs are higher due to the need for appropriate infrastructure to store and deliver the LPG. The high fuel cost of LPG indicates that obtaining process heat from LPG is likely to be the most expensive option in Australia. However, there are numerous industrial gas users in areas of Australia without access to pipeline gas that are reliant on LPG for process heat.

[42] From: www.indexmundi.com/commodities/?commodity=propane&months=120&currency=aud

LPG price

Estimates of LPG prices for industrial users by State is shown in Table 30.

Table 30. LPG prices by state.

$/GJ	Qld	NSW	Vic	Tas	SA	WA	NT
LPG price low	21.2	19.4	18.3	24.5	19.8	24.1	37.1
LPG price high	35.6	30.2	25.5	28.4	28.4	37.4	39.2
indicative price	28	25	22	26	24	31	38

These estimates are based on published bowser prices for February 2015 minus the GST and LPG excise, the high price is from regional areas so it already factors in a transport cost.

LPG Boiler and ancillaries pricing

LPG boilers essentially the same capital cost as natural gas fired boilers. The additional cost of storage tanks is often rolled in to the supply contract so this asset becomes part of the delivered fuel price. Alternatively, an annual fee is charged for the tanks, which includes replacement when necessary.

5.8. Technical suitability of renewable energy solutions

A key determinant that must be established in addition to economic performance, is technical suitability. It is apparent that a renewable energy solution could in principle be engineered for every single current use of gas. There is however a major dichotomy between solutions that are proven and commercially available and those that are still in the pilot or even R&D phase. Given the low technical risk appetite of industrial gas users, and the drivers of renewable solutions costs, none of the pilot or R&D phase solutions are applicable unless the organisation in question had a parallel business agenda of engaging in technology development.

In regards to solutions that are commercially available, technical suitability can be considered based on the basic principle of use rather that precise industry specific considerations. Thus the following specific conclusions can be offered in this regard:

Hot water or steam

The majority of substitutable uses of gas are in the provision of hot water or steam. This ranges in temperature from 30°C up to 600°C. Solar thermal, Geothermal and Biomass boiler systems can produce hot water or steam over some or all of this temperature range respectively, at costs that depend on the temperature and cost of inputs. In each case, the hot water or steam is produced by heating cold feedwater via a heat transfer surface that is either directly heated by the renewable heat source, or else heated in a heat-exchanger by a heat transfer fluid. This means that declaring technical suitability is straightforward. If the same feedwater system is used as the default gas fired system would use, the temperature pressure and chemical composition of the hot water / steam should be essentially identical. The renewable solution essentially becomes an alternative plug in ‘black box’ provider of the water / steam.

Two key issues of technical suitability remain; the space needed to house the renewable system and the challenge of matching energy supply and demand over time. These questions can only really be answered on a business by business manner. However some general observations can be made.

Regarding space it can be observed that all renewable solutions will require more physical space than the gas based default system. This space usage may quite likely be additional to the gas system which is likely to be still needed in some role. Solar thermal solutions are directly area related to thermal capacity, with each kW_{th} of capacity requiring around 2 m^2 of collector plus as much again for access routes and connections. To place this in context, it is likely to be comparable to the footprint of the buildings involved with the business. With many solar solutions suitable for roof mounting, full roof use is indicative. Structural implications of loads on roofs are obviously case specific, but not overly onerous. Biomass solutions need to factor in delivery handling and storage of the feed material that will require substantial area in proportion to the size of the application. Biomass boilers are typically somewhat larger than gas boilers of the same capacity.

Attempting to match supply and demand with a renewables solution is linked to storage requirements. For a solar thermal solution, providing energy storage of around one day of thermal load is readily achievable and in the economic analysis carried out in this study, has been assumed as the baseline. Attempting to provide storage sufficient for worst case sequence of cloudy days or even seasonal variation, is however cost prohibitive. Thus the working assumption is that a gas boiler is retained to fill in any gaps in supply. This raises the question of the level of turn down that existing or default boilers can accept. Overall however these integration issues are standard engineering problems that can readily be addressed by solution providers. An individually engineered solution could consider options including:

- Limiting the solar thermal solution to a fuel saving contribution within the turndown range of an existing gas boiler.
- Dispensing with a solar thermal storage completely if a suitably flexible gas boiler is included.
- Having a high level of solar thermal storage, dispensing with the gas boiler and modifying the process and demand to follow available solar supply.
- Any optimal combination of the above.

With biomass, there is greater scope for storage of large energy volumes of raw material. The biggest question would be around the plausibility of sufficient storage to cover seasonable variability. It is likely that some level of gas fired capacity would still be retained in many cases, although it may be acceptable to reduce it to a fraction of full capacity.

Direct gas flame heating

Alternative combustible gas can be made cost effectively by either gasification or digestion of low cost biomass inputs. Solar driven options are still too expensive for serious consideration. The composition will not match that of natural gas though. Any gas combustor in a kiln, engine or boiler can in principal be modified and re-calibrated for such gases. For applications like boilers or engines, where the exhaust products are directly vented there are no major issues. On the other hand where a gas flame is used internally to an oven or cooking process, additional gas purifying / cleaning equipment would be needed. This level of complexity and extra cost is not likely to be viable at this point, nor is the technical risk likely to be acceptable to industry users, so the most prospective use of bio derived gases is in applications that are not sensitive to combustion product composition.

Power generation

As noted above, engines and potentially also gas turbines can be modified and re-calibrated for bio derived gases. Most major landfills in Australia already have reciprocating engine systems running on landfill gas. Combined cycle (gas turbine plus steam turbine) power plants have some potential for the addition of solar derived steam into the steam cycle. This represents a major system re-design however and has not been considered in any detail in this study.

Chemical processes

Bio derived gases could substitute for natural gas as feedstock for chemical processes. However, high cost gas purification and clean up would be needed and such applications are thus not very prospective.

The key high gas consumption specific examples are worth discussing individually.

Use of gas for calcining in Alumina refineries is essentially a very high temperature process heat application. Bio derived gases could possibly be applied if a sufficiently large resource were available. Advanced solar thermal concentrating solutions can be postulated but they are still in the R&D phase.

Ammonia plants have been identified as large gas users. Conventionally natural gas is converted to hydrogen for ammonia synthesis in steam reforming reactors operating at around 800°C. In principle renewables could substitute for either the heat to drive reforming or the feedstock or both. Research groups around the world have demonstrated pilot scale solar thermal driven steam reforming of methane, including CSIRO at Newcastle, however while this looks an encouraging future prospect worthy of continued effort it is not yet economically viable. Production of pure solar hydrogen is still extremely expensive but may ultimately have a future role to play. In principle it could readily be accepted into an existing ammonia plant as long as it was free of water vapour. Hydrogen could be produced by biomass gasification if there was a sufficient resource available. It would need major investment in post processing and purification of the gas to be acceptable.

Cement kilns conventionally gas or coal is combusted with the clinker in the kiln. The fuel not only acts as a source of heat but also as a reducing agent in the process. Solid biomass material can be substituted in a straightforward manner.

A systems approach

The present investigation is by necessity finite in its scope. It is examining the direct substitution of natural gas with renewable energy technologies. The analysis must be general in nature and seeks to establish which technologies if any are technically and economically feasible and under which circumstances should a gas user consider further investigation. Specific technology configurations that have not been studied here that are likely to offer potential benefits for gas users include:

- Use of bio derived gas in gas engine systems to provide both electrical power and process heat.
- Heat pumps that are operated by non-renewable electricity.
- Staged systems operating in series to achieve a desired endpoint temperature.
- Hybrid systems that combine renewables with gas in an optimal way.

It needs to be emphasised very strongly that every company and each commercial facility will have different circumstances of resources, demand, existing systems and economic imperatives. A specific investigation is needed in every case and to the greatest extent possible it should take a full systems approach. Thus as well as direct substitution of gas use, investigation could include:

- Overall review of energy efficiency opportunities.
- Examination of issues around electricity use and the potential for simultaneous modifications to electricity and process energy supply.
- Examination of underlying process to consider low risk modifications to operating strategies informed by gas, electricity and renewable supply variability in price availability and peak demands.

5.9. Summary

The relevant renewable energy sources that can be considered for direct substitution of natural gas use are biomass, solar and geothermal. From these sources it is bioenergy and solar thermal systems that are of most relevance to industrial gas users. Hot sedimentary aquifer based systems could play a niche role for low temperature applications for the minority of gas users who might be co-located with a resource. PV or grid electric driven heat pumps also offer lower temperature process heat they would compete with solar thermal solutions on economic grounds. They may be more relevant if a user was also looking for alternative on site provision of electricity.

Bioenergy technology comprises, combustion boilers, gasifiers and biomass digestors. All have higher capital costs and complexity than gas fired systems. Capital costs scale according to a power law with small systems more expensive per unit capacity than large. There are many large scale examples of the technology around the globe and the technology is largely commercially mature. Most of the risk with a bioenergy solution lies with the biomass supply. The costs of fuels can be expected to fluctuate with supply and demand. Apparently zero cost waste streams will have an inherent value when they are more widely used. Climatic variations will affect the availability of many biomass types. As interest increases, progress with more efficient and larger scale production from short cycle energy crops can be expected, however these new initiatives will carry enhanced risk in their early stages of commercial operation. There can be social licence issues to contemplate if biomass use competes with food production or creates an incentive for native forest harvesting.

Solar thermal systems come in a range of technologies of increasing complexity and cost as higher temperatures are required. These range from simple flat plate systems, through evacuated tubes, trough and Fresnel linear concentrators to tower / heliostat systems. They also have a size based cost dependence. There are also examples of large commercial application around the world although many instances are still at an earlier stage of commercial maturity. Performance analysis of solar thermal systems requires use of full year solar data sets and is effected by demand profiles and operating temperature.

Solar thermal systems are by their nature capital intensive. That is the price that must be paid for a system that collects a relatively low energy density resource but has no fuel price risks. Whilst commercial scale examples exist around the world, of all the various solar thermal technology options, the industry and supply chains are still immature for most, particularly in Australia. Overall, the level of technology and supplier risk is higher for solar thermal systems.

A major issue with geothermal systems is that assessments of potential prior to drilling are probabilistic. There is uncertainty in the depth an aquifer will be found at, the flow rates the strata will allow and what temperature will be found. This represents a major risk issue for a large capital cost investment.

Heat pumps are a possible solution for lower temperatures. They are commercially mature however have not been used a great deal in Australia for process heat.

Least technical risk to a gas user would be provided by plugging in a renewable solution that heated a water / steam working fluid to the same conditions as an existing gas fired boiler.

Identifying an optimal solution requires detailed site specific study and should take a full systems approach including examination of energy efficiency measures and electricity supply also.

6. RENEWABLE RESOURCES

6.1. Bioenergy Resources

Bioenergy has the potential to provide a significant proportion of Australia's energy supply. Geoscience Australia report long term potential of up to 73 TWh electrical, 30% of current consumption (Geoscience Australia 2014). Bioenergy feed stocks are extremely variable, and include:

- Agricultural residues, including
  - sugar cane residues,
  - grain stubble,
  - animal wastes, from both production and processing
  - horticultural wastes
- Energy crops - purpose grown tree crops, often mallee species
- Forestry residues (thinnings and sawdust)
- Urban wastes, including
  - food/ organics,
  - garden waste,
  - paper and card,
  - wood waste
- Sewage gas
- Landfill gas
- Woody weeds

The 2008 Bioenergy Roadmap (CEC 2008a) focused on electricity generation (ignoring heat and liquid fuels) and set a target for 2020 electricity generation from bioenergy at nearly 11 TWh_e, which would equate to approximately 97 PJ potential thermal energy.[43] The long term potential is estimated to be seven times that amount, including a 47 TWh_e contribution from agricultural stubble. Even excluding stubble, the long term potential is assumed to increase by 250%, with the biggest growth in animal and urban wastes, which both approximately double. Figure 77 shows each feed stock's contribution to the roadmap target at 2020, with a more detailed breakdown given in Table 31.

[43] Assuming that electrical output was based on 40% overall conversion efficiency.

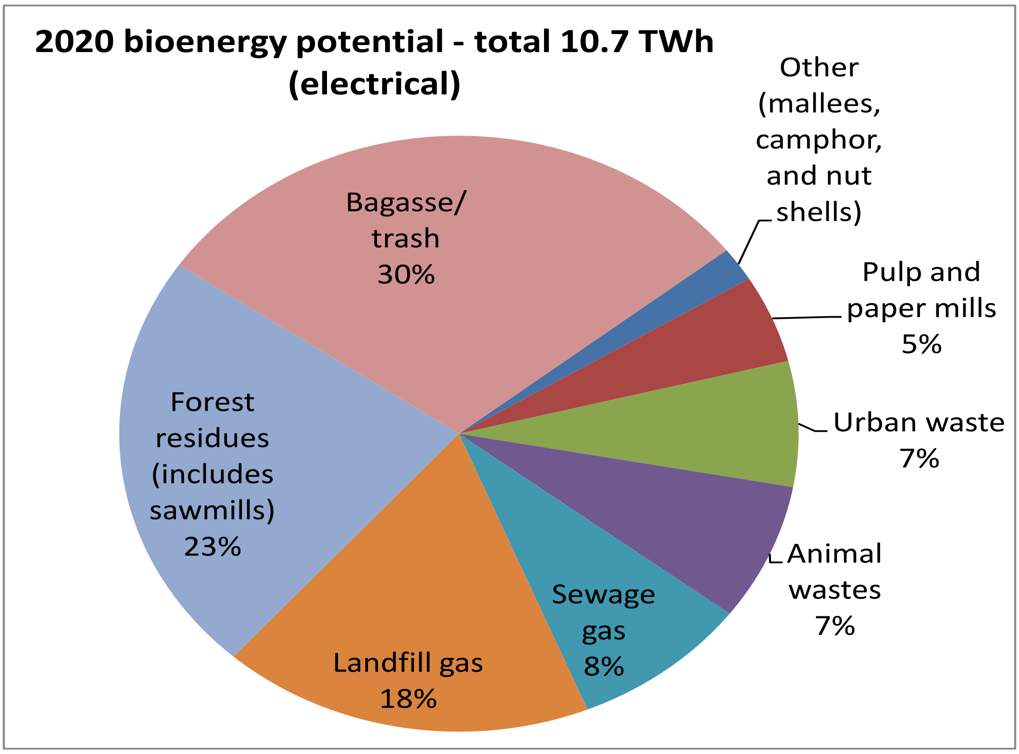


Figure 77 Bioenergy potential at 2020, all sources, from (CEC 2008b).

Bagasse, sewage gas, and landfill gas together account 56% of the 2020 target, and stubble accounts for more than 60% of the long term target.

Bagasse is most commonly used for cogeneration in the sugar industry, with 467 MW_e currently operating in Australia (most supplying heat as well), and a further 16 MW_e proposed (Geoscience Australia 2012; CEC 2013)

Sewage gas is typically used for cogeneration plants, providing on-site electricity and heating at sewage treatment plants. There is currently capacity of 59.1 MW_e at Australian sewage treatment plants, with another 1 MW_e in development (Geoscience Australia 2012).

Landfill gas is generally used for electricity generation for export, as there is rarely heat demand on site. There are currently 164 MW_e of landfill gas generators operating in Australia (Geoscience Australia 2012).

Stubble is a very large resource in the long term, but unlikely to be developed at large scale in the medium term, as the requirements for collection and compaction impose considerable costs relative to other biomass and energy sources. Stubble is therefore not dealt with further here as it is unlikely to provide a viable alternative for large scale industrial gas use in the medium term. Small plants for rural heat applications may be feasible, as occurs in the UK for example

Urban bioenergy resources offer significant energy potential but are likely to be utilised at centralised collection points. The current focus of applications is on the export of electricity for sale, rather than substitution for industrial gas, owing to the higher value of electricity.

Only forest residues, energy crops, animal wastes, and pulp and paper mill wastes, are discussed further in this report. Forest residues account for 23% of the projected potential from bioenergy at 2020, with animal wastes and urban wastes accounting for 7% each, pulp and paper 5%, and energy crops and woody weeds together 2%.

6.1.1. Bioenergy feedstocks - general considerations

There are some important distinctions which apply within each category, and will have a strong influence on cost effectiveness:

- Does the feed stock require collection or does it arise at a processing plant? For example, stubble left after a crop or in forest residues requires collection, while abattoir or paper mill wastes arise at a single point. As collection and transport costs are a limiting factor for many bioenergy feed stocks, this will strongly influence cost effectiveness.
- Is the feed stock a waste which would incur disposal costs if not used for bioenergy? This may result in a low, zero or even negative cost for the fuel, while for some feed stocks (such as energy crops) the fuel cost will have to cover all the production costs.
- What technology is suitable? The main division is between liquid and solid feedstocks, with the former suitable for anaerobic digestion, while the latter suitable for combustion or gasification/ combustion.

Situations where the bioenergy fuel can be used at or very close to the point of production, and where the fuel cost is zero will be the most cost competitive. In these situations the fuel would frequently incur disposal costs if not used for bioenergy.

These considerations would indicate that animal processing, food production and pulp and paper mill wastes are likely contenders for gas substitution. The bioenergy resource arises on site and requires disposal, and the sectors have a significant thermal demand. In addition, there are already examples of these resources being used for heat and power.

Table 31 Bioenergy target in Australia at 2020 (electricity) and estimated heat potential from CEC, 2008

	Base unit for projection		2020 electricity potential GWh/yr	2020 Heat potential PJ/yr
LIVESTOCK				
Poultry	94,384,000	population	297	2.7
Cattle (feedlots)	870,025	population	112	1.0
Pigs	1,801,800	population	22	0.2
Dairy cows	1,394,000	population	22	0.2
Abattoirs	1,285,000	tonnes	337	3.0
SUBTOTAL			**790**	**7.1**
OTHER AG RESIDUES				
Nut shells			1	0.009
Bagasse	5,000,000	tonnes	3000	27
Sugarcane trash	4,000,000	tonnes	165	1.4
SUBTOTAL			**3166**	**28**
ENERGY CROPS/ WOODY WEEDS				
Oil mallee			484	4.4
Camphor laurel			20	0.2
SUBTOTAL			**504**	**4.6**
FOREST RESIDUES				
Native forest (public & private)	2,200,000	tonnes		
Plantation (public and private)	3,800,000	tonnes		
Sawmill and wood chip residues	2,800,000	tonnes		
SUBTOTAL			**2442**	**22**
PULP AND PAPER MILLS WASTES				
Black liquor			365	3.3
Wood waste			85	0.8
Recycled paper wet wastes			8	0.07
Paper recycling wastes			48	0.4
SUBTOTAL			**506**	**4.576**
URBAN WASTE				

Food and other organics	2,890,000	tonnes	126	1.1
Garden organics	2,250,000	tonnes	262	2.4
Paper and cardboard	2,310,000	tonnes	38	0.3
Wood/timber	1,630,000	tonnes	295	2.7
SUBTOTAL			**721**	**6.5**
LANDFILL/ SEWAGE GAS				
Landfill gas	9,460,000	tonnes	1880	16.9
Sewage gas	735,454	tonnes	901	8.1
SUBTOTAL l			**2781**	**25**
Overall total			**7,294**	**101**

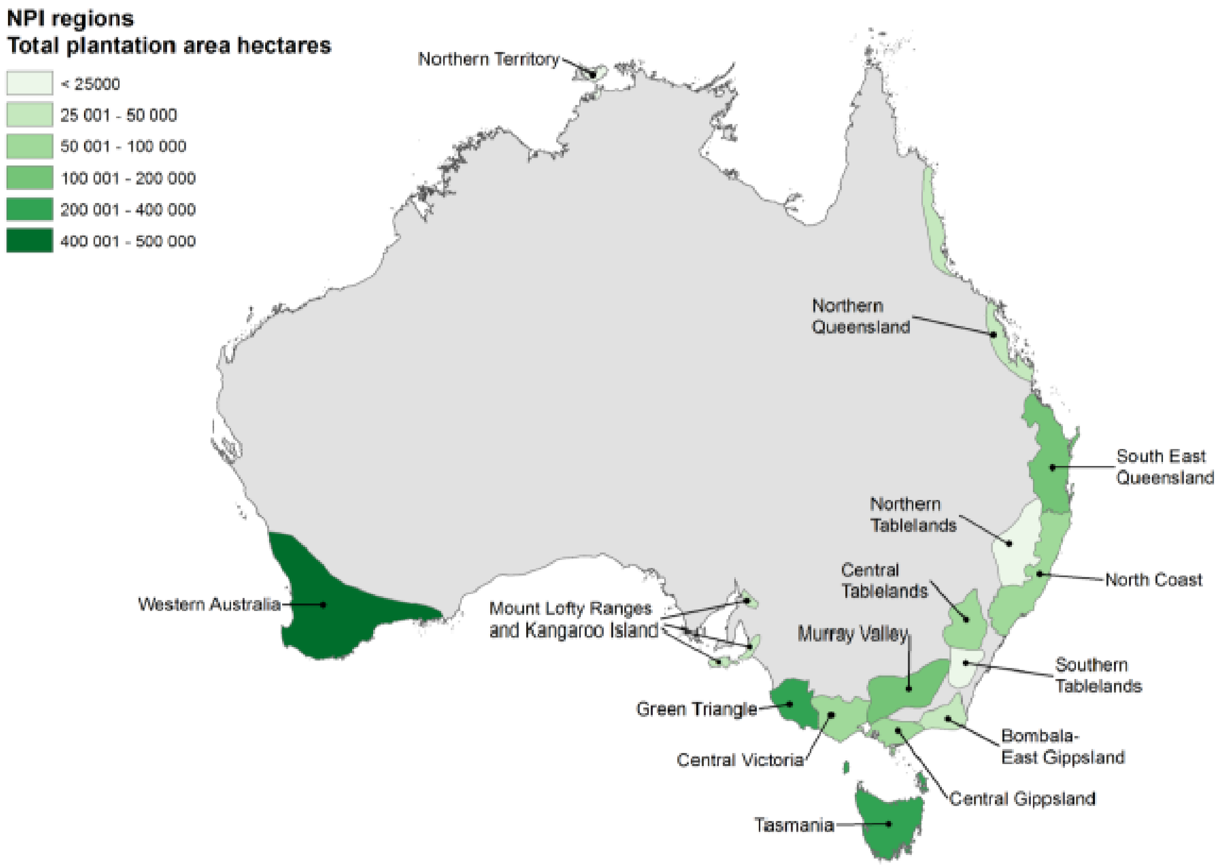
Note: Electricity target at 2020, converted to heat potential by assuming the conversion efficiency to electricity was 40%.

6.1.2. Forest residues and wood pellets

Forest residues are a large resource, with a long term potential in the region of 7.3 TWh (CEC 2008b) and an estimated potential of 10.5 TWh from plantation residues in 2030 (Stucley et al. 2012). Figure 78 shows the plantation resources around Australia. There is a concentration of resource in the south west of Western Australia, Tasmania, and the 'green triangle' in Victoria, with a secondary concentration in south east Queensland. Despite the size of the resource, only 1% of bioenergy capacity is currently for wood waste plants.

Forest residues include both thinnings arising at the plantation, and timber and sawdust wastes arising at sawmills. Sawmill wastes may be considerably cheaper to use, as they arise at a process facility, and may otherwise require disposal, while plantation and forest floor residues will usually require chipping, collection and transport. However, there are competing uses for sawdust, such as compost or bedding.

Figure 78 Plantation resources around Australia From Gavran, 2013



When there is proximity to a pulp and paper facility or an export port, a large percentage of sawmill residues are sold as wood chip. This is particularly true for the softwood plantation industry in South Eastern Australia. Price for export chip varies with market fluctuation, and was recently $140 per dry tonne for softwood, equivalent to approximately $7/GJ[44]. Hardwood chip (typically from blue gum plantations) commands a premium of approximately 20% over this price.

Sawmill wastes therefore account for most of the current bioenergy production from waste wood. Use may be electricity generation for onsite use and export, or thermal applications, particularly for drying timber. Table 32 lists some thermal applications at wood waste facilities.

[44] https://www.forestryconnect.com/blog/australian-woodchip-and-log-export-prices-on-the-move/

Table 32 Thermal applications using wood waste (Stucley et al. 2012)

Owner	Plant Location	Capacity MW(th)	Technology	Fuel
Visy Pulp & Paper	Melbourne, Vic	30	Water tube boiler	Sludge & Wood waste
ITC	Launceston, TAS	3	Water tube boiler	Dry Chip / Shavings
Nestlé	Gympie, QLD	16	Water tube boiler	Coffee waste / Wood waste
FEA	Georgetown TAS	20	Water tube boiler	Wood waste
Hyne & Son	Tumbarumba, NSW	15	Thermal Oil Heater	Wood waste
Carter Holt Harvey	Oberon, NSW	12	Thermal Oil Heater/Fibre drying	Wood waste (MDF and sawmill waste)
AKD Sawmill	Colac, VIC	15	Thermal Oil Heater	Wood waste
Hyne & Son	Tuan, QLD	12.5	Thermal Oil Heater	Wood waste
Starwood Australia	TAS	22	Water tube boiler	Biomass
Laminex	Gympie, Qld	24	Thermal Oil Heater	Wood waste
Carter Holt Harvey	Gympie, Qld	10	Hot gas – dryer	Dust, fuel oil
Carter Holt Harvey	Tumut, NSW	20	Hot gas – tunnel dryer	Wood waste, dust

Wood Pellets

Processing wood wastes into pellets may provide a long term alternative to gas. Pellets have a number of advantages over wood chips or other bioenergy fuels, primarily because they have relatively high energy density, and are easy to transport, store, and use for both heat and power. There are a set of European standards for pellets which cover parameters such as energy content, size, bulk density, ash, and mineral content. Their predictability makes them attractive for industrial applications, and suitable for highly mechanised handling systems. Table 33 shows the bulk density of pellets compared to other wood residues.

The wood pellet market is highly developed in Europe, but still at an early stage in Australia. There are currently two industrial scale wood pellet companies in early operational stages, one in Albany in southern Western Australia , and one in south east Queensland. Combined production capability is 375,000 tonnes per year, equivalent to 6.3 PJ. Pellet cost is expected to be $12/GJ ex plant from the Albany plant when it is operational (Allen 2014). Details on the two production facilities are given in Table 34.

Table 33 Bulk densities of wood pellets and other wood residues (Stucley et al. 2012)

Type	Bulk Density (kg/m^3 dry and ash free)
Pellets	556-625
Softwood chips	179-192
Hardwood chips	227
Sawdust	161
Planer Shavings	97

Table 34 Wood pellet production in Australia, From Allen, 2014 and Altus Renewables[45]

Company name	Status	Capacity Tonnes/yr	PJ/ yr	Price ex plant ($/GJ)	Comment
Plantation Energy Australia	Reopen 2014	250,000	4,250	$12	Can increase production by 125,000 tonnes/yr if required. All production currently going to Korea.
Altus	2014 - under construction	125,000	2,125	unknown	

Plantation Energy Australia expects all their output to go to Korea by ship, although they would be able to divert pellets to supply locally if orders were received. The plant is modular, in stages of 125,000 tonnes, so they would increase the production scale in the event of a domestic market developing. Minimum order size is approximately 5 tonnes (Allen 2014).

Domestic transport costs are not available from the companies, as any production is currently exported. Neither plant is close to major markets but both could use sea or rail to move pellets to capital cities. This could add significantly to the delivered cost.

Should a gas substitution market develop there would be scope for another pellet production facility, perhaps in the green triangle area of Victoria, and potentially for expansion of the two existing plants.

Australia also has several small scale pellet manufacturers, who typically make up to a few thousand tonnes per year of pellets from saw mill wastes or other wood residues. These pellets

[45] www.altusrenewables.com/oper_proj.html

are used for heating as well as in animal bedding applications. Typical delivered price for tonnage quantities is $750 per tonne, which is approximately $40/GJ.[46]

6.1.3. Livestock, animal products, and food products

Wastes from intensive animal production and food processing include wastes suitable for specialised combustion systems, such as poultry litter, and a range of wet wastes suitable for anaerobic digestion, including manure and slurries with varying amounts of water. Intensive livestock production includes larger piggeries, beef feedlots, and intensive poultry production. In these cases manure and slurry disposal requires collection and treatment of wastes, which may incur significant costs. Processing plants are also suitable, including dairies, abattoirs and other food production industries.

Operating and proposed bioenergy facilities from intensive livestock and food processing are listed in
Table 35Table 35
Piggeries have considerable potential for cost effective biogas capture and use, with recent feasibility studies for the Pork CRC showing payback periods of between 1.2 and 8.5 years (E. McGahan et al. 2013). There is currently energy recovery from manures from just under 8% of the Australian herd (Tait 2013).

The Pork CRC is actively promoting the installation of biogas capture and use at piggeries, and has a bioenergy support program run from the University of Queensland[47] .

The distribution of intensive livestock industries are shown in Figure 79 to Figure 81, effectively the distribution of the major animal wastes suitable for biogas applications. It is notable that the regional locations of these sources of biomass correlate well with the general location of many gas users identified in Figure 12. The livestock facilities are of course themselves gas users in many cases.

[46] Colin Stucley, personal communication, 2014
[47] http://porkcrc.com.au/research/program-4/bioenergy-support-program/

Table 35 Operating and proposed biogas plants at intensive livestock and food processing sites (Clean Energy Council, 2013; McGahan, Barker, et al, 2013; Poad & McGahan, 2010)
C = combustion, AD = Anaerobic Digestion,

Company name	Town	Type	Status	Size (MWe)	Fuel
AJ Bush Rendering Plant	Beaudesert, Qld	AD	operating	0.1	abattoir waste
Rockdale Beef	Yanco, NSW	AD	operating	0.9	abattoir waste
Westside Meat Works	Bacchus Marsh, Vic	AD	operating	0.1	abattoir waste
Murray Goulburn Co-op Ltd	Leongatha, Vic	AD	operating	0.7	dairy waste
McCain's Foods	Ballarat, Vic	AD	operating	3	food waste
EarthPower Technologies	Camellia, Sydney	AD	operating	3.5	food waste
Australian Tartaric Products	Mildura, Vic	AD	operating	0.6	Food & agricultural wet waste
Berry Bank Piggery	Windermere, Vic	AD	operating	2.9	piggery manure
Burrangong Meat Processors	Young, NSW	AD	Reopening	0.8	abattoir waste
QAF Meat Industries	Corowa, NSW	AD	Proposed	0.24	piggery manure
Cleveland Power Pty Ltd	Mt Cotton, Qld	C	Proposed	7.5	poultry manure
Darling Down Fresh Eggs	Toowomba, QLD	AD	Proposed	unknown	Poultry waste

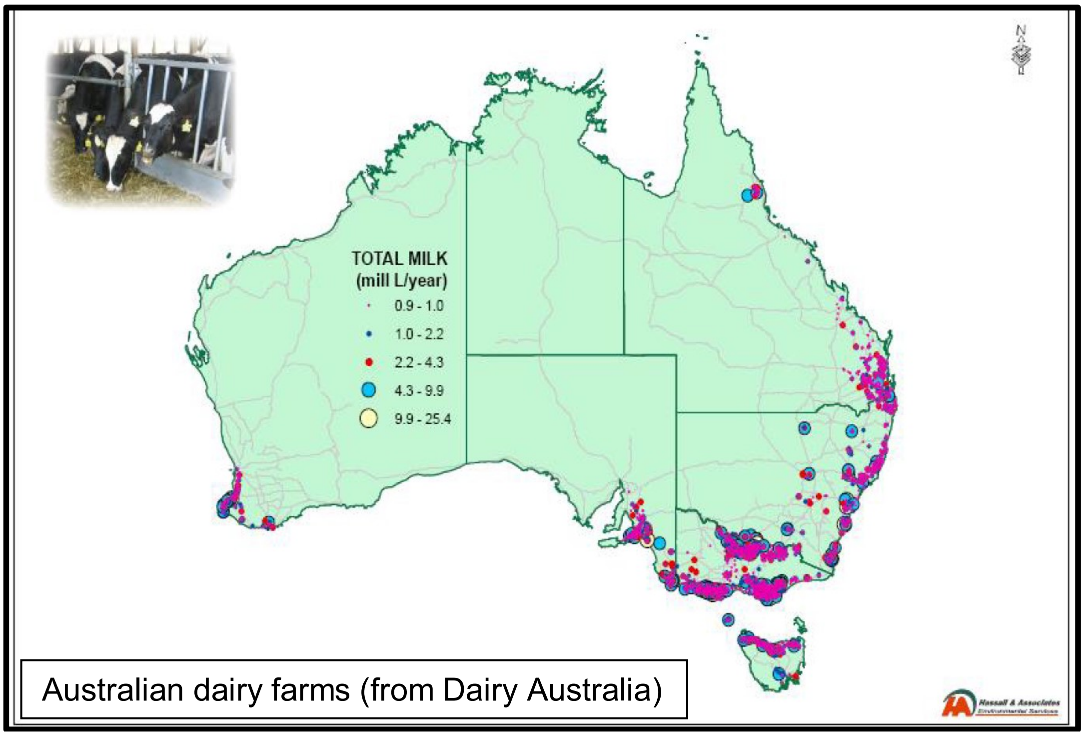


Figure 79 Dairy distribution in Australia (from GHD Pty Ltd, 2007)

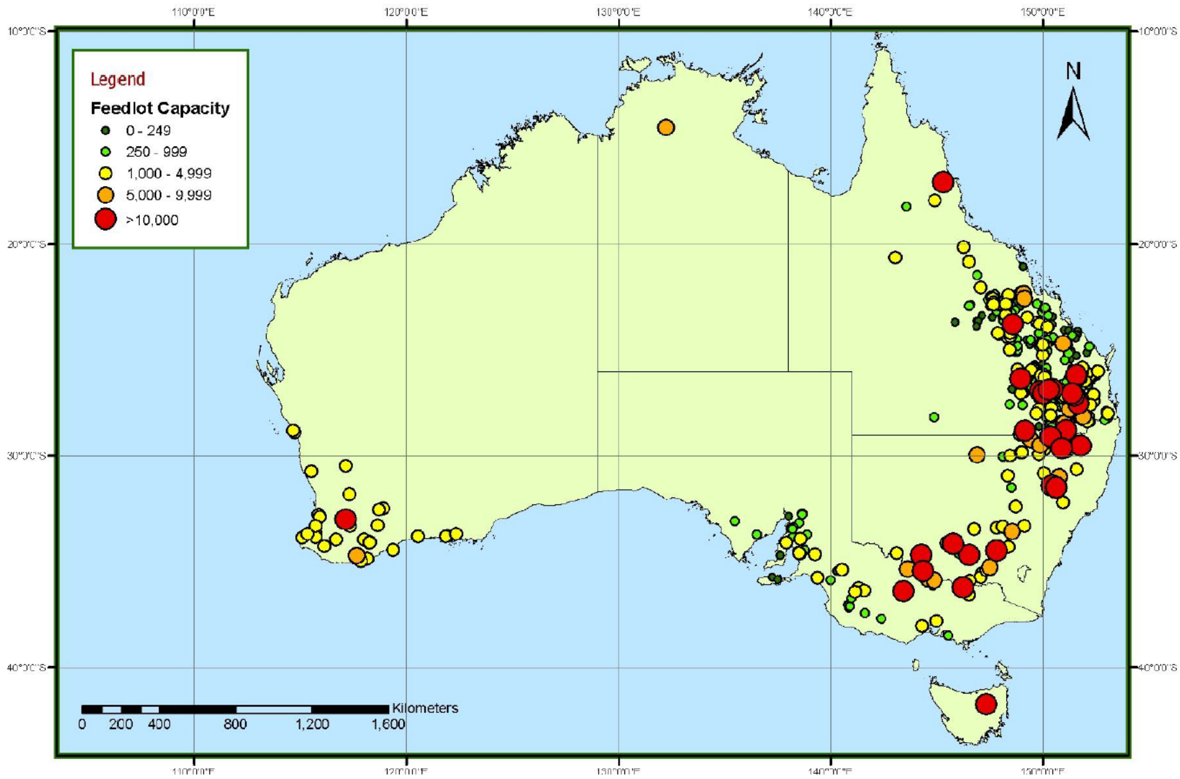


Figure 80 Feedlot and piggery distribution in Australia (from GHD Pty Ltd, 2007*)*

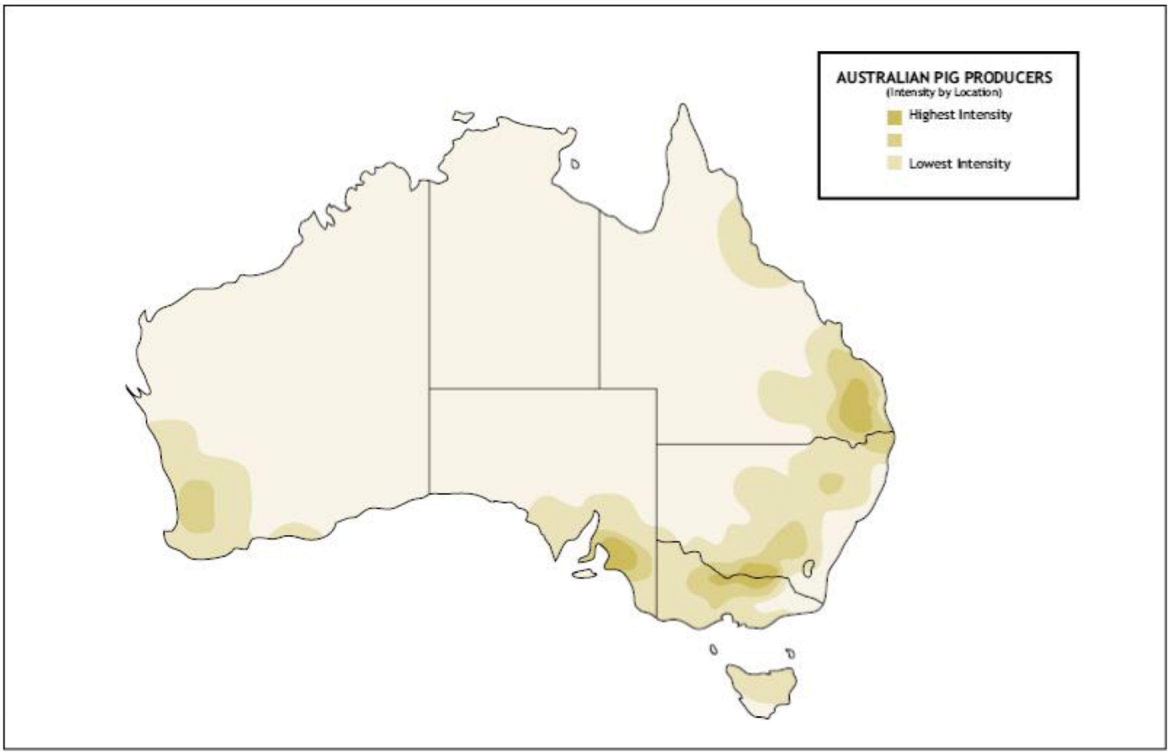


Figure 81 Piggery distribution in Australia (from GHD Pty Ltd, 2007*)*

6.1.4. Pulp and paper

The pulp and paper industry currently accounts for 10% of Australian bioenergy generation, with three power stations operating, as shown inTable 36. In each case the feed includes black liquor[48]; use of this material for energy is standard operating procedure for such facilities world-wide. The waste arises on site, and bioenergy generation will both reduce waste disposal issues and reduce imports of electricity and gas.

Table 36 Bioenergy facilities at Australian pulp and paper mills (all combustion)

Company name	Town	Commission	Size (MW_e)	Fuel
Visy Paper	Tumut, NSW	2001	17	Wood waste & black liquor
Visy Paper	Gibson Island, Qld	1997	2	Black Liquor
Australian Paper	Maryvale, Vic	1989	24	Black Liquor

The industry is dominated by a six large companies, and only two have so far acted on the opportunities for bioenergy. Visy has installed an additional bioenergy plant in Melbourne (2009), with a small electrical output and a large thermal output (see Table 32).

[48] black liquor is the waste product from digesting pulpwood into paper pulp, consisting of, hemicelluloses and other extractives from the wood.

6.1.5. Energy crops

Energy crops could provide an alternative to gas supply in the long term, and may provide considerable co-benefits in the form of shelter belts, carbon storage, and salinity control. However, implementation requires the establishment of an effective supply chain, including planting, harvesting, chipping and delivery, which is not yet in place.

Near term production costs before transport average $47 per green tonne, equivalent to $4.7/GJ, with these costs expected to drop to approximately $2.6/GJ once the industry is mature[49]. Scale is important to reduce costs in these on-farm operations. The location of the trees relative to an effective road system and to the end users will also have a significant impact on cost and thus on viability. On-farm mallee eucalypts are currently limited to the south west of Western Australia, and establishment and growth of new tree crops to reach first harvest could be expected to take up to ten years at other locations. However alternative tree crops may be provided via the extensive plantings of blue gums in eastern and southern Australia that due to yield or location are potentially non-viable for expert wood chip.

Mallees, woody weeds, and nut shells combined make up 2% of the Bioenergy Roadmap target at 2020, and approximately double in the long term, mostly because of projected growth in mallee production.

6.1.6. Bioenergy fuel costs

The cheapest bioenergy feedstocks will be those that occur on site, and require handling for waste disposal. These fuels will be zero cost, so the cost of replacing existing energy sources with bioenergy is almost entirely dependent on the capital cost of the technology. Conversion at the time when existing boilers require replacement is likely to be the most cost effective. Note however that many residues created by the saw milling industry have existing markets, for example in the horticulture and livestock industries.

Table 37 gives indicative costs per GJ for selected feedstocks. Note that costs for wastes that do not arise on site will always have to cover transport, and any processing which occurs.

[49] Production costs are from (Stucley et al. 2012), and energy content per green tonne calculated from (Wu et al. 2008)

Table 37 Indicative costs per GJ for various bioenergy resources (Stucley et al. 2012)

Resource	Indicative cost per GJ
Animal wastes, sewage sludge, landfill gas	Generally zero, and may be negative if disposal costs are avoided
Wood process residues, bagasse etc. used on site	\$0 - 0.20/GJ (1)
Short cycle crops (such as oil mallee)	\$5-7/GJ near term, \$3/GJ mature industry (1)
Wood pellets	\$12/GJ ex plant (2), add \$0.3/GJ up to 15km, \$0.8/ GJ up to 70km (1)

6.2. Solar Resources

Concentrating solar technologies only convert the direct beam component of solar radiation. Flat plate, evacuated tube or Photovoltaic panels, convert both direct beam radiation and diffuse radiation that has been scattered by clouds or dust etc. Direct beam is quantified by measuring Direct Normal Irradiation (DNI), meaning the intensity of flux on a surface that is assumed to be always normal to the sun.

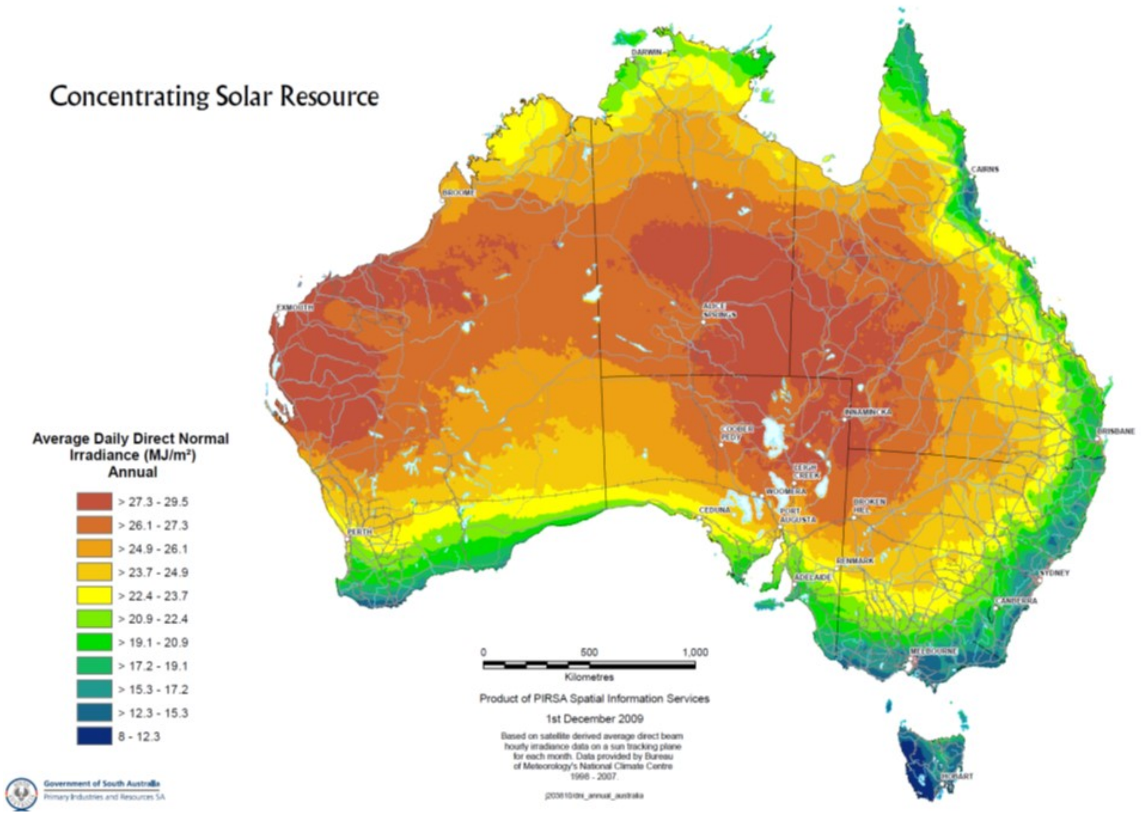


Figure 82: Map of the distribution of Direct Normal Irradiance produced by the government of South Australia.

Figure 82 illustrates the annual average distribution of DNI across the continent. Total radiation is quantified by measuring Global Horizontal Irradiation (GHI), meaning the total flux on a horizontal surface. Figure 83 illustrates the annual average distribution of GHI across the continent.

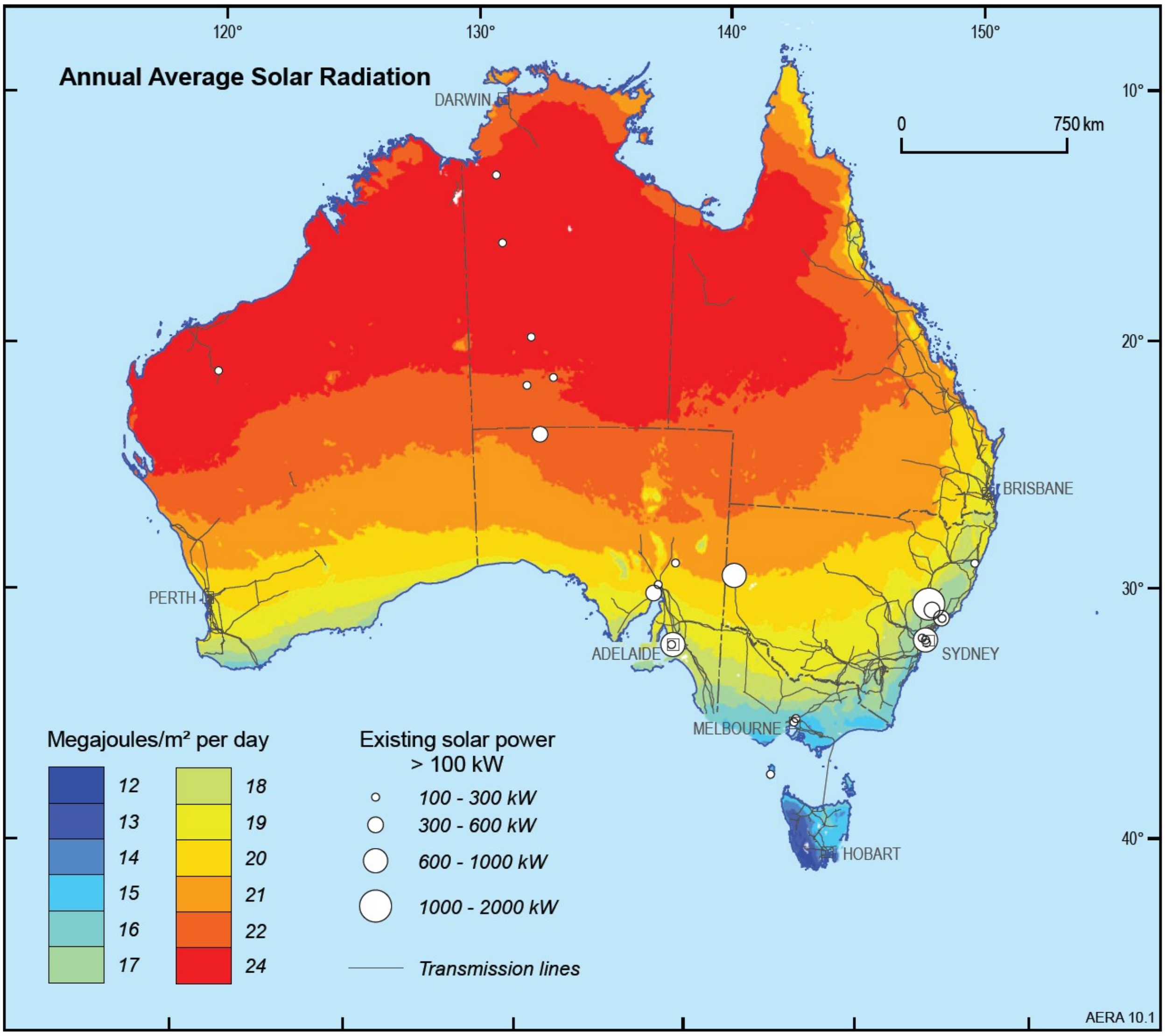


Figure 83: Map of the distribution of Global Horizontal Irradiance (From Bureau of Meteorology and Geoscience Australia 2009 as provided in ABARE 2010)

It can be seen that there is a strong correlation between the DNI and GHI however the Northern tropical areas show a tendency to higher GHI relative to DNI as a consequence of the increased amount of moisture in the air even under sunny conditions. The highest solar intensity regions in Australia are amongst the highest in the world. Most of the natural gas use however is located nearer the population centres around the coast, not in the highest solar resource areas. In a very approximate sense, it can be noted that any areas on the map showing an annual average daily Irradiance of around 16MJ/m^2/day or better (either GHI or DNI as most relevant) might be considered reasonable prospects for solar technologies.

The higher the level of average irradiance at a site the higher the average capacity factor will be for a system and hence the more favourable the economic performance will be. For an approximate indication, it is sufficient to simply estimate annual average from one of these maps.

For a more accurate feasibility study for a particular user / site, a range of data sources are available. Depending on the depth of a study, annual average values can be used, month by month average values can be examined and for most detailed examination, annual data sets of values in one hour or shorter time steps along with associated temperature humidity and wind-speed and other data can be used in complex models such as SAM. Such year long data files can be real years that are identified as being typical or best or worst extremes of variability, or alternatively Typical Mean Years (TMY) synthesised out of segments of real year data chosen to reproduce the annual average for the location.

Sources of data available include:

6.2.1. Bureau of Meteorology

http://www.bom.gov.au/climate/data-services/

The Australian Government's Bureau of Meteorology has satellite derived data sets of DNI and GHI (and other climate data) available. Hourly or monthly average hourly solar exposure over the period 1998 to 2007. The resolution of the data is 0.05 degrees (approximately 5km). They also have ground station based measured data for those stations that measure it.

6.2.2. The Australian Solar Radiation Data Handbook

http://www.exemplary.com.au/solar_climate_data/ASRDH.php

The Australian Solar Radiation Data Handbook (ASRDH) (ANZSES 2006) and its companion software AusolRad, was produced by the Australian Solar Energy Society. It offers tabulated average DNI and GHI data for a range of specific sites.

6.2.3. NASA

http://eosweb.larc.nasa.gov/sse/

The NASA website service allows solar data to be downloaded freely for any grid reference across the globe. The data is in the form of monthly averages and is derived from 22 years of satellite data with an effective 30km grid. Hourly data is derived using a calculation procedure based on an average day for each month.

6.2.4. Australian Solar Energy Information System

http://www.ga.gov.au/solarmapping/

Geoscience Australia is in the final stages of a joint Solar Resource Mapping project with BOM, that aims to improve solar data (including via the 8 new BOM ground stations) and improve Infrastructure and topographic data. The website has an interactive GIS type tool that allows the user to overlay roads and transmission lines for example.

6.2.5. Meteonorm

www.meteonorm.com

Meteonorm is a commercial weather data and modelling tool that provides approximately 20 years of data for global solar radiation and other climate data including temperature, humidity and wind speed. The data is collected from ground based weather stations and supplemented with satellite data where there is a low density of weather stations. Hourly values are available but are calculated from collected data using a stochastic model.

6.2.6. 3Tier

www.3tier.com/en/products/solar/

The company 3Tier have modelled solar datasets available commercially that includes wind and temperature data. 3Tier have modeled hourly values of Global Horizontal Irradiance, Direct Normal Irradiance and Diffuse Horizontal Irradiance at a horizontal resolution of 2 arc-minutes, (approximately 3 kilometers).

6.3. Geothermal resources

'Geothermal Energy in Australia' (Huddlestone-Holmes 2014) the CSIRO report to support ARENA's recent geothermal includes the resource map in Figure 84. This is an indication of the underlying resource that may potentially targeted by enhanced geothermal systems.

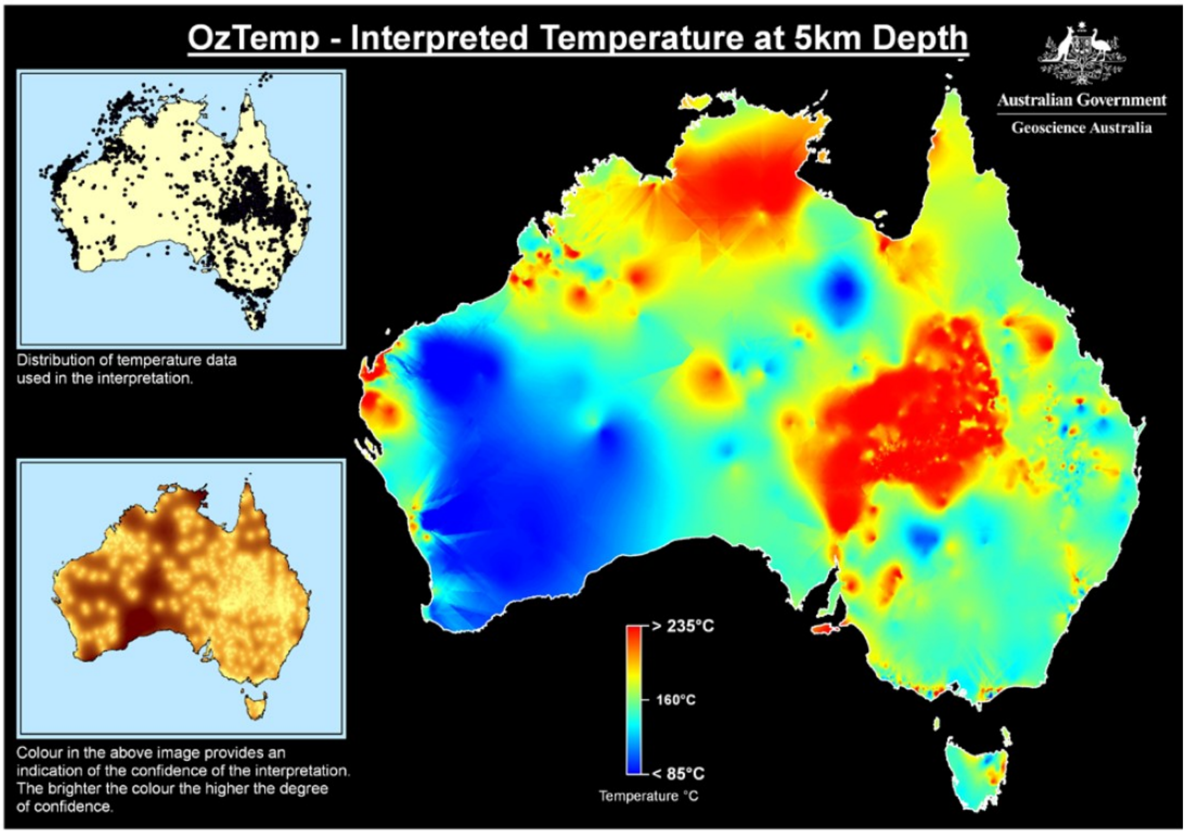


Figure 84. Crust temperature at 5km depth[50]

The map of licence areas shown in Figure 85 may provide a better indication of potential for supply of heat for direct use.

[50] www.ga.gov.au/energy/geothermal-energy-resources.html

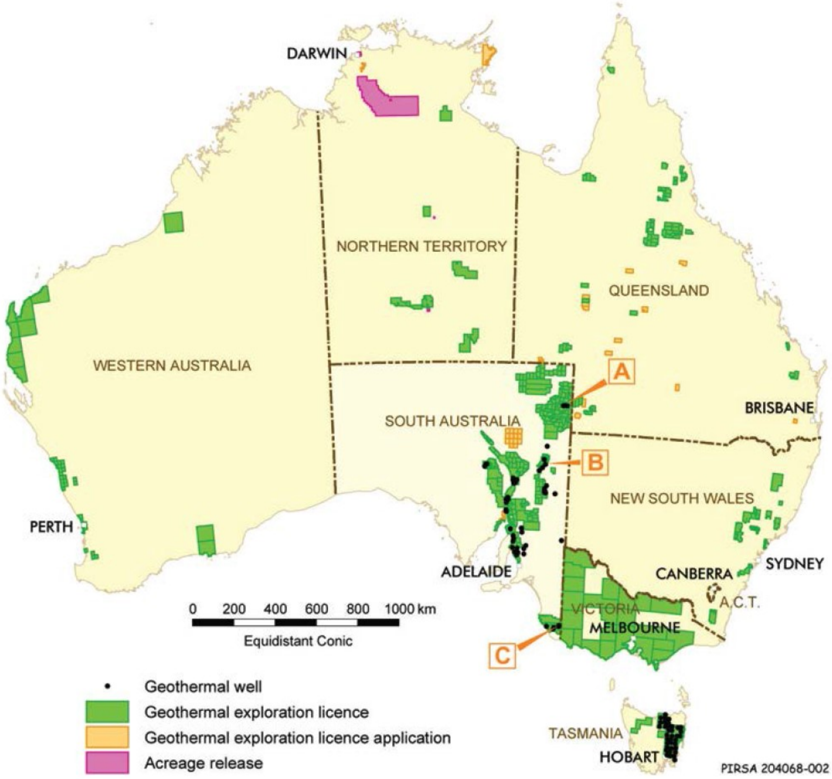


Figure 85. Geothermal wells, exploration licences, and applications (Huddlestone-Holmes 2014)

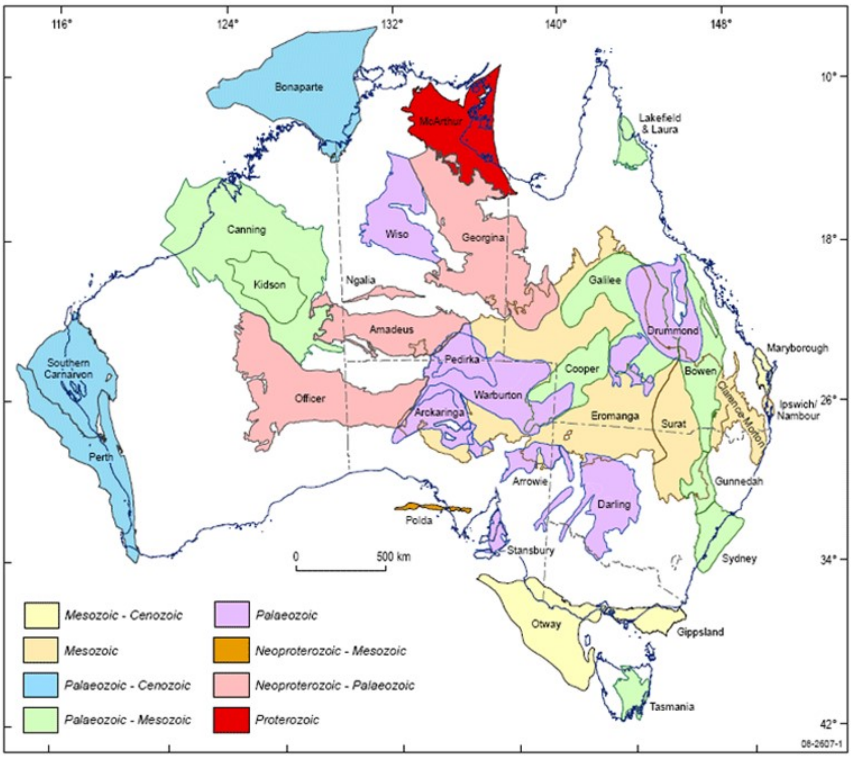


Figure 86. Distribution of onshore sedimentary basins in Australia (Geoscience Australia)

In regards hot sedimentary aquifers, resources can be found at approximately 30% probability in areas within sedimentary basins, this means on average around 5% of the continent is likely to be sitting on a useful resource. Figure 86 shows the distribution of sedimentary basins in Australia. Unfortunately, resource supply is not co-located with resource demand in most cases. The Great Artesian Basin is notable as it covers a very large area of the continent and is actually a combination of several of the sedimentary basins shown in Figure 86. Almost any location within the basin can be expected to yield hot water. Temperatures can be up to 90°C and depths are 1000 – 1500m. The Artesian basin is used to a high degree as a source of water for townships and farms and in many cases water that comes to the surface at an elevated temperature is simply allowed to cool before use.

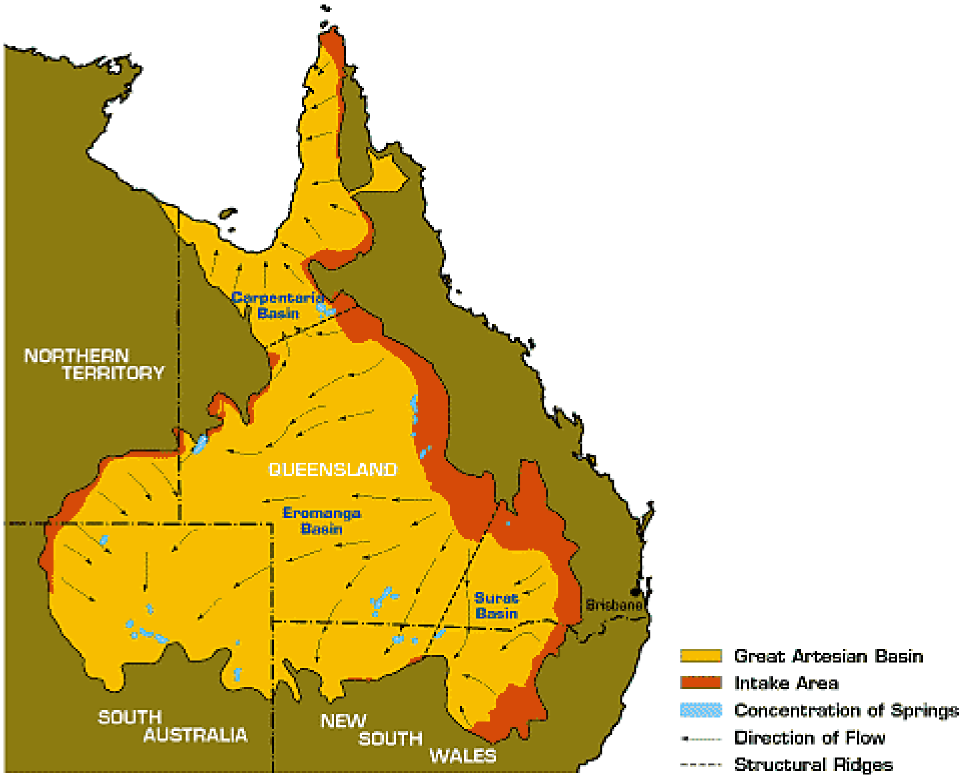


Figure 87. The Great Artesion Basin, (reproduced from http://www.travelling-australia.info/Infsheets/Greatartesianbasin.html)

Despite the large land area involved only a minority of gas users are located near the artesian basin,

The Yarragadee basin in the Perth region is also notable. This is a reliable source of hot water in the range of 40°C at depths of 800 – 1000 m and has been used in a range of projects for pool heating and space heating and cooling.

There is an interesting example of the Otway Basin in the Latrobe Valley in Victoria. It lies beneath the brown coal deposits at depths of 700 – 800m, extends some 50km, and offers temperatures up to 75°C (Driscoll & Beardsmore 2011).

For much of the Eastern part of the continent, between the artesian basin boundary and the coast, where a majority of gas users are located, the presence of a hot sedimentary aquifer resource is a low but not zero probability. Assessing the potential for a gas user, would require use of geological / hydrology expertise. State government departments with water resource responsibilities have considerable background knowledge. Assessment becomes a sequential analysis of probabilities that includes; is the location on a sedimentary basin; will water be present; will it be at an elevated temperature; will the strata allow reasonable rates of extraction.

6.4. Summary

Bioenergy feedstocks include; agricultural residues, energy crops, forestry residues, urban wastes, sewage gas, landfill gas and woody weeds. Costs range from zero or even negative for some waste materials to around $12/GJ for processed wood pellets. Whilst the handling technologies are mature technologies on a global scale, in Australia, supply chains are still largely undeveloped. There is considerably more potential than is currently utilised. The location of current resources is specific and linked to current land use.

Solar resources are well known at an average level and are higher towards the inland of the continent. There are key issues of day to day and seasonal variability. Australia's overall solar resource level is close to the best in the world.

There is a reasonable but not ideal correlation between the location of gas users and solar or biomass resources. The majority of industrial gas users would be able to identify some level of solar and / or biomass resource that could in principle be used.

Identifying accessible geothermal resources is harder and reliant on the skills of experts in the field. Local knowledge of the presence of hot sedimentary aquifers for a minority of gas users could be applicable.

7. THE ECONOMIC CASE

Capital costs and input costs for gas fired, bioenergy and solar thermal systems have been established in Chapter 5 and Chapter 6. Assessing economic performance requires a comparison of the cost of the renewable options with an assumed gas fired default.

A definitive description of methodologies for the financial analysis of energy systems is available from NREL (Short et al 1995).

Simple payback times based on dividing the capital cost of the renewable energy system by the annual savings in operating costs are often used as a metric. This is simplistic as it does not take into account the time value of money. At a more rigorous level a company is likely to use the Internal Rate of Return (IRR) as a metric to make investment decisions.

At an individual project level, there will be an existing or default new gas based system together with an assumed price for gas. Using this, payback time or IRR can be determined. For this investigation however, a general comparison is sought and it is clear that gas prices vary over a wide range depending on the user.

The Levelised Cost of Energy (LCOE) uses discounted cashflow analysis to establish a fixed unit cost of energy that accounts for operating cost and an amortisation of the investment. It can be calculated for a given technology solution independently for a range of possible input parameter vales. Options can be compared by their respective LCOEs. The methodology of LCOE calculation also means that for a favourable option compared to a default, the IRR can also be determined as the effective discount rate at which each option gives the same LCOE.

A selection of the graphs of the results in this chapter also appear in the summary report with different formatting, The key LCOE graphs appear in the executive summary of this report also with different formatting.

7.1. Levelised cost of energy

The Levelised Cost of Energy (LCOE) is defined as the constant per unit cost of energy which over the system's lifetime, will result in a total NPV of zero. In other words it is the 'break even' constant sale price of energy.

LCOEs can be in real or nominal terms, which can be confusing because they are expressed in year 0 dollar values in either case. A nominal LCOE represents a hypothetical income that declines in real value year by year, whereas a real LCOE has a constant 'value'. Since the total NPV via either method must be the same by definition, the nominal LCOE will be the higher of the two. Real LCOEs are typically used for future long term technology projections, whereas nominal ones are often used for short term actual projects.

$$LCOE = \frac{NPV(lifecycle\_costs)}{\sum_{1}^{N}\left(\left(annual\_generation \times (1-T)\right) \Big/ (1+DR)^{j} \right)}$$

Where *T* is the tax rate and *DR* the discount rate.

Industrial gas users are using gas as a business input, transforming it to an internally used energy service and then are subsequently paying tax as a consequence of the sale of a good or service. Thus the levelised cost analysis that should apply here can set the tax rate to zero in the denominator of the equation above, but still allow for tax deductions on operating inputs as discussed below. However it is recognised that dealing with tax issues is very company specific and so it has been left out of most of the comparisons.

Real LCOE's are considered here. A full description of the method is given in Appendix C.

7.1.1. Financial parameters for baseline

Whilst sensitivity analyses are presented, this study has chosen to adopt a set of baseline financial parameters that aspire to represent realistic numbers for a strong company able to access reasonable bank finance and treating the project as one of high strategic value and so accepting a return on equity at the lower end of expectations.

Specifically:

Cost of equity and cost of debt: The cost of debt is the high end of a range of 6.7 – 7.5% taken from the Australian Energy Regulator's 2014 decision for NSW network businesses.

- Nominal pre tax return on equity: 10%
- Nominal pre tax return on debt: 7.78%.

Debt share: 60%

Inflation: 2.5%, the middle of the RBA's current target inflation band.

Loan term: 15 years, obtained from discussions with a major bank.

Depreciation period: 15 years.

System life: 20 years. The Californian trough plants are now operating continuously for over 20 years and clearly capable of continued cost effective operation. Boilers of various kinds also demonstrate lifetimes over 20 years, thus 20 years is taken as a conservative assumption.

Residual value: 5% of capital cost. An approximate assumption based on the possibility that systems could still be workable and upgraded after 20 years.

Tax: 30%, applied for deductibles at standard corporate rate. However whilst tax is included in the method, it has been exclude from most of the comparisons presented below.

O&M: 2% of capital cost per year.

7.2. Cost of energy services

In this section the cost of providing process energy (usually heat) is considered for the various technology options. The results are presented as a function of annual process energy demand. Capital costs are linked to system capacity, analysing economic performance is also strongly influenced by the capacity factor of operation.

Thermal capacity maps to an annual process energy demand according to the capacity factor of use as shown in Table 38.

Table 38 Relationship between thermal capacity (MW) and annual process energy produced / consumed (GJ) as a function of capacity factor.

Capacity Factor	0.5 MW	1 MW	5 MW	10 MW	20 MW	40 MW
10%	1,577 GJ	3,154 GJ	15,768 GJ	31,536 GJ	63,072 GJ	126,144 GJ
15%	2,365 GJ	4,730 GJ	23,652 GJ	47,304 GJ	94,608 GJ	189,216 GJ
20%	3,154 GJ	6,307 GJ	31,536 GJ	63,072 GJ	126,144 GJ	252,288 GJ
25%	3,942 GJ	7,884 GJ	39,420 GJ	78,840 GJ	157,680 GJ	315,360 GJ
30%	4,730 GJ	9,461 GJ	47,304 GJ	94,608 GJ	189,216 GJ	378,432 GJ
50%	7,884 GJ	15,768 GJ	78,840 GJ	157,680 GJ	315,360 GJ	630,720 GJ
70%	11,038 GJ	22,075 GJ	110,376 GJ	220,752 GJ	441,504 GJ	883,008 GJ

Gas or biomass boilers would be expected to operate with quite high capacity factors, however it depends on the demand profile of the user. A highly variable profile will result in a lower capacity factor than one characterised by near steady demand.

For solar thermal systems, the capacity factor will be limited to around 10- 30% by the variable solar resource. Hence large capacity systems are required to produce a given amount of process energy in a year. Thermal storage tanks will be needed to allow the collected energy to be used by a process with its own demand profile.

7.2.1. Natural gas fired

The capital costs for natural gas fired boilers have been presented as a function of thermal capacity in section 5.2.

Using the capital cost information together with an assumed 80% conversion efficiency and 70% capacity factor and neglecting tax issues, for a range of gas prices give the results for annualised cost as a function of process energy demand as shown in Figure 88.

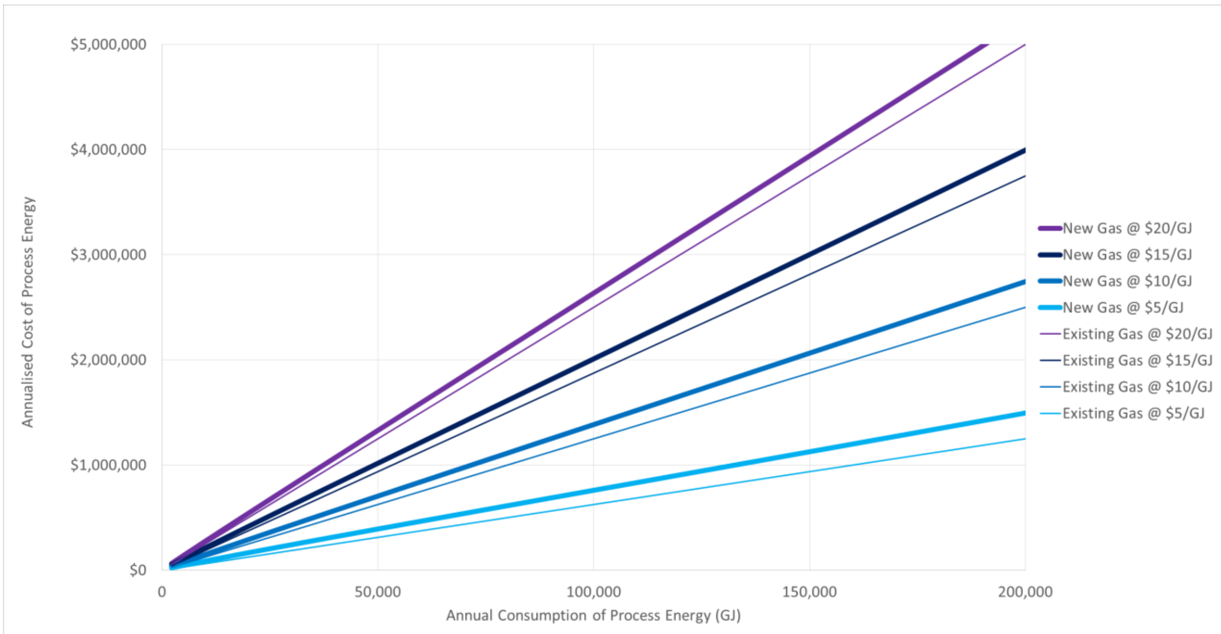


Figure 88. Annualised cost of natural gas fired process energy production considering either new build or already fully depreciated systems, for a range of gas prices.

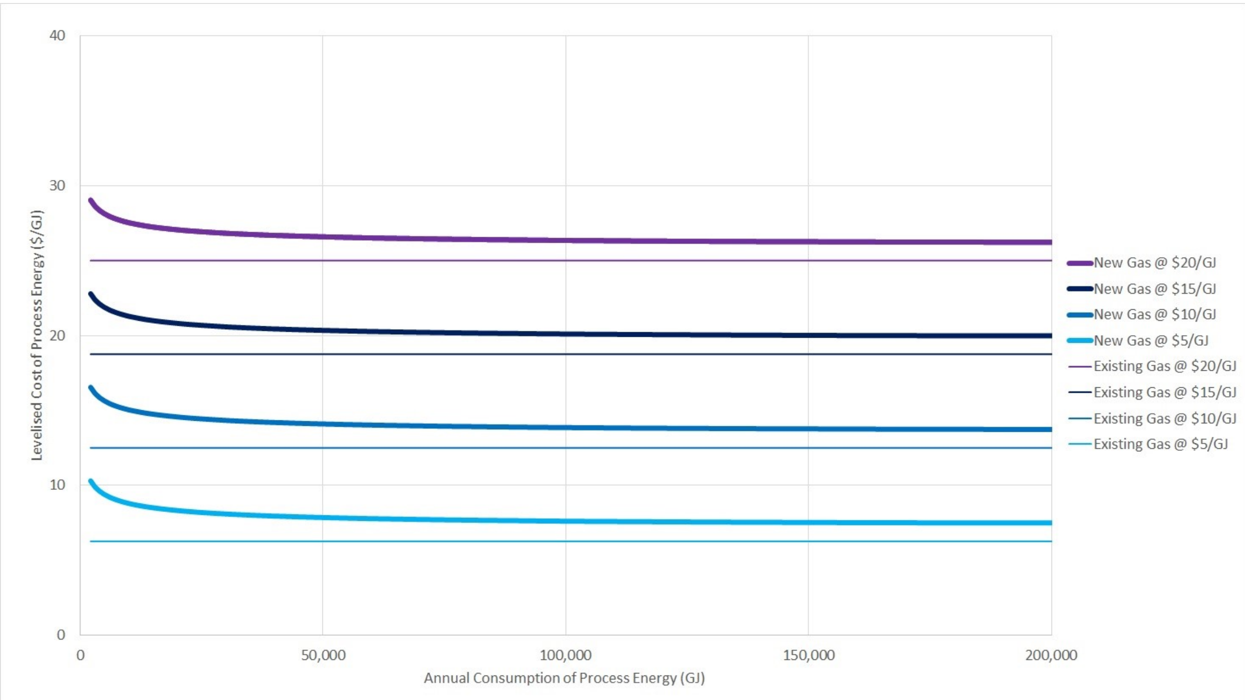


Figure 89. Levelised Cost of Energy of natural gas fired process energy production considering either new build or already fully depreciated systems, for a range of gas prices.

The graph shows lines for a new build system and also for one that is fully depreciated and so only gas fuel costs are taken into account. The gap between the two represents the amortisation of capital cost. In the case of the fully depreciated system, it can be seen that annualised costs simply increase in proportion to energy demand. For a new build system, amortisation of capital cost adds slightly to the annualised cost and represents a higher proportion for small systems which have higher per unit capacity cost.

The corresponding levelised cost of energy service is shown in Figure 89. LCOE is effectively the annualised costs divided by the annual energy demand.

In the case of the fully depreciated system, it can be seen that the levelised cost of the energy service is higher than the input fuel cost, reflecting the 80% conversion efficiency assumed. For a new build system, LCOE's are higher, allowing for the amortisation of the capital cost component. For small systems, the higher specific capital costs cause the upward trend in LCOE.

If tax deductions for fuel cost, O&M, interest and depreciation are allowed the effective LCOE of process energy drops. This is illustrated in Figure 90 for the case of $10/GJ gas and where a 30% tax rate is assumed.

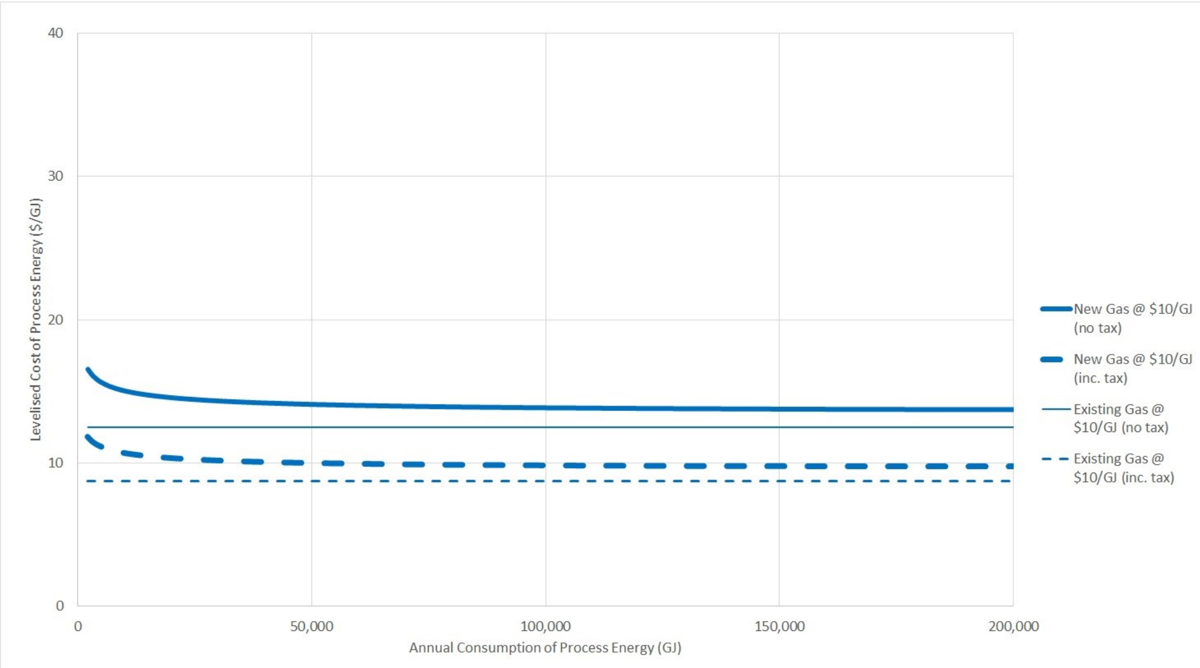


Figure 90. Levelised Cost of Energy of natural gas fired process energy production considering for $10/GJ gas, either new build or already fully depreciated systems, both with and without tax deductions.

As discussed in Chapter 3, the smaller mass market distribution connected customers see much higher prices and hence cost of energy service compared to the large transmission connected customers. Figure 91 reproduces the results of Figure 89 and also shows the indicative LCOE's based on likely gas prices as a function of annual consumption with regions shaded grey and pink, for 2014 and 2018 respectively. Thus it is seen that the likely gas LCOE range can be mapped as having a much stronger size dependence than would be associated with an assumed single cost of gas. This trend should be considered in comparison to renewable options considered later.

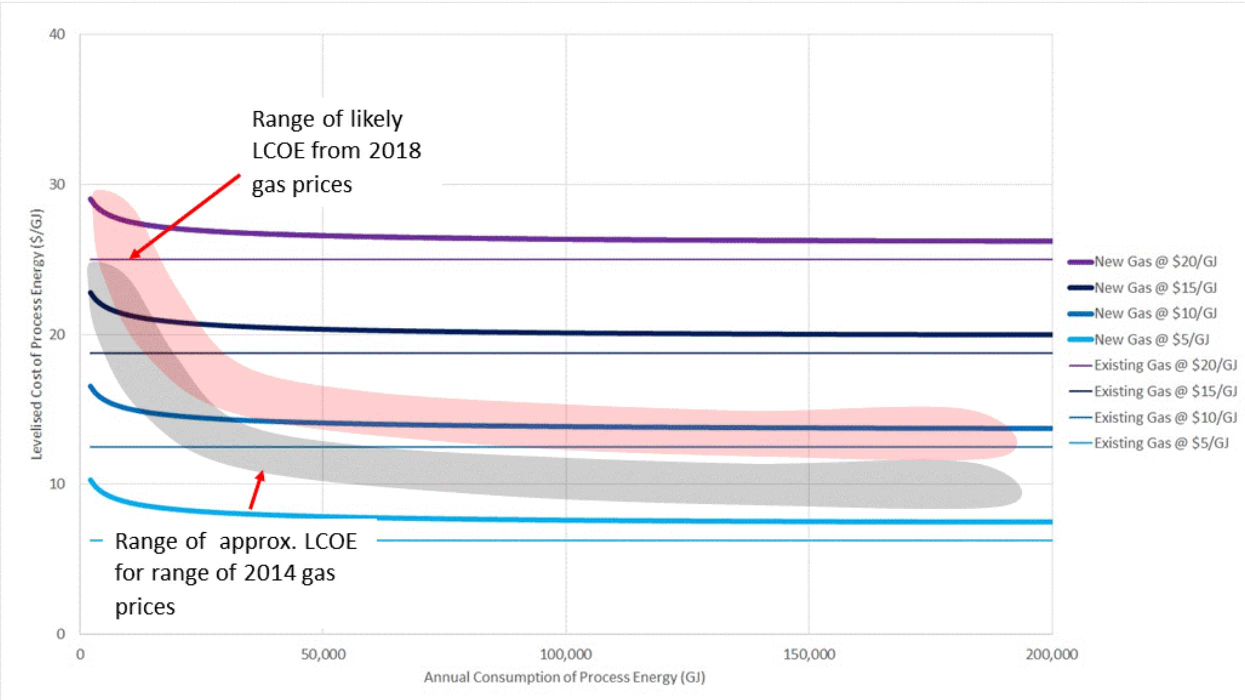


Figure 91. LCOE of natural gas fired process energy production considering either new build or amortised systems, together with a mapping of expected LCOE based on gas price dependence on user demand levels.

7.2.2. Initial Screening of renewable options

To establish an initial comparison of renewable options, a $1MW_{th}$ system producing heat at 100°C is considered. All the renewable options identified are capable of delivering heat at that temperature. The basis for this initial comparison is:

Geothermal

The specific costs in Section 5.5.2 of $571,500/$MW_{th}$ for hot sedimentary aquifers, when scaled using the same power law expression as used for the other technologies give a value of $3,490/kW at a size of 1MW. A geothermal system is continuously available, but demand may not be continuous so an estimated 80% capacity factor has been used.

Standalone PV Heat pump

Indicative heat pump costs are around $1,000/kW. If a COP of 4 is assumed, then a 250kW array is needed for a $1MW_{th}$ heat pump. At $2/W this adds $500 per kW_{th} of output. Capacity factor based on PV system has been estimated at 17% for a good to reasonable site.

Solar Thermal

At 100°C and 1 MW_{th}, the cost equation gives $908/kW. An evacuated tube array would be the likely technology. This would achieve a relatively high capacity factor of around 30% at a good to reasonable site.

Biomass

The cost relationship suggests a specific cost of $2,737/kW at this size. With sufficient storage of fuel a 70% capacity factor is estimated. A zero cost waste stream is modelled.

The results are shown in Table 39.

Table 39. Capex, capacity factor, fuel cost & LCOE for indicative RE systems at $1MW_{th}$

Technology	Capital Cost ($/kW)	Capacity Factor	Fuel Cost	LCOE
Geothermal	$3,490	80%	n/a	$11.6/GJ
PV Heatpump	$1,500	17%	n/a	$22.9/GJ
Solar Thermal	$908	30%	n/a	$8.1/GJ
Biomass	$2,737	70%	$0/GJ	$10.4/GJ

In this case, the solar thermal system offers the lowest LCOE, followed by a biomass system with zero cost fuel, geothermal and then a standalone PV heat pump system.

As a direct comparison it should be noted that all the base resources are unlikely to be available as options at any given site. The results together with other analysis carried out suggest the following general conclusions:

- A geothermal system is highly dependent on a locally available resource which may not be easy to determine. The cost of drilling wells is very dependent on the depth of the resource. If a sufficiently shallow and sufficient temperature aquifer were present, it is worth considering.
- Under these circumstances, solar thermal clearly outperforms PV plus heat pump solutions. It can be observed however that for sufficiently low temperature difference between source and use, the COP will be higher, reducing the size and cost of PV array needed, and the effective cost of the heat pump per unit output would also decrease. Thus for low temperatures, or recovery of heat from waste streams that are close to the temperature of use, the PV heat pump option may be worth considering.
- A heat pump system directly grid powered, would operate with much higher capacity factor. In such a case the overall performance would be strongly dependant on the marginal cost of electricity that applied but can be expected to be very competitive with other low temperature sources. In such a system a behind the meter PV array could also be added, for overall minimisation of greenhouse gas intensity and possible reduction in peak electrical demand charges.
- The solar thermal solution appears capable of delivering process heat at costs that are below costs faced by at least some gas users. Noting the strong dependence of cost on temperature and size, further analysis is required.
- Whilst the biomass solution in this case results in a somewhat higher LCOE than solar thermal, it can be noted that best solar resources and best biomass opportunities are almost complimentary in location and rarely coincident, so the best choice of technology would depend on the circumstances. The cost of bioenergy systems is largely unaffected by the process temperature as these are typically below 250°C, so it could be expected that at higher temperatures, close to the same LCOE would result and the competitive position against solar thermal would improve.

More detailed analysis of the options is presented in the following sections.

7.2.3. Bioenergy vs gas

The capital costs of biomass fired boilers, biomass gasifiers and biomass digestors were shown to be quite close in section 5.3.2. In this section, bioenergy options are considered as a single class with capital costs taken as those of combustion boilers and used as indicating the average performance of the other configurations.

Direct comparison to natural gas fired systems is now limited to the conservative case of considering gas fuel costs only, based on the idea that an existing gas fired system would be retained as backup. Tax deductions are also not considered.

Figure 92 presents the annualised cost of bioenergy solutions compared to gas for a range of possible biomass and gas fuel costs. Figure 93 shows the same comparison as LCOEs. The width of the shaded lines represents the uncertainty in the determination. It follows an estimated +-15% uncertainty and site specific range to the capital cost estimates.

The annualised cost curves for biomass are seen to cross and become less than those of gas fired systems at various size points. These crossover points are easier to identify in the LCOE curves as the point at which the biomass option becomes more cost effective than a gas fired system that is already amortised.

The larger the plant, the more attractive a biomass solution is compared to gas of a given price, this is due to the size dependent capital cost contribution that favours larger plants.

Whilst biomass LCOE's are much higher for small systems, the increase is almost in direct correlation with the higher gas prices seen by smaller users, thus there is no apparent favourable size based niche market apparent from this analysis.

A $7/GJ biomass fuel cost upper limit appears to roughly match future gas price related cost of process energy. More expensive biomass will struggle to find a market.

Figure 94 presents the comparison in terms of IRR. For a biomass fuel cost of $0/GJ, corresponding to an on site waste material, a positive IRR is achieved even at $5/GJ gas as long as energy demand is more than 50,000GJ/year. At higher gas prices, IRRs are increasingly large.

For biomass at $5/GJ, a positive IRR is only obtained at $10/GJ gas for demand greater than 50,000GJ/ year and at $10/GJ biomass, the gas prices needs to be around $15/GJ.

The overall conclusion however is that there are circumstances where a bioenergy solution will be competitive with gas at the present time and this will strengthen as gas prices increase in the future.

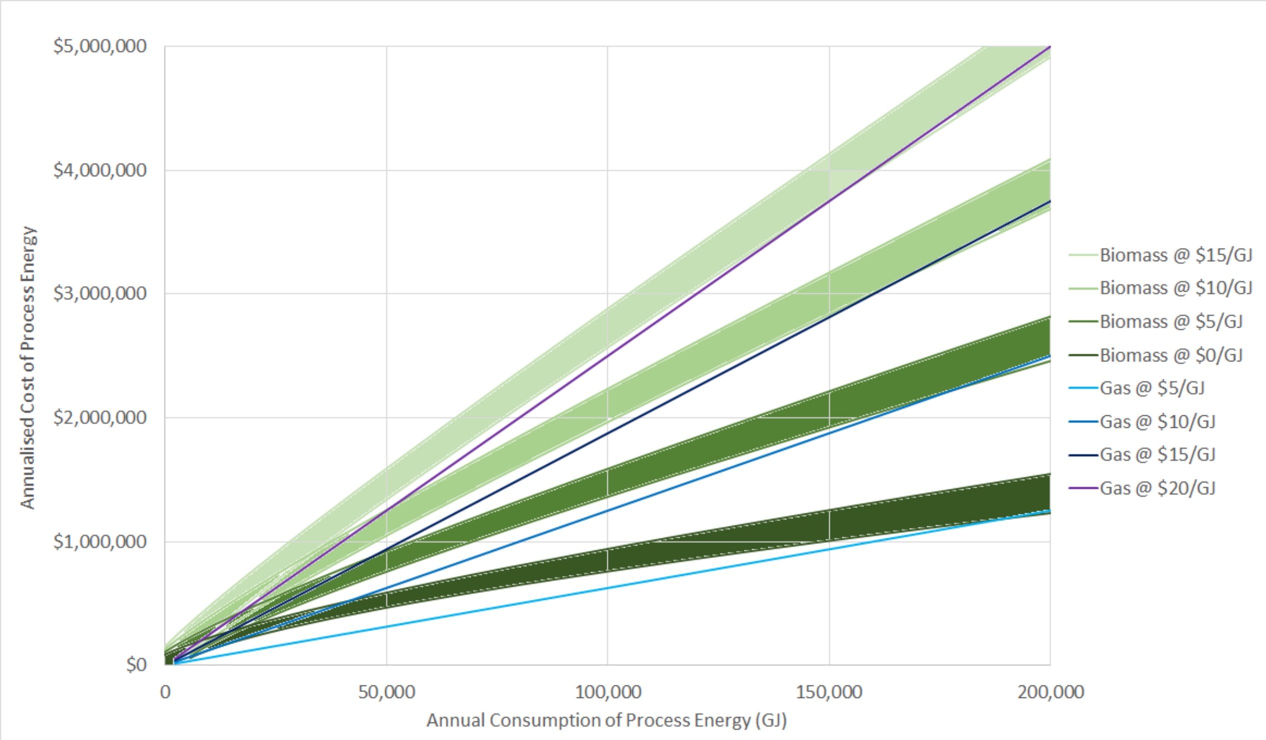


Figure 92. Annualised cost of Biomass and natural gas fired process heat as a function of annual demand.

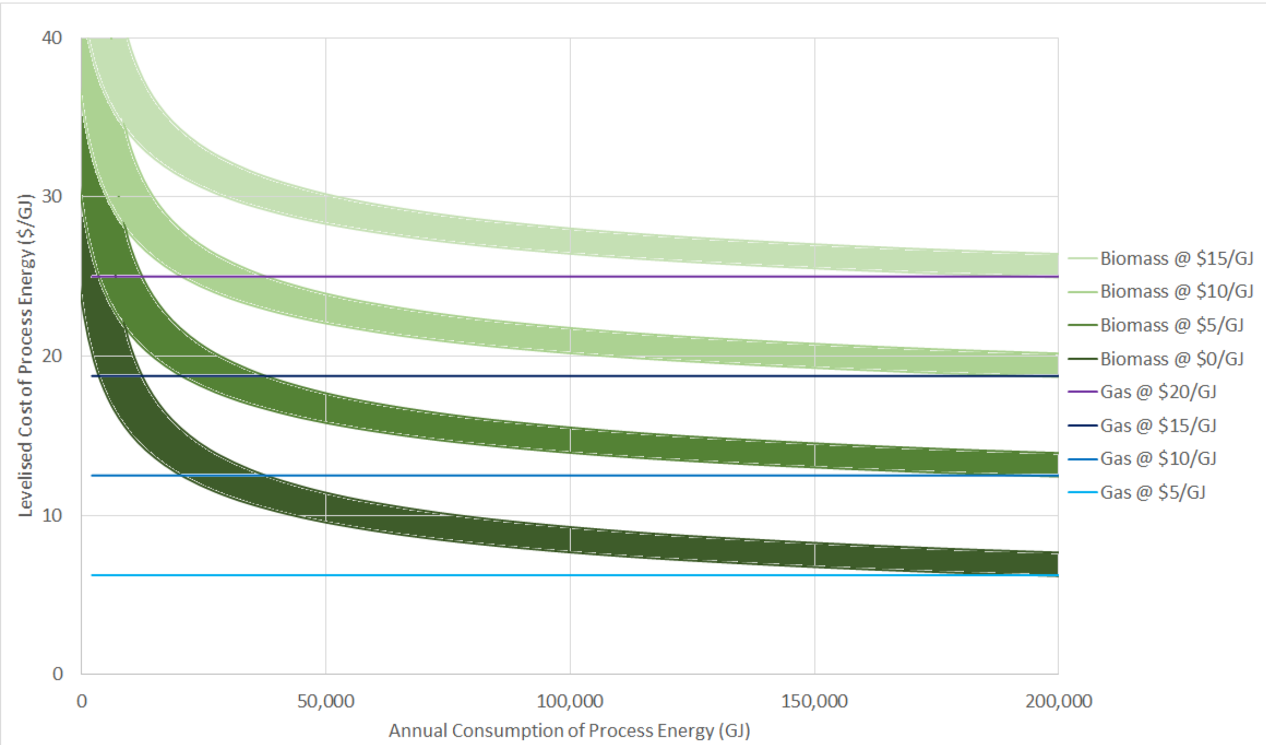


Figure 93. LCOE of bioenergy and existing gas.

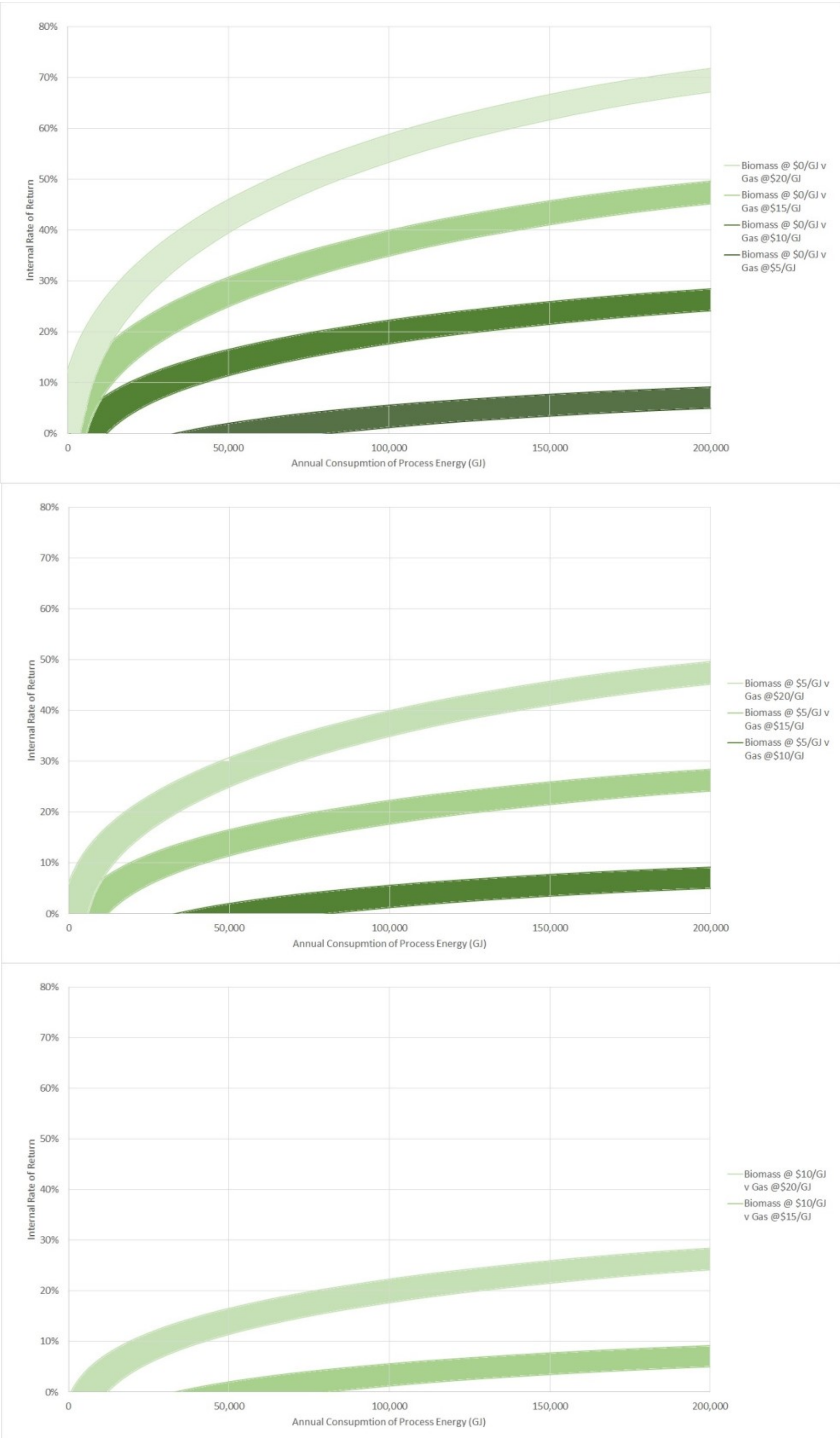


Figure 94. IRR of bioenergy vs existing gas systems for gas prices of $5, $10 and $15/GJ for various biomass costs.

7.2.4. Solar thermal vs gas

For a comparison of solar thermal options against gas, a range of specific temperatures have been individually examined. As a starting point a ‘reasonable’ solar site represented by Brisbane, has been analysed. Figure 95 shows annualised costs for 100ºC, 200ºC, 400ºC and 600ºC systems. Figure 96 shows the corresponding LCOEs and Figure 97, IRRs for the particular temperatures.

The shaded band for the solar thermal systems results is indicative of the possible range of values due to the various uncertainties and variations in system configurations possible. These are larger than they are for bioenergy solutions as there is no input fuel cost so the fractional uncertainty in capital cost translates directly to that of LCOE or annualised cost. The estimated capital cost variation is also larger at +/-20%.

No cost of land is included, it is assumed that the user takes advantage of existing land or roof space. Operation and Maintenance costs are assumed to be 2% of capital cost per year.

It is apparent that solar thermal systems for temperatures below approximately 150°C should be quite competitive on this basis with gas fired solutions over almost the entire size range at current gas prices. In claiming this, reference is made again to the observation that small users already pay much higher prices for gas than large ones.

Looking at the higher temperatures, systems at around 200°C (small trough or Fresnel concentrators) appear to have some prospects if wholesale gas prices reach $10/GJ. At 400°C present costs for solar technology are too high for viability even at likely future gas costs. At 600°C and above there is an even higher cost gap.

As with bioenergy, the overall conclusion however is that there are circumstances where a solar thermal solution will be competitive with gas at the present time and this will strengthen as gas prices increase in the future.

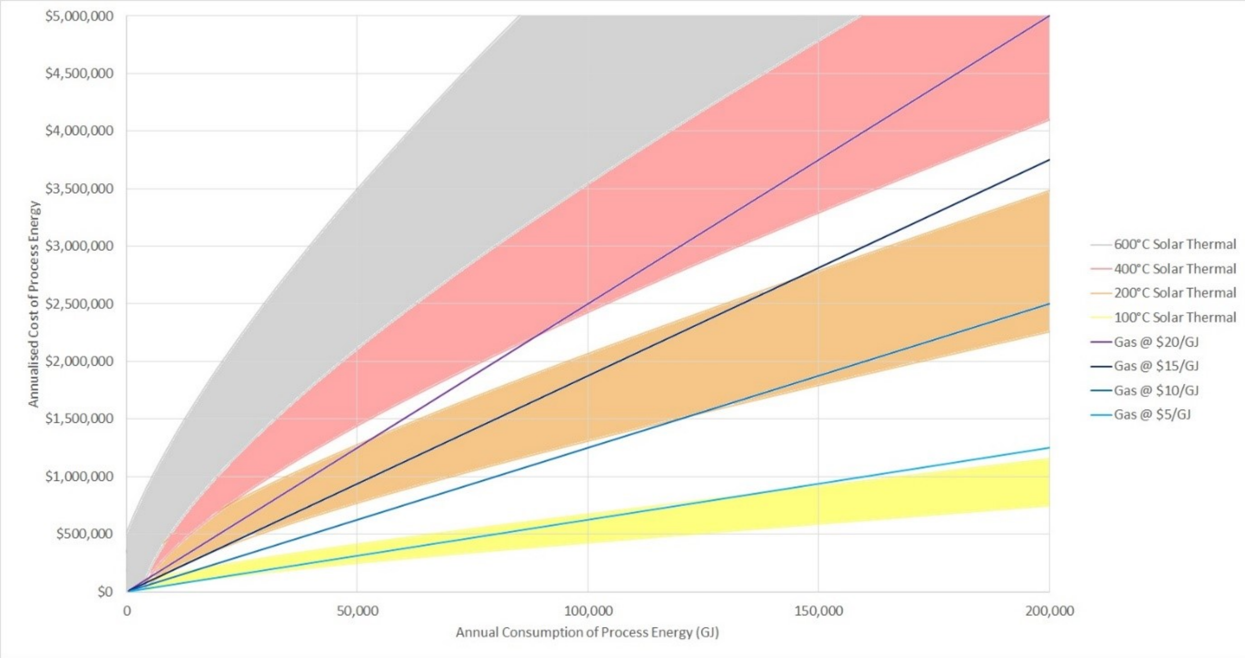


Figure 95. Annualised cost of solar thermal and gas.

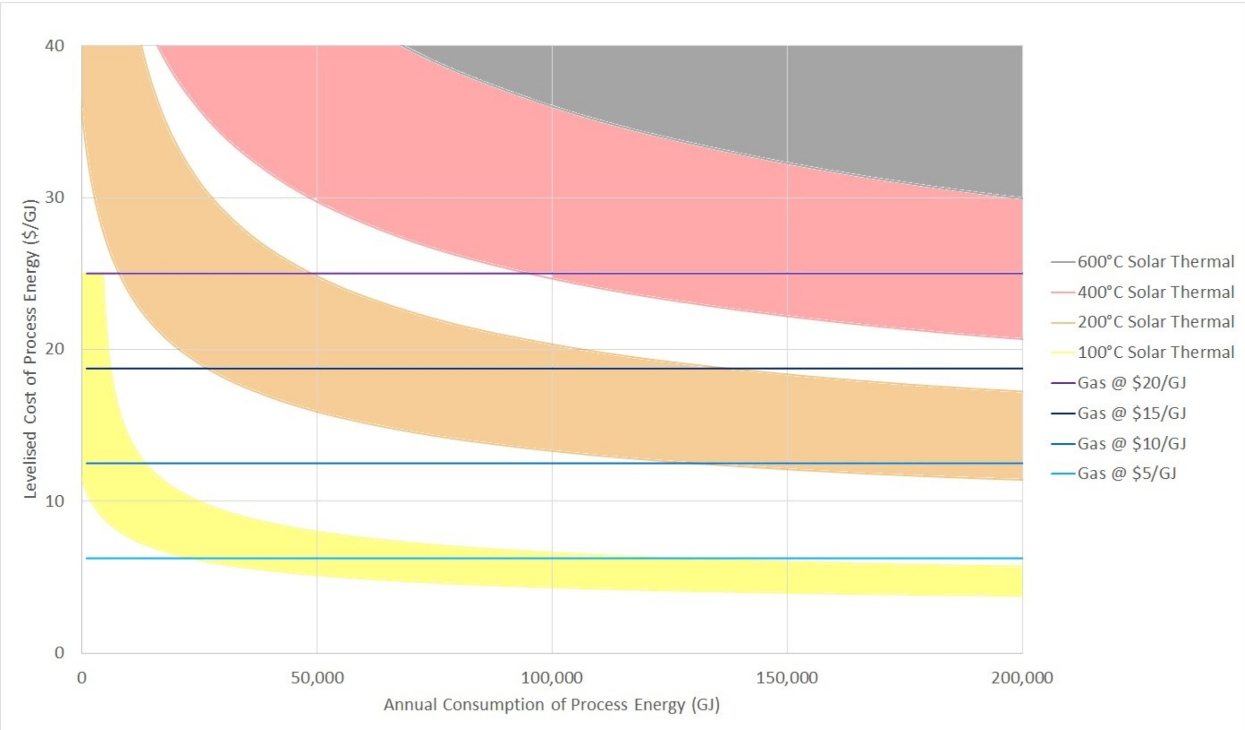


Figure 96. Solar thermal LCOE v gas LCOE, capacity factors used; 31.1% (100°C) – evac tube, 14.1% (200°, 400° & 600°C) – trough, zero land cost assumed.

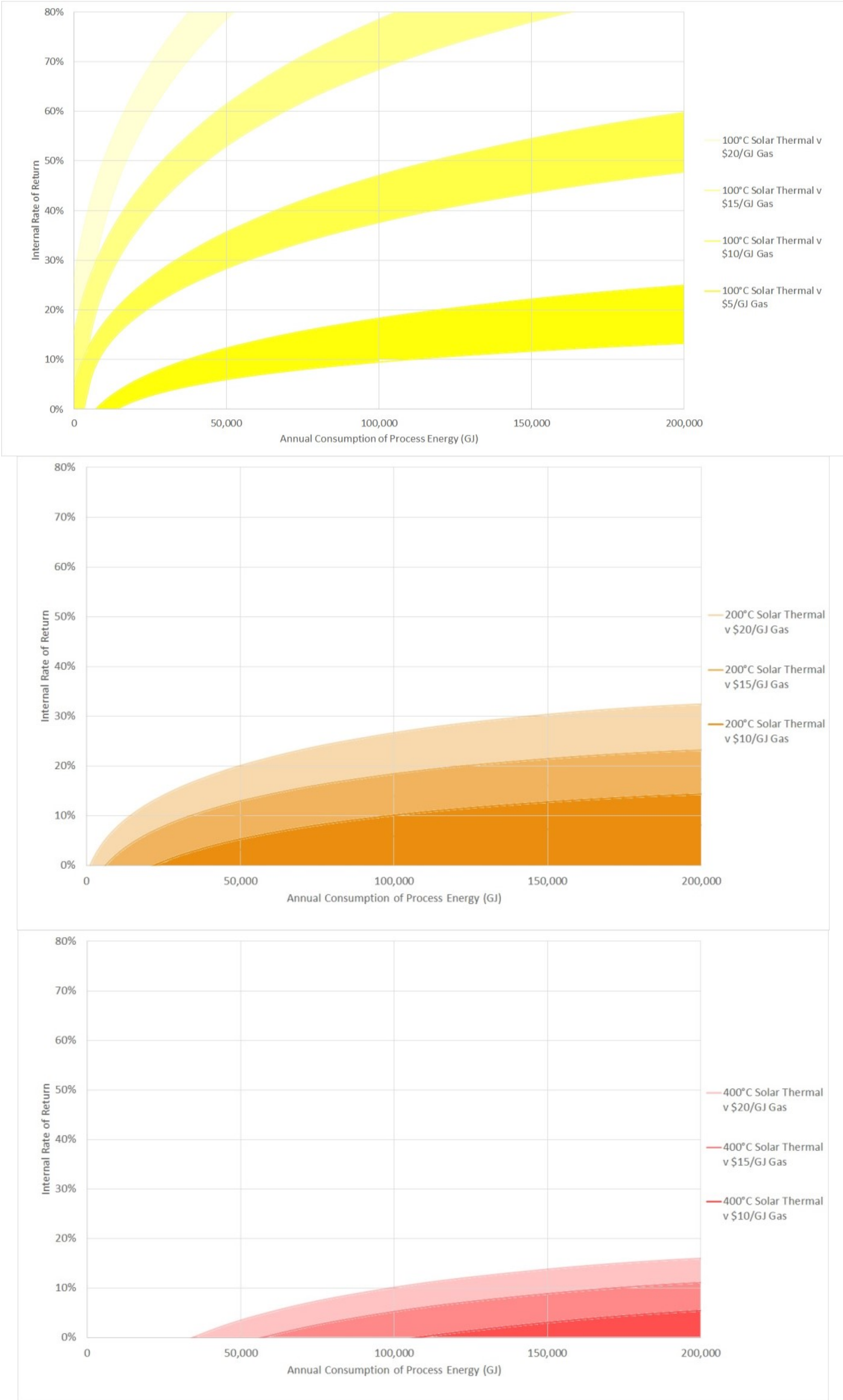


Figure 97. IRR of solar thermal at 100°C, 200°C & 400°C vs existing gas

It is instructive to consider the effect of solar resource level on these conclusions. Figure 98 presents the results for a 200°C system modelled for Melbourne (9.6% capacity factor), Brisbane (14.1% capacity factor and Alice Springs (21.7% capacity factor), representing the range of possible Australian locations.

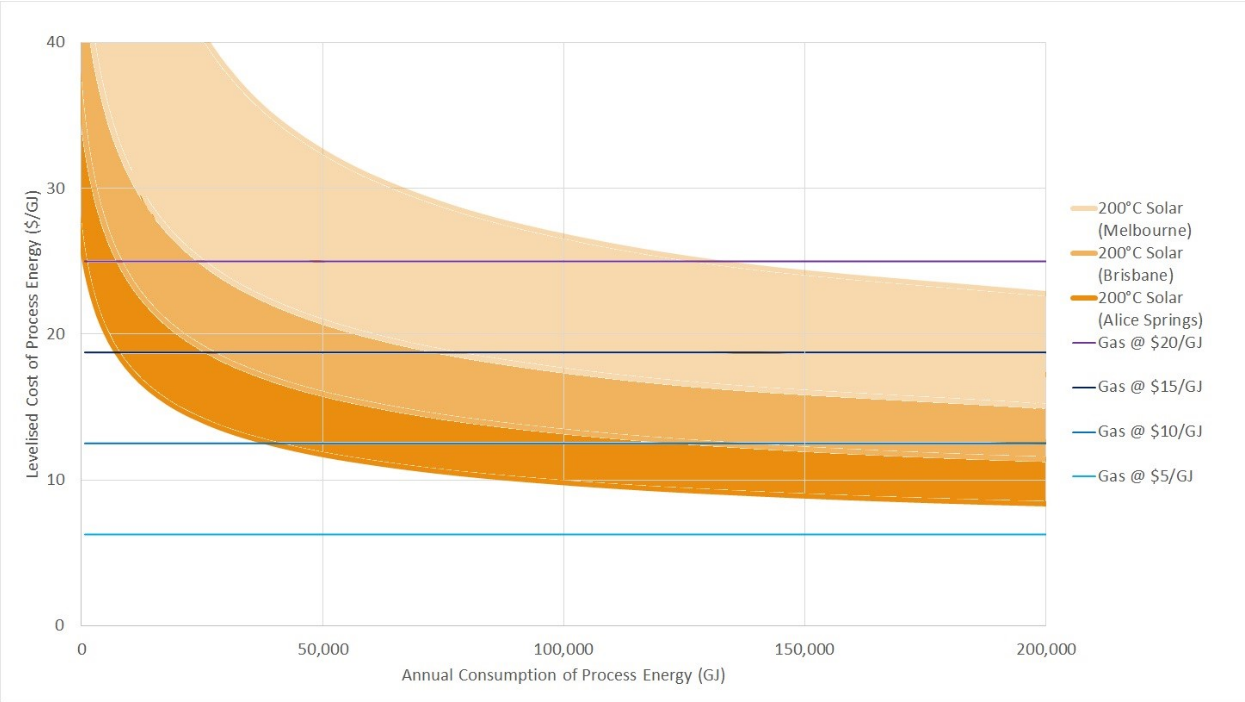


Figure 98. Solar thermal LCOE for 200°C process heat for poor, reasonable and excellent solar resource locations.

It is apparent that such a system that would be at borderline viability in Brisbane, would look quite competitive in a location like Alice Springs. On the other hand, application in a location with a lower solar resource like Melbourne would not make economic sense unless the user was in a regional area and already paying very high prices for gas.

The 10% return on equity in the baseline financial assumptions was chosen to represent close to the lowest value likely to be considered for a strategic action on the part of an industrial user. As has been discussed in Chapter 4, many companies would look for Internal Rates of Return of 20 or 30%. Figure 99 examines the 100°C case for these three rates of return on equity. It transpires that a 20% rate of return would still suggest viability in some cases and even 30% would not be out of the question. This is the case largely because the loan fraction of the total investment remains at 60% with a 7.5% per year interest rate.

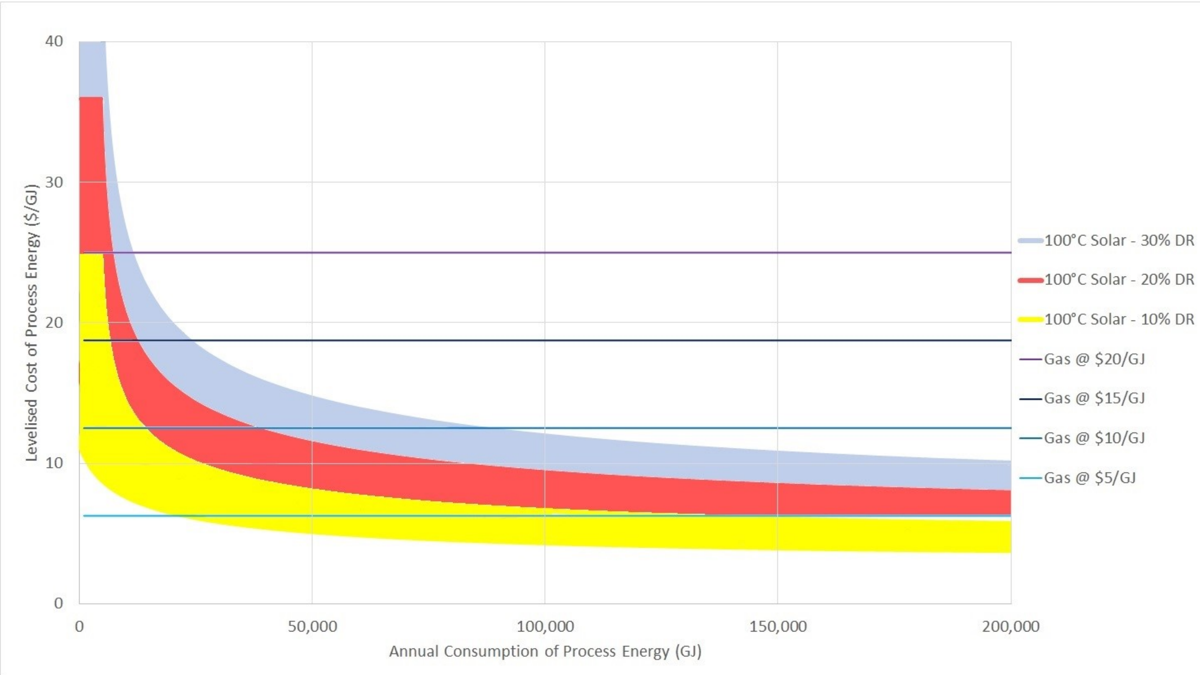


Figure 99. Solar thermal LCOE for 100°C process heat for various discount rates for equity.

7.2.5. Geothermal vs gas

The economics of geothermal energy are largely dictated by the local resource and the utilisation of this resource. A shallow resource can be tapped at less expense than a deeper resource, and the higher the temperature and flow rate of the resource, the greater the energy available to the user. If the flow rate and temperature determine the amount of energy available at any one time, the utilisation refers to the amount of time this available energy can be used in processes.

Flow rates depend on the porosity of the aquifer, and the power of pumps applied. Pump loads have an electricity cost which can become prohibitive if flow rates are driven too high. However, for a properly designed well into a suitably porous aquifer, pumping loads are a small fraction of the total heat yield. Hence, electricity costs contribute only slightly to LCOE.

When compared to low temperature solar thermal, biomass and heat pump systems, capital costs are high and increase with depth. However the energy is available on a 24 hour continuous basis and if the utilisation factor is high, the economic performance will be best. Fuel (electricity) costs are low making marginal production inexpensive once a well is drilled. Hence, resource depth and utilisation is the major determinant of the LCOE.

Annualised costs and LCOEs are shown in Figure 100 and Figure 101 respectively, for depths of 1000m, 1500m and 2000m, for the typical case of 30L/s flow rate, 10c/kWh electricity. The IRRs for these three depths are shown in Figure 102.The width of the curves reflects uncertainty in cost of wells and achievable flow rates. The flat annualised cost curves (Figure 100) are symptomatic of the fact that a single well is sufficient to cover a range of energy demands, and the cost of energy production is small once the well is drilled. The LCOE's shown in Figure 101 depict one well being utilised up to 80% at ~170,000 GJ/yr, before a discontinuity at the point where it is assumed that a second well must be constructed. In this case, it has been assumed that the second well will enjoy economies of scale according to the cost-scaling coefficient of 0.7 used throughout this report. This discontinuity is seen in both the annualised cost curve the LCOE curves and the IRR curves.

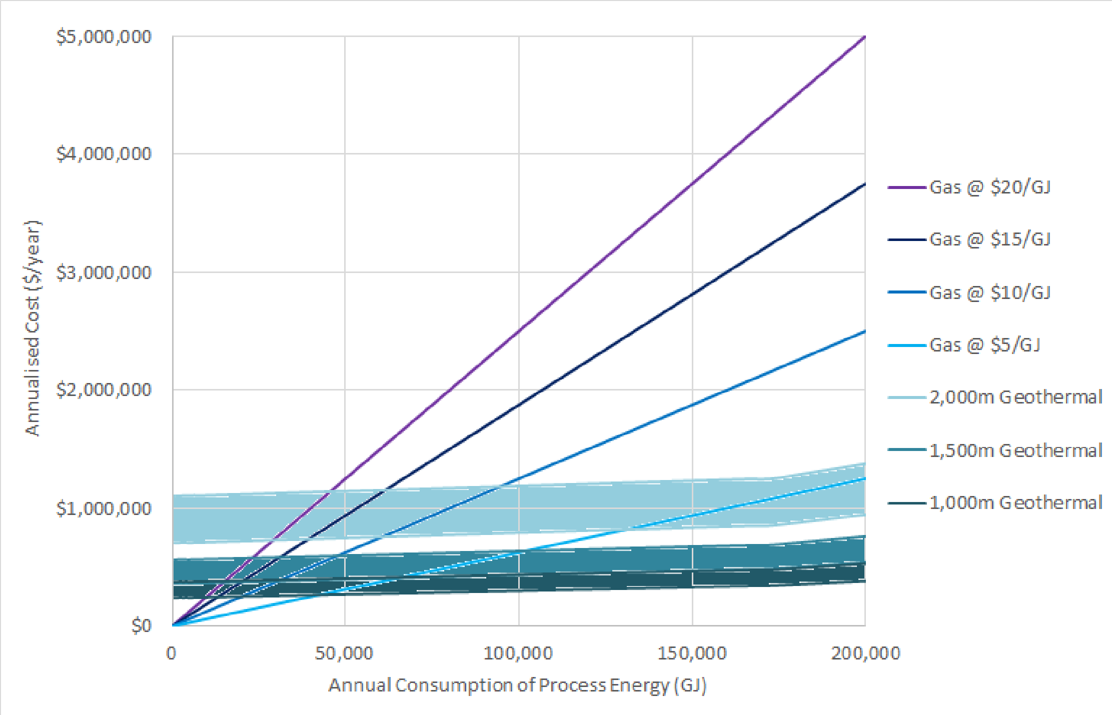


Figure 100. Annualised cost of 75°C geothermal heat at various depths for 30l/s flow rate, 10c/kWh electricity.

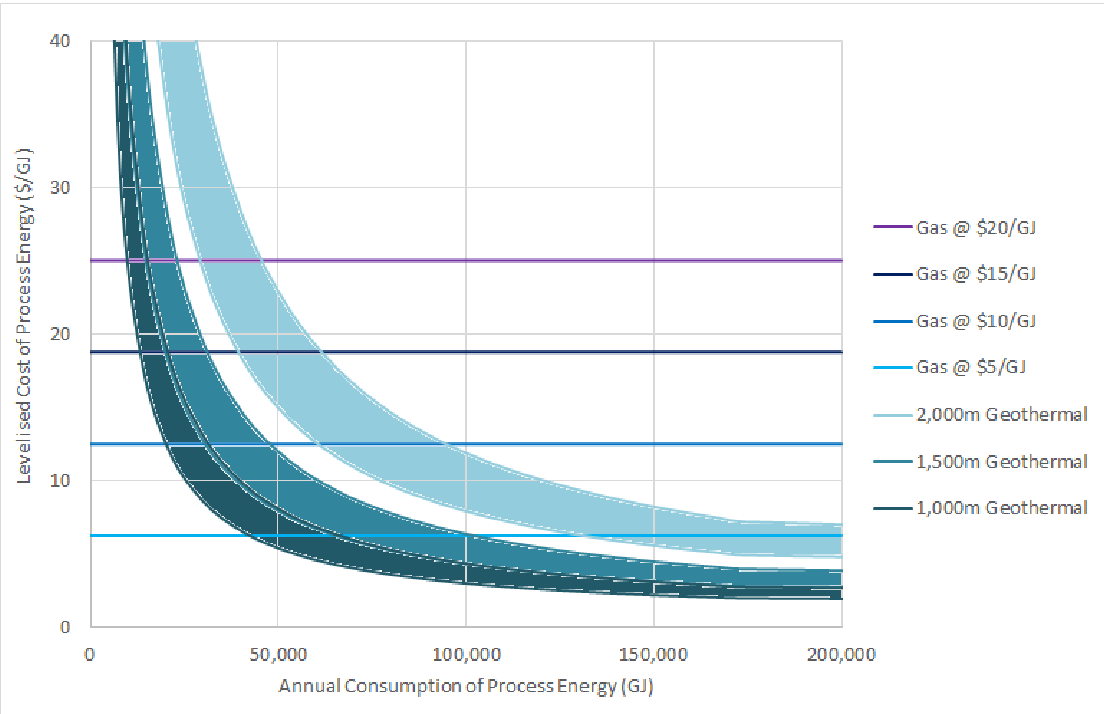


Figure 101. LCOE of 75°C geothermal heat at various depths for 30l/s flow rate, 10c/kWh electricity.

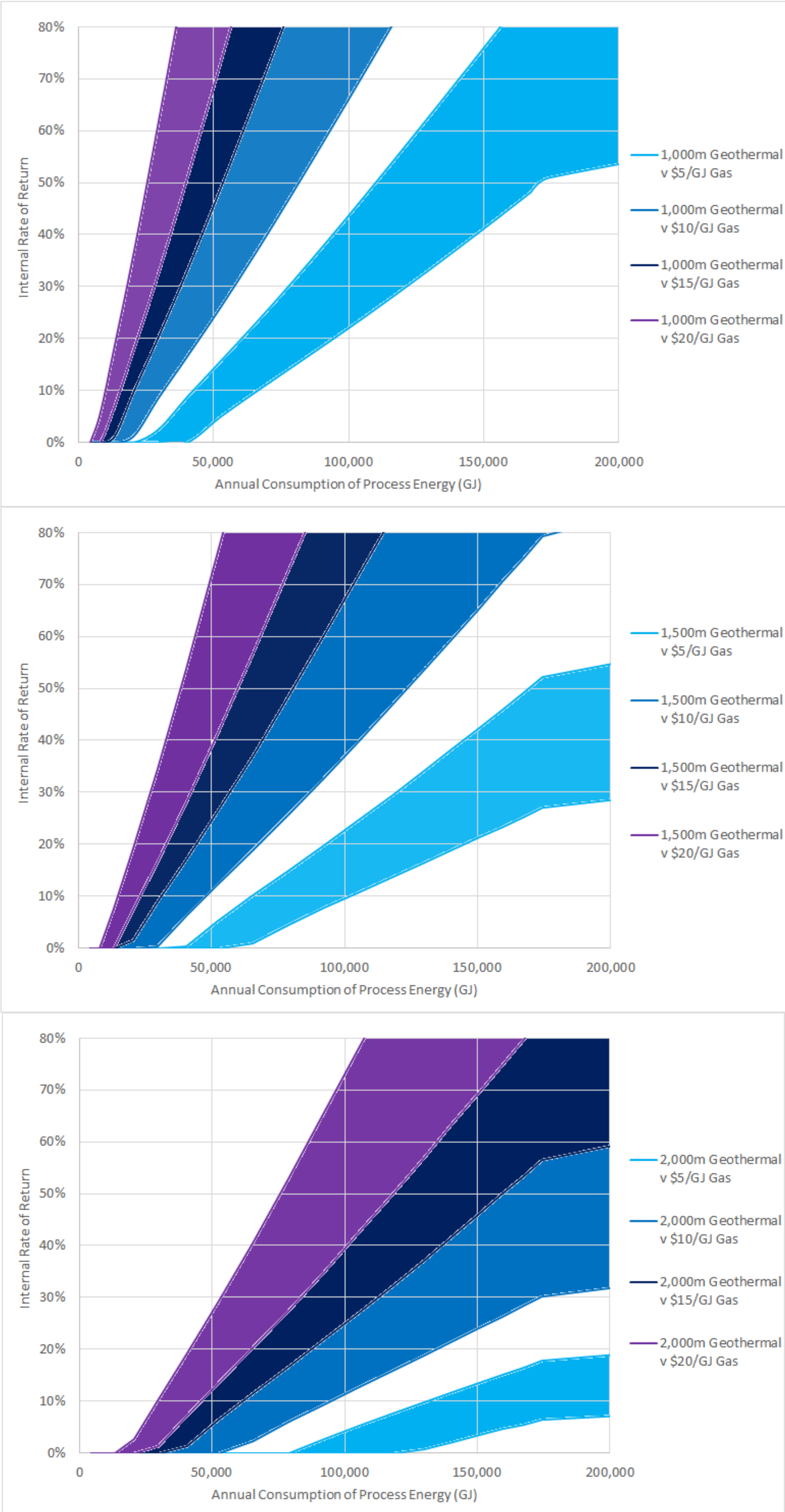


Figure 102. IRR of 75°C geothermal heat at 1,000m, 1,500m and 2,000m depth gas prices for 30l/s.

Both achievable flowrate and temperature have a small effect on the LCOE.

The sensitivity of the LCOE to flow rate was examined with the results depicted in Figure 103. For clarity the shading to indicate ranges of variability has been left off as the variation between flow rates is less than the overall spread. It can be seen that the LCOE's are essentially equal until the point where the low flow rate well is fully utilised, and another must be drilled to serve greater demand. Up until this point, the low flow rate well is actually cheapest as the capital cost is the same, while the marginal pumping costs are lower at lower flow rates. The high flow rate well would become the cheapest option if the chart were extended out further, as the same capital cost would be amortised over greater heat delivery.

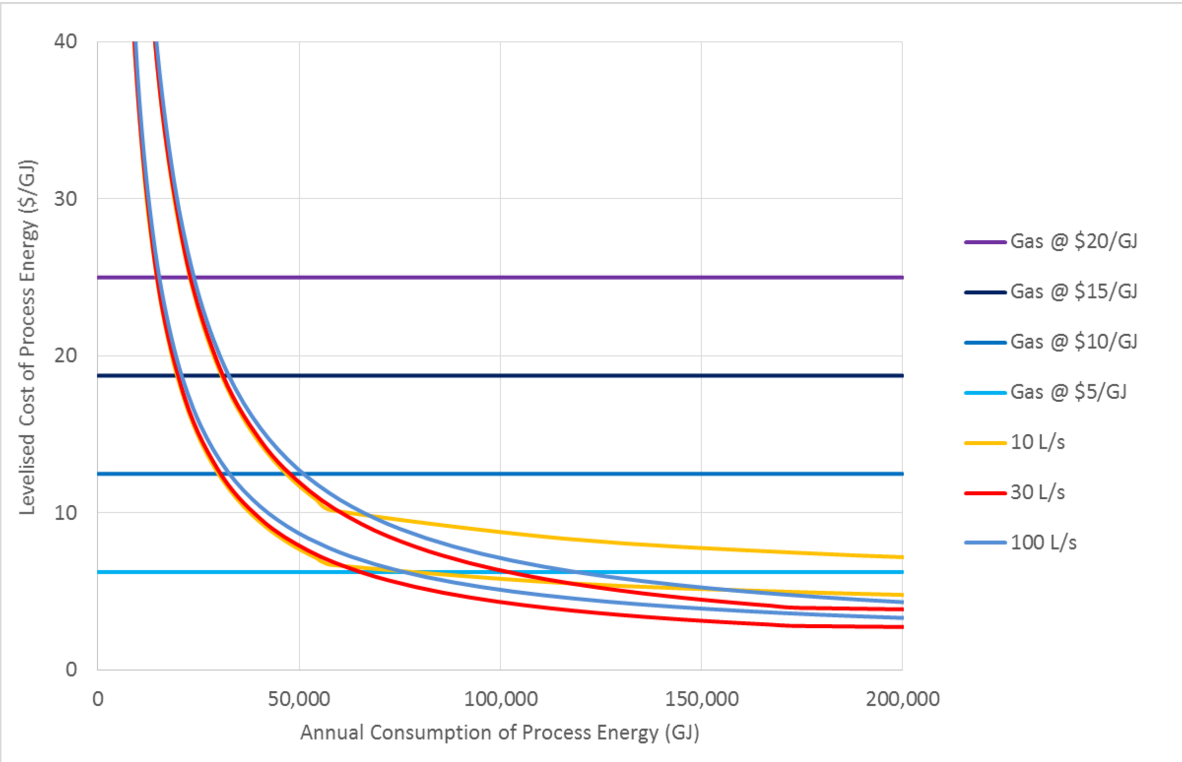


Figure 103. LCOE of 75°C geothermal at 1,500m depth for various flow rates

The direct effect of temperature of a well is a change in the amount of massflow needed to meet a specific heat demand. The difference again is much smaller than the overall range in the results.

For a user, the suitability of an aquifer is largely a question of whether it is hot enough for the process or not.

The overall conclusion from this analysis is there is a very strong crossover point of annual energy demand above which a geothermal solution can be very cost effective, below that point it is not. The cross over point is determined by the cost of gas and the depth of the resource.

7.2.6. Heat pumps vs gas

For a heat pump run with a high capacity utilisation factor, the major determinants of LCOE are the electricity price and the coefficient of performance. Capital costs are low compared to solar thermal, biomass, and geothermal options, and so the input electricity costs dominate the LCOE.

The coefficient of performance is affected mostly by the temperature elevation required, and the thermodynamic efficiency of the heat pump. For analysis, COP was assumed to be 50% of the maximum theoretical value (assuming an ambient temperature of 20°C), with uncertainty of ±20%. Capex figures were taken from section 5.6 with uncertainty set to ±25%. Figure 104 depicts the annualised cost of heat pumps run at an 80% capacity factor with 10 c/kWh electricity. Figure 105 depicts the LCOE for the same scenario. The bands of spread result from a combination of uncertainty and spread in cost and COP of ±25% and ±20% respectively.

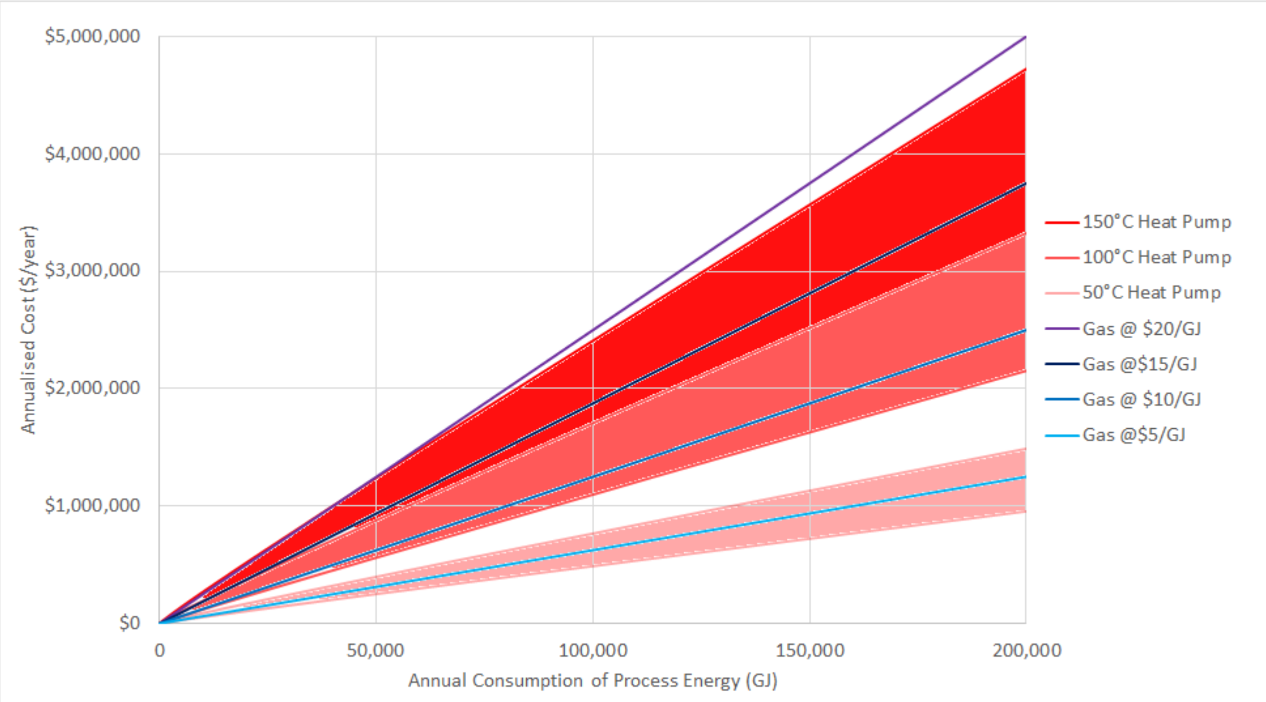


Figure 104. Heat pump annualised cost for 10c/kWh electricity price, for various outlet temperatures from a 20ºC source temperature.

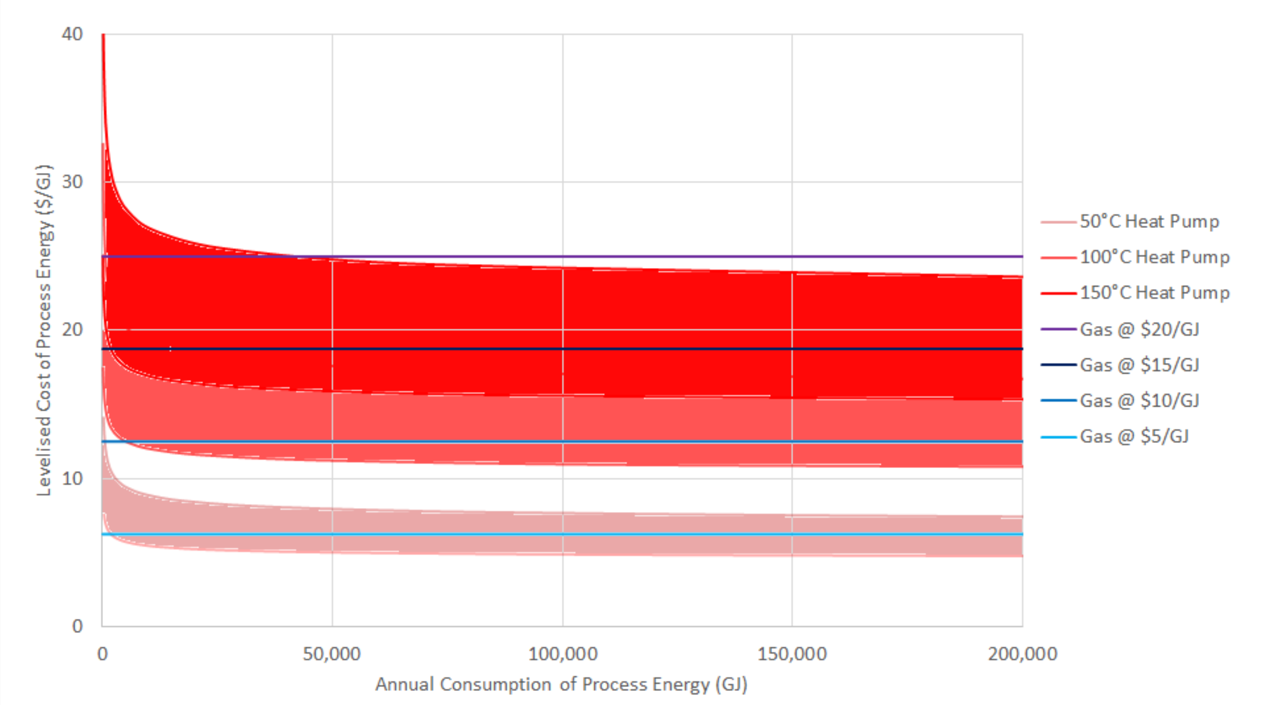


Figure 105. Heat pump LCOE for 10c/kWh electricity price.

At low temperatures, heat pumps can be seen to be highly competitive with natural gas. As discussed above, the COP and the electricity price largely determines the LCOE and hence the economic feasibility. The effective fuel cost of a heat pump can be thought of as the electricity price divided by the COP, while the fuel cost for an existing gas boiler is the gas cost divided by the boiler efficiency.

As the capital cost of the heat pump with an 80% capacity factor is only a minor determinant of the LCOE, LCOE curves are quite flat and IRR's are extremely sensitive to the difference between gas fuel cost and input electricity costs as shown in Figure 106. Of all the technologies examined in this investigation, heat pumps are most notable in this regard. As the estimate of the amount of input electricity needed for a heat pump is impacted by uncertainty in the COP, a very broad range of IRR's results for each temperature.

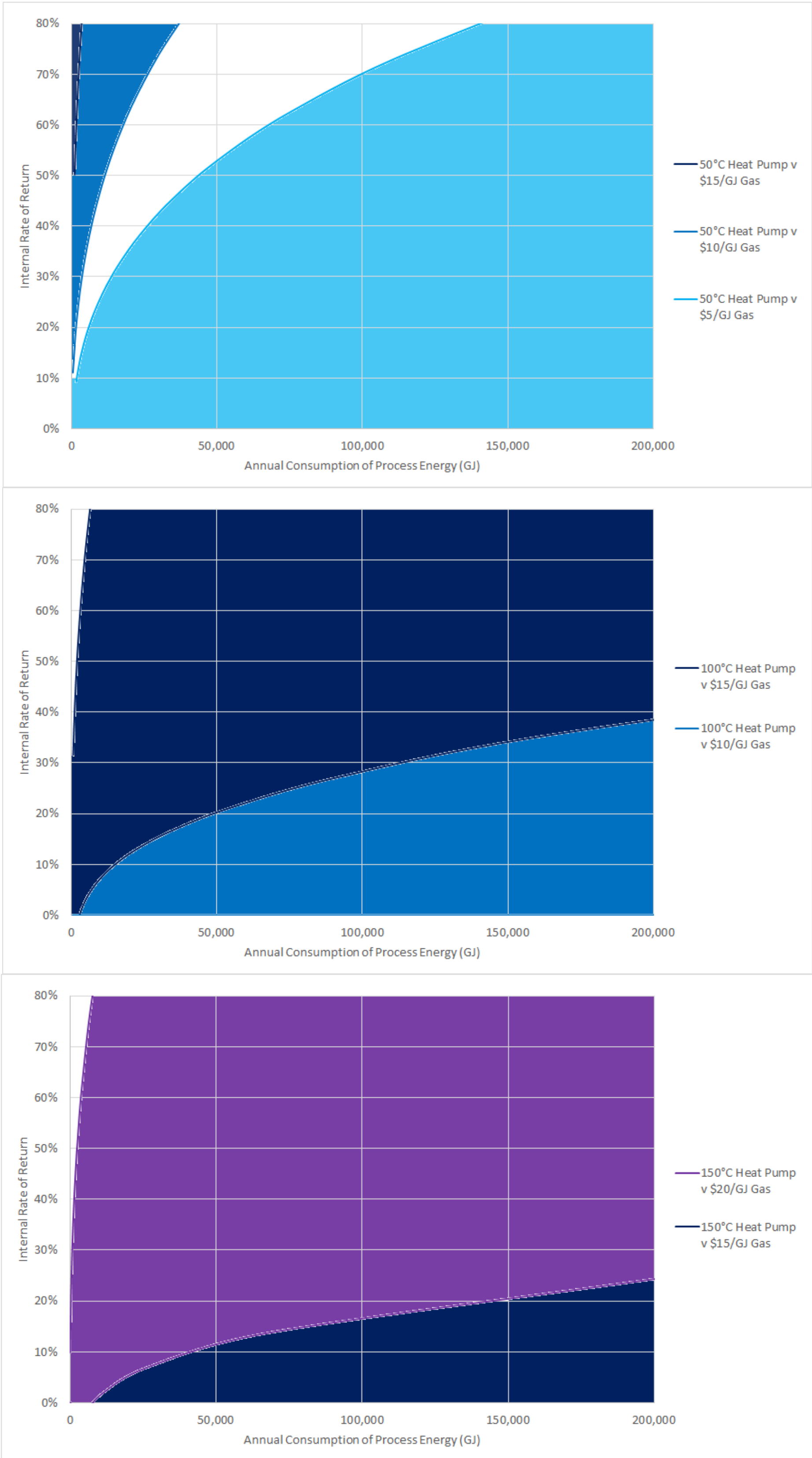


Figure 106. IRR of 50, 100 and 150°C heat pump heat against various gas prices for 10c/kWh electricity.

Figure 107 depicts the sensitivity of the LCOE of 100°C heat from heat pumps for various electricity prices.

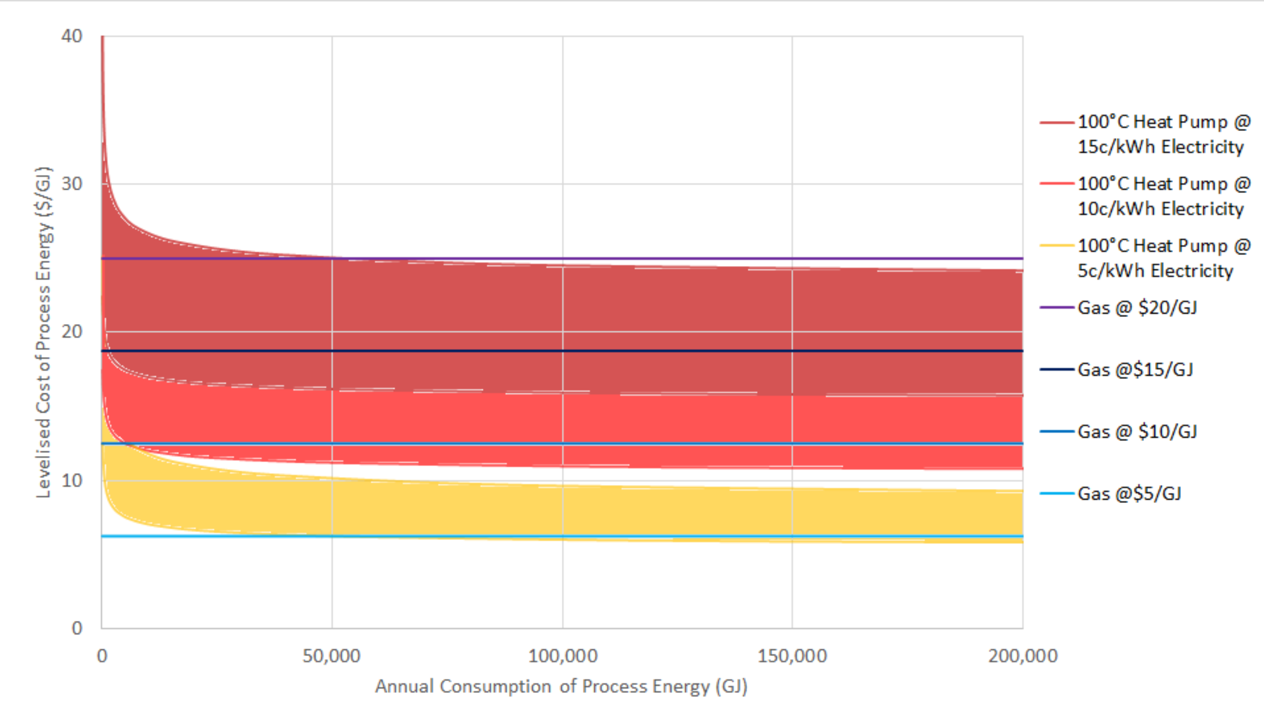


Figure 107. LCOE of 100°C heat pump heat at various electricity prices.

The almost parallel nature of the curves again speaks to the input energy costs being the main determinant of cost effectiveness. In mathematical terms, a heat pump solution is worth detailed investigation if:

(cost of electricity)/COP < (cost of gas)/(boiler efficiency)

Where the costs are converted to the same units using 1kWh = 3.6MJ.

Figure 108 examines the effect of capacity utilisation factor. In Figure 108, there are two lines for each utilisation factor, indicating the top and bottom of the range of spread expected. In this case the shading is left off as the overlap between the cases is very large.

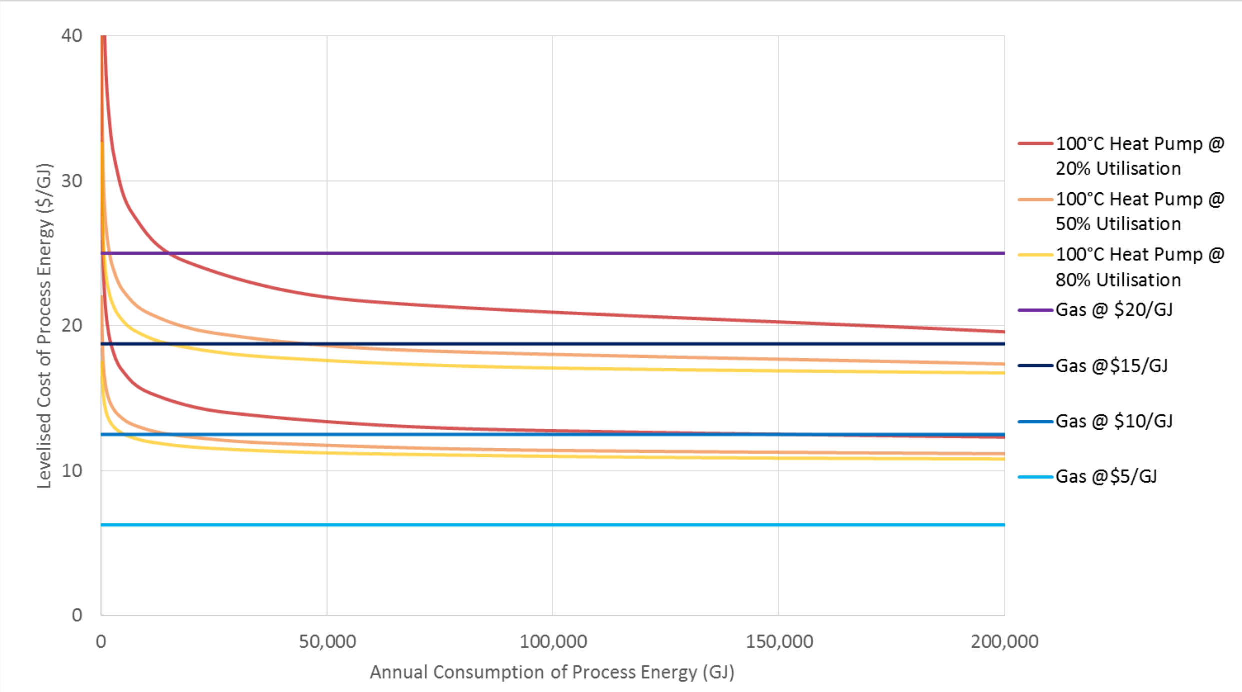


Figure 108. LCOE of 100°C heat pump heat at various capacity factors for 10c/kWh electricity.

The capacity factor, indicating the utilisation of the heat pump, can be seen to impact the shape of the LCOE curves. At higher utilisation, the LCOE flattens out toward the effective fuel cost more quickly than the lower utilisation LCOE's. In this case, the same capital cost has been amortised over a greater energy output, and hence the LCOE approaches this lower limit sooner.

While the input electricity cost for a directly PV-powered heat pump will be equal to the LCOE of PV (~10-20c/kWh) the major difference between grid electricity and PV electricity is the availability. A grid powered heat pump can run at much higher capacity utilisation factors than a PV powered heat pump (which is constrained by a solar capacity factor of 15-20%), and hence the capital cost can be amortised over more heat production, lowering the LCOE. Examining the curves in Figure 108, the best that could be expected would be break even compared to $10/GJ gas for a large scale system at a good solar site. Hybridising PV with grid electricity offers a path to reducing effective greenhouse gas emissions whilst maintaining reasonable economic performance. If a hybrid PV solution is implemented in the context of examination of peak demand charges and other factors an overall improved position could be possible. The option also exists to enter into a supply contract for exclusively renewable electricity, for gas users who wish to use the heat pump approach whilst achieving a zero greenhouse intensity.

The overall conclusion is that heat pumps are a very promising solution for gas users needing process heat below 100°C with high capacity utilisation. The main determinant is the ratio of electricity to gas prices. Directly PV driven heat pumps however do not appear to be as good as a solar thermal solution however, due to the lower capacity utilisation factor of the heat pump.

7.2.7. Other non renewable options

The scope of this study specified consideration of direct renewable substitutions of natural gas use by industrial users. It should be considered however that these industry sectors already use a range of energy inputs and have other non renewable options that can be considered. The key energy sources in this regard are:

- LPG (Liquid Petroleum Gas) (23 PJ/yr),
- Coal or coal briquettes (218PJ/yr),
- Fuel oil and other sources (241PJ/yr) and
- Grid electricity

Regarding LPG or fuel oil, they are effectively fuels than can directly substitute for natural gas. Indeed they can use essentially the same burners / boilers with retuning. However these are fuels that are more flexible in use and so of higher value in the market place. There is no realistic scenario where an existing natural gas user would find that LPG or fuel oil would offer a long term cheaper option. Those users who are using LPG or fuel oil are doing so because they are simply too far from a natural gas pipeline and those are the only options for fuel delivery. Thus those companies can be regarded as an additional constituency which might consider a renewable energy option. All the analysis presented here applies equally to those users, they simply represent users facing input fuel costs that are at the high end of the range modelled here and thus will see proportionately better rates of return on a renewable option.

Coal economics compared to renewables

Coal is a very low cost fuel source as provided to Australia’s power stations. Industrial users do run coal fired boilers and systems for process energy.

A coal fired boiler system with all its associated fuel handling and storage systems has a capital cost that is the same or a few percent less than that of a biomass boiler. They are both considerably more costly than a gas fired boiler. Coal prices after delivery by truck could range from $2/GJ - $6/GJ.

Figure 109 show annualised costs for operation with coal at $2, $4 or $6/GJ compared to gas costs of $5, $10 or $15/GJ. This is followed by the corresponding levelised costs of process energy and the Internal rate of return relative to various gas prices for the specific example of $4/GJ coal.

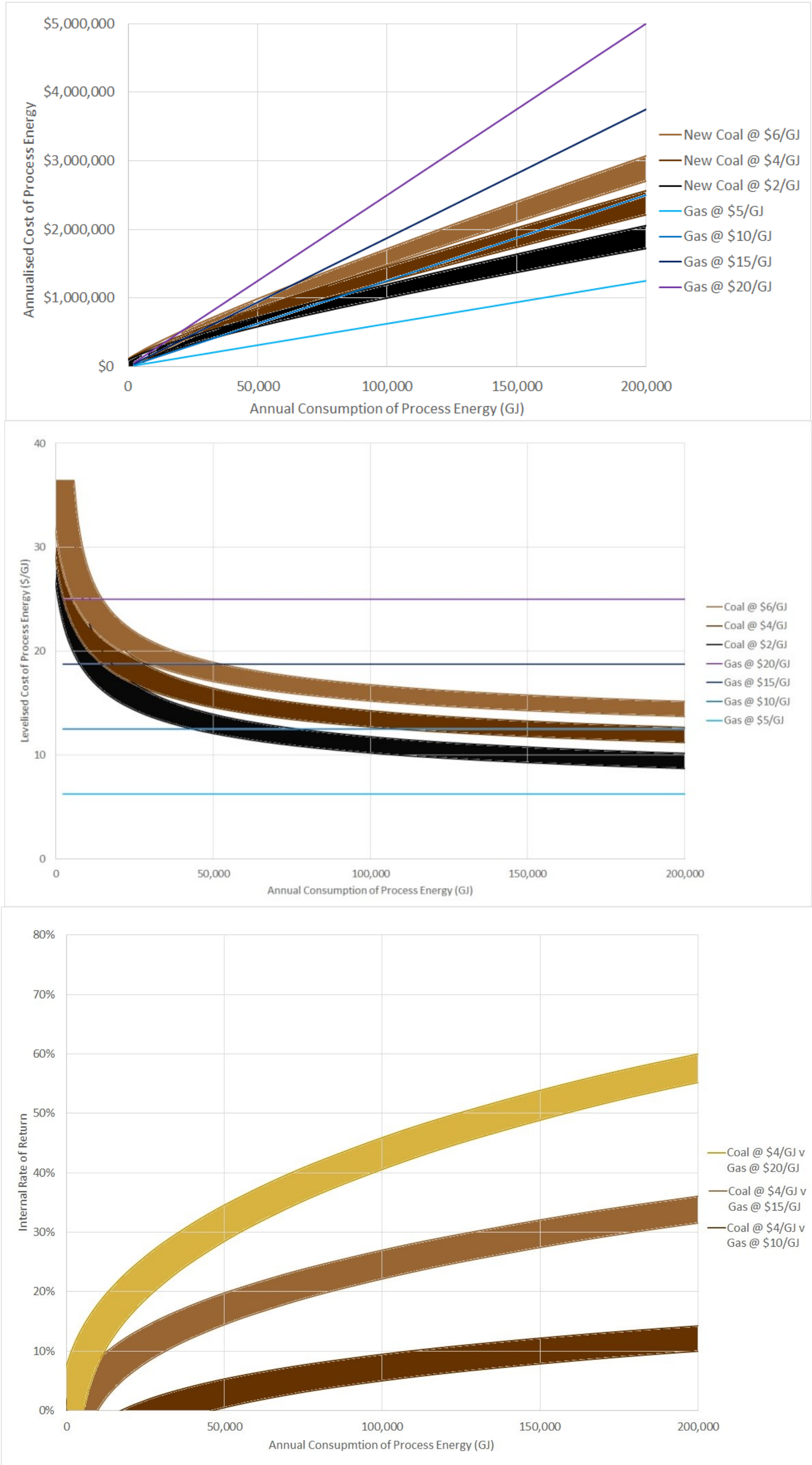


Figure 109. Annualised cost, LCOE and IRR of coal vs gas

Given the equality of capital cost between coal and biomass fired systems, the LCOE of process energy provided by new-build coal and biomass will only differ according to the variation in fuel cost. Figure 110 shows LCOEs for coal ranging in cost from $2/GJ to $6/GJ, also shown is bioenergy LCOE's for the wider likely range of biomass cost of 0 to $15/GJ.

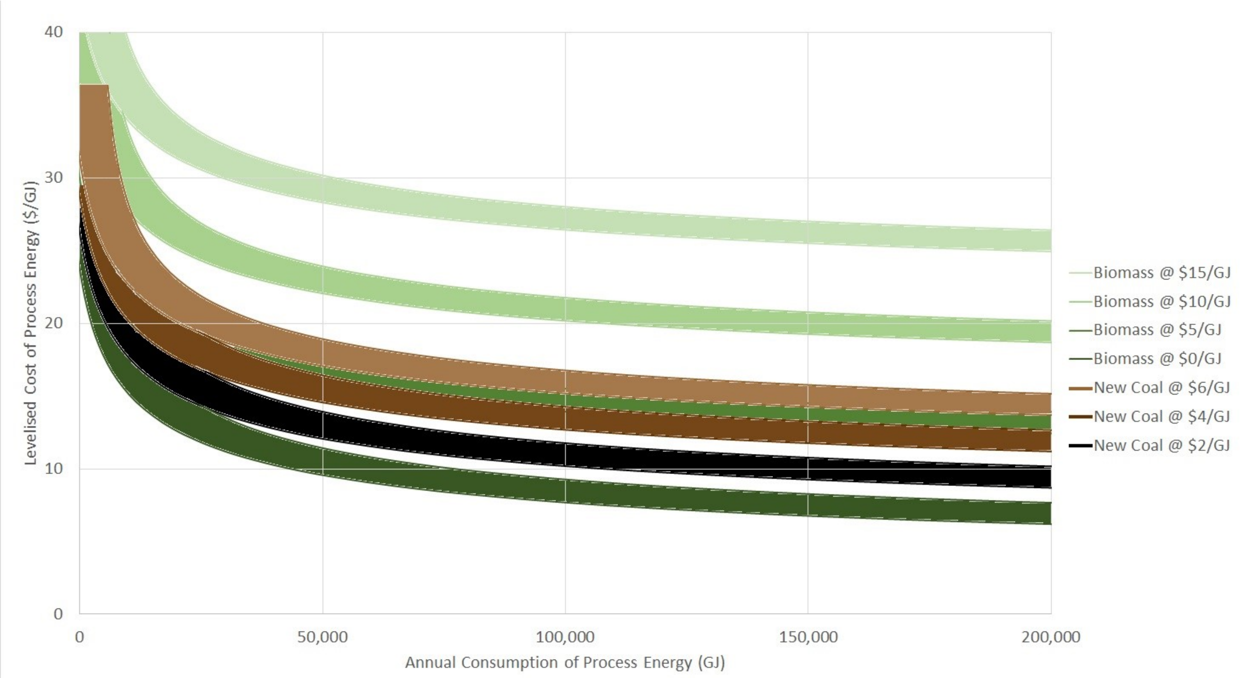


Figure 110. LCOE of New-build Coal and biomass

Biomass can be a cheaper option, particularly if the biomass is a waste resource and costs $0/GJ. These opportunities will be limited and site specific. On average coal systems are likely to be more cost effective than most biomass sources

It is interesting to contemplate the idea of a multi-fuel facility that could be designed as primarily biomass fired but use coal as a backup in case of biomass resource constraints.

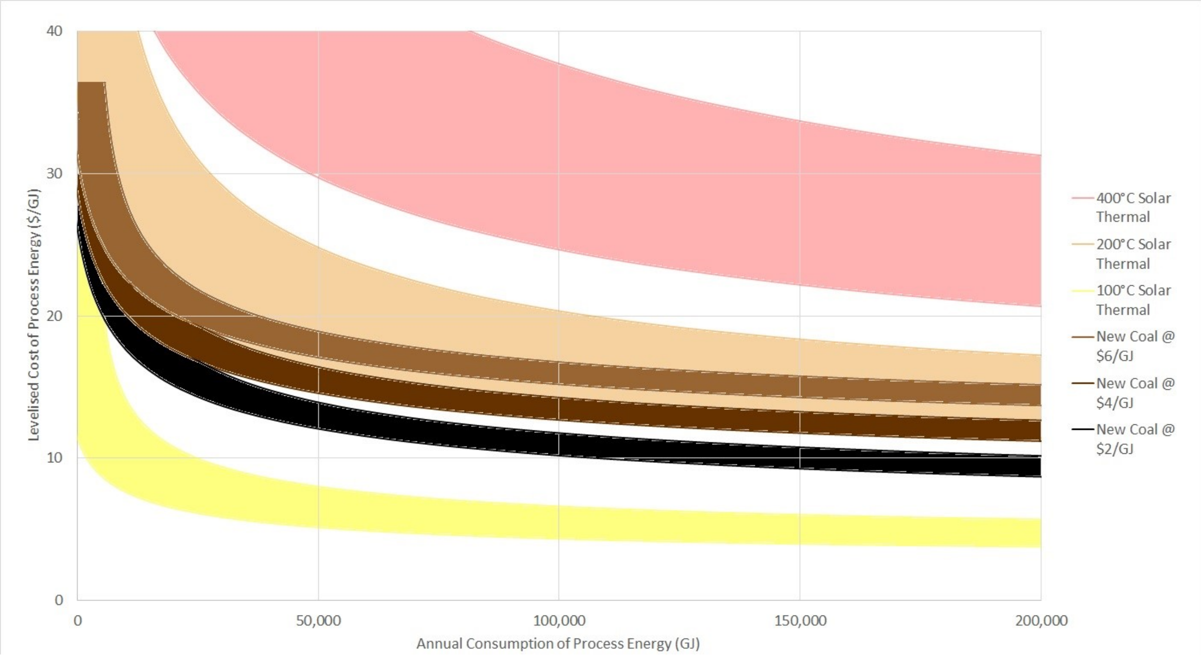


Figure 111. LCOE of New-build Coal and Solar Thermal

The coal and solar thermal LCOE comparison in Figure 111 indicates that new-build coal is the cheaper form of providing process heat for temperatures above 100ºC. There are still opportunities for solar thermal to displace coal in providing heat below 100ºC. However, obtaining the capital for these opportunities may be challenging and the lower capital cost of a coal solution could be favoured.

Users considering a switch to coal would need to factor in to such a decision, the uncertainty around future carbon pricing regimes and social issues.

LPG economics compared to renewables

Figure 112 indicates that there are large opportunities for biomass to displace LPG that will reduce manufacturer's operational costs. Challenges to implementation potentially include limited biomass supply chains and those discussed in Section 5.

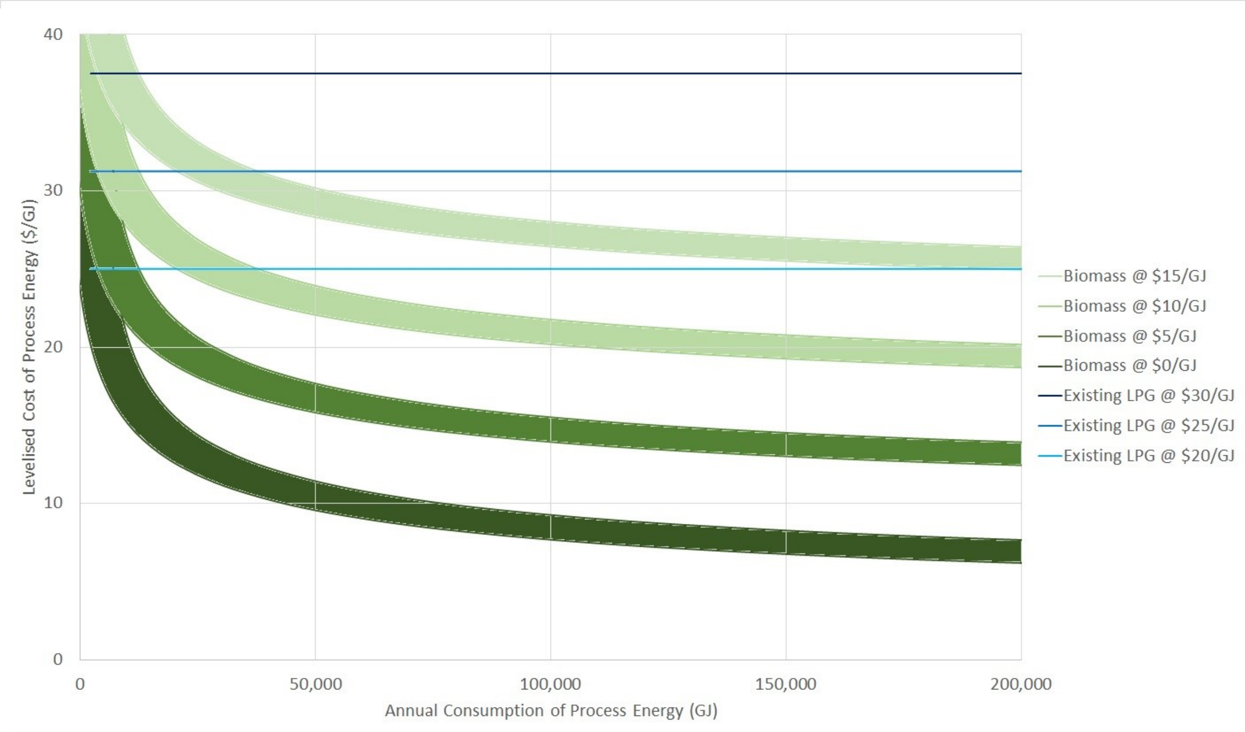


Figure 112. LCOE of existing LPG and new-build biomass

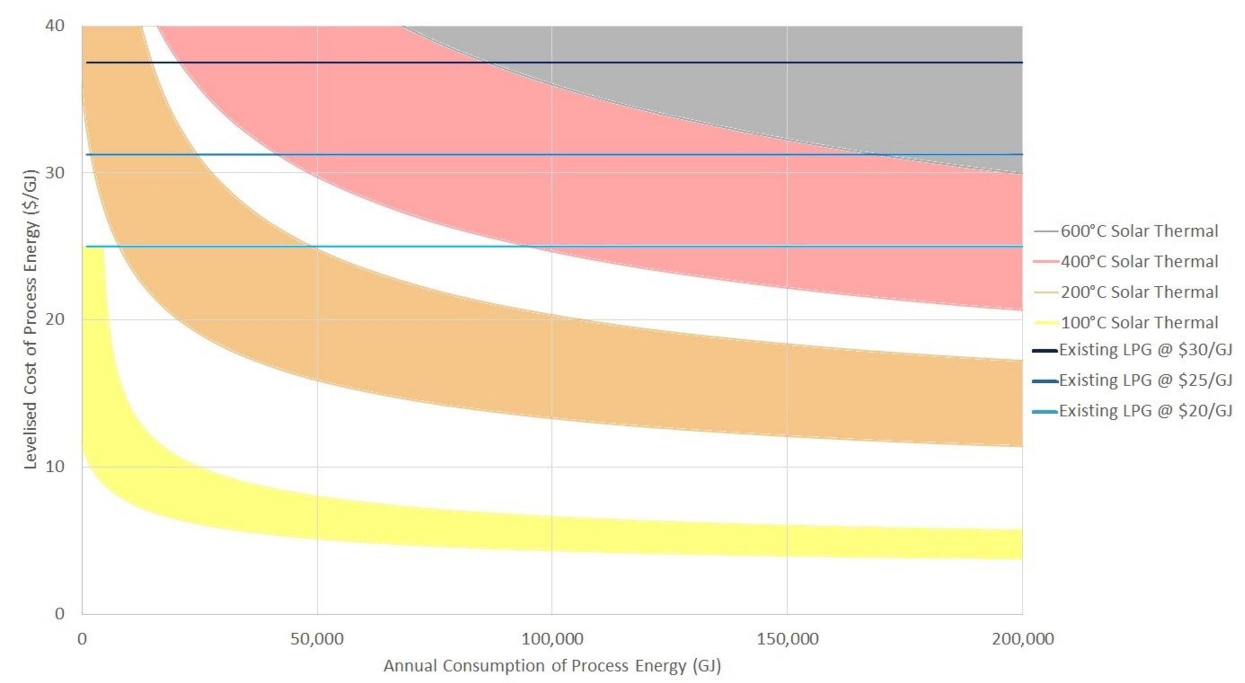


Figure 113. LCOE of existing LPG and new-build solar thermal

The LCOE of existing LPG and new-build solar thermal figure indicates that there are large opportunities for solar thermal to displace LPG in providing heat to 200ºC that will reduce manufacturer's operational costs. Challenges to implementation potentially include lack of awareness of the alternatives and those discussed in Section 5.

7.3. Summary

There does appear to be potentially economic opportunities for biomass, solar, geothermal and heat pumps both now and in the future. However these results must be considered in the light of:

- very high uncertainties in the cost of solar and biomass technologies,
- requirements for energy storage for solar thermal systems that are very case specific and further add to the range of possible cost,
- possible biomass fuel costs that could range from zero (waste) to more than $10/GJ,
- natural gas prices that under any future price regime, would be higher for small users on average.

Noting these points it would appear that:

- Solar thermal applications at temperatures below 150°C have potential at any size of application if the solar resource is reasonable.
- Biomass applications which can benefit from sufficiently low cost / negative cost waste type streams also have potential.
- Geothermal solutions are attractive for those users of process heat below 100oC who can access an aquifer of sufficient temperature and with sufficient demand to justify establishin a well pair.
- Heat pumps are attractive to gas users of process heat below 100oC who have a ratio of gas cost to electricity cost that is sufficient

8. CHALLENGES

8.1. Introduction

The successful deployment of new energy technology is not simply a matter of achieving technology cost targets. The technology itself must fit into a complex set of infrastructure, market and institutional parameters, or these must change to accommodate new approaches. The energy sector technology dissemination model proposed by (Haas 2001) and illustrated in Figure 114 provides a useful way of illustrating the various interactions and aspects which need to be considered.

Figure 114: Energy technology dissemination model (Haas 2001)

Government policy support typically targets technology development, via research, development and demonstration programs, or market support via targets or price signals. Achieving societal acceptance is strongly linked to the prevailing government attitudes and aims for the energy sector, as these in turn determine the market frameworks and support mechanisms in place. It should be noted, that societal attitudes directly or indirectly influence government policy, while energy resource use, technology selection and service delivery are often contentious political issues.

Customer demand follows from all of the above, with early adopters playing a key role in developing the market and the technology. Government support for demonstration projects is in turn an important means of attracting early adopters. However, the appropriate type and level of policy support which would be most useful for the various gas substitution technologies considered in this report depends very much on where the technology is on its development trajectory, as illustrated in Figure 115, as well as on the prevailing societal and market conditions. The next section summarises some of the most relevant policies in place worldwide.

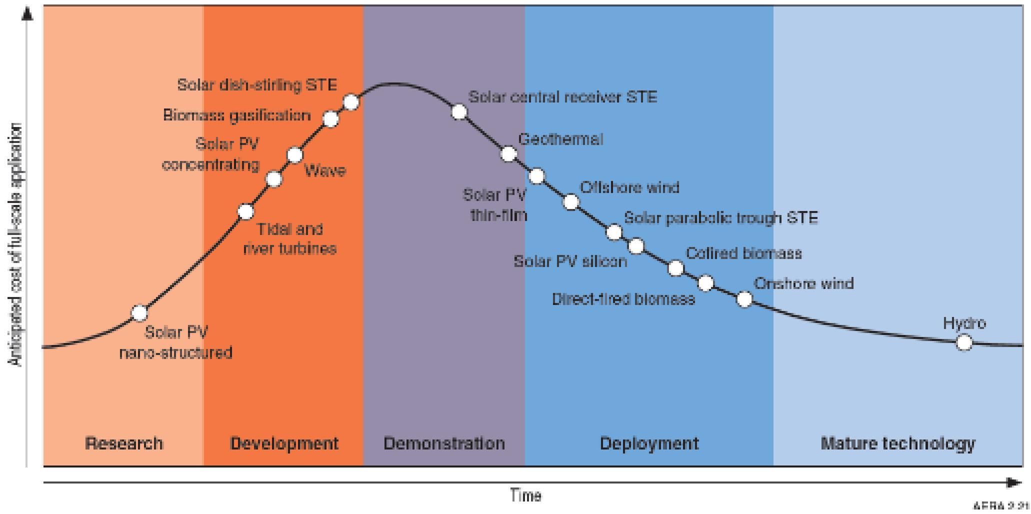


Figure 115. Typical cost variations for commercialising new renewable technologies (EPRI 2010)

In addition to the observations about varying levels of commercial maturity, whilst some renewable technologies are available as commercial products that present an industrial gas user with choices for meeting their existing needs, others are more in the way of being development opportunities for proponents of the technology in question, with the industrial gas user seen as an evolving target market. Off the shelf solar thermal components fall in the first category, deep stimulated geothermal systems in the second category. Biomass systems could fall in either category, largely determined by if there is an existing underutilised biomass ‘waste’ stream vs the commercial opportunity to establish a new plantation based commercial effort for example. Thus we could consider three possible scenarios:

- An existing gas user is able to choose from a suite of commercially available renewable energy solutions to meet the service currently provided by gas.
- A renewable technology developer establishes a new project with particular gas users in mind as a target market or partner / customers for energy produced.
- New and prospective renewable energy developments located by best available resources are used as the context to establish or expand manufacturing operations that would have previously used gas as the source of primary energy.

The next section summarises some of the most relevant policies in place worldwide to foster renewable energy uptake.

8.2. Australian and International Policy Measures

Governments have a range of reasons for providing renewable energy incentives. These have included, depending on jurisdiction, a lack of local energy resources, greenhouse gas or general environmental policies and support for local manufacturing (Watt & Outhred 1999). Depending on these reasons, the structure of the energy sector and the local political situation, different support strategies have been used.

Globally, policies to support the uptake of renewable energy are now very common. By early 2014, renewable energy support policies were in place at the national or state/provincial level in 138 countries, up from the 127 countries the year before[51].

Most of these policies related to power generation. While globally heating and cooling account for almost half of total energy demand, policies supporting the uptake of modern biomass, direct geothermal, and solar thermal technologies for heating and cooling lag far behind the renewable power sector for attention from policymakers.

The 28 EU Member States have introduced targets for specific shares of renewable heating and cooling. In addition, several countries in Africa, Europe, and the Middle East target the use of solar water heating. Overall, renewable heating and cooling targets exist in at least 41 countries worldwide and at least 19 countries have heat obligations/mandates in place at the national or state/provincial level to promote the use of renewable heat technologies[52].It is noteworthy that incentives for renewable heat are prominent mainly in cold countries where heat production for space heating makes up a large proportion of total energy consumption (Marmion & Beerepoot 2012). Further, in practice, developing policies to promote renewable energy heat are relatively challenging because:

- Renewable heat is a local resource and, unless district heating or similar systems are in place, surplus production cannot be fed back into a grid, so supply must match local demand.
- Whereas electricity is a homogeneous energy carrier, heat demand shows different temperature levels per technology and application.
- Heat demand is variable over time (diurnal, seasonal). For example solar thermal heat will most commonly be produced when space heating demand is low. For industrial applications, this means that supplementary energy sources are required if demand is constant over time.

[51] REN21 http://www.ren21.net/status-of-renewables/global-status-report/
[52] REN21

In addition challenges applying equally to distributed heat and electricity policy include that:

- The investor climate is fragmented. Building owners, commercial real estate developers and industrial site operators all have very different motivations affecting energy investment decisions.
- The disturbed energy market is heterogeneous: installers, architects, engineering consultants, contractors, fuel suppliers, complex heat infrastructures similarly have a range of incentives.
- Incumbent heat systems can cause lock-in effects. For example, countries with an extensive gas infrastructure or high dependence on oil might face more difficulties in moving towards renewable heat or electricity because of existing sunk costs and the need for different infrastructure, industry capacity, supply chains and skills bases.

Despite the latter point however, there are examples of renewable energy being incorporated into well-established systems. For example, in Denmark when electricity prices fall below a certain threshold due to windy conditions, district heating operators profit by turning off gas fuelled CHPs and heat is produced by wind powered electric heat pumps at very affordable prices.

Despite the relatively large number of policies supporting renewable power, and a smaller number of policies specifically supporting renewable heat, there appear to be very few policy measures which specifically target renewable energy substitution for industrial gas. The most relevant for the purposes of this study fall under more general policies of greenhouse gas reduction or fossil fuel substitution. These are described in the next section.

8.2.1. Capital subsidies

Government subsidies not only assist with the cost, but also provide a level of public confidence in new technology and its take-up.

Industrial energy users are used to paying for gas as they use it, with the capital costs for gas infrastructure having been raised and amortised by governments and utilities. Not surprisingly, industrial users show little appetite for investing their own funds to convert to renewables. Many of the large industrial gas displacement projects undertaken world-wide involve significant up-front capital cost, tax or other assistance, and/or a third party raising the funds and providing energy via a leasing or energy purchase agreement.

Examples of support for renewable energy uptake in the industrial sector include:

- Germany 25% of initial investment cost for industrial heat,
- Italy, capital grants,
- California Solar Water Heating and Efficiency Act – Starting with $34m /yr in 2010 for commercial / multi-family grants (30-40% of capital cost), reducing each year to $16M by 2017. Uptake had been very low by 2013 and grants were increased from $12.82/Th to $14.53/Th from July 2013. Only 7% of the initial target of 22.6m Therms per year by 2017

has been met, due in part to 20% fall in gas price and much lower falls in RE system prices than projected.[53]

In the past, Australia has had various programs, such as the Clean Technology Program[54] (which included the Clean Technology Investment Program, the Clean Technology Food and Foundries Investment Program, and the Clean Technology Innovation Program), which assisted small to medium sized industry with planning and implementation of energy efficiency and renewable energy deployment. Grants were available for research, development and commercialisation of clean technology products and to support investments in energy efficiency machinery and equipment. Large industry was assisted via the Energy Efficiency Opportunities program[55] , although this did not specifically target renewables.

8.2.2. Renewable Energy Targets or Portfolio standards

Targets for renewable energy have been widely used by State and central governments as a means of encouraging diversification, cleaner generation and as a means of meeting greenhouse gas targets. The mechanisms used to achieve the targets vary (Watt & MacGill 2014). They can be set as a capacity target, perhaps ramping up at a set rate over time, or as a percentage by a particular year. They can be technology neutral, have separate targets for a specified list of technologies, or provide different levels of support for each technology, depending on cost, stage of development or percentage penetration, for instance. Many operate via a tradable renewable energy certificate scheme, which has a market independent of the main energy market. Such target mechanisms expose renewable energy projects to wholesale or retail energy market signals while providing an additional production incentive for renewable energy production. They remain a potentially strong driver for establishing renewable energy markets where conventional supply is entrenched and market access is otherwise difficult. Targets often operate in conjunction with other support mechanisms, especially where certificate prices are low and would therefore not provide sufficient revenue for new technologies.

Examples of target mechanisms used for renewables in the industrial sector include (IEA SHC, 2014):

- Chinese Solar Thermal Obligations – enacted by provinces, in line with overall 11th Five Year plan for New Energy and RE Law of China.
- European targets for RE Heating and Cooling, mostly targeting buildings, but some, such as Netherlands, have included biogass, biomass, geothermal under its Heat Tariffs and UK includes RE Heat under its FIT policy.

As federal and state government support for renewables has started to wane, interest has increased at the local level, driven by environmental concerns, job creation aims and a broader

[53] http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=CA214F&s, accessed 30/08/2014
[54] http://www.business.gov.au/grants-and-assistance/closed-programs/CleanTechnology/CleanTechProgram-FactSheet/Pages/default.aspx
[55] http://energyefficiencyopportunities.gov.au/

interest in sustainable and self-reliant communities. Many cities have set targets, independently of State or Federal Government initiatives (REN21, 2014), for instance:

Overall energy targets:

- Boulder Colorado – 30% of total energy by 2020,
- Calgary, Canada – 30% of total energy by 2036,
- Cape Town, South Africa – 10% by 2020,
- Fukushima, Japan – 100% by 2040 and
- Paris – 25% by 2020.

Fossil Fuel displacement targets:

- Madrid, Spain – 20% reduction by 2020,
- Vaxjo, Sweden – 100% by 2030 and
- Seoul, Korea – 30% by 2030.

Other cities, including Berlin and Schönau in Germany and Boulder, Colorado, have plans to buy back their electricity systems, so that they can be managed at a local level, using local, renewable energy resources. This trend will mean that industries operating in these areas will need to transition to renewable options, and so will accelerate technology development and uptake.

8.2.3. Technology Demonstration

Demonstration systems are an important stage of technology and market development, providing developers the opportunity to manufacture and test new products at pilot or expected final scale, whilst also allowing prospective users an opportunity to see the product and process in operation. Renewables 2014 (REN21, 2014) cites a range of demonstration systems across all technology types and scale. Demonstration systems allow fine tuning of processes, monitoring of performance under real-world conditions and hence better estimation of O&M and life cycle costs. It is difficult, if not impossible, to develop a market without demonstration systems and in Australia there are currently very few renewable energy systems of the types described in this report for industrial gas substitution.

Government procurement can act as a valuable source of demonstration sites, since governments may be willing to accept the higher risks associated with new technology, on the basis of new industry, employment or energy security benefits. Although governments are not typically involved in industrial activities, there may be opportunities to demonstrate larger-scale solar thermal or other renewable energy technologies similar to those which may be applied in industry.

Demonstration systems can also be installed at designated demonstration sites or ‘parks’. Although not necessarily in ‘real-world’ industrial conditions, this can allow:

- a range of different technologies to be tested under the same conditions,
- easy access for prospective customers to inspect technologies (which can sometimes be difficult at industrial sites due to safety and commercial considerations),
- shared monitoring, O&M staff, load management, storage and other facilities, which can reduce costs for technology developers,
- sharing of knowledge amongst system developers, with benefits for all technologies, and
- prospects for development of shared supply chains and industry infrastructure in future market development.

8.2.4. Tax incentives

Tax incentives can operate at a number of levels, for instance, as exemptions from taxes, such as sales, payroll or import taxes; as tax deductions for individuals or businesses; via accelerated depreciation, or as tax credits. See for instance (KPMG 2011).

Exemptions from tax have most commonly been used during the industry development phase, although more recently, taxes on imports are being used in Europe and the US to protect local industry against cheaper imports, where these are considered to result from industry support programs introduced by other governments. Tax deductions or credits are more focused on the end user and on deployment.

Examples include:

- The US has used tax credits of 30% for businesses as its key federal government support mechanism for renewables (DSIRE, 2013). The tax credit is deducted directly from tax payable and any unused amount, if tax payable is less than the 30% credit, can be carried forward to the next tax year. For energy utilities, this has been an important driver for large-scale systems, as it can be used to meet renewable portfolio standards / targets, in States where these exist.
- Many countries provide exemptions from sales taxes or GST (VAT) for renewable energy system components. In Australia, the removal of sales tax exemptions when the GST was introduced was compensated for via the PV rebate program and similar support for solar water heaters.
- China uses a range of tax incentives, including reduced tax rates for renewables, VAT refunds at different levels for various renewables, tax credits for energy conservation (KPMG, 2011)
- The Netherlands offers tax deductions up to 41.5% for renewable energy investments under its Energy Investment Allowance, as well as accelerated depreciation for environmentally friendly assets
- Canada offers Accelerated Capital Allowances for specified renewables, including industrial process heat and fuels from waste.

8.2.5. Building and Planning Codes

Building codes can provide a useful indirect incentive for renewables. Energy rating schemes which provide credits for renewables have been used in NSW, Australia, to meet the BASIX requirements for new buildings or substantial renovations. Germany, France and other countries have provided higher incentives for innovation, such as building integrated or dual function products which provide electricity plus light, heat, shading.

Many building energy efficiency regulations started with requirements for the building shell, and nearly all efficiency regulations for new buildings include requirements for the building envelope. As the building's envelope improves, regulations focus on the energy efficiency of HVAC systems. Finally, when all parts of building and HVAC systems are covered, regulations address other installations and renewable energy[56].

Planning codes can also be useful in encouraging optimum orientation for new developments, which is critical to the opportunities then available for solar devices. Solar access regulations are increasingly important to prevent future overshadowing problems as more building owners invest in solar products.

Building and planning codes tend to focus more on residential and commercial buildings rather than industrial settings. Further, large industrial gas users, especially those producing process heat are unlikely to use gas for space heating.

8.3. Discussion

It is clear from the Stakeholder feedback, that industry has little appetite for new technology or risk. Of course, rapid increases in gas prices and/or difficulty in renewing gas contracts in future may increase interest in renewable options. In the short-term, encouraging industry to introduce new energy technologies will need focus on two aspects:

- technology development, commercialisation and demonstration, and
- reducing costs of technology change.

It seems unlikely that industry will change to renewable energy technologies until they are convinced the technology is reasonably mature and has an established supply chain. This is obviously very difficult to achieve in the short term. Given the current high level of uncertainty in Australian energy markets, support is likely to be needed for both the industry providing the technology, as well as for the industry deploying it.

A range of demonstrations of new technologies in as wide a range of applications as possible would assist. Industrial preference for purchase of energy services, rather than technology, may favour the establishment of supply chains based on leasing or energy service models, whereby

[56] Lausten, J. 2008. Energy Efficiency Requirements in Building Codes, Energy Efficiency Policies for New Buildings – IEA Information Paper. http://www.iea.org/publications/freepublications/publication/building_codes-1.pdf

the technology provider retains ownership and provides maintenance of the new technology, with the user merely paying for heat or other energy services.

Market support does not always lead to price reduction or technology development. Recent support for PV and solar waters heaters has had very different impacts. PV prices have plummeted, with both technology and deployment models evolving fast. Solar water heater costs on the other hand have increased. Further assessment of the industry characteristics is needed, including the level of competition, the skills base, the ease of capacity development and re-training, import or other restrictions, Australia-specific standards for both products and installation, which may restrict new products, and supply chain requirements for components, materials and spare parts.

9. CONCLUSIONS

It can be concluded as a result of this investigation, that there are indeed a range of options for substitution of natural gas use by renewable energy options, where the technology is proven and the economic analysis indicates that a positive internal rate of return is possible.

Specifically these are:

- Heating of water or steam on any scale and at any temperature using biomass fired boilers where a sufficiently low cost combustible biomass resource is available convenient to the location.
- Combustion of biogas digester gas in boilers, kilns furnaces or engines where the composition of combustion products does not affect the process and where a low cost digestible biomass resource is available.
- Combustion of biomass gasifier gas in boilers, kilns furnaces or engines where the composition of combustion products does not affect the process and where a low cost biomass resource is available.
- Heating of water or steam on any scale at temperatures below approximately 150ºC using solar thermal flat plate, evacuated tube or linear concentrator technologies in areas of reasonable or better solar resources.
- Hot sedimentary aquifers for low temperature process heat where a resource exists nearby to the point of use at reasonable depth.
- Heat pumps for low temperatures where the cost of gas and cost of electricity are in a sufficiently high ratio.

The prospect of future gas price increases should make these opportunities more appealing. However there are challenges arising from limited experience with the technology and supply chains that are inexperienced and low in capacity.

The industrial gas users examined in this study consumed approximately 412 PJ in 2013. The report authors estimate that, based on 2014 gas prices, the potentially viable market for renewable energy technologies is 50 to 100 PJ per year. At an indicative price of $9/GJ this is a potential saving on gas costs of the order of $450 to $900 million per year but with significant upfront investment needs. This potential market is likely to increase as gas prices rise and renewable technologies mature.

A trend of increasing gas prices in Australia is already in evidence and widely expected to continue as increasing demand for gas for LNG exports pulls the domestic price close to an opportunity cost that is determined by the international market. The actual price an individual gas user is or will be paying can vary over a very wide range compared to another user under different circumstances. Factors determining the actual price seen include, the consumer’s bargaining power, the timing of contract negotiation and how far toward the extremities of the distribution system the site is located. Gas tariffs are also often in a block structure of declining marginal cost, which makes measures to reduce but not eliminate gas use economically challenging.

However, in many cases the level of technical risk perceived by industrial gas users in renewable energy solutions remains high. Australian industrial gas users are technically risk averse and do not have a good understanding of the renewable technology solutions available. The supply chain for components in Australia is very immature and in many cases, equipment needs to be imported.

Whilst gas use is a significant business cost and there is great concern about the impact of future price rises, it is still only one of many factors effecting business profitability. Continuity of operation is paramount. Any new renewable solution needs to offer no lessening of the level of reliability experienced with existing gas based solutions and providers and advocates of such technology need to convince the decision makers in such organisations that this will be the case.

It is apparent that smaller industrial users, so called mass market customers, who are connected to the gas distribution system, pay considerably higher prices for gas than larger users connected to the gas transmission system. The net result is a sliding scale of gas price versus user size that ranges from parity with high ‘domestic’ prices for the smaller industrial users to close to wholesale prices for the largest transmission connected users. With future major movements in the wholesale price anticipated, it is the large users that will experience the greatest fractional change. The smaller users will see increases linked to the wholesale price as it is passed on, but with a large fraction of their price determined by transmission and distribution costs, the fractional change will be much smaller and possibly overshadowed by other effects. Overlaid on this is a wide range of variation based on user and location specific factors.

Whilst the higher gas prices faced by the smaller users would tend to suggest that they offer the greatest prospects for renewable solutions, there is also a trend in the cost of renewable solutions that is modelled by a power law relationship to size, with the specific cost of small systems being much higher than larger ones. In addition, there is also a trend to smaller users demanding shorter payback times on investments than larger ones. The overall consequence of this is that it is impossible to identify a size of application that appears more economically favourable than others at the present time.

Gas can be combusted to produce heat at temperatures of thousands of degrees, or readily converted to other high value chemicals. Consequently when it is combusted to produce heat at a range of lower temperatures, the thermal efficiency of the process is almost independent of the application. The key renewables solutions that have been identified as being commercially available and most likely to be cost effective are solar thermal and bioenergy. Solar thermal costs and performance are very strongly dependant on temperature, with a higher temperature requiring more complex and costly technology solutions. Thus it transpires that it is lower temperature applications in reasonably sunny locations that appear most cost competitive. Higher temperature and more complex solutions are not yet competitive with gas, even with higher gas prices. They are however close enough to parity, that future technology cost reductions linked to global increases in deployment will make them viable in the future. The timescale for this though is probably still 5 years or more.

Biomass system cost and performance is largely independent of temperature and application as it is for gas based systems. The main driver for determining viability is the cost of the biomass feedstock. It is apparent that biomass solutions involving an existing nearby supply of low cost or waste material look very attractive. Whilst concepts based on dedicated energy crops or forestry still offer great promise, they require major effort on the supply side to establish supply chains, and will be higher cost. As with the higher temperature solar thermal solutions, these are still some years away and are not available to existing gas users as an immediate solution.

There are many examples of renewable energy systems in Australia and around the world, providing energy services that could otherwise be provided by gas. Steps to improve access to information on proven solutions in a manner that is most accessible for gas users would obviously be of benefit.

Whilst economic analysis based on discount rates that may apply to a ‘strategic’ investment can be favourable, in many circumstances industrial gas users, have limited access to capital and expectations of much higher internal rates of return. There may be scope for third party organisations to make investments and offer energy services as a business model. There is also significant potential for targeted government policy initiatives that assist with grants, pilot systems, information sharing and low interest finance.

10. REFERENCES

ABARE, 2010. *Australian Energy Resource Assessment*, Australian Bureau of Agriculture & Resource Economics.

AEMO, 2013. *Gas Statement of Opportunities*, Australian Energy Market Operator.

AER, 2013. *State of the Energy Market*, Australian Energy Regulator.

Allen, D., 2014. Personal communication, Dick Allen, Plantation Energy Australia, 1/10/2014. , 2014(Vic).

Andersen, E.J., Oksen, F. & Olesen, J.V., 1992. Power plant Holstebro / Struer with separately fired superheater. In *Eckrohrkessel licensee conference*. Bamberg: ERK Eckrohrkessel GmbH.

Annas, J., Stein, W. & Hinkley, J., 2005. *Solar Process Heat for the Commercial & Industrial Sectors*,

ANZSES, 2006. *Australian Solar Radiation Data Handbook*, Australia & New Zealand Solar Energy Society.

ARENA, 2014. *Looking Forward: Barriers, Risks and Rewards of the Australian Geothermal Sector to 2020 and 2030*, Australian Renewable Energy Agency: ARENA.

Babcock & Wilcox Vølund A/S, 2008. Multifuel-fired Combined Heat and Power Plant Måbjergværket Måbjerg, Denmark.

Balfe, P. & Kelp, O., 2014. *Gas Consumption Forcasting*, Acil Allen Consulting.

Ball, A. et al., 2014. *2014 Australian Energy Update*, Australian Government Bureau of Resources and Energy Economics.

Beath, A.C., 2012. Industrial Energy Usage in Australia and the Potential for Implementation of Solar Thermal Heat and Power. *Energy*, 43(1), pp.261–272. Available at: http://linkinghub.elsevier.com/retrieve/pii/S0360544212003118 [Accessed September 26, 2014].

Becker, H., 2009. Industrial Heat Pumps. , pp.1–15.

Berntsson, T. & Franck, P.-A., 1997. *Learning From Experiences with Industrial Heat Pumps*,

BREE, 2013. *Gas Market Report*, Australian Government Bureau of Resources & Energy Economics.

CEC, 2008a. *Australian Bioenergy Roadmap*, Clean Energy Council of Australia.

CEC, 2008b. *Australian Biomass Resource Appraisal*, Clean Energy Council of Australia.

CEC, 2013. *Clean Energy Australia Report 2013*, Clean Energy Council of Australia.

Chang, Y.H., Chen, W.C. & Chang, N. Bin, 1998. Comparative evaluation of RDF and MSW incineration. *Journal of Hazardous Materials*, 58(1-3), pp.33–45.

Climateworks, 2012. *Industrial Energy Efficiency - Summary of Key Findings from ESI project*,

Deloitte, 2014. *Gas market transformations – Economic consequences for the manufacturing sector*,

Dolman, M. et al., 2011. *Achieving Deployment of Renewable Heat (UK)*,

Driscoll, J.P. & Beardsmore, G.R., 2011. Latrobe Valley Shallow Geothermal Project. In Hot Dry Rocks Pty Ltd.

ECOHEATCOOL, 2005. *Work Package 1: The European Heat Market*,

ECOPROG, 2013. *Waste to Energy - The World Market for Waste Incineration Plants 2013/2014*, Cologne.

EEA, 2007. *Europe's environment - The Fourth Assessment, Chapter 6: Sustainable Consumption and Production*, Copenhagen.

EPA NSW, 2013. *NSW Energy from Waste - Draft Policy Statement for Public Consultation*, Sydney.

EPA VIC, 2013. *Energy from waste - Publication 1549*, Melbourne.

EPRI, 2010. *Australian Electricity Generation Technology Costs*, Electric Power Institute.

ESAA, 2014. *Electricity Gas Australia*, Energy Supply Association of Australia.

European Parliament and Council, 2010. Directive 2010/75/EU on Industrial Emissions (Integrated Pollution Prevention and Control).

Evans & Peck, 2014. *Competitive Role of Geothermal Energy Near Hydrocarbon Fields*,

Garcia-Perez, M., Lewis, T. & Kruger, C.E., 2010. *Methods for Producing Biochar and Advanced Biofuels in Washington State - Part 1: Literature Review of Pyrolysis Reactors*, Department of Biological Systems Engineering and the Center for Sustaining Agriculture and Natural Resources, Washington State University, Pullmann.

Gavran, M., 2013. *Australian plantation statistics 2013 update*, Department of Agriculture, Fisheries, and Forestry.

GDF SUEZ, 2013. GDF SUEZ Opens One of the World's Largest Biomass Units in Poland.

Geoscience Australia, 2014. *Australian Energy Resource Assessment (Chapter 12: Bioenergy)*,

Geoscience Australia, 2012. Operating and proposed renewable energy generators. Available at: http://www.ga.gov.au/renewable/.

GHD Pty Ltd, 2007. Assessment of Methane Capture and Use from the Intensive Livestock Industry. A report for the Rural Industries Research and Development Corporation. , (07).

Gohlke, O., 2008. Verbesserungspotenziale der Energieeffizienz. In *Thermische Abfallbehandlung, 13. Fachtagung*. München: Schriftenreihe des Fachgebietes Abfalltechnik, Universität Kassel.

Gohlke, O. & Spliethoff, H., 2007. Innovative Approaches to Increase Efficiency in EfW Plants - Potential and Limitations. In *ISWA conference*. Amsterdam.

Haas, R., 2001. *Marketing Strategies for PV Systems in the Built Environment*,

Heat Pump & Thermal Storage Centre of Japan, 2011. *Data Book on Heat Pump & Thermal Storage System*,

Huddlestone-Holmes, C., 2014. *Geothermal Energy in Australia*, CSIRO.

IEA Heat Pump Centre, 2014a. *Application of Industrial Heat Pumps Part I*,

IEA Heat Pump Centre, 2014b. *Application of Industrial Heat Pumps Part II*,

JFE Engineering, 2011. *Operational Results of Fukuyama Recycle Power*, Yokohama.

Kaltschmitt, M., 1998. Nachwachsende Energieträger: Grundlagen, Verfahren, ökologische Bilanzierung. *Umweltwissenschaften und Schadstoff-Forschung*, 10(3).

KPMG, 2011. *Taxes and Incentives for Renewable Energy*,

Lamers, F. et al., 2013. *Alternative Waste Conversion Technologies - White Paper*, Prepared for ISWA by ISWA Working Group on Energy Recovery, Vienna.

Lempp, P., 2013. *Biomass Co-firing - Technology Brief*, IEA-ETSAP and IRENA, Abu Dhabi.

Linehan V, Thorpe S, Andrews N, Kim Y and Beaini F, 2012, ‘Food demand to 2050: Opportunities for Australian agriculture’, paper presented at ABARES Outlook Conference, Canberra, 5–6 March 2013, p. 1

Marmion, A. & Beerepoot, M., 2012. *Policies for Renewable Heat: An Integrated Approach*,

Marsden Jacob Associates, 2014. *Scoping Study on the Economic Impact of High Gas Prices*,

Mauthner, F. & Weiss, W., 2014. *Solar Heat Worldwide*, IEA Solar Heating & Cooling Programme.

McGahan, E. et al., 2013. *Five Piggery Biogas Capture and Energy Generation Feasibility Studies*,

McGahan, E.J. et al., 2013. *Conversion of Waste to Energy in the Chicken Meat Industry. RIRDC No 12/097.*,

Meehan, R., 2013. *Hybridisation of Fossil Fuel Energy Generation in Australia - Public report*, Prepared by Parsons Brinckerhoff for the Australian Renewable Energy Agency (ARENA), Melbourne.

Metso Corporation, 2011. World's largest biomass gasification plant inaugurated.

Pacific Pyrolysis, 2010. Demonstration Facility.

Perry, R. & Green, D., 1999. *Perry's Chemical Engineers Handbook* 7th ed., Kansas: McGraw-Hill.

Poad, G. & McGahan, E., 2010. Exploration of the Opportunities to Establish Anaerobic Digestion for the Generation of Biogas Final Report.

Pujol, M. & Bolton, G., 2015. *Potential for geothermal direct-use projects to displace gas use in industrial processes*, Available at: www.rockwater.com.au.

Sohi, S. et al., 2009. *Biochar, Climate Change and Soil: A Review to Guide Future Research*, CSIRO Land and Water Science Report 05/09, Glen Osmond, SA.

Spectrum Magazine, 2009. First-of-its-Kind at Skive. , 1(20).

Spliethoff, H., 2010. *Power Generation from Solid Fuels* 1st ed., Heidelberg: Springer.

Stevenson, W., 2007. Emissions from Large and Small MWC Units at MACT Compliance. *Unites States Environmental Protection Agency*.

Stucley, C. et al., 2012. *Bioenergy in Australia*, Bioenergy Australia, Sydney.

Sumio, Y., Masuto, S. & Fumihiro, M., 2004. *Thermoselect Waste Gasification and Reforming Process*, JFE, Technical report No.3.

Tadros, A. et al., 2009. Options for Biomass Utilization in Coal Fired Power Stations. *Journal of Thermal Science and Engineering Applications*, 1(4), pp.041008–1.

Taibi, E., Gielen, D. & Brazilian, M., 2010. *Renewable Energy in Industrial Applications: An Assessment of 2050 Potential*, Available at: http://www.unido.org/fileadmin/user_media/Services/Energy_and_Climate_Change/Energy_Efficiency/Renewables_.

Tait, S., 2013. *Biogas Energy for an Innovative Pork Industry*, Pork CRC.

Themelis, N., 2006. Energy Recovery from Global Waste-to-Energy. *Summer review issue of Waste Management World*.

Thong, J., 2015. Private communication.

Vannoni, C., Battisti, R. & Drigo, S., 2008. *Potential for Solar Heat in Industrial Processes*,

Vehlow, J., 2004. *Biogenic Waste to Energy – an Overview*, Forschungszentrum Karlsruhe, IEA Bioenergy Task 36, Karlsruhe, Germany.

Watt, M. & MacGill, I., 2014. *Advanced Concepts in Photovoltaics*,

Watt, M. & Outhred, H., 1999. *Electricity Industry Sustainability: Policy Options*,

Weiss, W., 2010. Solar Heat for Industrial Applications: Potential, Framework Conditions and Build Examples. In *Sustainability Victoria*. Melbourne, p. 47.

Wu, H. et al., 2008. Production of Mallee Biomass in Western Australia : Energy Balance. , pp.190–198.

APPENDIX A. ANZSIC CODES

The numbering system adopted in the ANZSIC is alphanumeric and has a hierarchical structure (see example below), where the leading alpha character denotes the industry division. The ANZSIC subdivision, group and class levels are denoted by numeric codes.

Level Example

- Division C Manufacturing
  - Subdivision 11 Food Product Manufacturing
    - Group 111 Meat and Meat Product Manufacturing
      - Class 1111 Meat Processing

Division Title

- A Agriculture, Forestry and Fishing
- B Mining
- C Manufacturing
- D Electricity, Gas, Water and Waste Services
- E Construction
- F Wholesale Trade
- G Retail Trade
- H Accommodation and Food Services
- I Transport, Postal and Warehousing
- J Information Media and Telecommunications
- K Financial and Insurance Services
- L Rental, Hiring and Real Estate Services
- M Professional, Scientific and Technical Services
- N Administrative and Support Services
- O Public Administration and Safety
- P Education and Training
- Q Health Care and Social Assistance
- R Arts and Recreation Services
- S Other Services

A	**Agriculture, Forestry and Fishing**	
	01	Agriculture
	02	Aquaculture
	03	Forestry and Logging
	04	Fishing, Hunting and Trapping
	05	Agriculture, Forestry and Fishing Support Services
B	**Mining**	
	06	Coal Mining
	07	Oil and Gas Extraction
	08	Metal Ore Mining
	09	Non-Metallic Mineral Mining and Quarrying
	10	Exploration and Other Mining Support Services
C	**Manufacturing**	
	11	Food Product Manufacturing
	12	Beverage and Tobacco Product Manufacturing
	13	Textile, Leather, Clothing and Footwear Manufacturing
	14	Wood Product Manufacturing
	15	Pulp, Paper and Converted Paper Product Manufacturing
	16	Printing (including the Reproduction of Recorded Media)
	17	Petroleum and Coal Product Manufacturing
	18	Basic Chemical and Chemical Product Manufacturing
	19	Polymer Product and Rubber Product Manufacturing
	20	Non-Metallic Mineral Product Manufacturing
	21	Primary Metal and Metal Product Manufacturing
	22	Fabricated Metal Product Manufacturing
	23	Transport Equipment Manufacturing
	24	Machinery and Equipment Manufacturing
	25	Furniture and Other Manufacturing
D	**Electricity, Gas, Water and Waste Services**	
	26	Electricity Supply
	27	Gas Supply
	28	Water Supply, Sewerage and Drainage Services
	29	Waste Collection, Treatment and Disposal Services
E	**Construction**	
	30	Building Construction
	31	Heavy and Civil Engineering Construction
	32	Construction Services
F	**Wholesale Trade**	
	33	Basic Material Wholesaling
	34	Machinery and Equipment Wholesaling
	35	Motor Vehicle and Motor Vehicle Parts Wholesaling
	36	Grocery, Liquor and Tobacco Product Wholesaling
	37	Other Goods Wholesaling
	38	Commission-Based Wholesaling
G	**Retail Trade**	
	39	Motor Vehicle and Motor Vehicle Parts Retailing
	40	Fuel Retailing
	41	Food Retailing
	42	Other Store-Based Retailing
	43	Non-Store Retailing and Retail Commission-Based Buying and/or Selling

H	**Accommodation and Food Services**	
	44	Accommodation
	45	Food and Beverage Services
I	**Transport, Postal and Warehousing**	
	46	Road Transport
	47	Rail Transport
	48	Water Transport
	49	Air and Space Transport
	50	Other Transport
	51	Postal and Courier Pick-up and Delivery Services
	52	Transport Support Services
	53	Warehousing and Storage Services
J	**Information Media and Telecommunications**	
	54	Publishing (except Internet and Music Publishing)
	55	Motion Picture and Sound Recording Activities
	56	Broadcasting (except Internet)
	57	Internet Publishing and Broadcasting
	58	Telecommunications Services
	59	Internet Service Providers, Web Search Portals and Data Processing Services
	60	Library and Other Information Services
K	**Financial and Insurance Services**	
	62	Finance
	63	Insurance and Superannuation Funds
	64	Auxiliary Finance and Insurance Services
L	**Rental, Hiring and Real Estate Services**	
	66	Rental and Hiring Services (except Real Estate)
	67	Property Operators and Real Estate Services
M	**Professional, Scientific and Technical Services**	
	69	Professional, Scientific and Technical Services (Except Computer System Design and Related Services)
	70	Computer System Design and Related Services
N	**Administrative and Support Services**	
	72	Administrative Services
	73	Building Cleaning, Pest Control and Other Support Services
O	**Public Administration and Safety**	
	75	Public Administration
	76	Defence
	77	Public Order, Safety and Regulatory Services
P	**Education and Training**	
	80	Preschool and School Education
	81	Tertiary Education
	82	Adult, Community and Other Education
Q	**Health Care and Social Assistance**	
	84	Hospitals
	85	Medical and Other Health Care Services
	86	Residential Care Services
	87	Social Assistance Services

R **Arts and Recreation Services**

89 Heritage Activities
90 Creative and Performing Arts Activities
91 Sports and Recreation Activities
92 Gambling Activities

S **Other Services**

94 Repair and Maintenance
95 Personal and Other Services
96 Private Households Employing Staff and Undifferentiated Goods- and Service-Producing Activities of Households for Own Use

APPENDIX B. MODELLING SOLAR THERMAL SYSTEM PERFORMANCE

Solar Hot Water System Introduction

A typical hot water storage tank consists of a cold water inlet toward the base of the tank, and a hot water outlet at the top. Heating is carried out by either an electrical element or a gas burner. As hot water is used, cold water enters the bottom of the tank, increasing in volume until the cold layer reaches the outlet, and the hot water “runs out”.

A solar hot water system takes cold water from the bottom of the tank, near the inlet, to the solar collector, returning it hot to the top of the tank. As solar energy is collected, the hot volume expands and the hot layer moves downward. The heat input from electricity or gas has been replaced by solar energy. A simplified explanation of the processes of a typical system is as follows:

- Sunlight strikes the collector, raising the temperature of the fluid inside it.
- When the temperature of the fluid in the collector exceeds the temperature of the cold tank fluid by a certain amount (typically 10°C), the circulation pump runs.
- Once the temperature difference has been reduced to some amount (typically 2-5°C), the pump stops.

If the temperature of the tank is already at its maximum, the pump will not start. If, in addition, the temperature of the collector exceeds its maximum design point, a pressure release valve might be used to avoid damage to components.

A booster system is typically required to ensure hot water supply in the case of poor weather. This may be in the form of an electric element or a gas burner. These boosters can be dispatched manually or automatically and may boost the temperature of the entire tank, or simply the water exiting the tank. The amount of boosting required will depend on the hot water usage, the size and insulation of the storage tank, the weather conditions (ambient temperatures, water temperatures, irradiance, wind speeds etc.) and the size, installation, and efficiency of the collector.

A SHW collector can be retrofitted to most existing tanks using a conversion kit. However, if the existing tank is vitreous enamel (glass-lined) and more than five years old, a new stainless steel tank will usually be recommended. Only new solar hot water systems including a new tank are eligible for Small-Scale Technology Certificates (STCs). Due to the value of STCs, the overall cost difference between retro-fitting and installing a full system is usually quite small.

Solar Hot Water System Modelling

ITP used the System Advisor Model (SAM) developed by the U.S Department of Energy's National Renewable Energy Laboratory (NREL) to conduct modelling of unglazed, glazed flat plate, and evacuated tube solar hot water systems at various locations around Australia. SAM implements a physical model to predict system performance, depicted in Figure 116. The collector can be specified by the efficiency parameters as described in Section 5.4.5: Performance analysis of solar thermal systems. Parameters can either be specified by the user, or else imported from the Solar Rating & Certification Corporation (SRCC) database. The SRCC is based in the US and provides independent testing and rating of solar collectors. ITP specified unglazed collector parameters according to those provided by Energetics (Annas et al. 2005), while using the SRCC database to model the Rheem L Series flat plate collector, and the Apricus AP-20 evacuated tube collector.

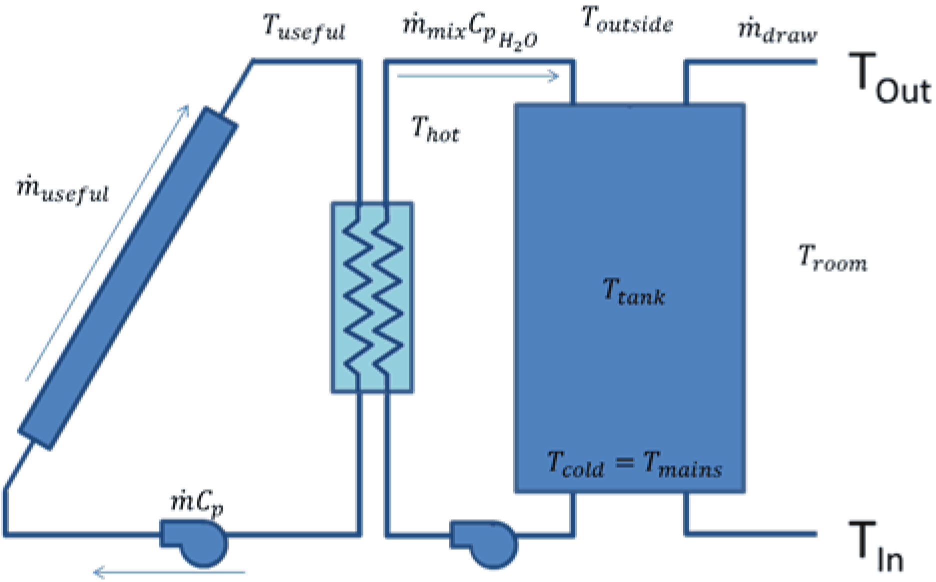


Figure 116. Schematic of SAM's SHW physical model[57]

SAM's SHW model dispatches the circulation pump when solar energy is being collected. This causes hot water to enter the top of the tank from the collector, while cold water leaves the bottom of the tank to the collector. While the pump is running SAM assumes the tank is fully mixed, as per Figure 117. The tank is assumed to be stored indoors, and the ambient temperature of the room can be set at the user interface. SAM uses this to estimate thermal losses to the environment (Q_{room}). ITP used the default value of 20°C in its modelling.

[57] SAM Help

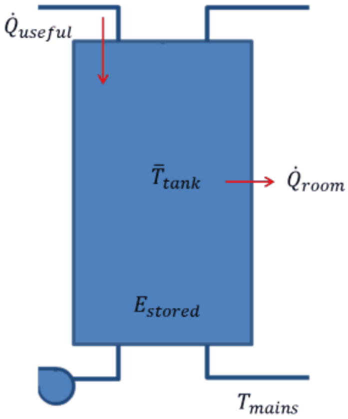


Figure 117. SAM SHW tank schematic (during solar collection)[58]

An energy balance can then be performed to determine the mean tank temperature, with energy input from the collector (Q_{useful}), and energy output via tank losses (Q_{room}) or to the load at T_{tank}. As the mass of the tank is constant, the following differential equation can be used:

$$\frac{dT_{tank}}{dt} = \frac{\dot{Q}_{useful} - \dot{Q}_{room} + \dot{m}C_p(T_{tank} - T_{mains})}{\rho V_{tank} C_p}$$

When no solar energy is being collected and the pump is off, SAM assumes the tank is stratified into hot and cold regions which are generated as hot water is drawn from the top of the tank, and cold water replaces it at the bottom. SAM models the hot and cold volumes and temperatures via the following differential equations:

$$\frac{dT_{cold}}{dt} = \frac{\dot{Q}_{room,cold} + \dot{m}C_p(T_{mains} - T_{cold})}{\rho V_{cold} C_p}$$

$$\frac{dT_{hot}}{dt} = \frac{\dot{Q}_{room,hot}}{\rho V_{hot} C_p}$$

Tank losses (Q_{room}) depend on insulation parameters specified by the user within SAM, while the energy incident on the collector is derived using hourly irradiance data for the location over a year. The efficiency of the collector in converting this energy to heat depends on the orientation and tilt of the collector, and the performance characteristics of the collector in question. These parameters are described in EQUATION above, and can either be specified by the user in SAM, or be imported from the Solar Rating and Certification Corporation (SRCC) database. The SRCC is based in the US and provides independent testing and rating of solar collectors.

Using these inputs, SAM solves the differential equations above once hourly to model the performance of a solar hot water system over a year. The results can be extracted from time series data which can be exported to Excel or similar. The two values which are most indicative of system performance are Q_{useful} and Q_{saved}.

[58] SAM Help

Q_{useful} refers to the energy delivered from the collector to the tank, and can be summed to determine the annual energy output of the collector. The result will depend on the orientation, tilt, and performance characteristics of the collector, in conjunction with the local weather (inclusive of both ambient temperatures and the solar resource in terms of both GHI and DNI) and the average temperature of the tank.

Q_{saved} refers to the energy use offset by the solar thermal system. It is derived by subtracting the total energy supplied by the electric boost system over the course of a year (Q_{aux}), as well as any energy used in driving the solar circulation pump (P_{pump}), from the energy which would be required if the electric booster was used as the sole heat source for the system ($Q_{aux\ only}$).

$$Q_{saved} = Q_{aux\ only} - Q_{aux} - P_{pump}$$

These two values are indicative of both the collector and system output and can be used to calculate LCOE.

APPENDIX C. LEVELISED COST OF ENERGY

The basic formula for evaluating NPV is:

$$NPV = \sum_j \frac{C_j}{(1+DR)^j}$$

where the cash flows C_j are those occurring at time (year) j and *DR* is the discount rate[59]. Cash flows can be measured in either nominal or real (independent of inflation) currency units. The discount rate can be either nominal, or real. NPVs can be calculated using real currency cash flow measurements together with real discount rates, or nominal currency cash flow measurements with nominal discount rates; the same NPV will be obtained in either case

For a renewable energy system, the key cashflows are the initial capital investments (negative), ongoing Operation and Maintenance costs (negative), the costs of ongoing inputs such as fuel for hybrid operation or water for cooling (negative) and implied income from energy produced (positive).

Key parameters are the discount rate and the assumed lifetime of plants, both of which have a significant impact on overall NPV results. A longer assumed plant life and a lower discount rate both work to improve NPVs for renewable generation. If the “marketplace” assesses that a project or technology is “high risk” this leads to the use of shorter lifetimes for amortisation and application of higher discount rates.

Detailed, project specific LCOE evaluations are based on complex spreadsheets summing every discounted cash flow over the system lifetime, which are then solved iteratively to establish the real dollar value of energy which gives the total NPV of zero.

Issues that are typically encountered include:

- Debt financing may be paid off over a different time scale to equity
- Tax benefits may apply in different jurisdictions
- Tax deductible depreciation may apply over a shorter timescale than the project.
- Construction is staged over several years and subject to higher interest rates for finance
- System output may take some time to stabilise as commissioning processes proceed after first start up.

---

[59] This is the most commonly recognised form or NPV on the assumption of annual compounding. Compounding can actually be done on any time scale including continuously, also in a strict mathematical sense, I is a fraction per unit time and is multiplied by the compounding time interval (in this case 1 year).

- System output may be subject to other predictable variations over time (such as a component with known degradation rate).
- Major overhaul type expenditures may be predicted at certain times in addition to overall continuous O&M.
- Various inputs may be subject to different escalation rates.

All these issues are project specific, depending on technology type, developer status and site chosen.

Studies that report LCOEs for energy systems are often poor at documenting all input parameter values and the methods used in a comprehensive way. In many cases, the methodology is actually intentionally withheld as it is embodied in proprietary financial models.

This study has adopted a methodology which is somewhat simplified but has sufficient complexity to allow issues of tax, cost of equity and cost of debt to be examined.

The life cycle NPV calculation is embodied in the following formula:

$$NPV_{LC\,\mathrm{costs}} = EQ - \sum_{1}^{ND} \frac{DEP \times T}{(1+DR)^{j}} + \sum_{1}^{NL} \frac{LP}{(1+DR)^{j}} - \sum_{1}^{NL} \frac{INT \times T}{(1+DR)^{j}} + \sum_{1}^{N} \frac{AO \times (1-T)}{(1+DR)^{j}} - \frac{SV}{(1+DR)^{N}}$$

Where:

EQ is the initial equity contribution from the project developer

DR is the nominal discount rate

ND the period (number of years) over which the system can be depreciated for tax purposes

DEP is the amount of depreciation in a year

T is the tax rate applying

LP is the annual loan payment

INT is the reducing amount of Interest paid each year as the loan is paid off

NL is the term (number of years) of the loan

AO is the annual operations cost which could be calculated from fixed and variable contributions as needed

N is the project lifetime

SV is the end of project life salvage value.

The simplifying assumptions used are:

- The analysis begins from the time of plant commissioning.
- Annual energy production is assumed constant over project life.

- The Equity contribution is assessed at the beginning of year 1 and so is assumed to have all costs of construction finance rolled into it.
- Depreciation is linear in nominal dollars.
- Loan payments are constant for each year of the loan and are in nominal dollars based on amortisation of a debt across a loan term using the standard annualisation formula.
- Annual O&M costs are constant per year in nominal dollar terms across project life. (this is possibly the most significant, since it doesn't reflect the lumpy expenditure likely on component overhaul).

To aid in understanding, LCOE can be simplified further if tax is not considered and the cost of capital (both debt and equity) can be rolled into a single discount rate. The result is:

$$LCOE = \frac{(F_R + \mathrm{O\,\&\,M}_{fixed})C_0}{PF_c} + O\,\&\,M_{\mathrm{var}iable}$$

Where:

P is the nameplate capacity of the system

F_c is the capacity factor

C_o is the total initial capital cost and

$$F_R \equiv \left(\frac{DR(1+DR)^n}{(1+DR)^n - 1} \right)$$

is the 'capital recovery factor' and is dimensionally the same as the discount rate. The capital recovery factor represents a rate of repayment that covers 'interest' plus paying off the capital in the system's lifetime.

Many studies report a Weighted Average Cost of Capital (WACC) which may be implied as being for use with this LCOE formula as the effective discount rate. There are a number of published formulas for WACC and these can also often include the tax rate, implying that they could be used in the simple formula. This is difficult and, given the lack of transparency in methodologies, should be treated with caution.

IT Power Renewable Energy Consulting

Southern Cross House, 6/9 McKay St, Turner, ACT
PO Box 6127 O'Connor, ACT 2602
info@itpau.com.au

itpau.com.au

abn 42 107 351 673
p +61 (0) 2 6257 3511
f +61 (0) 2 6257 3611