On farm power generation options for Australian vegetable growers

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Summary

Research into on farm power generation has produced details of the options, and explored feasibility of adoption of such systems. Growers can use this to help them make informed decisions about the economic, technical and operational costs and benefits of the various technologies, the challenges of installation and operation, and the suitability of systems to individual ventures.

Technologies studied were well established and in use. They included:

Devices which generate electrical power only:

- solar photovoltaics (PV)
- wind power
- natural gas generation
- Liquefied Petroleum Gas (LPG) power
- woody biomass power generation
- micro-hydro power generation

Proven solar alternatives:

- concentrating solar thermal
- concentrating solar PV

Storage technologies that support intermittent power generation options:

- lead-acid batteries
- micro-hydro as pumped energy storage
- chilled water/ice storage

Key factors for growers looking to adopt on farm power generation include:

- The cost of electricity from the grid
- Financial performance of power generation technologies relative to network supplied electricity
- Economic incentives, such as subsidies and feed-in tariffs
- Availability, quality and affordability of energy resources or fuel
- Ease of obtaining approvals and meeting regulatory requirements for power generation
- Desire to make farming operations more sustainable, which can also have marketing benefits
- Diversification of energy sources and potentially income as a risk management measure

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Summary of main findings

The detailed report provides accurate estimates of costs and returns of generating electricity on farm. Detailed case studies examine how the options could be implemented over a range of locations and crops.

The feasibility of such schemes is assessed by not only examining the economics, but also the regulatory requirements, incentives and impediments, illustrating the approximate investment required and likely reductions in power costs. No reliance or actions should be made based solely on the information contained in any of these materials without site and company specific investigations.

1. Solar photovoltaics (PV)

Solar PV should be economically viable for most vegetable growers, including those in less sunny regions, provided the current Small-Scale Technology Certificate (STC) government subsidies paid under the Renewable Energy Target (RET) remain. For example, a solar PV plant with a total establishment cost of $2500 per kW of capacity can be viable at a 10% Internal Rate of Return (IRR) with a 5–7 year payback period if electricity costs more than 12–15 c/kWh.

A key consideration in this analysis is that 90% of the electricity produced can be consumed on site.

Should the RET be repealed, this same solar PV plant then requires the current cost of electricity to be more than 19–22 c/kWh to be viable, which could be the case for some growers. Thus, solar PV may remain financially viable for some growers even if the RET is repealed.

2. Battery storage

Battery storage is not currently viable. It costs about $800 per kWh to set up, and required a current electricity price of more than 35 c/kWh before it would be economically viable. Further, given the significant uncertainty in the full cost of battery storage systems, the researchers cannot recommend the installation of battery storage at present.

3. Simple and cogeneration using reciprocating engine generator

The study considered three types of on-site power generation using reciprocating engines:

- Simple generation (ie electricity only)
- Cogeneration of electricity and process heat
- Cogeneration of electricity and process cooling

The key issue for viability is the cost of gas. The analysis found that simple or cogeneration requires fuel prices that can compete with the amount paid for electricity. Additional heating or cooling from cogeneration can provide another potential benefit. The capital cost and

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payback periods are less important than the cost of fuel, which dominates the financial performance.

Only network delivered natural gas is priced to reasonably compete with most current electricity prices. For example, a gas-fuelled generator with a capacity factor of 50% or more should be viable when the price being paid for electricity is more than 10c/kWh, provided that it consumes fuel with a price of 10 $/GJ or less.

With LPG not viable, on-site engine generation will not be viable for growers who do not have access to network delivered natural gas.

4. Wind turbines

This analysis focused on 50–500 kW capacity second hand wind turbines. Despite uncertainty about the total capital required to install a second hand wind turbine, it appears that they will be viable in many cases because they cost significantly less than new plant.

Wind is viable if the cost of electricity is more than about 10c/kWh and most of the electricity generated can be used on site. This analysis is based on:

- using second hand wind turbines with total capital expenditure of 1750 $/kW
- current subsidies (LGCs) are retained
- the turbine operates at 20% of capacity or higher
- a 10% internal rate of return is acceptable
- 100% debt financed at 6.5% pa interest over 10 years

If the Renewable Energy Target (RET) is repealed, this will have a weaker impact on the financial viability of wind than it does for solar PV. The breakeven point for viability would rise to at least 12c/kWh if LGCs (Large scale Generation Certificates) are removed. Because wind is intermittent, growers need to have an electrical load pattern that ensures most of the electricity generated can be consumed on site.

5. Woody biomass

On-site power generation using woody biomass was not analysed since it does not appear to be a significant resource for the large majority of growers, and because the performance of electricity generating plant that consumes this fuel is poor at the scale of individual growers. The most common method of generating electricity from woody biomass involves its direct combustion to drive a steam turbine. At around 100 kW and below, these steam plants tend to have significantly lower thermal efficiencies than, for example, the reciprocating engines discussed above. Thus, unless the fuel has a very low price and is readily available—which is not the case for most growers—power generation from woody biomass is likely to be unviable.

Regulatory incentives and government subsidies

The schemes currently in place include the Renewable Energy Target (RET) and feed-in tariffs. The RET can provide growers with financial incentives for installing eligible renewable energy power plant via creation and sales of renewable energy certificates either upfront (STCs for smaller systems) or annually (LGCs for larger systems). STCs are likely to be required for the viable installation of solar PV for many growers. Changes to the RET recommended recently by the RET Review could significantly impact the viability of on farm power generation options.

Feed-in tariffs vary by jurisdiction. With the exception of the Northern Territory and some parts of Western Australia, mandatory minimum feed-in tariffs have been significantly reduced from previously high levels, or scrapped altogether. The remaining mandated and voluntary feed-in tariffs offered by retailers are typically 5–8c/kWh for net export from small to medium scale systems. Since feed-in tariffs are often significantly below growers' electricity tariffs, consuming most of the power generated on site is much more important to a system's economic viability than generating income from feed-in tariffs.

Regulatory requirements to install and operate on farm power generation can be complex, onerous, time-consuming and costly. These requirements differ by type of generation as well as by location.

There are three key types of requirements relevant for on farm power generation installations:

1. Grid connection and technical requirements

Installation and grid connection for embedded generation plant needs to be approved by the distribution network service provider (DNSP), who will certify the technical performance of the plant. For medium and larger scale installations, the DNSP will conduct a network connection study to identify technical issues and any constraints on grid connection. Requirements for small scale generation (below 5–10kW) are typically more streamlined, particularly for rooftop solar PV installations. It is important to discuss feasibility of a proposed system as early as possible with the DNSP.

2. Planning and development approval

Growers need to contact their local government or council about planning and development requirements for technologies on their site. Planning and/or building permits may be required before construction and installation can commence, even for solar PV installations in some locations.

Typically, planning and development approvals are required for wind power and some stationary power plant. Preparing documents and supporting evidence is often time-consuming. Requirements differ between councils so there is no one set of guidelines to follow, adding significant cost and uncertainty to obtaining approvals. Environmental objections to the installation of turbines can be a major disincentive to investment in on farm wind generation.

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3. Engine fuels and emissions standards

Where an engine is fuelled by natural gas, LPG, biogas, petrol or diesel:

- standards governing the fuel and the appliance,
- regulations regarding atmospheric and noise emissions, and
- OH&S standards for workplaces and hazardous areas must all be met.

The associated processes are administered by different state environmental and OH&S agencies.

Keywords

Solar photovoltaics; solar PV; wind turbines; woody biomass; cogeneration; battery storage; energy efficiency; vegetables.

Introduction

Australian vegetable growers are significant consumers of electricity with on farm irrigation, heating and cooling processes and, for some larger growers, processing and packing plants creating significant power demands. As electricity retail prices have increased sharply across Australia (on average by more than 60% in real terms over the five years to 2013), energy costs have become a larger part of the cost base for growers and hence a focus for cost reduction. At the same time, falling installation costs of some renewables, such as solar PV, and incentive schemes have together created opportunities for growers to potentially reduce energy costs and meet sustainability goals.

In 2013, Applied Horticultural Research (AHR) reviewed the impact of climate variability on the Australian vegetable industry (on projects VG12041 and VG12049), with Parkside Energy contributing analysis and recommendations about energy efficiency opportunities and on farm power generation options for growers. The project recommended further evaluation of the technical and economic feasibility of different on farm power generation options as well as the need for detailed energy audits on vegetable growing farms to understand energy consumption and usage patterns.

In late 2013, HAL commissioned three related energy projects to investigate energy efficiency opportunities for vegetable growers and assess the potential for different forms of on-site power generation:

- VG13054 Energy audits and energy efficiency case studies – InfoTech Research
- VG13051 On farm power generation options – AHR and Parkside Energy
- VG13049 Biogas generation feasibility study – RM Consulting Group

These three projects, whilst separate and discrete, are working together to coordinate site selection, communication with growers and data collection where appropriate.

The objective of the On Farm Power Generation project is to investigate on farm power generation options and report on the feasibility of adoption to help growers make an informed decision about the economic, technical and operational costs and benefits of different technologies, as well as the challenges of installing and operating on farm power generation. The analysis and recommendations are focussed on technologies that are in existence and widely deployed, rather than experimental, to ensure project outcomes are practical for growers.

Following project set-up and scoping, the project was conducted in four stages, as illustrated in **Error! Reference source not found.** below.

Task 1 (Overview of key generation technologies) was the subject of the first report for the project. This involved a review all of the relevant technologies and their deployment and identified the scope of technologies to be examined during the case studies. These technologies included solar PV, wind power, natural gas generation, Liquefied Petroleum Gas (LPG) generation, woody biomass power generation and, where relevant, battery storage to support intermittent power generation options.

The scope specifically excluded examination of biogas generation since this is the subject of a separate, dedicated project (VG13049). The scope also does not include direct heating or cooling technologies that do not produce electricity, even though these may displace electrical energy. Thus, solar hot water, geothermal heating and cooling as well as gas or biomass fired boilers are not considered. Heat production is included only where combined with power generation (i.e. cogeneration and trigeneration).

Task 2 of the project presented case studies to analyse the feasibility of selected technologies at specific vegetable growing sites in Australia. Case study sites were selected by AHR after close consultation with Parkside Energy, the project's grower representative and HAL. Sites were selected to ensure a range of farming operations, locations and potential or installed technologies.

Task 3 was an economic analysis of the viable technologies using key methods of reporting the return on investment and a review of practical implementation issues, namely incentives schemes and regulatory requirements for installation and operation of on farm power generation.

Task 4 considered incentives and regulation for on farm power generation.

Task 5 was the communication of the project findings and recommendations via a series of grower workshops, fact sheets on relevant technologies, inclusion of project results and resources on relevant websites, publication of this final project report, and presentations to industry stakeholders.

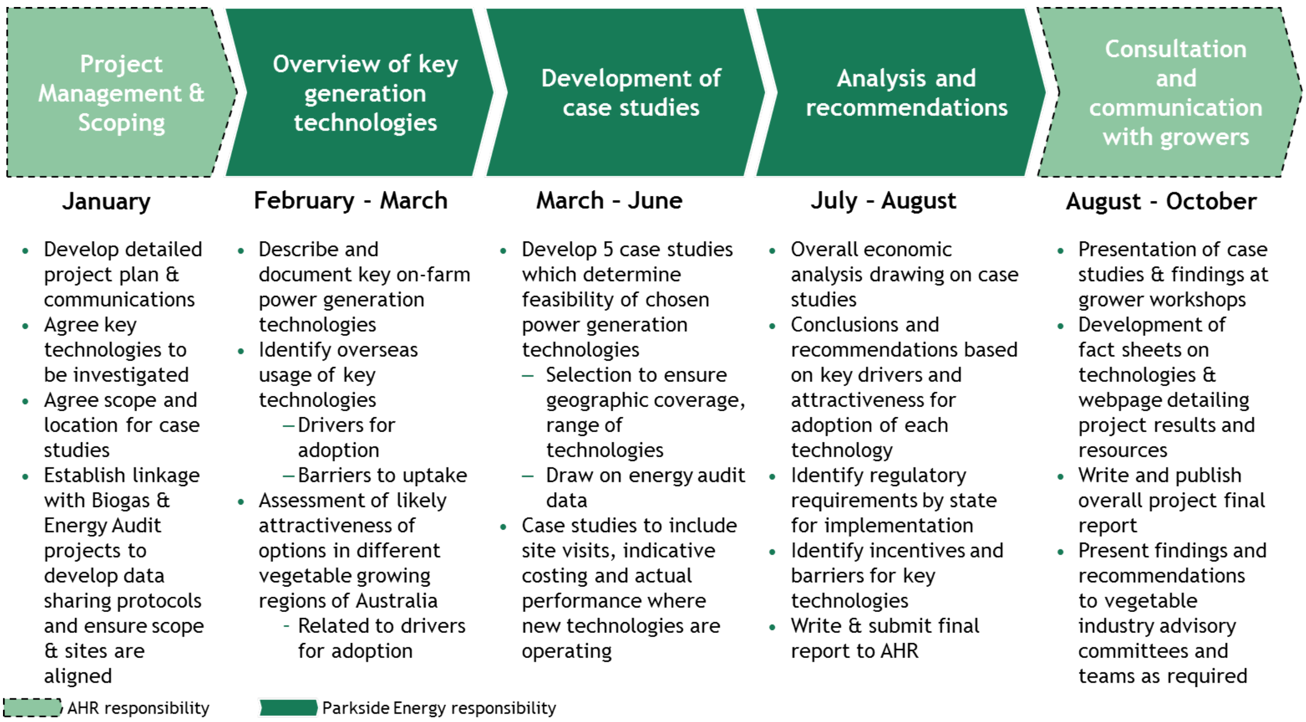

Figure 1: Overview of project stages and timeline

Nomenclature

CPI	Consumer Price Index
FiT	Feed-in-Tariff
FOM	Fixed Operating and Maintenance Costs
IRR	Internal Rate of Return
kW	Kilowatt
kWh	Kilowatt hour
LCOE	Levelised Cost of Electricity
LGC	Large-Scale Generation Certificate
MW	Megawatt
MWh	Megawatt Hour
NPV	Net Present Value
NSP	Network Service Provider
O&M	Operating and Maintenance
PV	Photovoltaic
RET	Renewable Energy Target
STC	Small-Scale Technology Certificate
TCR	Total Capital Required
VOM	Variable Operating and Maintenance Costs

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Task 1: Overview of on farm power generation options for vegetable growers

Summary

We consider that four power generation technologies are most plausible for increased deployment on farms:

- Solar photovoltaics (PV)
- Natural gas and liquefied petroleum gas (LPG) generation with a reciprocating engine, potentially with cogeneration or trigeneration
- Wind turbines
- Woody biomass power generation

All of these technologies are established and deployed around the world. With the exception of trigeneration and biomass generation, these technologies are already being used in the horticulture or related sectors in other countries. In Australia, a number of vegetable growers are utilising solar PV and wind power to generate electricity on-site and offset their grid power consumption.

We note that all forms of distributed power generation are most likely to be viable when displacing electricity purchased at the retail rate, rather than being sold into the wholesale market. Factors that drive the uptake of on-site power generation are varied and decisions are specific to growers and their local conditions. The key factors that influence growers in adopting on farm power generation include:

- Financial performance of power generation technologies, relative to network supplied electricity;
- Economic incentives, such as subsidies, feed-in-tariffs and high retail electricity prices;
- Availability, quality and affordability of energy resources or fuel; and
- Ease of obtaining approvals and meeting regulatory requirements for power generation.

Of course, growers will install power generation on-site where it is cost effective to do so, although it is often not simple to analyse this. Current deployment of technologies suggests that, under some conditions, they are economically viable.

In many of the major vegetable growing regions of Australia, there is good availability of appropriate energy resources. For example, solar resources are excellent in parts of Queensland, Western Australia, NSW and South Australia. Piped natural gas is likely most affordable and available for Victorian growers. Many of the best wind regions are in WA, South Australia, Victoria and Tasmania. Biomass resources are reasonably abundant. However, it is difficult to generalise about wind and biomass resources as these can vary significantly by site.

However, all of these technologies face challenges to achieve increased on farm deployment which were explored as part of the project:

1. *Uncertain financial viability of renewable power generation if incentives are reduced or removed*

   Incentives for renewable power generation have declined in recent years and the current review of the Renewable Energy Target (RET) may result in further cuts. It is not presently clear whether

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distributed renewable power generation (i.e. solar PV, wind and biomass) will remain viable without incentives.

2. *Uncertain regulatory environment for distributed intermittent power generation*

   Governments may seek to implement stronger measures to limit the penetration of distributed intermittent power generation to address network problems that may be created by these installations.

3. *Unavailability of networked natural gas at the farm gate*

   LPG and diesel are both delivered to the farm gate at similar prices. Networked natural gas is significantly cheaper than both, but is not available to many growers.

4. *Implementation challenges and barriers*

   Approvals are required to install and operate on-site power generation including approvals from local government (planning), State Environmental Protection Authorities or equivalent (emissions) and the distribution network service provider (grid connection). These processes add cost, risk and time for many power generation projects although they are likely to be least onerous for solar PV installations.

1. Introduction

This section of the report considers eleven different technologies for on farm power generation. The choice of these technologies is based on the interest that growers have expressed in certain technologies, as well as our own views of plausible options for on farm power generation. Biogas is not considered in this report since it is the subject of a separate project as noted in the Introduction [1]. Information about the financial performance of different technologies appears under Task 3.

This discussion presents the following for each of these eleven technologies.

- Description of features and how the technology works
- Level of maturity/deployment
- Latest developments/innovation
- Key strengths/attractiveness
- Drawbacks/limitations

Overall, we consider that four technologies are most plausible for increased deployment on farms:

- Solar photovoltaics (PV)
- Natural gas and liquefied petroleum gas (LPG) generation with a reciprocating engine, potentially with cogeneration/combined heat and power (CHP) or trigeneration
- Wind turbines
- Woody biomass power generation

However, all of these technologies face challenges to achieve increased on farm deployment:

1. *Uncertain financial viability of renewable power generation if incentives are reduced or removed*

   Feed-in tariffs have been dramatically reduced in some states in recent years, and have now become far more uniform across the country [50]. Further, the current Federal Government has initiated a review of the Renewable Energy Target (RET), with a potential outcome being that this target is reduced or scrapped, resulting in future Renewable Energy Certificates (RECs) falling in price or disappearing.

2. *Uncertain regulatory environment for distributed intermittent power generation*

   Some organisations, particularly some electricity distributors, consider that distributed power generation creates network problems, with the associated costs of solving these problems socialised across all consumers. Such problems are clearly manageable at present. It remains to be seen whether these issues do indeed become significant, and whether governments will then implement stronger measures that limit the penetration of distributed intermittent power generation. Some measures are already in place, particularly limitations on the maximum capacity of the installed plant.

3. *Unavailability of networked natural gas at the farm gate*

   LPG and diesel are both delivered to the farm gate at similar prices. Networked natural gas is significantly cheaper than both, but is not available to many growers.

Solar PV

Description of technology

Solar photovoltaics (PV) generate electricity by converting solar radiation into direct current, via the *photovoltaic effect*. The photovoltaic effect describes the creation of voltage in a material upon exposure to light. The first solar cell was constructed by Charles Fritts in the 1880s, and with slow development through the 20th century in Europe and the US, until, like wind generation, it began to grow strongly in the 1970s. Today's PV modules are descendants of the first silicon modules made at Bell Laboratories in the 1950s [2,3,4].

Independent of any particular form of solar technology, the availability of the primary energy resource – sunlight – is massive. Maps such as Figure 2 below are common, with the dark disks representing the total fraction of the earth's surface that could provide *all of the world's primary energy* demand (i.e. *all* energy currently consumed, including heat, electricity, fossil fuels, etc.) assuming a conversion efficiency of 8% (efficiency here is the fraction of the incident solar energy at sea level that is converted into electricity) [5]. Clearly, resource availability is not the issue!

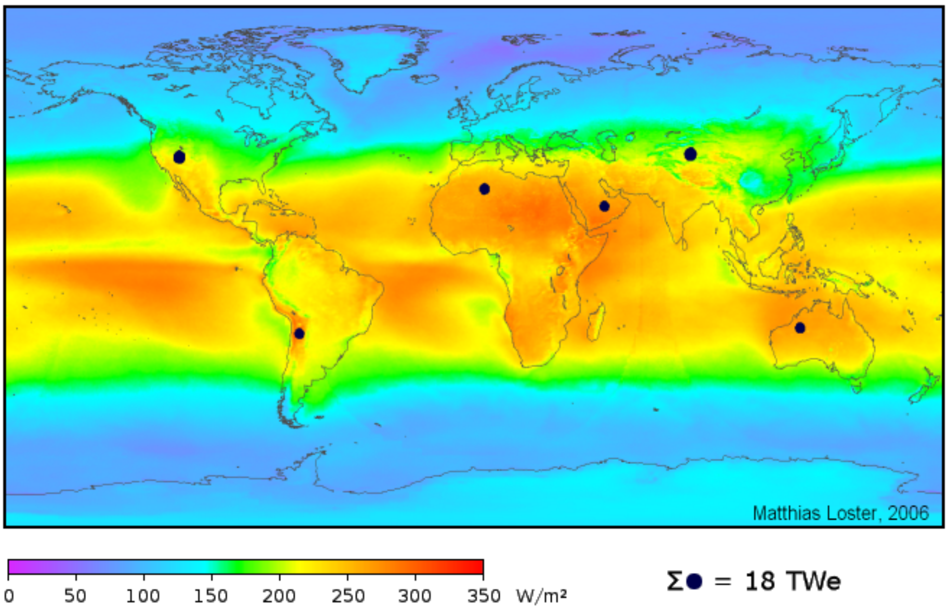

Figure 2: Surface level solar insolation around the world [5]

Level of maturity/deployment

Whilst solar PV still only contributes a small proportion of global electricity generation, there has been remarkable growth in its installed capacity and power generated over the last 10 years or so. This growth is due to several factors, particularly a rapid evolution in PV technology, significant reductions in cost, and the substantial subsidies that all renewables have attracted [2,3,4]. As a result, we consider that solar PV is one of the key options for on-site power generation.

Latest developments/innovation

Most solar PV modules currently in place use polycrystalline and monocrystalline silicon cells. Today, the performance and cost of these two cell types are very similar. So-called *thin-film* cells and other, more advanced technologies are also on the market. It remains to be seen which of these newer technologies challenge polycrystalline and monocrystalline cells for market share in the coming years.

Given the dominance today of polycrystalline and monocrystalline silicon cells, analysis in this project was based on these two technologies.

Key strengths/attractiveness

1. Renewable
2. Cost-effective at the best sites: 30-40% of Australian households in the best locations already have rooftop PV [6,7]. Unsurprisingly, most of these sites are in Queensland, South Australia and Western Australia. Such large penetration can only occur if PV makes financial sense for these households.
3. The cost of solar PV for on farm power generation should be lower than for households since the installations should be larger, and so have significant economy of scale. (The average size of a solar PV installation in Australia is roughly 3kW [6,7].) Further, as with household PV, the primary economic opportunity for on-site power generation with solar PV is displacing electricity that is purchased at retail rates, rather than being sold over the farm fence and into the wholesale market.

Drawbacks/limitations

4. Intermittent
5. Uncertain financial viability if incentives are removed: a common issue for all forms of distributed intermittent power generation.
1. Uncertain regulatory environment: a common issue for all forms of distributed *intermittent* power generation.

1.1. Concentrating solar thermal and concentrating solar PV

Description of technology

So-called *concentrating solar plants* can be either thermal or photovoltaic (PV). In both cases, the solar plant features mirrors that concentrate sunlight onto a small area. In the case of a *concentrating solar thermal* plant, this small area converts the sunlight into thermal energy carried by the plant's *working fluid*. This working fluid may be steam or some other fluid. If the working fluid is steam, electrical energy is usually generated by a steam turbine. If the working fluid is not steam, subsequent steam production by heat exchange and then steam turbine based generation normally occurs.

Concentrating solar PV plants feature a PV array at the focus of the mirrors. In this case, electricity is generated directly from the incident solar radiation.

Level of maturity/deployment

Whilst the operating principles of these plants are well established, particularly for concentrating solar thermal, significant opportunities appear to exist for improving their design and performance and thus cost [8]. These opportunities span all aspects, from fundamental improvements in key technologies in these plants through to improvements by greater deployment.

Latest developments/innovation

Both concentrating solar thermal and concentrating solar PV power generation have received significant interest in recent years, with several sites now operating or under construction in the US, Spain and elsewhere [8]. Of particular note is the Australian company *Solar Systems* [9], which has been developing concentrating solar PV for some time.

Key strengths/attractiveness

1. Renewable
2. Some concentrating solar plants are *semi-despatchable*: concentrating solar thermal often has intermediate, thermal energy storage between the solar receiver and the steam turbine generator. This means that these plants may be semi-despatchable, i.e. not truly despatchable since the duration of this energy storage is normally less than a day.

Drawbacks/limitations

1. Preferred scale unlikely to be suitable for growers: A general trend in concentrating solar plants has been the move to larger installations, typically capacities in the hundreds of MWs, suggesting that economics of scale are significant. Plants of this size are unlikely to be useful for growers.
2. Cost-effectiveness: concentrating solar thermal and PV plants appear to have levelised costs that are between those of fixed PV and on-shore wind [10]. Given the preferred scale of these plants, they should be participants in the wholesale electricity market, as is the case for bigger wind farms. They therefore face significant economic competition from wind for a given level of renewable energy subsidy.

1.2. Natural gas and liquefied petroleum gas (LPG) generation

Description of technology

Natural gas and *liquefied petroleum gas (LPG)* are commonly used fuels in several sectors. Both are mixtures of variable content. Natural gas is primarily methane, but may also feature significant amounts of ethane, propane and other gases. It is a gas at ambient conditions, and needs to be chilled to cryogenic temperatures (below -150degC) to become *liquefied natural gas (LNG).* In contrast, LPG is primarily comprised of propane and butane, and is a liquid at ambient temperatures and moderate pressures. When stored as liquids, both LNG and LPG have energy densities (~20MJ/lt) that are comparable to gasoline and diesel (~30MJ/lt), and so have advantages over gaseous natural gas in applications that required more compact storage.

The combustion of both natural gas and LPG in reciprocating engines can result in significantly lower emissions of greenhouse gases and *regulated pollutants* (carbon monoxide, oxides of nitrogen, oxides of sulphur and unburnt hydrocarbons) than coal and diesel [11,12]. These environmental benefits of natural gas and LPG are in addition to natural gas' significantly lower price than diesel in Australia. Since fuel costs are a large part of the total cost of operating stationary power plants and vehicles, sales of gas fuelled reciprocating engines for power generation and transport are strong globally.

These low prices are due to the now commonly appreciated boom in natural gas and LPG production [13,14]. That large growth in both is occurring at the same time is not surprising, since most of the world's LPG comes from the processing of so-called *conventional* and *unconventional* natural gas [15]. The massive *Gorgon Project* in Western Australia is a good example of conventional natural gas and LPG. *Shale* resources across the US and *coal seam methane* in Queensland, Australia are unconventional resources that have grown enormously in the last ten or so years. The production of natural gas via the anaerobic digestion of farm waste or renewable resources is also becoming more common [1].

Level of maturity/deployment

Reciprocating engine driven power generation fuelled by both natural gas and LPG are mature technologies that are widely deployed. Typical capacities range from 10kW to 10MW.

Latest developments/innovation

Reciprocating engines have the fastest dynamic response of any common thermal power plant, as well as the highest efficiency of any simple cycle, thermal power plant. As a result, they are suited to low greenhouse gas emission, *hybrid power generation* in combination with renewable resources such as wind, solar and biomass. These hybrid systems have significantly lower greenhouse gas emissions than normal, fossil fuelled plant, but usually also significantly lower costs than renewable plant [16,17].

Key strengths/attractiveness

1. Well understood and reliable form of distributed power generation.
2. High capacity factor, despatchable generation that can be modulated to suits growers' needs over a day.
3. Networked natural gas, if available, is significantly cheaper than diesel on an energy basis.
4. Emissions: the regulated pollutant emissions from natural gas and LPG fuelled power generation can be significantly lower than those of diesel fuelled power generation.

Drawbacks/limitations

1. Natural gas prices in the Eastern states of Australia are anticipated to rise significantly once LNG export from Queensland commences in the coming years. LPG prices are likely to follow this, since natural gas is its primary competitor for heating and cooking applications.
2. Network delivered natural gas has a significantly higher price in NSW and Queensland than in Victoria and Tasmania [18]. Again, LPG prices will likely track these variations.
3. Poor access to natural gas network: many growers do not have access to the natural gas network. As a result, they only have access to delivered diesel and LPG.
4. The price of LPG is usually comparable to diesel on an energy basis: given that diesel fuelled generation is a very similar technology to that of these other two fuels, LPG fuelled on farm power generation does not likely pose significant financial benefits over diesel fuelled generation. The primary use of diesel generators as backup generators then suggests that such opportunities are limited.
5. Emissions: the emissions from natural gas and LPG fuelled power generation can be easily managed, but require approval from government prior to commissioning (e.g. State EPAs).

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1.3. Wind power

Description of technology

Small scale wind power has been a feature of agricultural operations for hundreds of years, with windmills used to pump water for irrigation and mill grain. Windmills for the production of electrical power were developed in the 1880s. With the advent of large scale electricity generation and transmission, many smaller wind turbines were decommissioned. There has been a resurgence of wind power since the 1970s with modern wind turbines being installed in large numbers in Denmark, UK, Spain, the Netherlands and other countries. Whilst larger turbines are usually installed as part of commercial wind farms, in some countries, small to medium scale wind power remains a part of the energy landscape.

Wind turbine generated electricity typically transforms the kinetic (mechanical) energy in the wind first into shaft (mechanical) energy via the turbine, and then into electrical energy via an electrical generator. Modern wind turbines range in size from a few kWs to several MWs in capacity. Today, most wind farms are made up of multiple turbines in the range of 1-4MWs. Farms currently feature wind turbines at smaller sizes than this, with capacities of 100kW to 2MW not uncommon.

Level of maturity/deployment

After hydroelectricity, wind is the second largest form of renewable electricity generation, and currently generates about 2% of global electricity. Of particular note is the rapid rate of growth of wind globally since 2001, with slightly less than an order of magnitude growth in installed capacity and proportion of global power generation during this period. Globally averaged capacity factors are currently about 20% [19].

Latest developments/innovation

Farms currently feature wind turbines at capacities typically ranging from 100kW to 2MW. Turbines of this size are significantly smaller than those in modern wind farms, and a continuing trend is that individual turbines are becoming continually larger. Turbines of 4MW or more are now being installed.

One finding of grower interviews was that several Australian growers have purchased reconditioned, second hand wind turbines from Europe. These turbines have capacities of 500kW or below, and are reported to be functioning well when installed. The key here is that the capital cost ($/MW capacity) of these turbines is significantly lower than new turbines. Since the total cost of ownership of wind turbines is mostly its capital cost, a cheaper, second hand wind turbine should have a similarly lower total cost than a new turbine.

Key strengths/attractiveness

1. Renewable
2. Cost-effective at the best sites: wind is usually the cheapest form of renewable power generation, provided that the wind resource on a given site is of high enough quality. As a result, several farmers in Australia already operate wind turbines that displace retail purchased electricity and/or sell into the wholesale market.

Drawbacks/limitations

- Intermittent

  Significant cost sensitivity to the quality and location of the wind resource: this is particularly an issue for smaller wind farms, such as those likely to be connected to a farm's power systems. In such cases, localised features in the landscape, such as small hills, trees and buildings, can cause significant reductions in the actual power generated by smaller wind turbines. As a result, great care is required in determining the best location for the turbines on a farm, particularly if the best wind resource is not close to existing power infrastructure. In such cases, the cost of the power infrastructure can render the installation unviable.

- Uncertain financial viability if incentives are removed: a common issue for all forms of distributed intermittent power generation.
- Uncertain regulatory environment: a common issue for all forms of distributed intermittent power generation.

1.4. Woody biomass power generation

Description of technology

Biomass is biological material from living or recently dead organisms. It takes numerous forms, in particular:

- Fuelwood and charcoal,
- food, fibre and wood processing residues,
- crop residues,
- animal wastes,
- forest harvest material,
- landfill gas,
- Municipal solid waste (MSW).

These different biomasses are used as feedstocks in many different processes to produce liquid fuels (e.g. ethanol, biodiesel), gaseous fuels (e.g. biogas), solid fuels (e.g. wood chips, briquettes), as well as electricity and heat. Of these, the most common form of biomass use today is its centuries-old use - as an energy resource for domestic heating and cooking, mainly in developing countries. Biomass remains roughly 10% of global primary energy supply [19].

Some of these forms of biomass can be classified as *woody*, i.e. "the roots, wood, bark, and leaves of living and dead woody shrubs and trees. Woody biomass is primarily comprised of carbohydrates and lignin produced through the photosynthetic process" [20]. Globally, the vast majority of power generation from woody biomass is via its combustion generating steam in a boiler, which then drives steam turbines. This is the case also in Australia. The vast majority of woody biomass used in Australian power generation is bagasse from sugar cane, which produces approximately 2% of Australia's electricity [21].

Level of maturity/deployment

Steam turbine driven power generation is of course a very mature technology, regardless as to whether its energy source is uranium, coal, natural gas, woody biomass

or some other fuel. Woody biomass driven steam plant are widely used around the world.

Latest developments/innovation

As with any steam plant, improvements in plant efficiency are now incremental, with increasing plant efficiencies continuing to appear

Key strengths/attractiveness

1. Renewable: is a renewable form of power generation *provided that its fuel is responsibly sourced*.
2. Cost-effective in best cases: it is one of the lowest cost forms of renewable power generation *provided that a low cost fuel is available in sufficient quantities* [10].

3. High capacity factor, despatchable power generation: is the only currently widely used form of renewable power generation that has a high capacity factor and is despatchable (i.e. its power output can be varied when requested)

Drawbacks/limitations

1. Significant cost sensitivity to fuel availability: several studies have shown that the cost of generating power is sensitive to the distance over which the woody biomass is transported between source and power plant, e.g. [22].
2. Economics favour installations at a larger scale than typical individual growers: the capital cost ($/MW of capacity) and the efficiency of steam turbine power generation are strongly dependent on scale, with devices smaller than roughly 1MW typically having high plant costs per unit capacity, and low thermal efficiency (i.e. 20% or less). Both of these contribute to higher costs.
3. Emissions: the emissions from woody biomass combustion can be smoky and high in both the *regulated pollutants* and so-called *air toxics*. This can cause issues of local community acceptance, and requires approvals from government (e.g. State EPAs).

1.5. Fuel cells

Description of technology

A fuel cell is a device that converts chemical energy in a fuel directly into *direct current* electrical energy [23]. This contrasts with combustion or steam driven engines, which convert the fuel's chemical energy first into heat (thermal energy) and mechanical energy, and then into electrical energy, with each step incurring inevitable energy losses. Fuel cells can therefore be highly efficient devices with low pollutant emissions.

The first demonstration of a fuel cell was by William Grove around 1838, who showed that hydrogen and oxygen could be made to react to produce water and a small electric current (Figure 3). The electrochemical conversion of hydrogen and oxygen to water proceeds via the following simple reaction.

$$2H_2+O_2 \rightarrow 2H_2O$$

For an acid electrolyte, the anode and cathode reactions are respectively as follows.

$$2H_2 \rightarrow 4H^+ + 4e^-$$
$$O_2 + 4H^+ + 4e^- \rightarrow 2H_2O$$

In these two reactions, the hydrogen ions H^+ migrate from the anode to the electrolyte, and from the electrolyte to the cathode. The electrons e^- migrate through the electric circuit, thereby providing electrical power. Eventually, one or both of the hydrogen or oxygen is consumed, and power generation ceases.

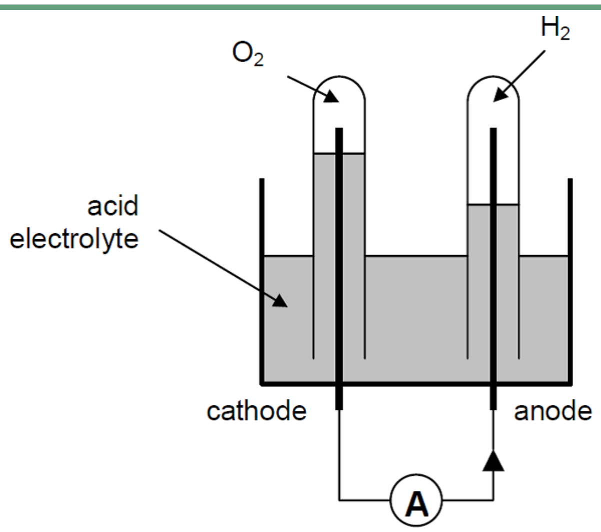

Figure 3: Schematic of a simple, hydrogen/oxygen fuel cell

The example above is the simplest fuel cell, and a number of different types running on different fuels have since been developed. These are usually categorised by the type of electrolyte used, such as those in Table 1. Shown in this table are two of the more common, so-called *high temperature fuel cells*, the MCFC and the SOFC. Whilst these devices still feature electricity generation via hydrogen/oxygen chemistry, they operate at sufficiently high temperature such that other, more common, hydrogen bearing fuels such as natural gas and LPG are *internally reformed* into hydrogen prior to the electrochemical reaction [24].

Type	**Usual fuel**	**Operating temperature**	**Typical capacity**	**Likely application**
Proton exchange membrane (PEM)	Hydrogen	50–100 degC	1W – 100kW	Automotive power, portable electronics, low power CHP
Molten carbonate (MCFC)	Natural gas	~650 degC	100kW – 10MW	Distributed power generation, combined heat and power
Solid oxide (SOFC)	Natural gas LPG	500–1000 degC	1kW – 10MW	Distributed power generation, combined heat and power

Table 1: Examples of different fuel cells [23]

Level of maturity/deployment

The SOFC is the most commonly considered fuel cell for natural gas fuelled, distributed power generation, including combined heat and power. However, SOFCs and fuel cells more generally have only found niche application in several areas, and are still not commonly deployed. The reasons for this are several, particularly those discussed below. It is also important to note that the invention of the fuel cell predates that of all of the devices that dominate power generation today: diesel engines, spark ignition engines and the steam turbine are late 19th century inventions, and the gas turbine is a 20th century invention.

It is therefore our view that SOFCs, and fuel cells more broadly, are not presently a practical option for on-site power generation, and require major improvement in their cost-effectiveness and robustness in order to be so. We therefore do not propose considering them for further analysis in this project.

Latest developments/innovation

Fuel cells received much attention in the 1990s and 2000s. More recently, both commercial and research interest in SOFCs seems to have waned. A local manufacturer, Ceramic Fuel Cells Limited (www.cfcl.com.au) manufactures and sells small scale SOFCs, although total annual sales are in the hundreds of units.

Key strengths/attractiveness

The closest competitor to natural gas fuelled SOFCs is the natural gas fuelled engine generator. Relative to these generators, natural gas fuelled SOFCs have the following strengths:

1. Higher efficiency: typically around 50% or even higher, compared to 35-40% for engine generators [24].
2. Low pollutant emissions: much lower emissions of regulated pollutants.
3. Quiet, vibration free operation: much quieter and almost vibration free since rotating vibrating parts are located in the device's auxiliary systems. The fuel cell itself is motionless during operation.
4. Highly reliable if operated very carefully: primarily because there are no moving parts.

Drawbacks/limitations

Relative to natural gas fuelled engine generators, natural gas fuelled SOFCs have the following drawbacks:

1. High plant cost: per unit of capacity, SOFCs are significantly more expensive than engine generators. This more than offsets low (fuel) operating costs, making total cost of ownership uncompetitive.
2. Lack of robustness in practice: SOFCs are very sensitive to so-called *poisoning*, particularly by oxides of sulphur. Since sulphur is present in most natural gases, great care must be taken to supply the SOFC with high quality fuel, often with *desulphurisation* of the fuel beforehand. In practice, poisoning is a serious issue that presents significant problems for the mass adoption of SOFCs.

1.6. Geothermal energy

Description of technology

Geophysical processes generate thermal energy in the earth at different depths. This energy resource can be very large, and geological formations can also serve as significant forms of energy storage. Thermal energy can be extracted and used directly, in which case it is referred to as *geothermal heating*. If thermal energy is transformed into electricity through one of several different processes, it is called *geothermal electricity*.

Level of maturity/deployment

Both geothermal heating and electricity are typically found in areas with high seismic activity and/or abundant *and accessible* geothermal resources. Data from the International Energy Agency's Geothermal Initiative shows that this is the case, with EU member states, Japan, New Zealand and the USA all making use of geothermal energy for agricultural and industrial activities [25]. In contrast, Australia has no recorded agricultural and industrial activities employing geothermal.

Since geothermal energy is not currently used in Australian industry or agriculture, this was not analysed further.

1.7. Cogeneration and trigeneration

Description of technology

In general, cogeneration and trigeneration refer to systems that generate two or three energy outputs respectively from a single energy input. In practice these systems are almost always considered to be:

- Cogeneration: a gas or liquid fuelled electrical generator with the recovery of its waste heat as either hot water or steam via heat exchangers. The water or steam can then be used for heating. Cogeneration is also often called combined heat and power (CHP).
- Trigeneration: as for cogeneration but only with hot water production. This hot water can then be passed through an absorption chiller to enable cooling rather than heating when required.

Thus, in practice, cogeneration produces electricity and heat from the fuel input and trigeneration produces electricity and heat or electricity and cooling, depending on need. At the farm scale, the power plant will be a reciprocating engine as discussed in section 1.3. Cogeneration and trigeneration can be very efficient, with 80% or more of the chemical energy in the fuel often transformed into either electricity or thermal energy.

Level of maturity/deployment

Cogeneration is widely practiced in cooler climates where demand for heating is large. A common example is the simultaneous generation of electricity and heating for a residence or office by a natural gas driven generator, with waste heat transferred to water that circulates through the building's hydronic heating system. Cogeneration is also practiced at larger scales, with networked hot water or steam being piped through local communities.

Trigeneration is less widely practiced, but still used around the world. It is less widely practiced for two reasons: the global need for cooling is less than that for heating, and because the addition of the absorption chiller makes the economics of trigeneration significantly more challenging than cogeneration.

Both cogeneration and trigeneration are rarely used in Australia due to our moderate climate. Emerging exceptions to this are large office blocks and public swimming pools. Nonetheless, total installed capacity of cogeneration and trigeneration in this country remains low.

Latest developments/innovation

Cogeneration and trigeneration may have particular use in protected cropping where the combustion of LPG is used to both heat a greenhouse and produce elevated CO_2 levels within the greenhouse. In this case, cogeneration and trigeneration produce another output of value (CO_2) in addition to electricity and thermal energy. Since the CO_2 is used in the greenhouse, direct feed of the engine exhaust into the greenhouse is required, thereby also avoiding the need of an exhaust heat exchanger in the case of cogeneration.

Key strengths/attractiveness

1. As for 'natural gas and LPG generation' previously
2. High efficiency usage of fuel energy.

3. Separately despatchable electrical and thermal energy generation through engine control, within limits.

Drawbacks/limitations

1. As for 'natural gas and LPG generation' previously
2. Higher capital cost and complexity than conventional burners or boilers, making financial analysis sensitive to more inputs. This is particularly the case for trigeneration.

1.8. Battery and thermal energy storage

Description of technology

There continues to be a great deal of interest in battery storage as a potential means of accommodating the intermittency of renewable power generation, particularly that of solar PV and wind. Numerous forms of battery storage are being considered across a range of scales. Some of these batteries are proposed to balance large parts of the grid, or an entire, large wind farm. Others are much smaller, and are intended to allow a small site to operate 'off grid' or avoid export to the grid.

These different battery technologies include the most advanced, such as lithium-ion batteries, as well as some of the most established, like lead-acid batteries. Each of these different technologies has different technical characteristics and financial performance.

Level of maturity/deployment

Battery storage is a long standing and widely used means of storing electricity from stationary power plant. Today, such systems are most commonly used in remote areas, where a diesel generator and a battery bank commonly provide reliable power in the absence of an electrical network.
Adoption of distributed power generation with battery storage is highly sensitive to the full cost of delivering diesel to the site and the absence of the electricity network. Depending on location, diesel fuel cost can be much higher than prices in urban areas, thereby justifying the additional capital cost of the battery and its integration.

Latest developments/innovation

Renewable forms of power generation, in particular solar PV, are also being increasingly integrated into these *remote area power supplies* (RAPS) since delivery of diesel fuel is often expensive and the remote area is often one of good solar resource.

Key strengths/attractiveness

1. Enhanced reliability in regions with less reliable network infrastructure: this may be a particularly significant benefit if stock values are large and frequently exposed to such risks.

Drawbacks/limitations

1. Cost: whilst there are a wide range of costs for different battery technologies, the cheapest of those that are deployed have an estimated levelised cost of at least roughly 100-200 $/MWh [26]. Since this is similar to typical differences between peak and off-peak energy prices, we expect the economics of on farm battery storage to be marginal.

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1.9. Chilled water energy storage

Description of technology

An alternative to on farm electrical energy storage is the use of chilled water or ice, including ice slurries. These forms of energy storage typically make use of refrigeration plant and large storage tanks. Different vegetables are either bathed in these tanks during their cooling, or water from these tanks is sprayed onto produce in cool rooms.

Level of maturity/deployment

Since chilled water storage appears to be well understood and widely practiced by growers already, we do not propose to analyse it further in this report.

1.10. Micro-hydro systems

Description of technology

Hydropower is of course a very old technology, with water wheels being one of the main, pre-industrial forms of power generation. The world's first hydroelectric power plant went into operation in 1878 in the UK, and large scale deployment occurred in parallel with electrification in the 19th and 20th centuries, e.g. the famous Mohne Dam of 'Dam Busters' fame in Germany (early 20th century) and the Hoover Dam in the US (1930s) [2,3,4].

Hydroelectricity is electricity derived from the movement of water. This movement may involve changes in elevation and thus the water's potential energy, or the energy may be extracted from the water's kinetic energy. In either case, the mechanical energy of the water is imparted to a turbine which, in turn, is connected to a generator that produces the hydro-electricity.

Hydroelectricity is the largest source of renewable energy globally, accounting for roughly 90% of all renewable electricity [19]. As of 2011, roughly 16% of global electricity generation came from hydroelectricity. Further, globally installed capacity has grown significantly in recent years, particular due to new, large plants in China, which is now the largest hydroelectricity generator in the world. In contrast, Australian hydroelectric generation has remained relatively flat for some time now.

Hydroelectricity is the most despatchable of all commonly used power generation technologies, including fossil plant. It is increasingly seen as complementary to other renewables in reducing resource intermittency.

Hydroelectric power typically takes one of the following forms:

1. *Conventional* dammed hydroelectricity: the most common of the large scale forms of hydropower.
2. *Run-of-the-river* hydroelectricity: makes use of the kinetic energy in flowing water.
3. *Micro-hydro*: which are typically up to hundreds of kilowatts in capacity.
4. *Pumped storage hydroelectricity*: stores energy in the form of water pumped to higher elevations during periods of low demand, such that it can be released when demand is high.

Micro-hydro, either as a net generator or as a source of on farm, pumped storage, is the relevant form of power generation for this project.

Level of maturity/deployment

Pre-industrial forms of (mechanical) power generation would be called micro-hydro today! As a result, the numerous types of micro-hydroelectric plant in existence are mostly very mature technology. As with fuel cells, the invention of micro-hydroelectric power generation predates that of all of the devices that dominate power generation today.

Latest developments/innovation

Relative to other forms of on farm power generation, particularly for the other renewables, there appears to be no significant step-change developments in micro-hydro.

Key strengths/attractiveness

1. Highly despatchable: power can be modulated very quickly, *provided that water is available*, meaning that it is well suited for compensating intermittent renewable energy.

Drawbacks/limitations

1. Uncertain financial performance that is likely unviable given low level of deployment: difficult to determine resource availability for a smaller site since water availability is highly localised and variable.
2. Installation costs of micro-hydro power generation are highly site specific.

Finally, micro-hydro's still low level of deployment, particularly compared to large scale hydro and other forms of renewable power generation of comparable scale, suggests that the economics of micro-hydro remain uncompetitive. They were therefore not further analysed in this project.

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2. Deployment of on farm power generation technologies by vegetable growers

Section 1 concluded that there were four broad types of power generation that could be viable as on-site power generation options for vegetable growers in Australia: wind power, solar PV, woody biomass and gas generation with reciprocating engines including co-generation/combined heat and power (CHP) plants or trigeneration.

With the exception of trigeneration, these technologies are already being used in the vegetable growing sector or other agricultural sectors in Australia or other countries. Selected examples of deployment of these technologies are discussed below to illustrate their usage in horticulture or related sectors.

Whilst data on the penetration of on farm power generation technologies are not readily available, it is clear that in some countries on-site power generation is widespread (for example, in the Netherlands) whilst it is less common in other countries. Factors that drive the uptake on on-site power generation are varied and decisions are specific to growers and local conditions. Of course, growers will install power generation on-site where it is cost effective to do so, although it is often not simple to analyse this. However, the key factors that influence growers in adopting these technologies include:

- Financial performance of on-site power generation options, relative to network supplied electricity;
- Economic incentives to install on-site power generation: Government subsidies to purchase equipment, incentives to generate and/or export power (such as feed-in-tariffs) or simply high retail electricity prices which make alternatives more attractive;
- Availability, quality and affordability of energy resources or fuel: for example, good solar radiation or wind resources, access to affordable natural gas or LPG and availability of quality woody biomass;
- Ease of obtaining approvals and meeting regulatory requirements for power generation: local community and Government support and clear processes for obtaining approvals are enabling for all forms of power generation;
- Desire to make farming operations more sustainable: motivation to reduce carbon footprint and/or a commercial imperative to improve ‘green credentials’ to satisfy customer demands; and
- Desire to decrease dependence on external providers: recent rises in electricity prices and using energy exports to supplement income from vegetable growing activities can make on farm power generation a sensible risk management measure.

2.1 Solar power

2.1.1 Australian deployment

A number of growers and other farmers have already installed on farm solar PV, with two examples described below. A greenhouse in South Australia which has trialled the application of solar thermal technology to produce tomatoes, capsicums and cucumbers is also described briefly below.

Linton Brimblecombe, Lockyer Valley, Queensland

In 2010, Lockyer Valley vegetable grower, Linton Brimblecombe installed a 30kW solar plant on his farm. Rather than install solar panels on farm buildings or sheds, Linton and his brother worked with an engineer to connect a single axis tracking plant which tilts the panels to track sunlight over a day and hence maximise the power generated.

At the time of his investment, the Queensland Government offered feed-in-tariffs of 44c/kWh to encourage installation of solar panels under the Solar Bonus Scheme [32]. These feed-in-tariffs are legislated to run until 2028, so any electricity exported from Linton's solar system attracts this rate provided he remains eligible for the Solar Bonus Scheme. Linton is investigating installation of further solar capacity, however as incentive schemes have changed significantly, the new scheme will not attract the same feed-in-tariff. The present and potential future solar systems on Brimblecombe operations will be analysed later in the project.

The Loose Leaf Lettuce Company, Western Australia

The Loose Leaf Lettuce Company in Gingin has worked to reduce energy costs over a number of years, with their latest project the installation of a 100kW solar PV system in December 2013. Maureen Dobra of Loose Leaf Lettuce Company worked with solar energy company, Solargain, and an energy consultant to determine the right system for her energy needs and to cost effectively offset her power bill.

Network rules in Western Australia mean that systems with inverter capacity over 30kW are not allowed to export excess power to the grid so the system includes reverse power protection, installed by a registered electrical engineer. 400 polycrystalline panels have been installed on sheds in an east/west orientation which, although reducing overall power output, will produce a less 'peaky' or flatter production curve so that more of the energy produced by the system can be consumed on site over the whole day.

The system is anticipated to produce around 160,000 kWh per year which will offset up to half of the energy needs of the Loose Leaf Lettuce home farm operations. The system has been operational since late February and was analysed as part of the Loose Leaf case study. Anecdotally, the solar panels are already having a significant impact on peak consumption.

Sundrop Farms, Port August, South Australia

Sundrop Farms established a commercial trial of an innovative greenhouse growing system in 2010. The Sundrop system uses solar thermal technology to desalinate seawater for irrigation and to provide power and heat [33]. The greenhouse in Port Augusta, South Australia, has been growing tomatoes, capsicums and cucumbers using this method [34]. In August 2013, the Clean Energy Finance Corporation (CEFC) announced in-principle agreement to co-finance an expansion of the Port Augusta trial to demonstrate a 20 hectare greenhouse facility using the same technologies [35].

2.1.2 International deployment

In the UK, it is estimated that at least one-third of the nearly 3GW of solar PV capacity installed since 2010 has been in the agricultural sector [36]. In the US, a 2009 survey of renewable energy on US farms found that more than 7200 farms had installed solar PV panels with about a quarter of these installations in California [27]. Given the significant incentives in place to encourage investment in renewable energy technologies since 2009, this number is likely to have grown substantially. Many other countries have invested heavily in solar PV, including Germany and Spain, and there are examples from many countries of vegetable growers and processors installing solar power to offset energy costs.

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Alan Bartlett & Sons, Cambridgeshire, UK

In March 2013, Alan Barlett & Sons, a large carrot and parsnip grower and processor in Cambridgeshire UK, installed a 1.2MW solar system consisting of more than 4000 solar panels on the 30,000sqm roof of their large processing plant in Chatteris. In the process, the installation became the largest privately owned, roof-mounted solar PV installation for self-use in the UK [37].

The owners of the business invested in solar energy to lower energy costs and because their supermarket customers always “challenged [them] to reduce energy use” [37]. After evaluating wind and solar power, they selected solar power based on attractive economics: with incentives and feed-in-tariffs, it was self-financing from year one. In addition, a solar system could be installed quickly, without planning permission.

The system was installed for self-use of the energy produced. The processing and packing plant is a major consumer of electrical energy, running 24 hours and with about three quarters of the energy consumed during the day. The owners anticipate the system will offset around 20% of its energy needs. They cannot export energy to the grid in the event that they generate excess energy; a nearby wind farm of 12 turbines has restricted their ability to do so, due to concerns that too much energy could be pumped into the grid.

The business financed 20% of the investment, with a fixed, low interest loan covering 80%. To give maximum return from the UK incentives for renewable energy, subsidies for the 1.2MW solar system were split so that 250kW attracted the highest generation feed-in-tariff of 11p/kWh and 950kW was eligible for the ROC (Renewable Obligation Certificate) which is traded on the market with rates typically 9-14p/kWh. In the first year of operation, the owner anticipates that the system will earn £180,000-185,000 from reduced energy bills and income from the FiTs and ROC, whilst the loan repayment will be £145,000 [37].

Grimmway Enterprises, Bakersfield, California, USA

In 2010, Grimmway Enterprises Inc, one of the world’s largest carrot growers, installed a 233kW solar PV plant at one of their farms in Arvin, California. The solar array offsets more than 50% of the energy use at the pumping plant on this site [38]. In 2012 and 2013, Grimmway worked with Conergy Projects Group again to install an additional four solar plants in their Californian operations totaling 4.5MW capacity [39].

Three new solar installations were completed in late 2012 at sites in the San Joaquin Valley and construction of the fourth installation was completed in July 2013 at Grimmway’s Mountain View location. Each installation has capacity of approximately 1.1MW and features nearly 5,000 solar modules [39]. It is expected that these solar plants will generate roughly 30% of Grimmway’s total energy demand and significantly reduce electricity costs [40].

‘Solar sharing’ in Japan

Some small scale growers in Japan are pioneering ‘solar sharing’ combining food cultivation and energy generation. Solar PV panels are mounted above vegetable crops at specific intervals and angles on specially designed structures. The structures, made of pipes and panels and similar to a garden pergola, allow sufficient sunlight for photosynthesis of crops and are designed to accommodate agricultural machinery [41].

At the 34.4 kW Kazusatsurumai Solar Sharing Project in Chiba Prefecture, the grower installed 348 PV panels 3 metres above his small vegetable crop. The PV system produces about 35,000kWh each year and cost 12.6 million yen (~ AUD$140,000) to install. The system attracts a FIT rate of 42 yen/kWh for

20 years, earning 1.6 million yen (~AUD$17,500) annually, dwarfing the income stream from farming of 100,000 yen (~AUD$1,100) [41].

2.2 Wind power

There are several different models or options for on-site wind power for vegetable growers today, as illustrated by the uses of wind power by vegetable growers described below:

- The most common application is small to medium scale turbines (often single turbine installations) for self-use, connected behind the meter.
- However, some growers have chosen larger capacity installations that they use in energy consuming processes on the generation site as well as 'wheeling' excess power to other properties in their operations.
- A third alternative is for growers to install turbines on their land and feed directly into the grid – either as a standalone generator or, more commonly, as part of a larger wind farm with turbines on multiple sites. Arrangements can vary significantly from payment to wind energy provider for lease of turbine site only, to power purchase agreement with the energy provider through to outright ownership and operation of the turbines and participation in the grid as a small generator.

Wind power is most suitable for growers with significant loads on site which can be offset by wind generation where the demand is consistent throughout the year and where power requirements are around-the-clock. In addition, wind power is feasible where there is a suitably windy site for the turbine close to existing power infrastructure, which is often not the case for many growers and farmers.

2.2.1 Australian deployment

The experience of growers in Australia who have evaluated or who are operating wind power is that unless the possible site for the turbines has excellent wind resources, it is most economical to install small to medium scale wind turbines for self-consumption. In addition, it is interesting to note that the Australian growers we interviewed have all installed re-conditioned second-hand turbines and that installation of new turbines was not considered economic.

West Hills Farm near Lancelin, Western Australia

Large Western Australian vegetable grower Sumich has installed 5MW capacity at their West Hills Farm near Lancelin. The processing plant at the West Hills Farm processes and packs more than 1000 tonnes of carrots each week and is a significant consumer of energy.

Commissioned in two stages in 2012 and 2013, the wind generation facility comprises ten 500kW Enercon E-40 turbines which were sourced second-hand from Italy when an operating wind farm was being re-powered. The turbines are estimated to generate between 60-90% of the energy required on the West Hills farm site. The processing plant uses around 80% of the wind power generated on site with any excess exported to the grid (or wheeled across the network to other Sumich properties).

Sumich worked with Blair Fox, a Perth-based renewable energy project developer, to develop and construct the wind farms. Blair Fox provided project management, including construction of the wind farm, management of the network connection and obtaining all approvals. Blair Fox has an ongoing role in operating the wind farm infrastructure, including maintenance and asset management.

Sumich and Blair Fox have also partnered to establish another 5MW wind farm to the east of Lancelin at Karakin. It has a similar configuration to the West Hills farm with the wind farm embedded within an existing agricultural load. However, the turbines sites are leased from local growers. The wind farm consists of 10 Enercon E40 500kW turbines and electricity is utilised by local properties.

Robert Nichols in Sassafras, Tasmania

Robert Nichols is a poultry producer and grower at Sassafras in Tasmania where he runs Nichols Poultry and grows poppies and vegetables on 620 acres. The on-site poultry processing plant is a significant consumer of energy and after significant research into wind power over a number of years, Rob installed a 225kW wind turbine in 2008 to provide power for his poultry factory.

Rob chose to install a second-hand Vestas V27 turbine from Denmark since he estimated that a second hand turbine would have a payback period of around 5 years compared to 15 years for a new turbine. He sourced and dismantled the turbine, and shipped it to Tasmania where it was re-conditioned and re-commissioned.

As is common with embedded wind generation, the location of the turbine was a compromise; the turbine is sited 70 metres from the factory which is not the ideal location for maximum generation but enables the turbine to plug directly into the factory switchboard. Whilst the capacity factor is "not brilliant", it is still economic for energy generation. Initially the wind turbine supplied around 50% of the energy needs of the factory but as demand has grown at the site, it currently generates around 35% of the energy demand. The factory uses all of the power generated with around 70% consumed at time of generation; the excess energy that is fed into the grid is later bought back, paying the local provider network and distribution charges.
Rob has subsequently established another business, Blowing in the Wind Pty Ltd, which procures, constructs and maintains medium scale wind turbine generators. Blowing in the Wind has assisted with installation of three additional turbines, at Sisters Creek, Wesley Vale and on Flinders Island. The business works with clients to procure and construct the turbine as well as securing all approvals and meeting grid and regulatory requirements, and provides ongoing maintenance of the turbines.

Andrew Nichols in Sisters Creek, Tasmania

Andrew Nichols runs a 1500 acre property in Sisters Creek raising chickens and beef cattle, alongside mixed cropping including canola, vegetables and poppies. A significant part of the business is a chicken hatchery which supplies day-old chicks to Nichols Poultry.

In 2012, Andrew and his son, Michael, worked with Blowing in the Wind (Andrew's brother's business) to install a single 225kW wind turbine to power chicken sheds, the hatchery and an industrial kitchen. The power needs are significant and 24 hour. Andrew was interested in putting in wind power to offset power consumption and reduce power bills and because of a focus on sustainability on the Nichols property.

Similar to the turbine installed at Nichols Poultry in capacity, the turbine tower is different in that it is a lattice design which is easier and cheaper to dismantle and re-assemble. The turbine was installed in 2012 and has been operating for around 18 months. The turbine has reduced energy consumption at the switchboard significantly with savings of $3,000-4,000 per month. Michael anticipates that the pay-back period will be around 5-6 years at current performance.

2.2.2 International deployment

In the United States, a 2009 survey of renewable energy on US farms found that around 1400 farms had installed just over 1800 wind turbines, with the vast majority (99%) less than 100kW in capacity [27].

In the UK, just over 23,500 small to medium turbines had been installed across the country to the end of 2012 with total capacity of around 102MW [28]. Individual units ranged from micro turbines (0-1.5kW) up to medium turbines (100-500kW) for both off-grid and on-grid applications. The majority of the turbines installed are very small turbines (1.5kW or less) with only 46 turbines in the medium range. Of the total, just under two-thirds or around 15,000 turbines were installed on farms [29].

Vine House Farm, UK

Bird seed and organic vegetable grower Vine House Farm in Lincolnshire (UK) has installed wind power, solar PV and a biomass boiler on their farms as part of their commitment to the environment and sustainability. They have two types of wind turbines, operating under different models:

- In 2006, Vine House Farm installed three 2MW wind turbines which feed directly into the national grid; they are part of the 16MW Deeping St Nicholas wind farm, which consists of eight 2MW turbines on two sites [30].
- In 2012, Vine House Farm installed two 75KW wind turbines on their farm at Baston Fen for self-use [30].

In addition, at three of their farm sites, a total of 200kW of solar panels was installed on south facing farm buildings. Excess energy not used on the farms is fed into the grid. Since 1980, the farm owner has also operated a biomass boiler fed by straw, cardboard and wood to heat the farmhouse and offices [31].

2.3 Gas generation with reciprocating engines: Cogeneration and trigeneration

The use of cogeneration or combined heat and power (CHP) in large commercial greenhouses is widespread in the Netherlands and is also present in some other countries, with growers generating power and heat on-site. Profitability of gas-fired cogeneration systems is driven by the difference between the natural gas purchase price and electricity sale price. When the selling price of electricity exceeds the price paid for natural gas by an amount that covers the costs of operating the cogeneration system, the system becomes profitable. Dutch greenhouse growers maximise profits from cogeneration by operating their cogeneration engines when the difference between gas purchase price and electricity sale price is greatest [42].

The cogeneration plants are commonly fired by natural gas or LPG but can also be fired by other fuels, such as woody biomass. The plants produce electricity for the greenhouse operations and any associated processing plants on the same site as well as heat and hot water to maintain appropriate greenhouse temperatures. An additional by-product from the exhaust of a gas-fired generator is CO_2 which is scrubbed (or cleaned of other gases and pollutants) and injected into the greenhouse to promote plant growth.

One study conducted in 2010 estimated that greenhouses in the Netherlands produced around 10% of the power in that country [42]. Large greenhouse tomato grower, Royal Pride Holland, installed an 8MW cogeneration plant in 2008 at their 45 hectare greenhouse and reported a 20% reduction in production costs since installing the engines [42].

Cogeneration has also been adopted in the UK by greenhouse growers. Thanet Earth, a partnership between the UK's largest fresh produce supplier and several Dutch growers, is one of the UK's largest greenhouse complexes and produces capsicums, tomatoes and cucumbers. At least five cogeneration units with capacities ranging from 2.4MW to 3.3MW each provide power, heat and CO_2 to the greenhouses [43]. The Tangmere Airfield Nursery near Chichester, West Sussex, is one of Europe's largest capsicum greenhouse nurseries and operates natural gas fuelled CHP plants [43].

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Canadian and US tomato growers have also installed co-generation facilities, such as the 12MW cogeneration plant at Great Northern Hydroponics' greenhouse tomato operation in Ontario, Canada [42] and the 8.8MW CHP unit at Houweling's Tomatoes Camarillo greenhouse in California [44].

Cogeneration has been not commonly used in protected cropping in Australia to date. We are aware of two greenhouse tomato operations using cogeneration. For example, a cogeneration plant at tomato grower D'Vine Ripe in Two Wells, South Australia runs on natural gas to produce electricity, heat and CO_2 for one of the largest protected cropping horticulture operations in Australia [45,46]. Some growers are using LPG or biomass boilers to generate heat and/or CO_2, but not electricity.

We are not aware of any growers globally using trigeneration. Nonetheless, this may be more attractive in Australia than Europe, where cogeneration is more widely practiced, given our hotter climate.

3. Attractiveness of technologies in major Australian vegetable growing locations

In this section, we look top-down at the attractiveness of the viable on farm power generation technologies identified in Section 1 in major vegetable growing locations around Australia. Section 2 summarised six key factors influencing adoption of on-site power generation technologies:

1. Financial performance of technologies;
2. Economic incentives, such as subsidies, feed-in-tariffs and high retail electricity prices;
3. Availability, quality and affordability of energy resources or fuel;
4. Ease of obtaining approvals and meeting regulatory requirements for power generation;
5. Desire to make farming operations more sustainable; and
6. Diversification of energy sources and potentially income as a risk management measure.

A number of the factors listed above will be site specific as well as specific to the operations of a particular grower; however, it is profitable to briefly examine some drivers of adoption across Australia: namely, economic incentives, availability and affordability of energy resources and ease of obtaining approvals.
Factor 1 above, financial performance of different on-site power generation technologies, is examined in detail under Task 3. Previous analysis conducted for project VG12049 in 2013 indicated a wide range of financial performance for the relevant technologies and that the technologies would only compete against retail electricity under the most optimistic or favourable conditions. Suffice to say, the cost of the generation plant is key to this financial analysis and for some of these technologies (e.g. solar panels), plant cost has been rapidly declining. In addition, there may be options to reduce plant cost by installing reliable second-hand plant (e.g., wind turbines, CHP plant or natural gas engines).

The last two factors (sustainability and risk management) pertain to a particular grower's motivations and situation and were not examined in this report.

AHR provided Parkside Energy with data on vegetable production by location across Australia. From this data, Parkside Energy worked with AHR and the project's grower representative to identify a set of locations that, whilst not exhaustive, would account for a significant proportion of vegetable growing in Australia across a range of locations. These locations are shown in Table 2 which appears later in this section.

3.2 Economic incentives for on-site power generation

The Australian Energy Regulator publishes information about retail energy prices annually in its State of the Energy Market report. Retail electricity prices have risen significantly over the last 5 years, with increases of 64% in real terms (87% nominal) in the 5 years to 2012-13 [18]. Whilst the analysis is focused on residential and small business customers, larger commercial customers would have experienced similar price rises. These rapid increases have set the scene for consideration of alternatives and hence have created a more attractive environment for on farm power generation options.

Feed-in-tariffs for exporting excess energy generated to the grid vary by jurisdiction and historically there have been significant differences between jurisdictions. For example, the Victorian Premium Solar Feed-in-Tariff Scheme, which closed in September 2011, provided 60c/kWh to customers exporting solar power with a system less than 100kW [47]; the NSW Solar Bonus Scheme paid 60c/kWh (gross metering) or 20c/kWh (net metering) [48]. Schemes in South Australia and Queensland provided feed-in-tariffs of 44c/kWh [49,32].

However, the significant differences in feed-in-tariff rates have to a large extent disappeared in the last 2-3 years and rates for most states and territories (with the exception of NT) have converged on 6.5-8.5c/kWh [50,51,52]. There will likely be further changes to these rates, for example the Queensland Government has announced that from 1 July 2014, there will be no regulated feed-in-tariff for customers in South East Queensland. Instead, customers will need to negotiate voluntary feed-in-tariffs with retailers who are offering tariffs of 4-10c/kWh [32]. NSW also has a voluntary feed-in-tariff scheme with benchmark rates published annually to assist consumers in selecting retailers' offers [53]. Most of the state-based schemes are for small-scale systems of 5-10kW, although some cover systems up to 100kW. Some of the schemes extend feed-in-tariffs to wind power, whilst others are exclusively for solar PV installations. These schemes are examined further under economic analysis of on farm power generation for growers.

The Renewable Energy Target (RET) was established to encourage installation of renewable energy generation capacity by providing financial incentives for renewable energy generation. Split into two different schemes covering small scale and large scale generation, the RET creates tradable certificates based on actual generation (MWh) by renewable generators and an obligation for liable market participants to purchase and surrender a certain number of these certificates each year. The certificates typically trade around $35-40/MWh although can vary from $10-60/MWh on a daily basis [54]. This scheme is currently under review by the Federal Government, hence there is significant uncertainty about its future. Any change in the scheme could have a significant impact on the attractiveness of investing in renewables.

Some growers may be able to access specific grants for renewable installations from either national or state based granting organisations. However, these are not traditional incentives or subsidies, and applications have variable success rates. A number of these schemes were described in detail in project VG12049, although some have since been closed or are under review.

3.3 Availability and affordability of energy resources and fuel

3.3.1 Currently installed capacity of different technologies in growing regions

Section 1 of this report showed that the following forms of **distributed** power generation are significantly deployed in different sectors around the world: solar PV, natural gas and LPG generation, wind turbines and biomass generation. We therefore consider them to be plausible options for on farm power generation given the appropriate circumstances. Of these, solar PV and wind turbines are already widely installed in Australia and are being used by some vegetable growers, as discussed in Section 2. Natural gas or LPG power generation and woody biomass power generation do not appear to be in significant use by growers.

The Clean Energy Regulator (CER) maintains a register of all forms of power generation that qualify for inclusion in the Renewable Energy Target (RET) [6]. The Renewable Energy Target (RET) is split into the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES).

Eligible technologies in the SRES include three technologies considered in Section 1 of this report:

1. Solar PV up to 100kW in capacity
2. Small-scale wind up to 10kW in capacity
3. Small-scale hydro systems up to 6.4kW in capacity

These three technologies create Small-scale Technology Certificates (STCs) as part of the RET. Data for the number of installations and their total capacity is available by post-code [6,7], thereby showing how widely deployed these technologies are in different growing regions.

Table 2 shows the estimated percentage of *all dwellings in that post-code* with solar PV installed in different growing regions [6,7]. (Note that multiple regions may have the same post-code, and that this data is for all dwellings and not just farms, vegetable or others.) There are significant variations nationally, with parts of Queensland, South Australia and Western Australia featuring more than a quarter of dwellings with solar PV. Unsurprisingly, Tasmania has the lowest levels of deployment given its lower levels of solar irradiance.

Location	Post code	Dwellings with PV (%)
New South Wales		
Bathurst	2795	10.4
Cowra	2794	9.6
Mangrove Mountain	2250	10.8
Queensland		
Bowen	4805	14.6
Bundaberg	4670	24.4
Gatton	4343	26.9
Kalbar	4309	32.8
Wallaville	4671	22.2
Tasmania		
Devonport	7310	6.0
Scottsdale	7260	9.8
Sisters Creek	7325	6.7
Smithton	7330	2.9

Location	Post code	Dwellings with PV (%)
South Australia		
Murray Bridge	5253	25.6
Virginia	5120	37.7
Victoria		
Cranbourne	3977	14.4
Longford	3851	14.7
Maffra	3860	15.3
Mildura	3500	7.8
Werribee	3030	13.1
Western Australia		
Carnarvon	6701	5.9
Gingin	6503	18.5
Lancelin	6044	10.5
Mandurah	6210	25.4
Manjimup	6258	9.6

Table 2: Percentage of dwellings with solar PV installed in different growing regions [6,7]

The CER data [6] shows negligible registration of small-scale wind and small-scale hydro. We think that this is not surprising for two different reasons. First, the capacity limit of 10kW for small-scale wind is much smaller than almost all wind turbines deployed in Australia, including those currently deployed by growers and discussed in Section 2 of this report. Thus, if these wind turbines are registered with the Clean Energy Regulator, they will qualify for Large-scale Generation Certificates (LGCs) rather than STCs.

Second, we found no evidence that hydro power was in significant use by growers. This is consistent with our understanding of its cost, particularly relative to solar PV and wind, as discussed in Section 1. The negligible registered capacity of small-scale hydro with the CER [6] supports this.

3.2.2 Availability, quality and affordability of different energy sources

The availability, quality and affordability of energy resources or fuel for each of the four plausible forms of on farm power generation are now considered.

Solar PV

Table 2 showed that solar PV is already widely deployed in Australian vegetable growing regions, but with significant variations nationally. Figure 4 shows the corresponding national variations in annual solar exposure, which quantifies the available solar resource. South-Eastern Queensland, Central South Australia and South-Western Western Australia are the vegetable growing regions with the best solar resource, and all of these regions already have significant solar PV deployment. Similarly, Tasmania has the lowest solar exposure and the lowest levels of deployment. This demonstrated relationship between the available solar resource and deployment is clear and fundamental.

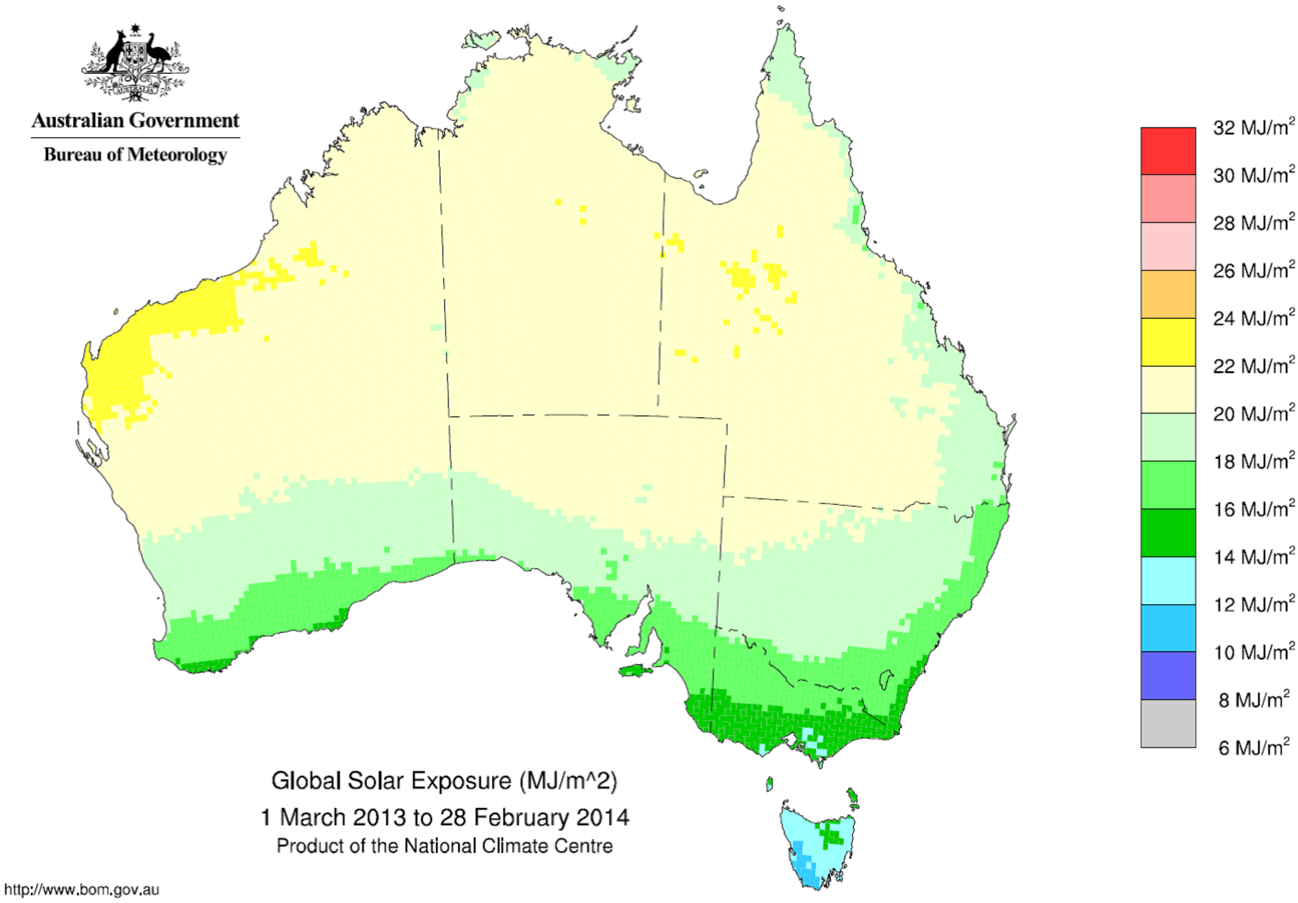

Figure 4: Annual, global solar exposure across Australia [55]

However, variations in deployment are not solely due to solar resource availability. An example of this can be seen from the Victorian data, with Mildura having a lower deployment than suburbs in greater Melbourne such as Cranbourne and Werribee (Table 2), even though Figure 4 shows that Mildura has greater solar resource availability. Similarly, in Western Australia, Mandurah has a significantly higher deployment than Lancelin even though it should have a marginally worse solar resource.

These differences are expected to be due to socio-economic factors, since two regions in the same state will have the same history of incentives. Similarly, historical and geographic variations in feed-in tariffs are also expected to have a large effect on deployment, as discussed later in this Section of the report. As a result, care must be taken when determining the importance of solar resource availability in different growing regions relative to other factors, with such analysis beyond the scope of this present report. Nonetheless, the significant levels of currently installed solar PV capacity in growing regions is a strong indicator of its potential for growers in particular regions.

Natural gas and LPG generation

LPG is delivered by truck across Australia to both service stations and many other sites. Any levy-paying grower should therefore have access to LPG. A typical delivered price of LPG is 75-85 c/L, which corresponds to $33-37/GJ; however, prices can vary significantly and some growers may be paying as much as 125 c/L. Fixed annual charges are also levied for on-site storage facilities with these fixed charges usually a small part of the total cost of LPG use.

Representative prices for networked natural gas are more difficult to determine for two reasons. First, few growers appear to use networked natural gas, thus making bill data difficult to obtain. Second, the tariffs for networked natural gas are complex and depend significantly on the scale and location of the consumer.

The most accessible data on the cost of networked natural gas is for *small energy customers*, whom the National Retail Energy Laws [56] define as consuming 1TJ p.a. (32kW thermal continuous) of natural gas. These Laws also require retailers to make prices publically available. A survey of these published retail prices, for example [18], shows that retail natural gas prices vary significantly with level of consumption even for small energy customers. A typical Victorian household consuming 24 GJ of natural gas per year will be charged roughly $30/GJ by Origin Energy, inclusive of all charges. However, if that same customer of Origin Energy consumed at the defined limit for smaller energy consumers of 1TJ, they will be charged roughly $18/GJ, almost half the price [57].

Further, small energy customers pay significantly more for natural gas in Queensland, South Australia and NSW than in Victoria [18]. Retail rates above $40/GJ are not uncommon in Queensland (Figure 5).

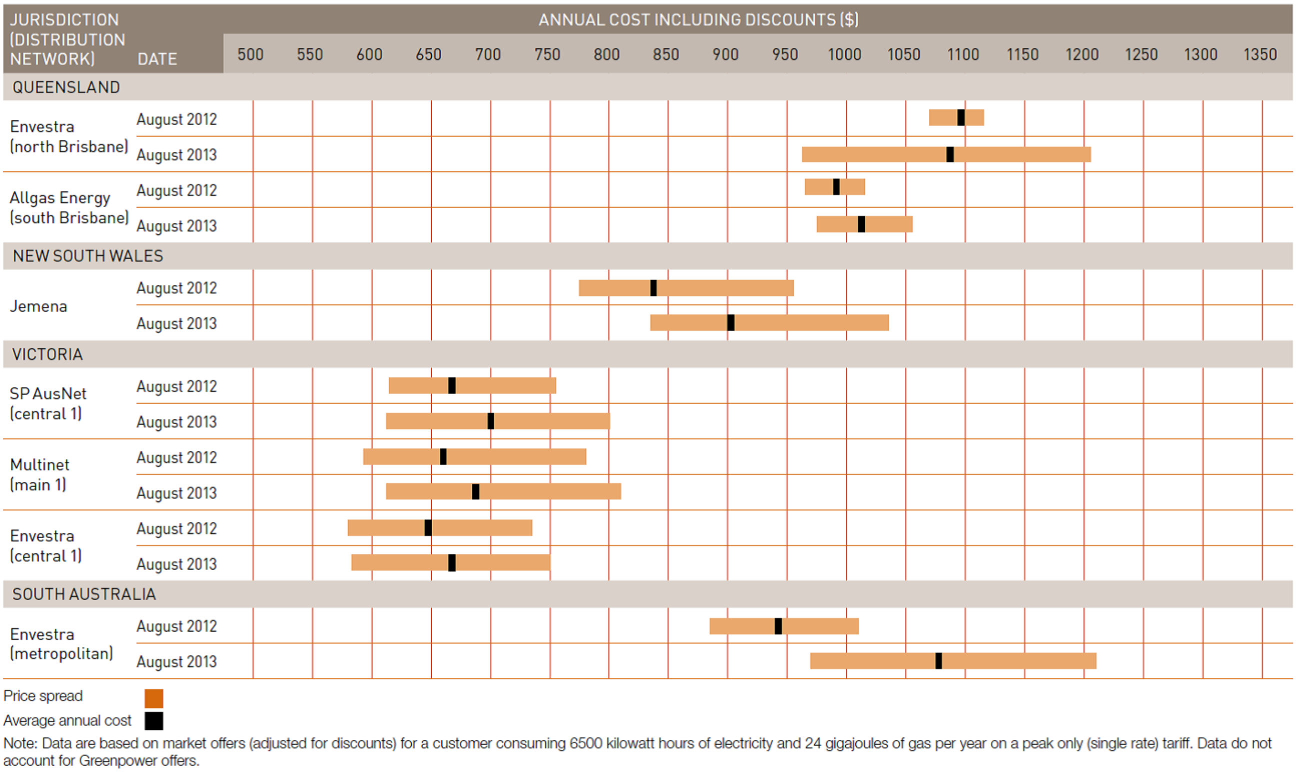

Figure 5: National variations in the annual (August 2012-August 2013) retail cost of natural gas for small energy consumers, assuming 24 GJ p.a. consumption [18]

These small energy customers will be almost entirely residences and small businesses. Few growers are expected to be in this class. Anecdotally, however, we are told by retailers that similar economies of scale also exist for larger consumers, although publically available data on this can't be obtained. As a result, we consider that a reasonable rate for networked natural gas for growers will be in the range $10-20/GJ inclusive of all charges, and perhaps less.

Of course, networked natural gas needs to be available at the grower's property, and in many cases it isn't! This is despite the fact that major natural gas pipelines pass through most of the major vegetable growing regions in Eastern Australia (Figure 6), leaving growers with diesel or LPG as their only practical fuel options.

Since most growers should earn the fuel tax credit for on farm use of diesel, it will cost roughly $1/L or roughly $30/GJ excise free. Since diesel fuelled power generation is a very similar technology to that of natural gas or LPG, LPG fuelled on farm power generation does not likely pose significant financial benefits over diesel fuelled generation. The primary use of diesel generators as backup generators suggests that such opportunities are limited.

Thus, a significant opportunity for growers appears to be in gaining access to natural gas at a significantly cheaper price than both diesel and LPG. It remains to be seen whether this will occur, as it is not within the direct control of growers, and rather in the hands of those controlling the natural gas supply chain – government, retailers and distributors.

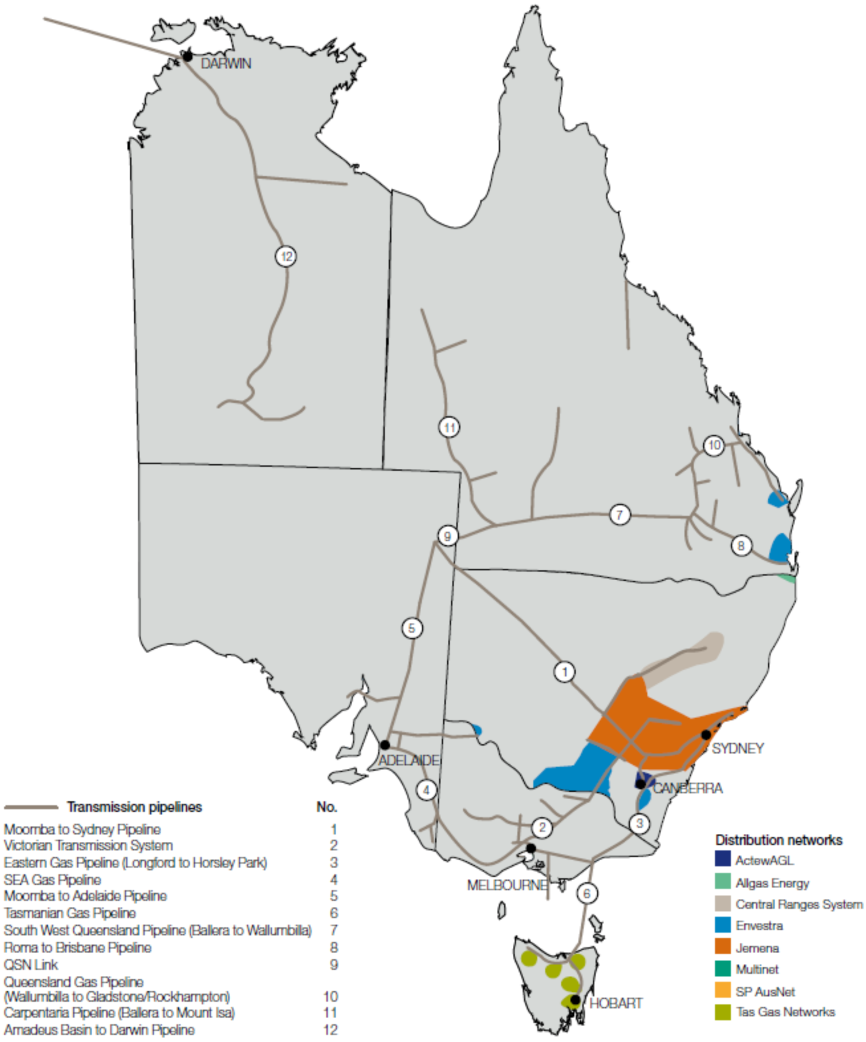

Figure 6: Major natural gas pipelines in eastern Australia [18]

Wind turbines

An average wind speed of 7 m/s is one commonly accepted indicator of a good wind resource, e.g. [58]. Figure 7 shows that such regions are either off-shore or mostly in Western Australia, South Australia, Victoria and Tasmania. Section 2 of this report showed that several growers are already using wind turbines on their farms, and these growers are generally happy with the turbines' financial performance. However, these growers are not necessarily in regions of the best wind resource, and their turbines do not always have what would normally be considered to be acceptable capacity factors. Thus, indicators of resource availability such as Figure 7 appear to have limited value in determining whether a particular grower should install wind turbines on their farm.

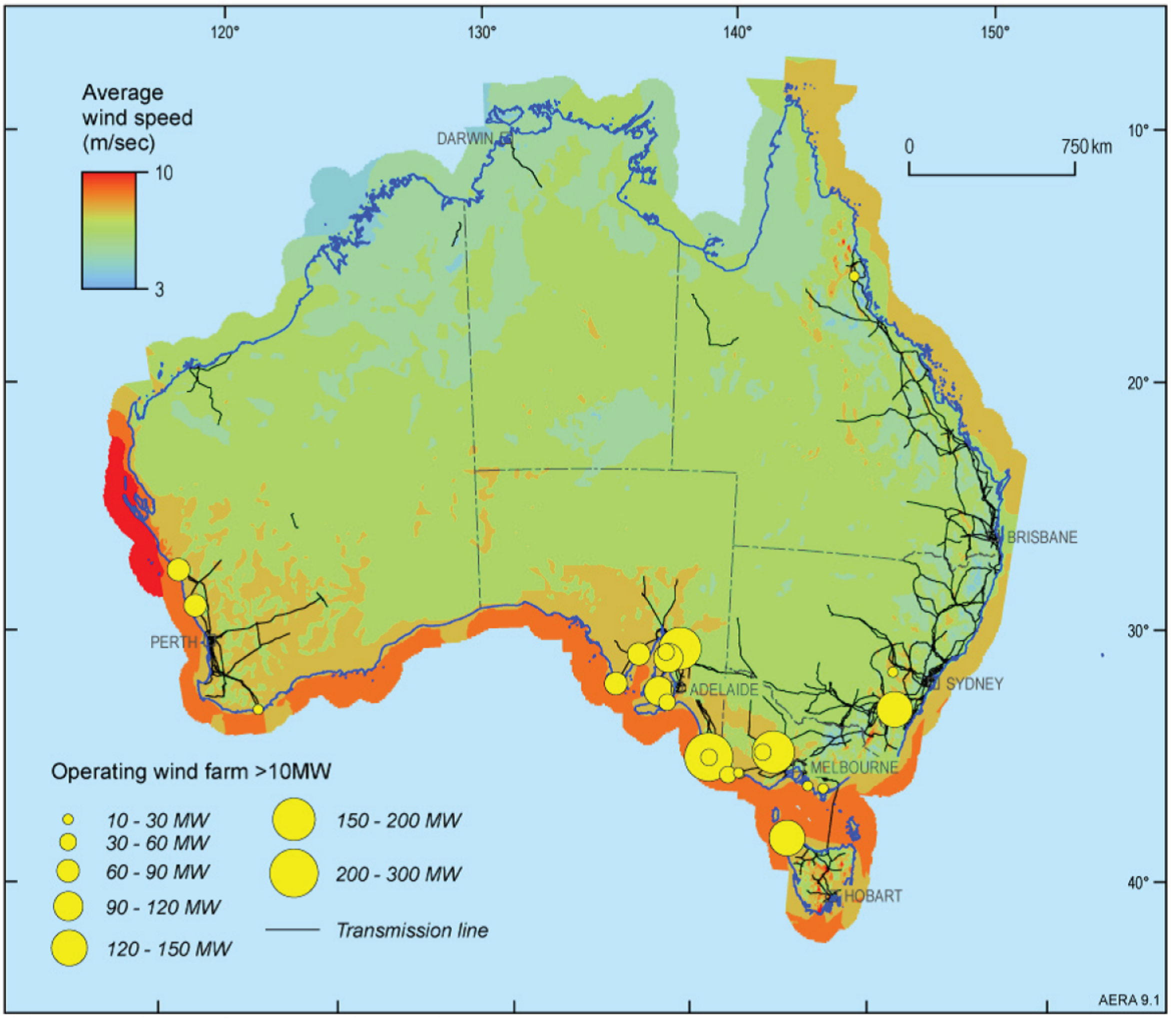

Figure 7: Average wind speeds across Australia [58]

Indeed, as discussed in Section 2, there appears to be two main drivers of the financial performance of on farm wind turbines. First, as discussed in the previous section, growers are often using second hand rather than new wind turbines. Second, in contrast to large wind farms, growers can use the electricity generated by on farm wind to offset their *retail* electricity consumption rather than participating in the wholesale market. These two factors make lower wind speeds and lower capacity factors more acceptable financially.

As a result, it is our view that wind turbines present a significant opportunity for on farm power generation, even in regions that may not have the best wind resource. Of course, such analyses can only be done on a case-by-case basis, and are dependent on the cost and condition of second hand wind turbines.

Woody biomass power generation

The availability and cost of biomass for growers is perhaps the most problematic of the resource assessments in this report, because it depends heavily on their own biomass production as well as that of their local region. On the latter, several studies give favourable assessments of biomass resource availability, with a recent study by CSIRO of particular note [59].

This CSIRO report [59] was commissioned by the Australian Energy Market Operator (AEMO), and divided the National Electricity Market (NEM) region into 43 polygons (Figure 8). (The Western Australian electricity market is not connected to that of the eastern states, and is not shown.) The report estimates the availability of several forms of biomass in each of these regions. A maximum annual amount of electricity that could be generated in each polygon was then estimated by assuming reasonable conversion efficiencies for transforming this biomass into electricity via combustion and a steam turbine.

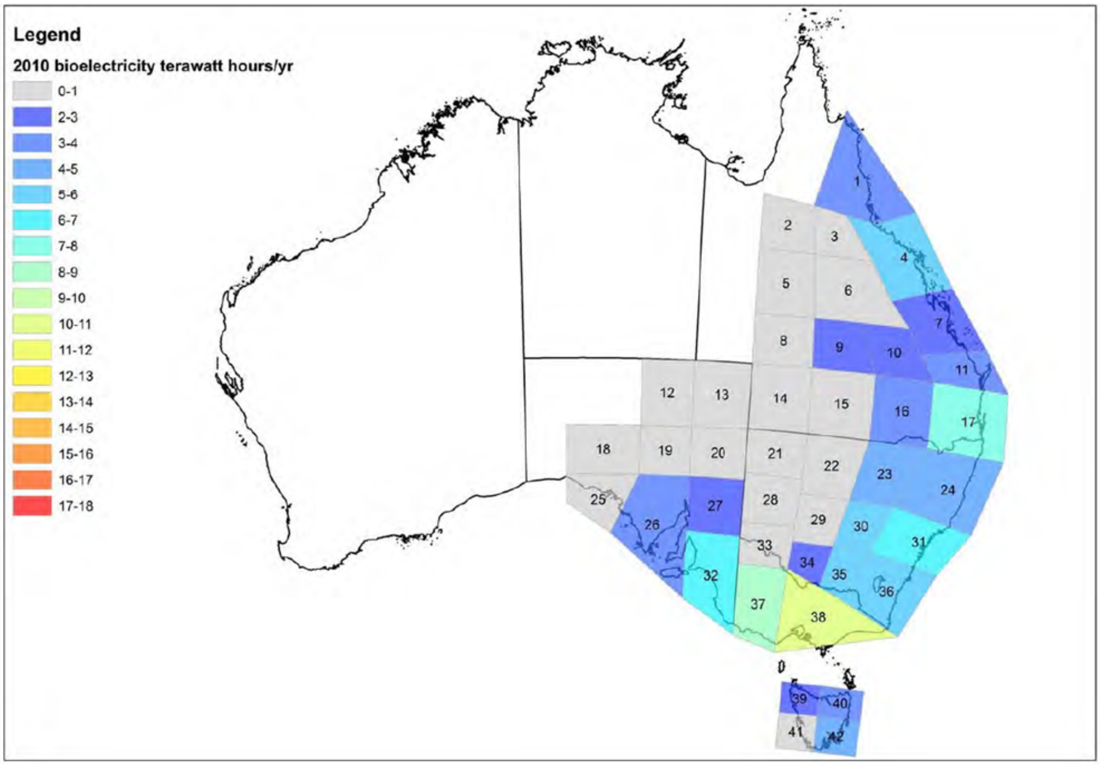

Figure 8: Potential contribution of biomass to electricity generation (TWh/yr) in 42 AEMO regions [59]

Figure 8 shows that the CSIRO report [59] estimates a large amount of biomass resource availability. For example, polygon 38 should contain almost all of Victoria's levy-paying growers, and is estimated to be able to produce 10-11 TWh p.a., which is roughly 5% of the entire NEM's current electricity generation per year. Of course, this CSIRO [59] estimate is an upper bound.

Further, the type and cost of biomass available to a given grower depend heavily on their own biomass production, the production in their local region and the costs of transport. In some cases, waste biomass can reasonably be considered to have zero cost, whilst in other cases it is uneconomically expensive. Given also the discussion in Section 1 on the challenges of generating electricity via steam turbines at the scale of typical growers, and the absence of its deployment amongst current growers in Section 2, we are therefore wary of optimistic assessments of woody biomass as an energy source for growers. Rather, we consider it less likely to be as significant an opportunity as the other three technologies considered in this Section.

3.3 Obtaining approvals and meeting regulatory requirements

For all of the technologies considered, there will be significant approvals required to install and operate on-site power generation. From interviews with growers in Australia and from knowledge of the experience in other industries and countries, these requirements pose significant barriers to adoption and prevent some proposals or projects from completing. Regulatory and local development requirements add cost, risk and time to many projects and delays and uncertainty in outcomes mean some projects do not proceed or are abandoned by the proponent.

Approvals typically required for on-site power generation include:

- Planning or development approval from local government or council,
- Approval from state-based Environmental Protection Authorities (EPAs) or equivalent regarding emissions of power plant (where relevant), and
- Grid connection approvals from the distribution network service provider (DNSP) and/or transmission network service provider (TNSP).

Planning approvals must be sought from local governments or councils for some technologies, including wind power and some stationary power plant, and whilst there is no common process or consistency in what councils require, development applications will examine visual impact, noise impact, environmental impact (impact on plants and animals) and for stationary power plant, air quality impact. In addition, during the planning process, proposals can be challenged and local community or other objections can force the proponent to invest in costly and extensive impact studies which renders the project financially unattractive.

Roof installations of solar panels usually do not require development approvals (with some exceptions) although ground mounted systems may need to be reviewed by council. This can make solar power generation a more attractive proposition for many growers relative to wind or other alternatives.

Stationary engines for power and manufacturing plants, including cogeneration plants, can impact air quality and emissions standards are regulated by state based EPAs. There are no national emission limits for stationary sources; state by state measures vary and are in a state of flux. In addition, there are also variations within states, for example in NSW, there are more stringent NO_x emission standards for natural gas fired co-generation plants in the Sydney and Wollongong Metropolitan Area and Wollondilly Local Government Area than the rest of NSW (250mg/m^3 vs 450mg/m^3) to address air quality issues in these regions [60].
Grid connection requirements are governed by the National Electricity Rules [61]. Customers must apply to the local DNSP or TNSP for grid connection of embedded generation, certifying the technical performance of the plant and a network study may be conducted by the DNSP (for example in the ACT, network studies are required for embedded generation of 30kW or above, at the customer's cost [62]).

The DNSP can also impose additional requirements which add cost to the project, e.g. installation of reverse power protection for plant to ensure that excess power is not exported or technical pre-approval checks for small systems. Anecdotally, grid connection issues vary by location and meeting requirements can be difficult. Uncertainty also increases for technologies which are less commonly installed; solar PV being more widely deployed and accepted would generally have clearer processes and requirements.

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Task 2: Case studies of on farm power generation

Summary

This report presents 5 case studies in which the technical and financial performance of different forms of on farm power generation are analysed. These include two case studies where growers already have on-site power generation. The growers featured in the remaining three case studies are considering different forms of on-site power generation. In addition to these five case studies, we have developed and included a further case study describing the experiences of a number of vegetable growers with installed wind power.

The analysis in this report assumes that *a company* purchases these forms of on-site power generation. This means that this purchase can increase the company's income by displacing electricity that would have otherwise been purchased from the network and, if available, by being paid a feed-in tariff for electricity sold into the network. Acquisition of on-site power generation can also reduce the company's *overall* taxable income by depreciating the plant and by deducting interest repayments on any associated debt financing.

The following forms of on-site power generation are analysed. On-site power generation using woody biomass *was not* analysed since none of the growers interviewed had a significant woody biomass resource.

1. *Solar photovoltaics (PV)*
   Two case studies – Loose Leaf Lettuce Company and Moira Farming – already have significant solar PV electricity generation on-site. Our analysis of these two existing solar PV plants confirms the attractive financial performance of these investments.

   Loose Leaf Lettuce's plant is perhaps most relevant since it only become operational in February 2014, and thus its capital expenditure is current. (Moira Farming's plant has been operating since 2012, and attracts generous feed-in tariffs that significantly improve the plant's financial performance but which are no longer available.) The attractive financial performance of Loose Leaf Lettuce's plant is the result of its relatively low capital expenditure and the high price of the network electricity that it displaces. Indeed, this high network electricity price was the highest of any of the case studies, and suggests that further solar PV should potentially be installed at Loose Leaf Lettuce.

   The importance of the price of the displaced network electricity carries through the analysis of solar at all of the remaining case studies. Solar PV was found to be viable *under certain conditions* at all of the case studies sites if STCs (defined in the report) are claimed *and* the large majority of the potentially generated electricity is used to displace network electricity. As these case studies included a Victorian grower, the more favourable solar conditions in Queensland and Western Australia do *not* appear to be necessary for solar PV's viability.

2. *Battery storage*
   Our analysis considers two, potential battery storage plants at Loose Leaf Lettuce. The first features storage of solar PV generated electricity that is currently not consumed on-site. The second assumes installation of a battery storage system in combination with additional solar PV. Our analysis found that the likely financial performance of the first battery storage plant was very poor, and does not appear attractive under any plausible, current conditions. However, battery storage *in combination with* additional solar PV installation appears to have significantly better prospects,

although it is still currently likely to be a poor investment. Further, since Loose Leaf Lettuce had the highest network electricity price of any of the case studies, the performance of battery storage at these other sites must be worse.

Two particular features of battery storage plants dominate their financial performance: the capital expenditure *of a fully installed and operating plant* and the utilisation of the plant, the latter typically quantified by the number of charging/discharging cycles per year. There continues to be large uncertainly in both the full cost of installed battery storage systems and the battery life. Further, charging/discharging cycles need to be almost daily in order for the plant to approach viability. Thus, caution is warranted, and it is recommended that the installation of battery storage is not undertaken until the industry has greater understanding of their technical and financial performance.

3. *Simple and cogeneration using a LPG or natural gas fuelled reciprocating engine generators*
   This report considered three types of on-site power generation using reciprocating engines.

   - Simple (i.e. electricity only) generation
   - Cogeneration of electricity and process heat
   - Cogeneration of electricity and process cooling

   Our analysis found that all of these three types of power generation performed very poorly if LPG was used as the fuel. This was because LPG delivered to the case study sites is simply too expensive to plausibly displace network electricity. (Note also that operation on diesel would have resulted in a similar financial performance since it has a similar price to LPG on an energy basis.) Indeed, fuel prices had to approach that of network delivered natural gas in order to be viable.

   As such, reciprocating engine based generation was found to potentially viable at only one grower that currently has a natural gas main running just outside their premises – Corrigan's Produce Farms. In this case, simple generation was not viable, but the cogeneration of electricity and cooling was potentially viable, even when an estimated cost of network connection is included. Of course, binding quotes on the gas price, network connection charges and on-site plant investment would be required in order to be confident of these costs.

4. *Wind turbines*

   Several growers in Tasmania, New South Wales and Western Australia already have wind turbines on their farms. These turbines are of a wide range of sizes and featured a wide range of financial performance. The most favourable installations have already demonstrated attractive financial performance through a combination of using second hand, and thus cheaper, turbines and acceptable local wind resource. However, one grower found very poor performance. Since local wind conditions are so variable and uncertain, caution is therefore warranted when considering the installation of on farm wind turbine generation. Nonetheless, attractive financial performance is possible if done correctly.

Viewed as a whole, these case studies demonstrate significant potential for on farm power generation, particularly from solar PV, wind and cogeneration. Nonetheless, care must be taken when examining the likely performance of any of these investments, with the following particularly important.

- The assumed capital expenditure of any form of on farm power generation should be that required to *fully install and operate* the plant. This expenditure is almost always significantly higher than the uninstalled plant cost alone, and usually has a significant impact on the plant's viability.
- The financing of the plant needs to be carefully considered, particularly in terms of the tax implications for the entity owning the plant and the proportion of debt financing. Indeed, 100% debt financing may be preferable, and is a common practice amongst the growers interviewed.
- Growers commonly use the payback period as the sole measure of the performance of an investment. Whilst this is a clear and useful metric, it can result in attractive investments being overlooked, particularly if the required payback period is too short. As such, discounted cash flow techniques – such as those presented in this report - should also be considered by growers.
- It is not possible to determine the future of STCs and LGCs (defined in the report) given the current political environment. Further, STC/LGC income appears to be essential in order for most, but not all, solar PV or wind installations to be financially viable.

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Case study methodology

The case studies presented in this report all assume that *a company* purchases any of the discussed forms of on-site power generation. This means that the following apply.

- Purchase of any form of on-site power generation can increase the company's income in two ways:
  1. by displacing electricity that would have otherwise been purchased from the network; and
  2. by being paid a feed-in tariff for electricity sold into the network.
- All purchased plant is depreciated over a stated book life. This means that, in a given year, acquisition of the plant can reduce *the company's overall* taxable income and thus reduce its tax repayments in that year. Note that the Australian Tax Office's (ATO's) method for *diminishing value depreciation* [1] is used.
- Interest payments on debt financing also reduce the company's taxable income.
- All analysis is undertaken *excluding* GST. This assumes that the company claims a GST credit on any purchases, and pays GST on feed-in tariffs and STCs/LGCs. (The latter are renewable energy subsidies that are defined below.)

Measures of plant financial performance

Four measures are used to quantify the financial performance of all analysed forms of on-site power generation. Note that all of these four measures feature the following.

- They include the tax benefits of interest repayments and depreciation.
- They are formulated in terms of *the change in* the company's cash flows due to operation of a given form of on-site power generation. As such, all analysis is done on an enterprise basis (i.e. the whole company), and not in terms of the cash flows to equity or debt holders.
- All analysis is done in real and not nominal terms.
- Any discounted cash flow analysis uses a discount rate of 7.1% real. This discount rate is derived from a 10% nominal value commonly used in similar studies which has a basis in the observed purchasing behaviour for solar PV in Australia [3]. Conversion from nominal to real used 10 year Australian average CPI of 2.7% (March 2004 to March 2014) [2].

The four measures of financial performance are:

1. The payback period (yr): This is the time required for the company's increased cash flows arising from plant operation to offset the total costs of installing and operating that plant. Note that the payback period is calculated using *undiscounted* cash flows.
2. The net present value (NPV, $): This is the sum of the present value of the change in the company's discounted cash flows over a given plant's life, including its initial capital investment. A positive NPV infers that the net return of a given plant is greater than that which would occur with the stated discount rate, and thus should be attractive to the company owner.
3. The internal rate of return (%, real or nominal): This is the annualised compound rate of return on the initial capital investment that plant operation achieves for the company. Once again, this return is defined in terms of the change in the company's cash flows that result from operating a given plant.
4. The levelised cost of electricity (LCOE, $/MWh): For a stated discount rate, this is the minimum average price that the electricity displaced from the network must be in order for a given form of

on-site electricity generation to have NPV=0. Thus, if the LCOE is less than the price of the displaced electricity, then this form of electricity generation is potentially attractive to the company. Note that the LCOE assumes that there is no export of electricity to the network. Further, the LCOE only has meaning for plant that generates electricity only.

Inputs used for all analyses

The following inputs were used for all of the analyses undertaken. Typical values of these inputs for all forms of on-site power generation considered are discussed later in this section, and listed in the Appendix of this report.

Inputs related to the plant capacity

- Plant Capacity (kW): This is the maximum power that the plant can produce.
- Total Capital Required (TCR, \$/kW): This is the total capital that is required *in order to install and commence plant operation excluding any incentive or subsidy*, e.g. the STC or LGC below. Note that the TCR differs from the cost of the uninstalled, complete unit. Where available, actual TCRs are used in the case studies, and estimates for the TCRs are discussed further below.

Technical inputs

- Capacity factor (%): The capacity factor is the average power produced by a plant in a given year normalised by its capacity.
- Fixed Operating and Maintenance Costs (FOM, \$/kW/yr): These are the fixed costs of operating and maintaining the plant per year, normalised by the plant capacity.
- Variable Operating and Maintenance Costs (VOM, \$/MWh): These are the variable costs of operating and maintaining the plant per year, normalised by the annual energy generated. As is normally the case in studies of solar PV, this figure is assumed to be zero throughout this report.
- Annual loss in performance (%): This is the annual reduction in the energy generated by a plant given the same energy input.

Inputs related to the electricity generated

- Feed-in tariff (\$/kWh): This is the price given to electricity generated by a plant on-site and exported into the network.
- Displaced electricity price (\$/kWh): This is the price of the electricity that would have been purchased from the network had it not been generated on-site.
- Proportion fed-in (%): This is the proportion of electricity fed into the network from the on-site power plant.
- On-site consumption (%): This is the proportion of electricity generated that is consumed on-site.

Financial inputs

- Cost of debt (%): This is the interest rate of any debt. A value of 3.7% real (i.e. 6.5% nominal) is used for all analysis as a typical rate for companies with the scale of those studied in this report.
- Inflation (%): This is assumed to be 2.7%, which is the Australian CPI averaged from March 2004 to March 2014 [2].
- Debt percentage (%): This is the proportion of the TCR that is borrowed at the cost of debt.
- Principal (\$): This is the amount borrowed.
- Equity investment (\$): This is the proportion of the TCR that is invested by equity holders.
- Plant life (yr): This is the operating life of the plant.

- Book life (yr): This is the duration over which the plant's TCR is depreciated (for tax purposes)
- Debt life (yr): This is the term of any debt used to finance purchase of the plant.
- Company tax rate (%): This is equal to 30% throughout this report.

Specific inputs for solar PV

This section discusses the specific inputs used for the analysis of solar PV. Typical values of these inputs are listed in the Appendix of this report. Some inputs that are specific to a given site are discussed in the specific case studies.

Renewable Energy Target (RET) related inputs

- Large-Scale Generation Certificates (LGCs, MWh): These are tradable certificates issued by the Federal Government as part of the current RET. In terms of this report, LGCs only apply to solar PV plant with a capacity greater than 100kW and wind plant with a capacity of greater than 10kW.
- Small-Scale Technology Certificates (STCs, MWh): These are tradable certificates issued by the Federal Government as part of the current RET. In terms of this report, STCs only apply to solar PV plant with a capacity of no more than 100kW and wind plant with a capacity up to 10kW.
- LGC / STC income ($): This is the income generated by the sale of LGCs / STCs. Unless specified otherwise, the LGC / STC price is 35 $/MWh (incl. GST), which is typical of current STC prices.

Note: The RET is currently being reviewed and hence this scheme could change in the near future.

Technical inputs related to solar PV only

- Fixed Operating and Maintenance Costs (FOM, $/kW/yr): Unless specified otherwise, the FOM of solar PV is assumed to be 10 $/kW/yr.
- Variable Operating and Maintenance Costs (VOM, $/MWh): As is normally the case in studies of solar PV, the VOM is assumed to be zero throughout this report.
- Annual loss in performance (%): This is assumed to be 0.5% for all solar PV plants examined.
- Lost energy without feed-in (%): This is the proportion of the annual electricity generation that could have been generated but was not used due to feed-in not being permitted.

Estimating the installed cost of commercial scale (10-100kW capacity) solar PV

- There are significant variations in the *installed* price of solar PV, particularly due to:
- the recent, large reductions in the *uninstalled* price of solar PV;
- the large range of different equipment manufacturers and qualities;
- the varying practices, prices and long-term prospects of different solar PV installers; and
- the widely varying ease of installation across different sites.

As such, obtaining independent, current analysis of these installed prices of solar PV is a priority. It appears that the two most reliable studies are a recent study by the *Lawrence Berkeley National Laboratory* (LBNL) [5] and the website of the Australian broker *Solar Choice* [6].

The LBNL [5] report states that, in 2012, the TCR of Australian solar PV systems of less than 5kW capacity was 3.1 $US/W without any subsidy or tax. This compares to the report's equivalent German price of 2.6 $US/W, both of which are some of the lowest prices across the nations surveyed. The LBNL report also states that the installed price of 10-100kW German systems was 2.10 $US/W in 2012. Assuming that the prices of these larger, commercial scale systems scale in proportion to those at smaller scale, this infers an installed price of Australian, commercial scale PV of 2.50 $US/W in 2012 without any subsidy or tax. Given current and recent exchange rates, these TCRs are essentially the same in US or Australian dollars.

The broker Solar Choice [6] presents aggregated price data from a group of installers across Australia. As of May 2014, they report 2.15 $/W to be the average installed price of 100kW capacity systems in Australia. The cheapest and most expensive 100kW installations at this time were 1.59 $/W and 2.60 $/W respectively. Prices at 10kW capacity are only a few percent higher on a $/W basis. Solar Choice [6] nonetheless qualify these reported price figures by stating the following.

- "… it is important to keep in mind that all of these figures are by nature indicative only, given the complexity inherent in the design, installation and grid connection of larger systems."
- "Prices do not ordinarily incorporate meter installation fees or additional costs for difficult installations."

Further, one of the growers examined in the case studies – Loose Leaf Lettuce - has begun operation of a 100kW solar PV installation in 2014. The actual, installed cost of this plant was 2.655 $/W without any subsidy or tax. Since the price of this single installation is above the most expensive reported value quoted by Solar Choice, it calls into question the generality of the Solar Choice data.

This report therefore uses the average for Australia that is estimated from the 2012 LBNL report, now summarised in Table 3, unless actual price data is used in a given case study. The low and high estimates are 25% of the medium result, which is consistent with the variability of the Solar Choice data as well as that proposed by the latest Australian Energy Technology Assessment (AETA) report from the Federal Government for utility scale solar PV [7].

low $/W	medium $/W	high $/W
1.88	2.50	3.13

Table 3: Estimated low, medium and high *installed* prices per Watt of capacity for commercial scale (10-100kW) solar PV in Australia. Note that these prices do not include GST and STCs.

Estimating the average price of the electricity displaced by solar PV generation

At any instant, if a given solar PV plant can generate more electricity than is being consumed on-site, that surplus electricity must be exported to the network, stored or lost. Financial analysis of any solar plant therefore requires an estimate of the annual proportion of solar PV electrical *energy* generation (in kWh) that occurs *below* different levels of on-site *power consumption*.

These proportions were determined from measured, minute-by-minute data from an operating solar PV plant that is located at the University of Queensland's Gatton campus [8] (Figure 9). This data should be particularly representative of solar PV plant performance at two case study sites - Kalfresh and Moira Farming – given their close proximity and that these proportions depend on local environmental conditions. However, the same proportions were also used for all other case studies. This was because similar quality, measured data was not available for these sites, and because the use of local data is only likely to have a minor impact on the financial analysis.

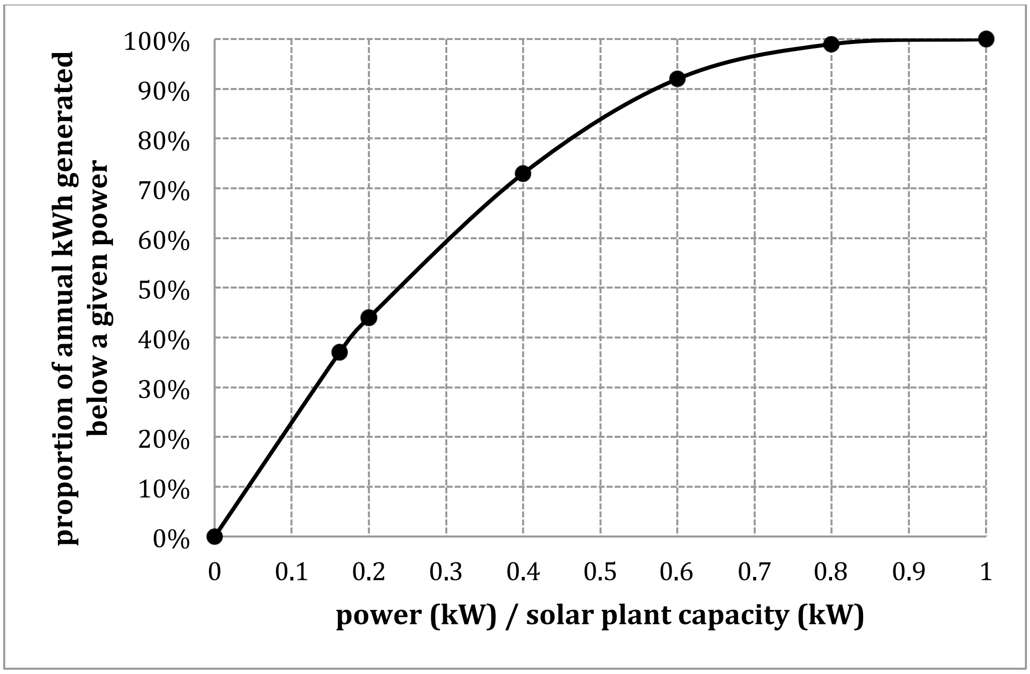

Figure 9: proportion of measured annual kWh generated below a given fraction of the capacity of a solar PV plant located at the University of Queensland's Gatton campus [8]. (Data for the 2013 calendar year.)

Since solar PV only generates during the day, then the *power* consumption during weekdays and weekend days then determines whether the electricity generated is on average consumed on-site. The average displaced electricity price over the year is then calculated as follows.

- If the potential solar power generation is less than the on-site power consumption, then all of the solar electricity displaces network electricity, and the displaced electricity price is the metered network price *for that day* (weekday or weekend).
- If the potential solar power generation is greater than the on-site power consumption, then Figure 9 above is used to calculate the proportion of this solar energy (in kWh) that displaces network electricity, and the displaced electricity price is again the metered network price *for that day* (weekday or weekend). The remaining kWhs are either fed into the network at a prescribed feed-in tariff, lost or assumed to be available for battery storage at a price of zero.

For cases without battery storage, the average displaced electricity price over the year is then the weighted average of the total kWh generated by the solar plant on weekdays and weekend days.

Specific inputs for battery storage

This section discusses the specific inputs used for the analysis of battery storage. Typical values of these inputs are listed in the Appendix of this report.

Inputs related to the plant capacity for batteries only

- Plant Capacity (kWh): This is the maximum amount of energy that can be stored within a battery.
- Allowable depth of discharge (%): This is the maximum allowable proportion of full discharge (in kWh) for a given battery.

Technical inputs related to batteries only

- Charge/discharge cycles (#/yr): This is the number of charge/discharge cycles experienced by a battery per year.
- Fixed Operating and Maintenance Costs (FOM, $/kW/yr): The FOM of battery storage is assumed to be 25 $/kW/yr [9].
- Variable Operating and Maintenance Costs (VOM, $/MWh): The VOM of battery storage is assumed to be 0.001 $/kWh [9].
- Annual loss in performance (%): This is assumed to be 0.5%.

Other financial inputs related to batteries only

- Plant life (yr): This is assumed to be 15 years [9].
- Book life (yr): Assumed to be the plant life.

Note also that this report makes the following, important assumptions.

- There is no energy loss over the charge/discharge cycle.
- That the cost of the electricity entering the battery is zero, i.e. this electricity is available and would otherwise have been lost, as is the case when solar PV generates more than is consumed on-site and network feed-in is prohibited.

Estimating the installed cost of battery storage

Estimating the total capital required (TCR) of a fully installed and operational battery storage system is difficult. This is due to several factors, in particular:

- the apparent absence of independent and complete information on the TCR of battery storage in Australia at a scale that growers are likely to employ (e.g. coupled with a solar PV plant of 10-100kW capacity);
- the range of different battery technologies;
- the uncertain lifetimes of different battery types (which includes their strong dependence on service history); and
- that the battery price is only a part of the overall TCR for an installed and operational storage system.

The most comprehensive and independent, recent study of energy storage technologies was undertaken by a consortium led by the Sandia National Laboratories in the US [9]. This study states that battery storage at a scale that is appropriate for growers currently has TCRs that vary from roughly 550$/kWh to several thousands of $/kWh (at full discharge), and that lead-acid based storage systems are generally cheaper than Li-ion based systems. Other, less comprehensive and less independent studies suggest that the TCR of Li-ion battery systems is 700-800 $/kWh [10,11].

Further, all of these reported TCRs do not include the cost of battery replacement. The Sandia study [9] reports 8 years to be a typical battery life and 15 years as the typical life of the rest of the plant. Other studies tend to suggest longer battery lives (e.g 10-12 years in [10,11]). Regardless of the source, battery life is much shorter than the life of the other technologies studied in this report. Further, if battery replacement is included in the analysis, then the total, lifetime cost of the storage system is significantly higher than these reported figures above.

Given these large uncertainties in the technical and financial performance of battery storage systems, the preferred approach taken in this report is to calculate the TCR required in order for a given battery storage system to have NPV=0. If this required TCR is much less than those typically reported, then the installation is unlikely to be viable. If this required TCR is similar to or greater than those reported, then it is plausible that battery storage may be viable, if not at the moment, then perhaps in the near future. In this latter case, further investigation with battery storage system suppliers is recommended to obtain more confident estimates.

Some of the analysis presented in this report also uses a *nominal* TCR of 800$/kWh for battery storage. We use this figure only as a rough indicator and because it is reasonably often quoted in the industry (e.g. [10,11,12]). Nonetheless, *the uncertainty in this figure must be acknowledged*.

Estimating the average price of the electricity displaced by battery storage

Since the controller of the battery storage system can choose when to discharge, this should preferably occur at a time of peak network tariff. Whilst this report makes this assumption where possible, it cannot always be achieved.

The most common example of this occurs when the battery storage system is charged over weekend days from solar PV. In this case, in order to minimise the size of the storage system, charging on Saturdays must result in discharge prior to recharging on Sundays. This discharge process will always be at an off-peak or shoulder time, depending on the case study. The energy stored on Sunday can then likely be discharged during the week at the peak tariff. In all cases, the average price of electricity displaced by the battery storage system is therefore the average of the tariffs most likely at the time of discharge.

Of course, an alternative to this example is to have a battery storage system of twice the capacity, and store the energy from both Saturdays and Sundays for discharge during peaks times during the week. However, this doubles the cost of the installation and halves the number of charge/discharge cycles, both of which significantly diminish the system's financial performance. As such, this approach is not considered.

Specific inputs for simple and co- generation using reciprocating engines

This report considers three types of on-site power generation using reciprocating engines.

1. Simple generation: This features a reciprocating engine connected to an electrical generator only.
2. Cogeneration of electricity and process heat: This features a reciprocating engine connected to an electrical generator, with the waste heat from the engine's cooling system and exhaust recovered via heat exchangers. This waste heat is used to heat water that is in turn used as process heat.
3. Cogeneration of electricity and process cooling: This is similar to the cogeneration plant above, but features an absorption chiller that uses the engine's waste heat to generate process cooling.

The specific inputs used for the analysis of simple electricity generation and cogeneration are listed below. Typical values of these inputs are listed in the Appendix of this report.

Capacity and capital required

- Total Capital Required ($/kWe): This is the TCR of the fully installed and operational plant normalised by the maximum electrical power output (kWe).

Technical inputs for simple and cogeneration only

- Fixed Operating and Maintenance Costs ($/kWe.yr): This is assumed to be 25 $/kWe.yr [7].
- Variable Operating and Maintenance Costs ($/MWhe): This is assumed to be 0 $/MWhe since the FOM above already accounts for significant annual Operating and Maintenance Costs (O&M).

- Engine capacity factor (%): This is assumed to be 80%, which is easily achievable for dispatchable plant, unless specified otherwise.
- Efficiency (for engines only, %): This is the electrical energy output per unit fuel energy.
- Coefficient of performance (COP, %): This is relevant to absorption chillers and refrigeration plant only. For an absorption chiller, this is the cooling power produced normalised by its heating power input. For a refrigeration plant, this is the cooling power produced normalised by its electrical power input. This report uses COPs for absorption chillers and refrigeration plants of 0.7 [13] and 2.5 respectively.
- Heat utilisation / engine utilisation (%): This is the proportion of time that the generated waste heat from an engine is used.
- Heat recovery efficiency (%): This is the proportion of available heat in the engine exhaust that is used. This report assume 80% in all cases.
- Boiler efficiency (%): This is the proportion of available energy in the boiler fuel that is used to produce process heat. Whilst not part of the engine system itself, this efficiency must be used to estimate the amount of boiler fuel displaced by cogeneration of electricity and process heat. This report assume 80% in all cases.
- Fuel costs ($/GJ): These are normalised on a GJ basis for all fuels, and are based on information supplied by growers or specialist advice [14].

Estimating the installed cost of simple, cogeneration systems

Simple and cogeneration systems are mature technologies, for which the *uninstalled* plant costs are well known. As a result, the total capital required (TCR) for a fully installed and operational system depends on three main factors.

- The manufacturer of the *uninstalled* engine and heat recovery system: Established manufacturers of engine generators with heat recovery systems are usually from the US, Japan and Germany. These systems are generally relatively expensive, but are carefully optimised for lifetime performance and reliability, which tends to add significant up-front cost. Manufacturers of these systems are also emerging from China, South Korea and Poland, and these can cost as little as half the price of the more established systems, usually at the expense of lifetime system performance and reliability.
- The cost of the *uninstalled* absorption chiller (if present): Low cost Chinese and Indian manufacturers of quality absorption chillers already dominate the global market. As such, the TCR of a cogeneration system that produces electricity and process cooling only costs roughly 20% more than that of the simple generation plant with heat recovery [13].
- The difficulty of installing the simple or cogeneration systems at a given site: The cost of installation is significantly higher than the uninstalled system costs. For 'brownfield' sites, such as those considered is this report, the difficulty of installation can also vary widely, such that +/-25% variations in the TCR is considered reasonable [13].

Financial analysis of simple and cogeneration systems over their operating lives demonstrate that the TCR is a small part of the total operating costs, with the price of fuel dominating. As such, it makes less sense for a grower to minimise capital expenditure by purchasing a cheaper plant if that means that the installed system's performance is diminished. Hence, this report assumes use of a generator and a heat recovery system from an established manufacturer.

Advice from specialists suggested that 1200$/kWe was a reasonable medium TCR for a *fully installed and operational* simple engine generator or a cogeneration plant that produces process heat [13].

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These TCRs for simple and cogeneration plants are roughly the same since installation of the exhaust system from simple generation plants in brownfield sites is usually similar in cost to that of the cogeneration plant with heat recovery [13].

The +/-25% uncertainty above then results in low, medium and high TCRs of 900, 1200 and 1500 $/kWe for simple generation or cogeneration of electricity and process heat. The 20% TCR premium for addition of the absorption chiller then results in low, medium and high TCRs of 1080, 1440 and 1800 $/kWe for the cogeneration of electricity and process cooling.

Estimating the average price of the electricity displaced by simple and cogeneration systems

Since simple generation and cogeneration plant can be controlled to produce power when requested, the average price of the electricity displaced is simply the weighted average of the tariffs that occur during the stated operating period.

1. *Loose Leaf Lettuce Company: Solar PV in Western Australia*

Western Australian vegetable grower, The Loose Leaf Lettuce Company installed a 100kW roof-top solar PV plant in December 2013. The expected financial performance of the solar power plant is examined as well as the feasibility of solar power storage options and on-site gas generation.

1.1. Background on Loose Leaf Lettuce Company operations

The Loose Leaf Lettuce Company grows and packs gourmet fresh salad vegetables in the Lennard Valley north of Perth. The business supplies Perth Market City and wholesalers, and operates over two sites. The home farm at Lennard Brook has 30 acres under irrigation as well as the packing and processing facility and cool rooms. The second property at Mooliabeenee has up to 100 acres under irrigation [33].

Crops grown by Loose Leaf Lettuce include fancy lettuce (different varieties), spinach, rocket, tatsoi, chard, mizuna [33]. Crops are grown year round with harvesting 5 days/week, 52 weeks a year. On average, 4 tonnes of salad leaves are harvested each day [40], with summer production around 25% higher than winter production.

Energy consuming processes across both farms include irrigation and pumping, washing, processing and packing processes in the factory, and cooling and refrigeration in the factory and for the five cool rooms. Cooling load includes a vacuum cooler which is used predominantly during summer to lower the temperature of the produce after harvest and before processing and packing. Irrigation and pumping on the home farm is driven by diesel motors; irrigation on the second property is electrically driven.

Waste produced each day within the packing and processing facility is estimated to be around 1.2 tonnes each day, 5 days a week. This waste is currently used as stock feed for a neighbour's cows [33].

1.2. Energy consumption and needs

The focus of the energy analysis and case study was the electrical load at the main facility on the home farm at Loose Leaf Lettuce Company which includes the processing and packing factory and cool rooms. Irrigation at the sites is intermittent and/or diesel-powered hence it will be difficult to justify investment in power generation plant to drive pumps.

Annual energy consumption for 2013 at the main facility was approximately 390MWh, with just under 70% consumed as peak energy. The facility operates during daylight hours, typically from 6.30am, five days a week. The cool rooms are run 24/7 and provide a baseload demand of around 20kW [39].

Figure 10 below shows indicative monthly electricity consumption across peak and off-period periods for the main processing facility. Seasonality in the electricity consumption is clear from this chart with energy use in the lowest month (June) around two-thirds of that in the highest month (January). This seasonality is driven by higher crop production and hence throughput in summer. In addition, there is higher electrical consumption by the cooling processes during summer months as the cool rooms work harder to maintain their temperature relative to higher ambient temperatures and there is increased use of the vacuum cooler to reduce the temperature of the salad leaves immediately after harvesting. This pattern of consumption is attractive for solar PV plants which produce less during winter months.

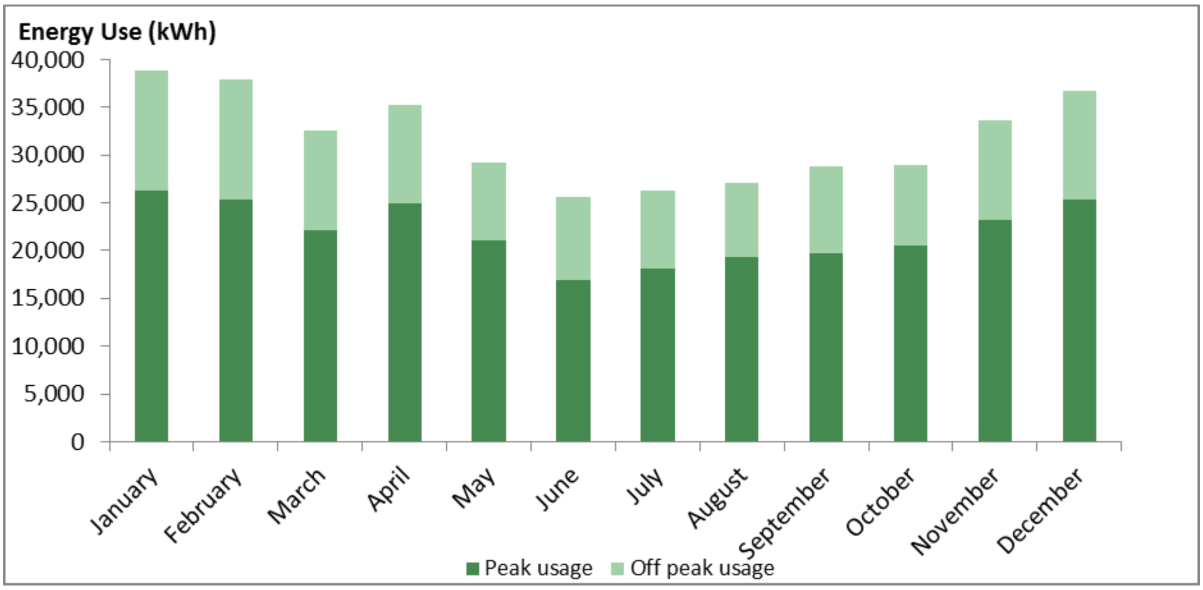

Figure 10: Monthly electricity usage (kWh) for peak and off-peak periods

Loose Leaf Lettuce has had a focus on reducing energy consumption for a number of years. In 2012, following the announcement that a carbon pricing scheme would be introduced in Australia, the company implemented a number of energy efficiency measures. The main focus was on efficient operation of the cool rooms as one of the major loads at the site. Cool rooms were serviced and resealed, cool rooms were turned off at night where possible and staff worked to ensure cool room doors remained closed. It is estimated that these changes reduced energy consumption by around 3% [37].

In addition, Loose Leaf Lettuce participates in a demand management program called Demand Response, run by global energy services company, EnerNOC, to reward electricity customers in agriculture and horticulture for reducing their energy consumption when required. The program operates to address supply shortages in the Western Australian electricity grid. At times of peak network demand, participants in the demand response program reduce their energy consumption and act as a 'virtual power plant' for the grid [43]. Participants are compensated by an availability payment (to be on standby) and by a dispatch payment (based on actual reductions in consumption when required). Businesses are given four hours advance notice for a dispatch that can last 2-4 hours [33,38]. Loose Leaf Lettuce has been enrolled in EnerNOC's DemandSMART™ Western Australia program since June 2012 [41].

In addition to the financial benefits of participating in the program, participants are able to access real-time data about their energy consumption by accessing EnerNOC's system via the internet. A small metering device is installed by EnerNOC to connect the grower's smart meter with the EnerNOC system and the grower can access the information portal online to see live data showing their energy profile at five-minute intervals. This has supported Loose Leaf Lettuce's energy efficiency improvements as they can see the immediate impact of making changes to how they use their cool rooms for instance [41].

Loose Leaf Lettuce pays bundled rates for electricity (i.e. the peak demand charges which are billed to other growers profiled are included in the per kWh rate). Tariffs in Western Australia are in general higher than other states as can be seen below in the rates being paid.

Key components of the bills are energy charges (with different rates for peak and off-peak consumption), environmental and market charges (driven by total energy usage over the period) and a daily supply charge. In essence, Loose Leaf Lettuce pays:

- 37.9c/kWh for peak consumption (8am-10pm weekdays),
- 14.4c/kWh for off-peak consumption (all other times),
- $1.49/day.

Total annual electricity cost for the main processing facility is approx. $114,000 excluding GST of which 99.5% is variable with consumption (kWh) and 0.5% is fixed i.e. cost is essentially variable with usage.

1.3. Feasibility of on farm power generation technologies

The analysis of options at Loose Leaf Lettuce Company focused on solar PV, storage for solar PV and simple generation and co-generation from LPG for the following reasons:

- The expected financial performance of the installed solar PV system was examined using the same methodology as that used for other case studies. With the system only operational since late February 2014, there was not sufficient data to draw firm conclusions about its actual performance. However, we examined the impact it has had on energy consumption to highlight its potential.
- We examined the feasibility of energy storage in conjunction with the existing solar PV plant, and analysed two possible configurations for energy storage.
- Since Loose Leaf Lettuce has significant cooling loads, we examined the feasibility of both simple generation and co-generation for electricity and cooling. We also analysed generation plant fuelled by LPG since there is no natural gas connection to this area.

Other possible options have been excluded from the analysis:

- *Biomass generation*: It is estimated that the factory produces around 312 tonnes of waste annually. However, since 90-95% of salad vegetable biomass is water, this is not a large enough biomass source on its own to justify investment in a biomass generator for energy production. There are no other known local sources of biomass that could be used to cheaply fuel a biomass generator.
- *Wind power*: Average annual wind speeds in the area are estimated to be 4-5/s [44,26,45], around the recommended minimum of 4.5-5m/s for consideration of wind power [23,24]. However, since Loose Leaf Lettuce already has solar PV generation on site, it would not make sense to install a second intermittent power source on the home farm without economic energy storage options.

1.3 Solar PV

Installation of the 100kW solar PV system

In 2013, Loose Leaf Lettuce Company worked with solar energy company, Solargain, to install a 100kW solar PV plant on the roof of their factory and cool rooms. Four hundred polycrystalline panels were installed on the buildings in an East/West orientation. Solargain predicts that the east-west orientation will reduce overall power output slightly compared to a north facing installation but will produce a less 'peaky' or flatter production curve so that more of the energy produced by the system can be consumed on site over the whole day.

Solargain proposed the system to Maureen Dobra of Loose Leaf Lettuce based on analysis of electricity tariffs and consumption and predicted a 4.5–5 year pay-back on the system taking into account the capital cost discount afforded by the sale of generated Small-scale Technology Certificates (STCs). Following significant interest from Loose Leaf Lettuce, Solargain then commissioned a load analysis of the site to understand the energy needs in greater depth, forecast the generation produced by the system and calculate the economic performance of the system.

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Solargain retained Mark Norman, solar energy consultant, to analyse Loose Leaf Lettuce Company electrical load and examine how much energy produced by a solar PV system could be consumed on site, and hence the economics of the system. Mark mapped 12 months of electrical load data against 12 months of predicted solar energy from the system to determine the financial performance of the system. He used the System Advisor Model (SAM) developed by the US Department of Energy's National Renewable Energy Laboratory (NREL) to forecast the electrical generation of the plant given local Australian climate data over 30 years. He also used SAM to calculate the financial impact of installation by looking at what could be consumed on-site at Loose Leaf Lettuce and what would not be consumed (either exported or lost).

For example, Mark created Figure 11 below to show the impact of the solar system for several days in January where the green line shows solar electricity generated, the red line is the electrical load and the blue line is the effective net consumption with solar installed. When the blue line is below zero, Loose Leaf Lettuce is buying electricity from the grid; conversely, when above zero, Loose Leaf Lettuce could be exporting electricity. For weekdays, the solar energy generated fits well within their energy consumption and it is only on weekends when loads are not sufficient to consume the solar energy.

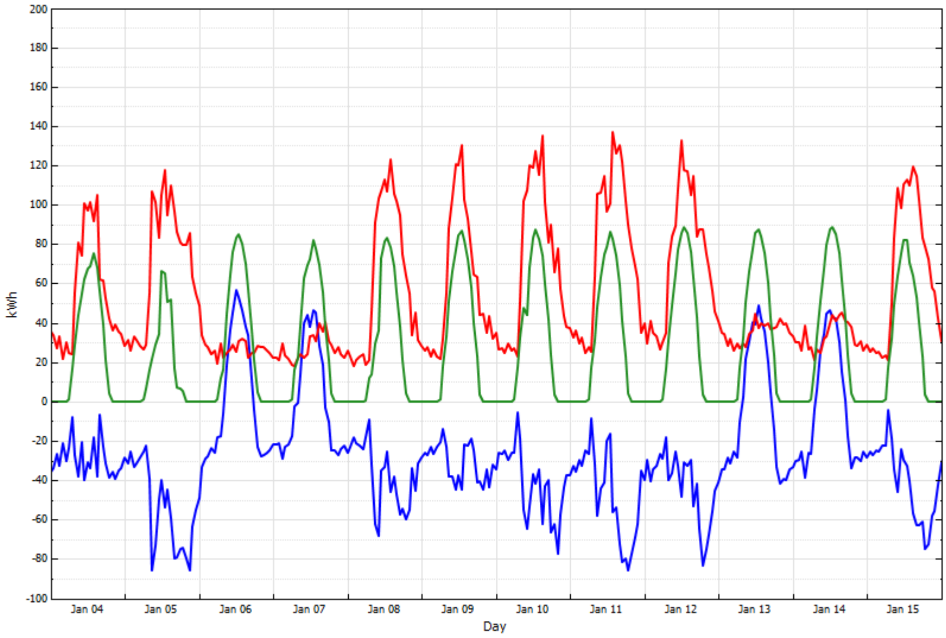

Figure 11: Solargain load analysis for Loose Leaf Lettuce [37]

Network rules in Western Australia mean that systems with inverter capacity over 30kW are not allowed to export excess power to the grid so the system design needed to include reverse power protection, installed by a registered electrical engineer. Hence the financial analysis was modified to factor in this 'clipping' of exported power to the grid.

On the basis of the load analysis and financial information, Maureen Dobra approved installation of the solar PV system at a cost of around $190,000 excluding GST and after STCs had been assigned to Solargain. It is important to note that the STCs had a value of around a quarter of the total purchase price for this system. This system cost is a *fully installed and operating price* and included not only PV panels and inverters but all of the building/council approvals, Western Power approvals, engineering fees, reverse power protection and other compliance equipment and overall management of the approvals process and installation.

Figure 12 below shows the final solar installation at Loose Leaf Lettuce Company. The panels are flush mounted on the roof to minimise installation cost.

Figure 12: Loose Leaf Lettuce Company 100kW rooftop solar installation

The process to obtain approval from Western Power to proceed with the project and sign off on the installed system should have added 90 days to the installation process. However, whilst the system took just over a month to construct, it was 9 months from date of signing of the sales order to the day that permission was granted to switch on the system. These delays appear to be a common issue plaguing larger solar installations in some states with the network operator and distributor changing approval processes and requirements over time. The system installation was completed in December 2013 and switched on at the end of February 2014.

During installation of the solar system, the energy retailer approached Loose Leaf Lettuce to announce changes in their tariff to include higher fixed supply charges as a result of their solar installation. These changes have not yet been implemented since Loose Leaf Lettuce is under contract, however if they proceed, the changes could add $10,000-15,000 per annum to Loose Leaf's electricity bill.

Impact of the system to date

The system has only been in operation since 25 February 2014. It is too early to draw conclusions about whether the system is performing as forecast; due to climate variability, observation over a much longer time period would be required. However, it is useful to examine the impact of the solar system on patterns of consumption, demand and finally cost for the 3-4 months since it has been operating.

Figure 13 below shows half-hourly demand (in kW) for the first five months of 2014. The profile shows a distinct drop in demand since the end of February. Figure 14 below provided by EnerNOC shows two days in March over the last 4 years and demonstrates how the solar system has significantly reduced the load at the site by taking out the peaks in the middle of the day. Figure 15 shows the peak, off-peak and overall consumption (kWh) for March, April and May for the last 4 years and it can be observed that consumption has dropped significantly during 2014 (mostly through reduction in peak consumption). Finally, Figure 16 shows the cost impact of the installation by comparing monthly bills for January-June for 2013 vs 2014. In the first two months of the year, energy bills were in fact above 2013 levels by 10-15%; from March onwards, the bills were 20-35% below the same month in the prior year. From date of installation, electricity costs are down 28% compared to the same four months in the prior year.

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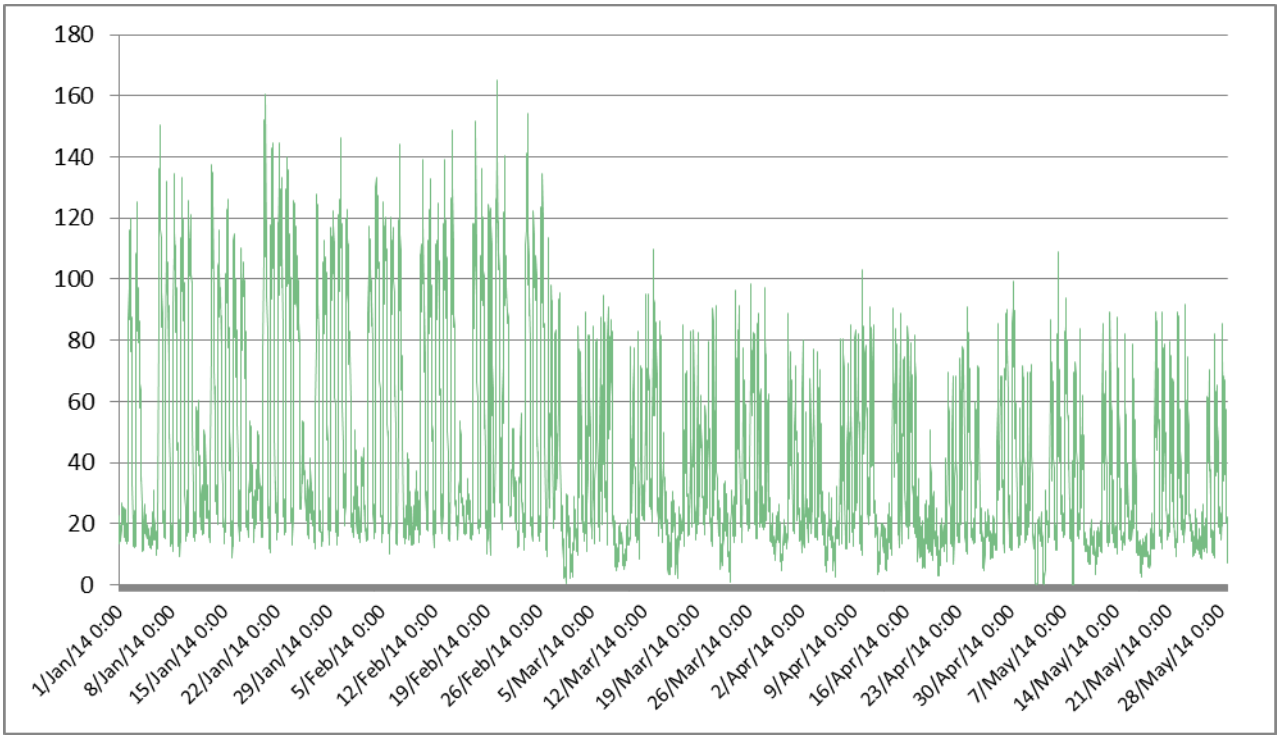


Figure 13: Loose Leaf Lettuce Half Hour Average Demand (kW) for January-May 2014 [39]

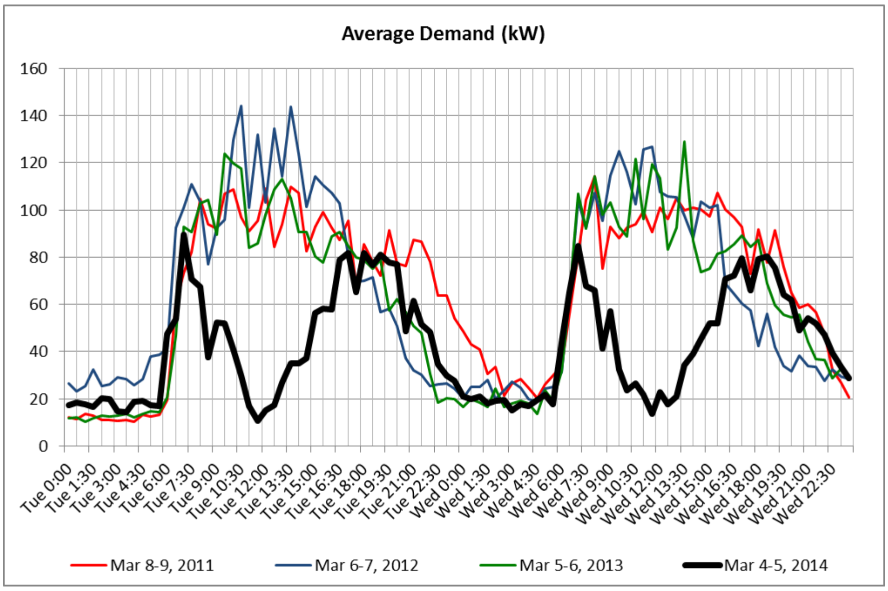
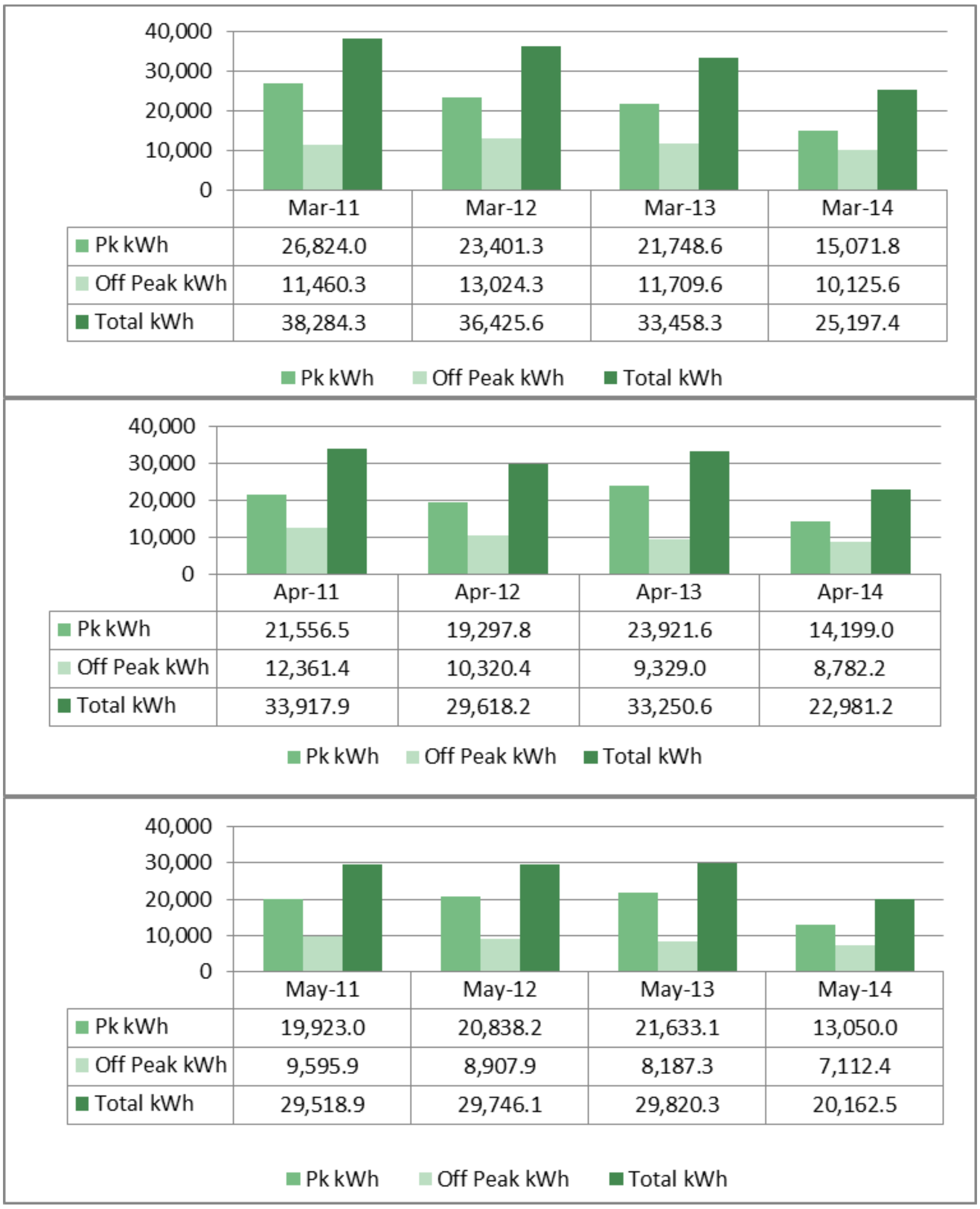


Figure 14: Loose Leaf Lettuce Half Hour Average Demand (kW) for Specific Time Periods from EnerNOC [38]



	Mar-11	Mar-12	Mar-13	Mar-14
Pk kWh	26,824.0	23,401.3	21,748.6	15,071.8
Off Peak kWh	11,460.3	13,024.3	11,709.6	10,125.6
Total kWh	38,284.3	36,425.6	33,458.3	25,197.4

	Apr-11	Apr-12	Apr-13	Apr-14
Pk kWh	21,556.5	19,297.8	23,921.6	14,199.0
Off Peak kWh	12,361.4	10,320.4	9,329.0	8,782.2
Total kWh	33,917.9	29,618.2	33,250.6	22,981.2

	May-11	May-12	May-13	May-14
Pk kWh	19,923.0	20,838.2	21,633.1	13,050.0
Off Peak kWh	9,595.9	8,907.9	8,187.3	7,112.4
Total kWh	29,518.9	29,746.1	29,820.3	20,162.5

Figure 15: Monthly electricity consumption for March, April and May 2011-2014 [39]

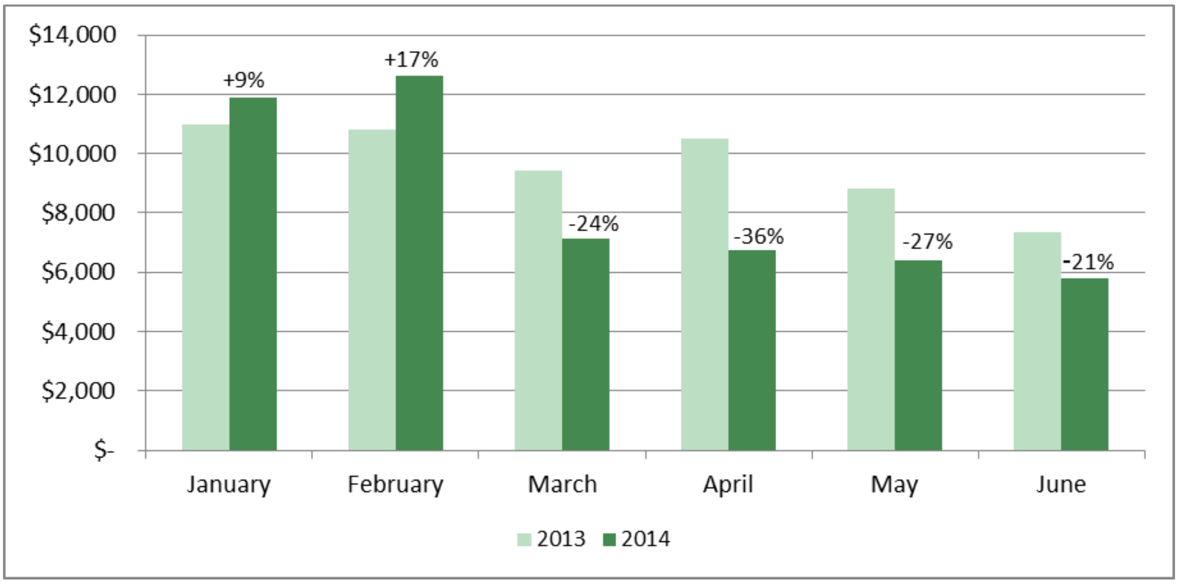


Figure 16: Monthly electricity bills excl. GST for January-June 2013 and 2014 [39]

Financial performance of the solar PV installation

We now consider the forecast financial performance of the solar PV installation at Loose Leaf Lettuce Company using the same methodology as applied for all other case studies. This installation is one of two operating solar plants that are examined in this report.

To summarise key assumptions for the modelling, the solar plant has the following features (Table 4):

- The *as-built, full cost of installing* this 100kW capacity plant was $265,537.09 ex GST, or 2655 $/kW of capacity, excluding any offset from STCs. The installer then paid 36$/STC ex GST for the STCs generated.
- Since the network service provider does not allow electricity to be fed into the network, any electricity that cannot be consumed on-site does not generate any income. Loose Leaf Lettuce Company has a baseload power consumption of about 20kW over nights and weekends. Using the method presented in Section 2 of this report, approximately 44% of the solar electricity (kWh) generated during the weekends can therefore be used on-site. Close to all of the solar energy generated during weekdays will be consumed on-site. This translates to a loss of approximately 16% of potential solar PV electricity generation across the year.
- Loose Leaf Lettuce Company has peak and off-peak metered network electricity prices of 37.9c/kWh and 14.4c/kWh respectively, covering the daylight hours of weekdays and weekends. This results in a weighted average displaced electricity price of 34.4c/kWh during the hours of solar power generation.
- The capacity factor and STC income are calculated using the procedure specified by the Federal Government's Clean Energy Regulator [4]. This classifies Loose Leaf Lettuce Company as being in zone 3, earning the stated STCs and having a capacity factor of 15.8%.

This capacity factor may be conservative for this installation. However, since the Loose Leaf plant has only been operating since February, a measured annual capacity factor cannot be obtained, and some estimate must be used. A survey of the literature suggests that solar plant in Western Australia performs better than some other zone 3 sites, such as those in Southern Queensland, with the Clean Energy Council estimating a 5% higher capacity factor for solar in Perth than in Brisbane [46]. However, there is no clear consensus and in order not to overstate financial benefits, a capacity factor of 15.8% has been used.

Table 5 presents a summary of the financial performance of Loose Leaf's existing solar PV plant. This plant has a strongly positive NPV, with a short payback period of 5.4 years and a high IRR of 20%. This excellent financial performance is the result of the fully installed cost of 2.655 $/W ex GST and the displaced electricity price of 344 $/MWh, the latter of which is the highest of any of the case studies. Indeed, the LCOE of this installation is only 158 $/MWh, which is significantly lower than this displaced electricity price. It is therefore clear that the Loose Leaf solar PV plant is an excellent investment.

Indeed, Table 6 shows that the Loose Leaf plant would still have been an attractive investment even if the STCs had not been claimed. *This means that, given the right conditions, solar PV is economic today without any subsidy.* Once again, as with the other case studies, the keys to this performance are the installed price of the solar PV plant and the displaced electricity price (Table 4).

This attractive performance of solar PV at Loose Leaf Lettuce Company also suggests that additional solar PV could potentially be installed. However, because export to the network is not permitted, the performance of any further installed solar PV will be most adversely impacted on weekend days when on-site demand is lowest. Accounting for this by making the conservative assumption that the capacity factor of additional solar is 15.8% during weekdays and not used at all on weekends (i.e. 11.3% over the entire week or entire year), results in the financial performance shown in Table 7 and Table 8. Assuming the same installed cost as Loose Leaf's current installation, these tables show that additional solar may be an attractive investment for Loose Leaf if it displaces their peak metered electricity at 37.9c/kWh, even without any subsidy. Both of these analyses assume that all of the additional electricity generated on weekdays can be consumed on-site. The net present value has not been calculated since it depends on the size of installation.

Sizing the capacity of this additional solar PV is complex and depends on several factors. These factors include the performance of the current solar installation in offsetting on-site demand, as well as whether or not to claim LGCs, rather than STCS, since Loose Leaf would then be over the 100kW capacity limit of STC eligibility. Ultimately, the best choice in capacity depends on what the owner most values and her appetite for risk. Nonetheless, making the initial investment in the 100kW system was a good decision given it enabled the STCs to be claimed upfront and so significantly reduced the overall capital investment.

Capacity and capital required		
Plant Capacity (MW)	0.1	
Total Capital Required ($/kW)	2655	ex GST
STC related inputs		
STC price ($/MWh)	39.6	with GST
STC zone rating (MWh/kW)	1.382	
STCs (MWh)	2073	
STC income ($)	82091	with GST
Other technical inputs		
Capacity Factor (%)	15.8%	
Lost energy without feed-in	16.0%	
Electricity prices		
feed-in tariff ($/MWh)	0	ex GST

displaced elec. price ($/MWh)	344	ex GST
Other financial inputs		
Debt Percentage (%)	100.0%	

Table 4: Inputs for an operating 100kW capacity solar PV plant at Loose Leaf Lettuce Company. (All other inputs are shown in Table 48 in the Appendix.)

Total Capital Required ($/kW)	2655
Total Capital Required less STCs ($/kW)	1909
Payback period (years)	5.4
NPV ($)	167,388
IRR (nominal, %)	20.0%
LCOE ($/MWh)	158

Table 5: Financial performance of the operating 100kW capacity solar PV plant at Loose Leaf Lettuce Company with STCs included. (Analysis is ex GST and assumes 100% debt financing.)

Total Capital Required ($/kW)	2655
Payback period (years)	7.7
NPV ($)	96,436
IRR (nominal, %)	14.3%
LCOE ($/MWh)	237

Table 6: Financial performance of the operating 100kW capacity solar PV plant at Loose Leaf Lettuce Company with STCs excluded. (Analysis is ex GST and assumes 100% debt financing.)

Total Capital Required ($/kW)	2655
Payback period (years)	9.5
IRR (nominal, %)	11.4%
LCOE ($/MWh)	332

Table 7: Financial performance of additional solar PV at Loose Leaf Lettuce Company with STCs excluded & assuming on-site consumption during weekdays only. (Analysis is ex GST, assumes 100% debt financing.)

Total Capital Required ($/kW)	2655
Payback period (years)	6.7
IRR (nominal, %)	16.3%
LCOE ($/MWh)	222

Table 8: Financial performance of additional solar PV at Loose Leaf Lettuce Company with STCs included & assuming on-site consumption during weekdays only. (Analysis is ex GST, assumes 100% debt financing.)

1.3.2 Battery storage

The use of solar PV on-site also raises the possibility of using of battery storage. Broadly speaking, this battery storage can be used in two ways.

1. *Battery storage plant 1: which features storage of solar PV generated electricity that is **currently not** consumed on-site.*
   Our estimates above suggest that approximately 56% of the electricity potentially generated on the weekend by the current solar PV plant is not used due to weekend consumption being considerably

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lower than weekday consumption. The electricity is effectively 'lost' since the network service provider does not allow feed-in. (All solar generated during the week should already be consumed.) In order to maximise the income from the storage plant, on average it will be charged on Saturdays, for discharging during the off-peak time that evening, and then charged again on Sundays for discharging during a subsequent peak period. This means that, on average, there will be two charge/discharge cycles per week. The average displaced electricity price in this case is therefore the average of the peak and off-peak rates, i.e. 26.2 c/kWh.

2. *Battery storage plant 2: which is installed in combination with additional solar PV.*
   We have also considered battery storage in conjunction with additional solar PV, since further solar installation would be more impacted by the network service provider not allowing feed into the network and because there may also be clipping of the weekday generation when the solar plant is operating at peak output. In this case, there will be on average seven charge/discharge cycles per week, with two at off-peak times (on the weekend) and five at peak times (during the week). The average displaced electricity price in this case is therefore the average of the peak and off-peak rates weighted by their discharge times, i.e. 31.2 c/kWh.

Table 9 shows the inputs used to analyse the financial performance of both of these potential plants.

Table 10 shows the estimated financial performance of battery storage plant 1. Two cases are shown. One case features the nominal TCR of 800$/kWh. As discussed in Section 2, this figure for a fully installed battery storage system is very uncertain because of several factors, with estimates in the most authoritative source varying from roughly 550$/kWh to several thousands of $/kWh for lead-acid and Li-ion based systems without battery replacement [9]. We therefore emphasise that a TCR of 800$/kWh is only nominal which is used in this analysis because it is a reasonably often quoted figure in the industry (e.g. [10]). Another case shows the TCR required for NPV=0. In order to address the large uncertainty in the pricing of battery storage systems, this case shows what the price needs to be in order for the system to be financially viable.

It is clear from Table 10 that the battery storage system's financial performance is very poor if its TCR is 800$/kWh or more. Table 10 also shows that the TCR has to be 188$/kWh or less in order for battery storage plant 1 to have a positive NPV. Thus, battery storage plant 1 does not appear attractive under any plausible, current conditions.

Table 11 shows the financial performance of battery storage plant 2, again with the same two cases for the TCR that were presented in Table 10 for plant 1. Once again, a TCR of 800$/kWh leads to a negative NPV. However, Table 11 also shows that much more plausible TCRs are required in order to achieve a positive NPV. This is primarily because of the much higher utilisation of battery storage plant 2 (i.e. seven vs. two charge/discharge cycles per week on average), as well as the higher average price of the displaced electricity.

Thus, whilst there appears to be a significant likelihood of any option having a negative NPV, battery storage *in combination with* additional solar PV installation appears to have better prospects than installing battery storage on its own at Loose Leaf Lettuce Company. Nonetheless, caution is warranted, particularly given the large uncertainty in the full cost of installed battery storage systems as well as the uncertain battery life, as discussed in Section 2. It is therefore recommended that the installation of battery storage is not undertaken until the industry has greater understanding of the technical and financial performance of battery storage systems, and Loose Leaf is confident of attractive financial performance.

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Capacity and capital required		
Allowable depth of discharge	80.0%	
Total Capital Required ($/kWh)	800	ex GST
Other technical inputs		
Charge/discharge cycles (#/yr)	365	
Fixed O&M ($/kW.yr)	25	
Variable O&M ($/kWh)	0.001	
Annual loss in performance (%)	0.5%	
Electricity prices		
Displaced elec. price ($/MWh)	312	ex GST
Other financial inputs		
Debt Percentage (%)	100.0%	
Plant life (years)	15	
Book life (years)	15	
Debt life (years)	10	

Table 9: Inputs for a potential battery storage plant at Loose Leaf Lettuce Company. (All other inputs are shown in Table 49 in the Appendix.)

	Nominal TCR	TCR for NPV=0
Total Capital Required ($/kWh)	800	**118**
Charge/discharge cycles (#/yr)	104	**104**
Displaced elec. price ($/MWh)	262	**262**
Payback period (years)	n/a	**8.6**
NPV ($)	-135,653	**0**
IRR (nominal, %)	-5.2%	**10.0%**
LCOE ($/MWh)	1261	**262**

Table 10: Financial performance of the potential battery storage plant 1 at Loose Leaf Lettuce Company. (All other inputs are shown in Table 49 in the Appendix.)

	Nominal TCR	TCR for NPV=0
Total Capital Required ($/kWh)	800	**687**
Charge/discharge cycles (#/yr)	365	**365**
Displaced elec. price ($/MWh)	312	**312**
Payback period (years)	9.9	**8.7**
NPV ($)	-22,471	**0**
IRR (nominal, %)	8.1%	**10.0%**
LCOE ($/MWh)	359	**312**

Table 11: Financial performance of the potential battery storage plant 2 at Loose Leaf Lettuce Company. (All other inputs are shown in Table 49 in the Appendix.)

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1.3.3 Simple and Co-generation using an LPG fuelled reciprocating engine generator

The financial performance of two different engine driven plants is now considered for Loose Leaf Lettuce Company. These plants both operate on LPG and have the following features.

1. Simple generation plant: This plant generates electricity only, with the plant's inputs stated in Table 12 for the medium TCR case of 1200$/kWe ex GST. This plant displaces *network electricity only*. It has a capacity of 20kWe, which is Loose Leaf's baseload electricity consumption, and so is sized to operate 24/7/365 in order to maximise equipment utilisation. Its capacity factor of 80% means that it generates 16kWe on average.
2. Cogeneration plant: This plant generates electricity and cooling for Loose Leaf's cool rooms, the latter via engine waste heat recovery and an absorption chiller. The plant's inputs are stated in Table 13. This plant displaces network electricity, where that electricity would have been otherwise used for any purpose, including driving the existing refrigeration plant. The cogeneration plant has a capacity of 15kWe and a capacity factor of 80%. This means that the average network electricity displaced is 17kWe, which is the sum of 12kWe from the generator and 5kWe from use of the absorption chiller rather than a refrigeration plant. Once again, this plant sizing was chosen to operate 24/7/365 in order to maximise equipment utilisation.

Cogeneration of electricity and heat was not examined since Loose Leaf does not require process heat. It is also notable that:

- Whilst these plants would likely be able to feed-in electricity to the network, this is unlikely to be financially attractive because the feed-in tariff that Loose Leaf Lettuce Company would get is likely lower than the price of their displaced network electricity.
- In contrast to the analysis for the solar plant, the average price of the displaced network electricity assumes that both the simple and cogeneration plants operate at the same power output across the entire week. This means that the average price of the displaced network electricity is now simply weighted by the proportion of hours per week with peak and off-peak tariffs, giving an average electricity price of 24.2c/kWh. Importantly, this price is significantly lower than the average price of the electricity that solar displaces.

Capacity and capital required		
Plant Capacity (MWe)	0.02	
Total Capital Required ($/kWe)	1200	ex GST
Other technical inputs		
Engine capacity factor (%)	80.0%	
Engine efficiency (%)	35.0%	
Electricity prices		
Displaced elec. price ($/MWh)	242	ex GST
Fuel price		
Fuel price ($/GJ)	55	ex GST
Fuel price ($/MWh)	198	ex GST

Table 12: Inputs for potential 20kWe capacity electrical generator at Loose Leaf Lettuce Company. (All other inputs are shown in Table 50 in the Appendix.)

Capacity and capital required		
Plant Capacity (MWe)	0.015	
Total Capital Required ($/kWe)	1440	ex GST
Other technical inputs		
Engine capacity factor (%)	80.0%	
Engine efficiency (%)	35.0%	
Heat recovery efficiency (%)	80.0%	
Chiller COP	0.7	
Refrigerator COP	2.5	
Electricity prices		
Displaced elec. price ($/MWh)	242	ex GST
Fuel price		
Fuel price ($/GJ)	55	ex GST
Fuel price ($/MWh)	198	ex GST

Table 13: Inputs for potential 15kWe capacity cogeneration (electricity and cooling) plant at Loose Leaf Lettuce Company. (All other inputs are shown in Table 51 in the Appendix.)

Table 14 presents a summary of the financial performance of the proposed simple generation plant using the low, medium and high TCRs of 900, 1200 and 1500 $/kW ex GST respectively. It is clear that all of these proposed plants perform very poorly on all metrics. This is because of the high price of the LPG available to the Loose Leaf Lettuce Company. Further, the large, negative NPVs of all plants in Table 14 show that the TCR has only a minor effect on the financial performance. Indeed, the LCOEs presented in Table 14 show that the displaced electricity prices must be substantially higher than current for simple electricity generation to be financially viable.

Table 15 shows that with an estimated delivered LPG price of 55 $/GJ (1.26 $/lt ex GST), cogeneration of electricity and cooling still has a negative NPV for all TCRs examined. Table 16 then shows the required fuel price in order to obtain NPV=0 for this proposed cogeneration plant. These prices of 29-30 $/GJ translate to roughly 0.68 c/lt of LPG, which is similar in price to the LPG sold at service stations in Australia's major cities, but significantly lower than prices paid by Loose Leaf and the other growers examined in this report. Indeed, these LPG prices are approaching that of network delivered natural gas, suggesting that cogeneration without supply of network delivered natural gas delivery is always likely to be unviable.

	Low TCR	Med TCR	High TCR
Total Capital Required ($/kW)	900	1200	1500
Payback period (years)	n/a	n/a	n/a
NPV ($)	-396,464	-401,109	-405,754
IRR (nominal, %)	n/a	n/a	n/a
LCOE ($/MWh)	607	611	615

Table 14: Financial performance of the potential 20kWe capacity electrical generator at Loose Leaf Lettuce Company. (All prices are ex GST and assume 100% debt financing.)

	Low TCR	Med TCR	High TCR
Total Capital Required ($/kW)	1080	1440	1800
Payback period (years)	n/a	n/a	n/a
NPV ($)	-217,338	-221,569	-225,749
IRR (nominal, %)	n/a	n/a	n/a
LCOE ($/MWh)	n/a	n/a	n/a

Table 15: Financial performance of the potential 15kWe capacity cogeneration (electricity and cooling) plant at Loose Leaf Lettuce Company. (All prices are ex GST and assume 100% debt financing.)

	Low TCR	Med TCR	High TCR
Total Capital Required ($/kW)	1080	1440	1800
Fuel price ($/GJ)	30	30	29
Payback period (years)	7.3	8.0	8.6
NPV ($)	0	0	0
IRR (nominal, %)	10.0	10.0	10.0
LCOE ($/MWh)	n/a	n/a	n/a

Table 16: Fuel price required to achieve NPV=0 for the potential 15kWe capacity cogeneration (electricity and cooling) plant at Loose Leaf Lettuce Company. (All prices are ex GST and assume 100% debt financing.)

1.4 Conclusion

Our analysis of the financial performance of two forms of on-site power generation on Loose Leaf Lettuce Company's premises obtained the following results.

1. *Solar PV*

   Loose Leaf Lettuce Company's existing 100kW capacity solar PV plant appears to be an excellent investment. This plant has a strongly positive NPV, with a short payback period of 5.4 years and a high IRR of 20%. This excellent financial performance is the result of the fully installed cost of 2.655 $/W ex GST, excluding STC discount, and the displaced electricity price of 344 $/MWh, the latter of which is the highest of any of the case studies. Further, this installed Loose Leaf plant would still have been an attractive investment even if the STCs had not been claimed. *This means that, given the right conditions, solar PV is economic today without any subsidy.*

2. This attractive performance of solar PV at the Loose Leaf Lettuce Company also suggests that further solar PV should potentially be installed. However, the performance of any further solar PV installation will be more adversely impacted than the existing solar plant by not being able to export to the network. Nonetheless, accounting for this, additional solar PV still appears to be an attractive investment if it displaces Loose Leaf's peak metered electricity at 37.9 c/kWh, even without any subsidy. Thus, whilst sizing the capacity of this additional solar PV is complex and outside the scope of this study, it should be considered.*Battery storage*

   Our analysis considered two, potential battery storage plants – one that features storage of solar PV generated electricity that is currently not consumed on-site, and another which is installed in combination with additional solar PV. This analysis found that the financial performance of the first battery storage plant was very poor, and does not appear attractive under any plausible, current conditions. However, battery storage *in combination with* additional solar PV installation appears to have better prospects, although there is still a significant likelihood of it having a negative NPV.

   Thus, caution is warranted, particularly given the large uncertainty in the full cost of installed battery storage systems as well as the uncertain battery life. It is therefore recommended that the installation of battery storage is not undertaken until the industry has greater understanding of the technical and financial performance of battery storage systems, and Loose Leaf is confident of attractive financial performance.

3. *Simple and cogeneration using an LPG fuelled reciprocating engine generator*

   Our analysis found that a LPG fuelled, reciprocating engine generator will demonstrate very poor financial performance at Loose Leaf Lettuce Company. This is because of the high price of the LPG available. Similarly, cogeneration of electricity and process cooling also appears to be uneconomic given these high fuel prices. Indeed, fuel prices approaching those of network delivered natural gas appear to be required if cogeneration is to be viable.

2. *Moira Farming: Solar PV in the Lockyer Valley, Queensland*

Lockyer Valley vegetable grower, Linton Brimblecombe constructed a 30kW solar PV plant on his property during 2010 and 2011. The financial performance of this existing solar power plant and the feasibility of a proposed additional 100kW solar installation are examined below.

2.1 Background on Moira farming operations

Moira Farming is located at Forest Hill in the Lockyer Valley, Queensland. The property of about 1200 acres typically has 800-900 acres planted with vegetables under irrigation. Whilst crops have changed over time, a typical current break-down of the crops under cultivation is shown below.

Crop	Area
Carrots	150 acres
Onions	150 acres
Pumpkin	70 acres
Sweet corn	250 acres
Broccoli	250 acres
Sorghum (dryland)	300 acres

Table 17: Typical mix of crops under cultivation at Moira Farming [15]

The majority of the crops are grown from February through to October/November, with sweet corn the only summer crop. Irrigation is required throughout the growing season, depending on rainfall, with water for irrigation provided by the water storages on the property. There are two large water stores (dams) and five smaller storages [16]. The main stores pump to the smaller dams which then supply the underground pipe network for irrigation. Linton aims to have 2 years of water supply in reserves in case of water shortage [17].

The crops are harvested throughout the growing season and are transported directly to a local packing facility for processing and storage; Moira does not have any on-site processing facilities or cool rooms/storage. As a result, pumping and irrigation are the key processes consuming energy on the farm. There is little biomass waste generated at Moira since no processing occurs on site and any waste is ploughed back into the soil to improve soil health.

2.2 Energy consumption and needs

There are five separate metered connections to the Moira operations [18]. One of these meters measures the net import or export of electricity at the Glen Cairn dam pump which is powered by the existing solar installation. Analysis of this installation and its impact on energy consumed and exported is covered extensively in the next section. Imports of energy from the grid at this meter are included in the charts and discussion below (i.e. the analysis excludes electricity exported to the grid but is net of energy consumption at the dam which is supplied from the solar installation).

Figure 17 below shows indicative annual electricity consumption across peak and off-period periods [18]. It is apparent that Greyfriars Road accounts for close to half of all energy usage and another meter almost a third of usage with three meters consuming much smaller proportions of the total electricity at the site.

Total annual energy consumption was approx. 470MWh with half of this energy consumed off-peak. The total cost (before accounting for payments for electricity exports) was around $98,000 per annum [18].

However, the power consumed by the pump at the Glen Cairn dam will be understated since some of the energy driving the pump is supplied by the solar installation. Due to the financial incentives to export solar power (discussed further below), Linton tries to limit the operation of the dam pump during daylight hours where possible. It is estimated that 30-35% of solar power generated is consumed by this pump which would be around 16,000-20,000 kWh per year [18].

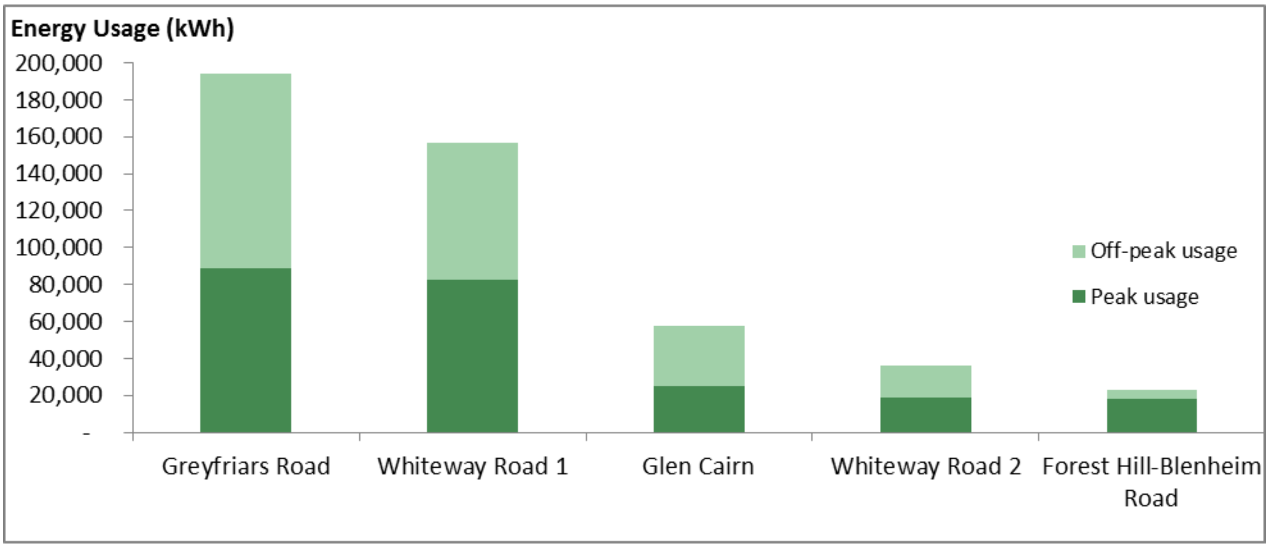

Figure 17: Moira Farming annual energy usage (kWh)

Other than the Greyfriars Road meter, energy is charged on a 'simple' tariff structure with billing on a quarterly or bi-monthly basis. Bill components are peak energy charge, off-peak energy charge and service to property charge. Peak rates are 23.2-25.5c/kWh and off-peak rates are 18.1-18.7c/kWh excl. GST [18].

The meter at the Greyfriars Road site measures consumption at the large dam which is under consideration for installation of a second solar PV plant. Due to higher annual consumption at this meter (over 100MWh per annum), the supply is on a contestable contract at unbundled rates. This means that charges for energy, network, market, metering and environmental components are made separately on the customer's bill.

Key drivers of the Greyfriars bills are energy charges (peak rates of 8c/kWh and off-peak rates of 5.4c/kWh), network charges (which are dominated by demand charges of $20.89/kW for monthly peak demand), and other fixed supply, environmental and metering charges. Energy charges account for around a third of the annual cost; the demand component of the network charges represent nearly 40% of the annual cost. Figure 18 shows monthly usage in kWh and demand in kW respectively [18].

It is clear that consumption varies significantly from month to month (and year to year) depending on rainfall and irrigation needs. Interviews and examination of monthly demand reports show that the pumps at the dam are commonly operated for 5-10 days continuously and then turned off for 5-10 days or longer [18].

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The monthly peak demand billed varies from month to month with demand for most months between 70-80kW. The significant spike observed in January occurs when flood pumping is required to fill the dam; this generally happens in one or two months of any given year [15,18].

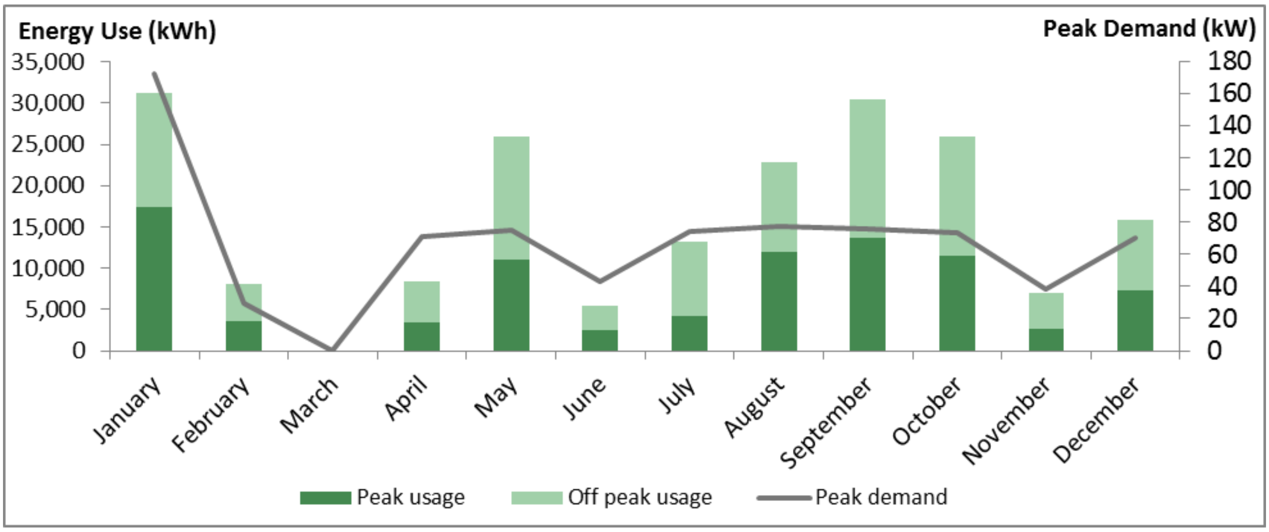

Figure 18: Monthly electricity usage (kWh) and peak demand (kW) for Greyfriars Road site

2.3 Feasibility of potential on farm power generation technologies

The analysis of options at Moira focused solely on solar PV for three reasons:

- There was already an existing solar PV installation in operation. . A second proposed solar installation was under consideration at this site and comparison of the existing and proposed installations were beneficial.
- There are limited resources for gas or biomass fuelled generation. For example, there is no natural gas connection to the property. There is little biomass waste produced since no processing occurs at Moira and any biomass waste is ploughed back into the soil. There are no local sawmills or other businesses that could supply cost effective biomass resources.
- Wind resources at Forest Hill were estimated to be lower than the minimum advised for installation of wind turbines (average annual wind speed of 4.5-5m/s) [23,24]. Average wind speed for Forest Hill is estimated to be 3-4m/s [25,26,27]. Further, since energy use at the site is intermittent, wind power was unlikely to be an attractive option especially in conjunction with solar PV power already installed.

This analysis focussed on two separate solar PV installations:

- The existing 30kW solar PV installation powering pumps at the Glen Cairn dam
- The proposed 100kW solar PV installation which would power pumps at the large dam at Greyfriars Road

For both of these installations, power use is not constant or predictable since the irrigation needs vary over the growing season and with the actual local weather conditions.

2.3.1 Existing solar installation powering pumps at the Glen Cairn dam

In 2010, Linton Brimblecombe and his brother decided to invest in solar power on their properties to reduce power costs and provide some protection against increasing power costs. The solar PV installation powering pumps at the Glen Cairn dam was developed as a result of this decision. Figure 19 shows the installation.

Figure 19: 30kW solar PV plant at Glen Cairn dam

It is a 30kW solar plant with single axis tracking. It is arranged in three rows of 60 panels each running north-south. The tracking system tilts the panels over the day from east to west. The images in Figure 20 below show the panel orientation at midday and at 3.30pm during late April. There are a range of estimates in the literature for the increase in power output from single axis tracking. Generally a single axis system should increase power output by 20% to 25% with some estimates increasing output by 30% [28,29,30]. The modelling undertaken therefore uses 20%.

Figure 20: Panel orientation at 12pm and 3.30pm in late April – effect of the tracking system

Linton purchased the Ecokinetics panels and Oelmaier inverter over the internet and installed them with his brother, he sourced the tracking system from a local engineer (JSH Engineering) and worked with local contractors to undertake construction and electrical work where required. Construction work included concrete reinforcements and footings for the arrays and construction of the shed housing inverters [15,16]. In addition, there was a modest cost for obtaining a change of use planning permit. The total cost of the system was approx. $167,000 of which around two-thirds was the cost of solar panels and inverter as can be seen in Figure 21 below [19].

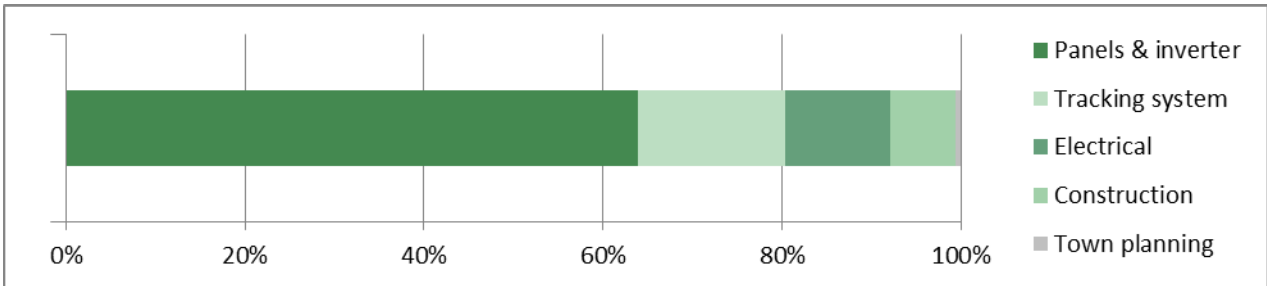

Figure 21: Breakdown of solar installation cost for Glen Cairn 'solar dam'

There was a significant lead time between purchase of the panels and connection of the solar arrays to the pump and grid. Linton purchased the panels in May 2010 but didn't receive the change of use permit until November 2010 so work on installation of the panels and tracking system could not commence until this time. In 2011, major flooding in the Lockyer Valley caused delays and repairs were required after one of the motors on the tracking system was lost during the floods. Construction of the shed housing the inverters was completed in late 2011. However, the solar system was only connected to the grid in April 2012.

Linton did not claim the Small Scale Technology Certificates for his installation. If he had claimed and traded the certificates on his solar plant in 2012, they would have been valued at around $17,000-20,000 (including GST) or just over 10% of the total investment. The price of STCs during 2012 was significantly lower than current values and fluctuated from around $25 to $33 per STC [31,32].

At the time of investment, the Queensland Government offered feed-in-tariffs of 44c/kWh to encourage installation of solar panels under the Solar Bonus Scheme [32]. These feed-in-tariffs are legislated to run until 2028, so any electricity exported from Linton's solar system attracts this rate provided he remains eligible for the Solar Bonus Scheme. In addition, his retailer (Origin) provides a voluntary feed-in-tariff of 6c/kWh on top of this Solar Bonus Scheme payment; rates for the voluntary FiT can be changed at any time [22]. It is important to note that businesses registered for GST are liable to pay GST on any feed-in-tariff income. The effective rate received up to 1 July 2028 excluding GST is thus 45.5c/kWh. We assume that after this date only the Origin FiT remains.

Performance of the solar plant to date

The solar installation at Moira does not log power output generated by the system. The only known generation is the solar power exported to the grid. This is shown below in Figure 22. Due to the generous feed-in-tariff described above, Linton tries to minimise the pump use during daylight hours to maximise financial returns. However, this is not always possible and Linton estimates that the pump might be running up to 40% of the time that the solar system is generating power. Solar exports will vary significantly quarter to quarter given variation in irrigation needs (affecting on-site consumption) and climate (affecting total solar generation). From connection to the grid in April 2012 to the end of January 2014, the system had exported over 62 MWh of electricity with a value of $28,536 excluding GST [18].

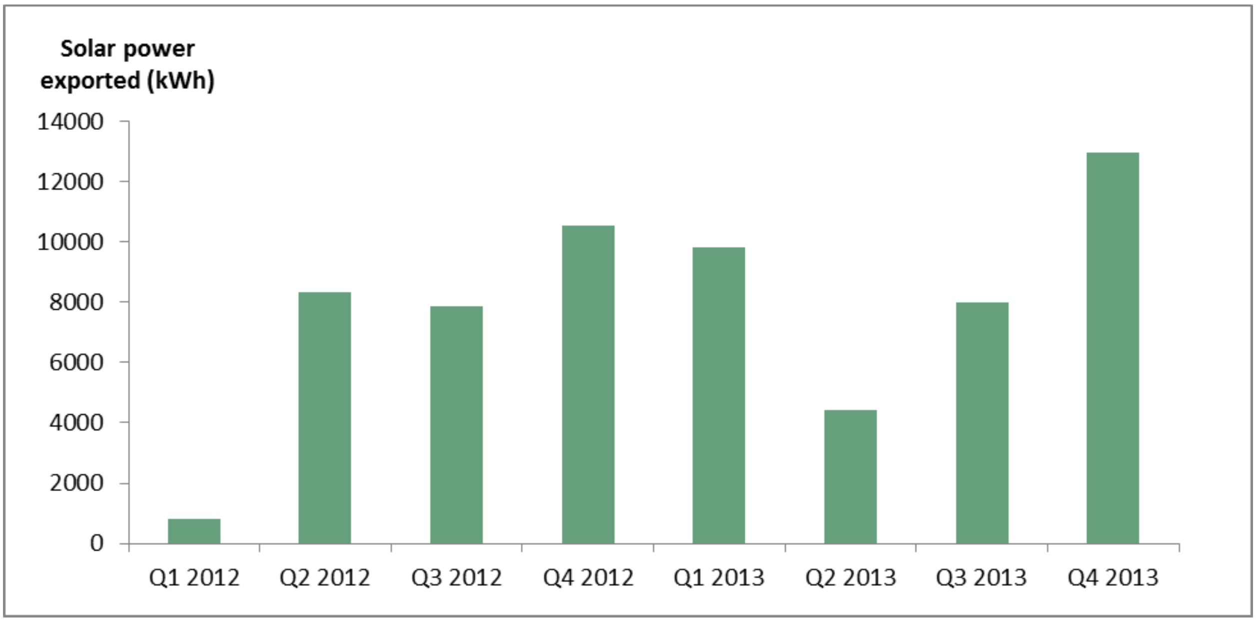

Figure 22: Solar power exported from Glen Cairn solar PV installation [18]

To estimate the solar generation that is consumed by the dam pump, an analysis of the solar output from the 25kW rooftop solar PV installation at the nearby University of Queensland (UQ) Gatton campus was performed [8]. Data on this system over a number of years is available and given its close proximity to Moira, the output of the Moira system has been estimated using the UQ Gatton system as a reference for the time period, scaled up for larger installation size and the increased output due to the tracking system.

Using tariff information and 20-30% range for the increased output from the tracking system results in the following estimates of solar power generated, solar power consumed on-site and the total value of the solar power generated from connection in April 2012 to end of January 2014:

	@20% increased output from tracking system	**@30% increased output from tracking system**
Total solar generation (kWh)	89,816	97,468
Solar generation exported (kWh)	62,779	62,779
Value of solar generation exported	$ 28,535.91	$ 28,535.91
Solar generation consumed on-site (kWh)	27,848	35,500
Value of solar generation consumed on-site	$ 5,897.40	$ 7,527.88
Total value generated	$ 34,433.31	$ 36,063.78

Table 18: Value of solar power generated by Glen Cairn solar PV installation April 2012 to January 2014 [18]

2.3.2 Proposed 100kW system at Greyfriars Road pumping station

In 2013, Linton Brimblecombe began exploring the possibility of an additional larger solar installation at the Greyfriars Road dam. Linton approached a Brisbane-based solar installation company, MC Solar & Electrical, to examine the feasibility of putting in a large ground mounted system to drive pumps at the Greyfriars Road dam [20].

MC Solar & Electrical proposed a 100kW system which would pump water 365 days a year, using a variable speed drive on the pump motors to vary the power consumption of the motors to match solar output. The proposal included a programmable logic controller (PLC) regulating the variable speed drive. Linton would be required to provide equipment and an operator to assist in leveling the site and installing ground mount screws and trenching – these additional costs are not reflected in the proposed costing below.

The solar contractor provided Linton with a preliminary feasibility study of the solar pumping station, based on estimates provided by Linton of the current average use of the pump (10 hours a day at peak times using 30kW pump and 10 hours a day during off-peak times on 43kW pump). The proposal assumes that there would be a limited need to draw power from the grid and that the system would receive no feed-in-tariff. If the consumption at this meter drops below 100MWh/year, then Linton could apply to be reclassified onto a small business tariff and may be able to negotiate a small feed-in-tariff (likely to be 4-8c/kWh).

The commercial electricity contract with Origin for this meter prohibits Linton from feeding power back into the grid, hence the system would also need to include reverse power protection systems. However it is not clear whether these components are included in the costing provided.

The contractor's proposal included the following estimates of performance and cost:

Annual system output	146,000 kWh per year
Total system cost (at December 2013)	$173,000
Total value of STCs	$78,300
Power consumed – no solar average Power consumed – solar average	22,301 kWh per month 12,000 kWh per month
Peak demand – no solar Peak demand – solar	43.6 kW per month 5 kW per month
Monthly savings	$2,700
ROI	3-4 years

Whilst the proposal appears attractive at face value, there are a number of important factors which may undermine achievement of these projected financial returns.

- The system output assumes a higher capacity factor than conservative estimates (16.7% vs 15.8%), hence the system output could be up to 10,000kWh per year lower than projected.
- The total annual energy consumption for 2013 at the Greyfriars Road meter was 194,400 kWh which is well above the projected output of the system. To consume at the limit of the solar output and eliminate energy and demand charges as projected, energy consumption by pumps at this station would need to reduce by 25%.

- In addition, the current energy consumption varies significantly day-to-day and month to month. From Figure 18 above, the monthly consumption can vary from 0-30,000 kWh. In addition, examination of monthly demand reports highlights significant variation day-to-day. The proposal assumes that the current pumping pattern will change to suit solar output. It is unclear whether this is feasible some or all the time. If not able to be changed, it is clear that on 'pumping days' the solar system will not produce enough power to drive the pumps and power will be consumed from the grid. In addition, on 'non-pumping days', the solar power generated will not be consumed or exported.
- Further, the proposal assumes that demand charges will drop significantly because current highly variable peak demand will reduce to a very low demand. Currently the peak demand charges account for almost 40% of the energy bills so if Linton needed to pump overnight or increase pumping above solar output at any time during a month, these peak demand charges would remain at the current levels. However, if overall consumption did reduce well below the 100MWh level and the meter was reclassified on a small business tariff, the energy rates would likely increase significantly but the peak demand charges would be eliminated from the tariff.

Given the uncertainty about whether and how much pumping practices can be changed without compromising irrigation and crop outcomes, we have analysed the proposed solar system on the basis of how the pump has typically operated.

2.3.3 Financial analysis of solar PV plants

We now consider the financial performance of the two solar PV installations at Moira Farming.

1. *The existing, 30kW capacity solar PV plant at the Glen Cairn dam*

   Analysis of this plant uses the inputs listed in Table 19. Of particular note are the following.

   - The TCR is 5548$/kW, which is discussed above and is our understanding of the full cost of installation for this ground-mounted system.
   - The capacity factor of this plant is estimated to be 19%. This assumes that single axis tracking achieves a 20% greater capacity factor than a similar, fixed panel plant. This is a conservative estimate that is discussed further above. This estimate must be made, despite the plant having operated for some time, since the actual electricity output of the solar PV plant is not measured.
   - As with all other solar PV plants studied in this report, the capacity factor of a fixed panel plant is calculated using the procedure specified by the Federal Government's Clean Energy Regulator [4]. This classifies Moira Farming as being in zone 3, with a fixed panel capacity factor of 15.8%. Increasing this figure by 20% results in the quoted capacity factor.
   - We estimate that 70% of the total solar electricity generated is fed into the network. This is an estimate based on the analysis of meter data above. Once again, this estimate must be made since the actual electricity output of the solar PV plant is not measured.
   - The feed-in tariff of 50c/kWh with GST only runs until 2028 (year 16 of plant operation), at which time we assume that it changes to 6c/kWh with GST. The former feed-in tariff was available for 16 year lock-in in 2012, and the latter is the feed-in tariff that new installations currently receive.
   - The displaced electricity price is 23.5c/kWh, which assumes that the displaced electricity is weighted by the weekday and weekend daytime metered rates.
   - Moira Farming fully equity financed this installation.

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2. *The proposed, 100kW capacity solar PV plant at the large dam on Greyfriars Road*

Analysis of this plant uses the inputs listed in Table 20. Of particular note are the following.

- The TCR used is 2000$/kW, which is the grower's estimate of a plausible TCR given quotations that he has received to undertake this project. This estimate may understate the TCR given estimates for roof-top solar PV TCRs in Table 48 and since ground-mounted systems are typically more expensive due to additional costs associated with ground mounting.
- The capacity factor for this fixed panel plant is 15.8%, in keeping with the procedure specified by the Federal Government's Clean Energy Regulator [4] for zone 3 plant.
- The network service provider is unlikely to allow feed-in from this plant. Hence, it is important to understand the proportion of electricity generated that would not be consumed. Historical pumping practices vary greatly across the year and we were not able to obtain detailed demand data for this meter. However, examining monthly energy reports which showed daily energy usage in kWh and kW, we estimate that on 42% of the days in a year the pumps were on and could have consumed all of the potential solar output. Conversely, 58% of the electricity potentially generated cannot be used since it cannot be fed into the network or used to drive the pumps. Whilst we acknowledge the shortcomings of this method for estimating consumption, more robust data was not made available. Moreover, since the pumps are either on or off for hours to days at a time, this estimate is likely reasonable.
- The average displaced electricity price is 10.2c/kWh, which assumes that the displaced electricity is weighted by the weekday and weekend daytime metered rates, and pumping is equally likely on any given day.
- We assume that this installation will be fully debt financed, as this is commonly done and gives some benefit to the owner.
- We assume that there is no reduction in network demand charges as a result of solar PV installation. This is because these charges are driven by peak monthly metered demand (in kW) and since the peak monthly demand will not in general coincide with solar output.

Capacity and capital required		
Plant Capacity (MW)	0.03	
Total Capital Required ($/kW)	5548	ex GST
STC related inputs		
STC income ($)	0	with GST
Other technical inputs		
Capacity Factor (%)	19.0%	
Proportion fed-in	70%	
Electricity prices		
feed-in tariff ($/MWh) up to year 16	500	with GST
feed-in tariff ($/MWh) post year 16	60	with GST
feed-in tariff ($/MWh) up to year 16	455	ex GST
feed-in tariff ($/MWh) post year 16	55	ex GST
displaced elec. price ($/MWh)	235	ex GST
Other financial inputs		
Equity Percentage (%)	0.0%	

Table 19: Inputs for the existing 30kW capacity, single tracking solar PV plant at the Glen Cairn dam. (All other inputs are shown in Table 48 in the Appendix.)

Capacity and capital required		
Plant Capacity (MW)	0.1	
Total Capital Required ($/kW)	2000	ex GST
STC related inputs		
STC price ($/MWh)	35	with GST
STC zone rating (MWh/kW)	1.382	
STCs (MWh)	2073	
STC income ($)	72555	with GST
Other technical inputs		
Capacity Factor (%)	15.8%	
Lost energy without feed-in	58%	
Electricity prices		
displaced elec. price ($/MWh)	102	ex GST
Other financial inputs		
Debt Percentage (%)	100.0%	

Table 20: Inputs for a proposed, 100kW capacity solar PV plant at the large dam on Greyfriars Road. (All other inputs are shown in Table 48 in the Appendix.)

Table 21 presents a summary of the estimated financial performance of the existing 30kW capacity, single tracking solar PV plant at the Glen Cairn dam. This analysis suggests that this plant was a good investment. Assuming current, estimated pumping practices, this plant has an estimated payback period of 10.2 years and an IRR of 9.3% nominal. However, Table 21 also shows that if pumping is only done using network electricity, for example at night, and thus features 100% network feed-in of solar PV generated electricity, the financial performance of the solar plant becomes more attractive. Either way, this financial performance is primarily due to the generous feed-in tariff that has been guaranteed for this plant until 2028, but which is no longer available to new installations, as well as a relatively high displaced network electricity price. Indeed, this feed-in tariff and displaced electricity price resulted in this plant having good performance despite its relatively high TCR of 5548$/kW. This TCR is twice that of some current installations, in part because the cost of solar PV plants has fallen significantly in the last few years and in part because ground-mounted systems are more costly than roof-top systems.

Also, as discussed above, Moira Farming did not claim the STCs that this plant had generated. Had it done so, Table 22 then shows that with an estimated 2012 STC price of 28$/MWh (also discussed above) and historical pumping practices, the payback period would have fallen to 9.1 years and the IRR increased to 10.7% nominal. Since the opportunity to claim these STCs is now passed, we nonetheless emphasise that the financial performance of this operating plant is already good, and can be improved further with optimised pumping practice.

	Current pumping	Pumping at night
Total Capital Required ($/kW)	5548	5548
Proportion fed-in	70%	100%
Payback period (years)	10.2	8.9
NPV ($)	-8,226	9,033
IRR (nominal, %)	9.3%	10.8%
LCOE ($/MWh)	n/a	n/a

Table 21: Financial performance of the existing 30kW capacity, single tracking solar PV plant at the Glen Cairn dam, assuming current estimated levels of electricity feed-in as well as maximum feed-in. (All other inputs are shown in Table 48 in the Appendix.)

Total Capital Required ($/kW)	5548
Payback period (years)	9.1
NPV ($)	7,581
IRR (nominal, %)	10.7%
LCOE ($/MWh)	n/a

Table 22: Financial performance of the existing 30kW capacity, single tracking solar PV plant at the Glen Cairn dam, assuming current estimated levels of feed-in and 2012 STCs claimed. (All other inputs are shown in Table 48 in the Appendix.)

Table 23 presents a summary of the estimated financial performance of the proposed, 100kW capacity solar PV plant at the large dam on Greyfriars Road. The NPV of this proposed installation is significantly negative, its payback period is almost as long as the plant life and its IRR is only 3.7% nominal. This is despite the relatively low TCR of 2000$/kW, and arises primarily because of our estimate that 58% of the potentially available solar electricity will be lost due to a mismatch between the generation and pumping loads, as well as the relatively low metered electricity price. This proposed 100kW capacity

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solar PV plant therefore does not appear to be a good investment, unless there is a significant increase in the utilisation of the electricity that it potentially generates.

We therefore also calculated the proportion of total potential generation that must be consumed on-site in order for this plant to have NPV=0 (Table 23). This analysis found that 92% of all the solar generated electricity must be used to displace the network delivered electricity; a proportion that is considered unlikely given the highly variable nature of when the irrigation pumps are required. As such, this proposed plant does not appear to be viable under plausible operating conditions.

	Current Pumping	Pumping for NPV=0
Total Capital Required ($/kW)	2000	2000
Lost energy without feed-in	58%	8%
Payback period (years)	22.5	10.5
NPV ($)	-54,232	0
IRR (nominal, %)	3.7%	10.0%
LCOE ($/MWh)	222	102

Table 23: Financial performance for the proposed, 100kW capacity solar PV plant at the large dam on Greyfriars Road, assuming estimated levels of lost energy with current pumping practices as well as the lost energy required for NPV=0. (All other inputs are shown in Table 48 in the Appendix.)

2.4 Conclusion

Our analysis of the financial performance of two solar PV installations at Moira Farming obtained the following results.

1. *The existing, 30kW capacity solar PV plant at the Glen Cairn dam*

Operating since April 2012, Moira Farming's existing 30kW capacity solar PV plant appears to have been a good investment. This plant has an estimated payback period of 10.2 years and an IRR of 9.3% nominal, if our estimates of historical pumping practices continue. However, if pumping is only done using network electricity, for example at night, and thus features 100% network feed-in of solar PV generated electricity, the financial performance of the solar plant becomes more attractive. Either way, this financial performance is primarily due to the generous feed-in tariff that has been guaranteed for this plant until 2028, but which is no longer available to new installations, as well as a relatively high displaced network electricity price. Indeed, this feed-in tariff and displaced electricity price resulted in this plant having good performance despite its relatively high TCR of 5548$/kW.

Also, as discussed above, Moira Farming did not claim the STCs that this plant had generated. Had it done so, then with an estimated 2012 STC price of 28$/MWh and historical pumping practices, the payback period would have fallen to 9.1 years and the IRR increased to 10.7% nominal.

2. *The proposed, 100kW capacity solar PV plant at the large dam on Greyfriars Road*

It has been proposed that this plant would be used to drive irrigation pumps whose electricity is currently metered on a contestable contract with a relatively low price. Further, since network feed-in will be unlikely for this proposed plant, we estimate that only 42% of the potentially generated solar electricity will be used by these pumps if current pumping practice continues. As a result, the NPV of this proposed installation is significantly negative, its payback period is almost as long as the plant life and its IRR is only 3.7% nominal. This is despite the relatively low, quoted TCR of 2000$/kW.

This proposed 100kW capacity solar PV plant therefore does not appear to be a good investment, unless there is a significant increase in the utilisation of the electricity that it potentially generates. We also calculated that 92% of total potential generation that must be consumed on-site in order for this plant to have NPV=0, a proportion that is considered unlikely given the highly variable nature of when the irrigation pumps are required. As such, this proposed plant does not appear to be viable under plausible operating conditions.

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3. Corrigan's Produce Farms: Exploring on-site generation in Victoria

Corrigan's Produce Farms consumes significant electrical power across all seven days of the week. Given this significant and consistent electrical load at the site, we explored whether on-site generation is viable for this Victorian grower.

3.1 Background on Corrigan's Produce Farms operations

Corrigan's Produce Farms has 210 hectares under cultivation over 3 farms in close proximity at Clyde North in south-east Gippsland [63]. The farms are located on the edge of Melbourne, with significant new housing developments within several kilometres [60].

Corrigan's Produce grows and packs vegetables for supermarkets, wholesalers and interstate markets [63]. Their product line includes baby cos lettuce, salad onions, celery, pak choy, leeks, silverbeet, celeriac and kale. Baby cos lettuce is the largest crop, accounting for around half of all plantings [62]. Corrigan's supplies more than 2.4 million cos lettuces each year to one of their major customers Coles [64]. The business operates 7 days a week, year round, with summer busier than winter.

The home farm includes processing facilities where vegetables are washed, sorted, graded, cut and packed. There are also three large cool rooms used to rapidly reduce the temperature of the vegetables after harvesting, to maintain vegetable temperature after processing, and for storage at optimal temperatures following packing and packaging [58,59,60]. In a recent energy audit of Corrigan's Produce, the cool rooms were estimated to consume more than 60% of the total electricity used in the processing facilities, workshops and offices on the home farm [62].

On each of the three farms, there are pumping and irrigation processes which operate as needed depending on local rainfall and crop requirements [59]. Any waste produced in the fields or at the processing facilities is ploughed back into the soil to improve soil health.

3.2 Energy consumption and needs

There are five metered connections to Corrigan's Produce operations. One of these meters (at the main facility) measures electricity consumption at the processing shed, cool rooms and offices as well as the pumping at the twin dams south of the facility, and accounts for the majority of consumption and cost. The remaining four meters measure power consumption for pumping and irrigation at different dams [58,61].

Figure 23 below shows indicative annual electricity consumption at these five meters across peak and off-peak periods. The main facility meter accounts for 70% of all energy usage, two meters consume 10-12% of the total energy each and the two smallest meters 3-4% each [61].

Consumption at the four irrigation meters varies significantly by month or by quarter and this volatility in consumption would make it difficult to justify investment in power plant. For this reason, we focussed the energy analysis and case study on the main facility.

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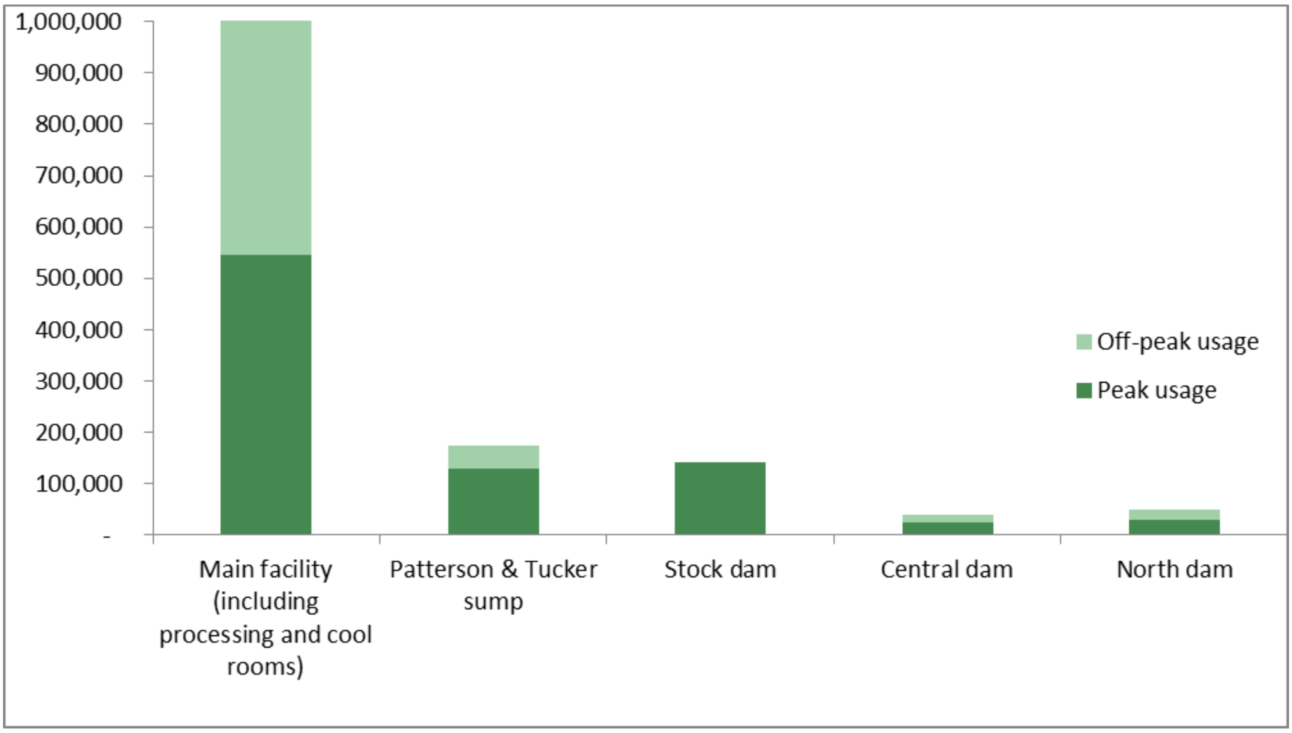

Figure 23: Corrigan's Produce Farms annual energy usage (kWh) [61]

Annual energy consumption for 2013 at the main facility was approximately 1000MWh, with 55% consumed as peak energy. Figure 24 below shows the electricity consumption by month across peak and off-peak periods. Whilst consumption does vary between winter and summer, consumption in the lowest month was still more than 70% of the peak month consumption. Hence there is a consistent load at the factory which operates during daylight hours, 7 days a week for 11-12 hours a day. Baseload demand is 60-100kW year round [61].

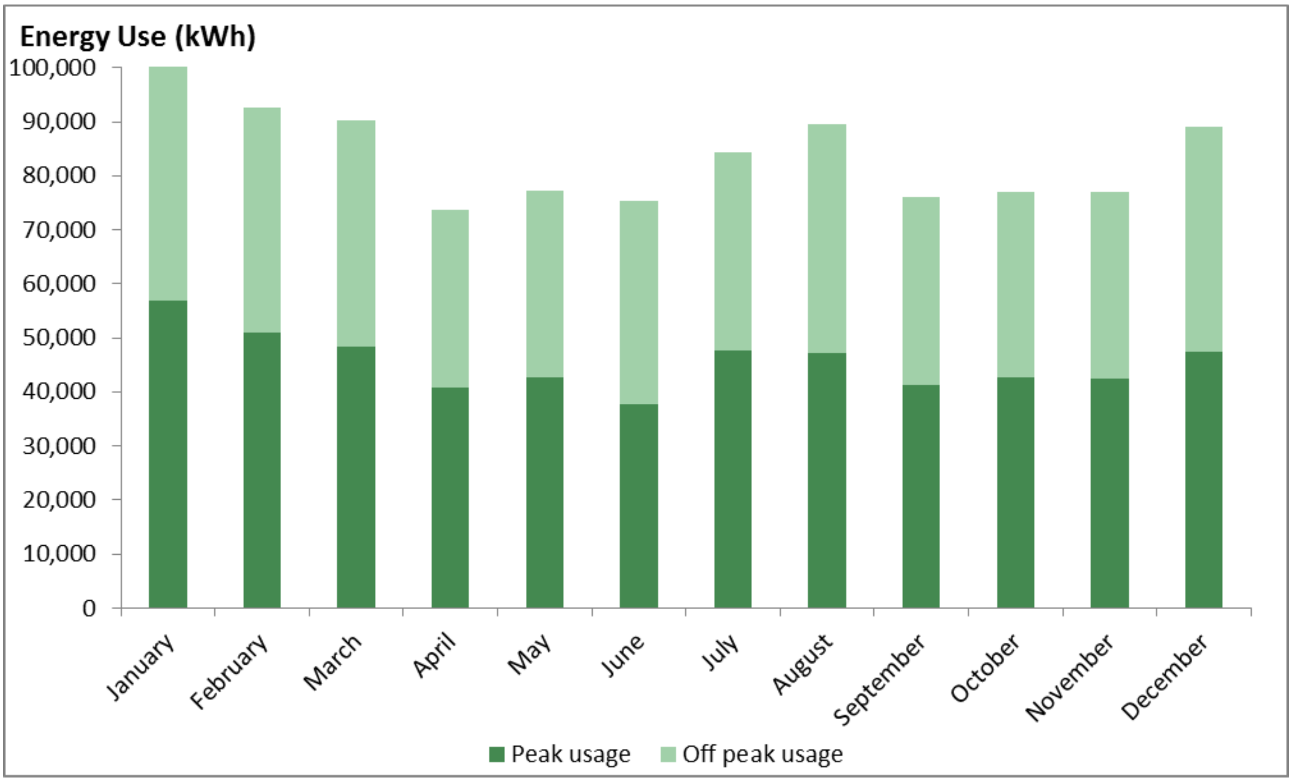

Figure 24: Monthly electricity usage (kWh) and peak demand (kW) for the main facility [61]

Corrigan's Produce is on a contestable contract for its main facility meter. Key components of the bills are:

- energy charges (with different rates for peak and off-peak consumption),
- network charges (including consumption charges for peak, shoulder and off-peak period as well as demand charges levied per kVA of variable demand and demand capacity),
- and other environmental, market, service and metering charges.

The tariff structure is more complex than that examined in other case studies. With the addition of network charges for the shoulder period, the effective total charges per kWh during the three time-of-use periods are 14.1c/kWh peak, 15.0c/kWh shoulder and 9.4c/kWh off-peak[1]. In addition, there is a demand capacity charge of $3.36/kVA/month charged on maximum demand capacity of 300kVA and a variable demand charge of $4.96/kVA/month charged on an annual set-point of 255kVA (likely to be the maximum metered kVA during the previous 12 month contract period). Network access, metering and service charges add $22.82/day to the bill [61].

Total annual electricity cost for the main facility is approximately $185,000 excluding GST, of which energy charges account for almost a quarter and network charges are more than 60%. Network demand charges (variable and capacity charged per kVA) are about 15% of total annual spend [61].

[1] Peak: 3-9pm weekdays; Shoulder 7am-3pm weekdays, 9-10pm weekdays and 7am-10pm weekends; off peak 10pm-7am on weekends and weekdays; during summer these times shift to an hour later.

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3.3 Feasibility of potential on farm power generation technologies

The analysis of options at Corrigan's Produce Farms focused on solar PV and generation from LPG or natural gas for the following reasons:

- With significant roof space and seven day/week operation during daylight hours, Corrigan's Produce Farms may be a good candidate for solar PV at their main facilities.
- Similarly, the consistent baseload and consumption patterns may improve the economics of generation on-site using natural gas or delivered LPG. Whilst Corrigan's is not presently connected to the gas network, connections are available that make use of piped natural gas an option.

Other possible options have been excluded since the available energy resources are not attractive.

- *Biomass generation*: There is little biomass waste generated at the facility and no other known local sources of biomass that could be used to cheaply fuel a biomass generator.
- *Wind power*: Average annual wind speeds in the area are estimated to be 3.5-4m/s [65,26,66], below the recommended minimum of 4.5-5m/s for consideration of wind power [23,24].

3.3.1 Solar PV

We now consider the financial performance of a proposed, 100kW capacity solar PV installation at Corrigan's Produce Farm. This proposed solar plant has the following features (Table 24).

- The estimated low, medium and high Total Capital Required (TCR) in Table 48 were used to estimate the likely financial performance. Table 24 shows these inputs for the medium TCR of 2500$/kW ex GST.
- The capacity factor and STC income are calculated using the procedure specified by the Federal Government's Clean Energy Regulator [4]. This classifies Corrigan's as being in zone 4, earning the STCs stated in Table 24 and having a capacity factor of 13.5%.
- Most network service providers no longer allow electricity to be fed into the network from solar systems of 100kW capacity. However, whilst Corrigan's baseload power consumption is approximately 80kW, this occurs at night since they operate seven days per week all year round. Thus, all electricity generated by a 100kW capacity solar PV plant will be consumed on-site, and since the analysis is insensitive to assumptions about feed-in-tariff, this will be ignored.
- Corrigan's weekday and weekend daytime electricity prices are 14.5c/kWh and 15.0c/kWh respectively. This results in a weighted average displaced electricity price of 14.7c/kWh. Since network demand charges are based on an annual or agreed set point, the analysis assumes that there is no reduction in these charges as a result of solar PV installation.

Capacity and capital required		
Plant Capacity (MW)	0.1	
Total Capital Required ($/kW)	2500	ex GST
STC related inputs		
STC price ($/MWh)	35	with GST
STC zone rating (MWh/kW)	1.185	
STCs (MWh)	1777	
STC income ($)	62195	with GST
Other technical inputs		
Capacity Factor (%)	13.5%	
On-site consumption	100.0%	
Electricity prices		
displaced elec. price ($/MWh)	147	ex GST
Other financial inputs		
Debt Percentage (%)	100.0%	

Table 24: Inputs for a proposed 100kW capacity solar PV plant at Corrigan's Produce Farm. (All other inputs are shown in Table 48 in the Appendix.)

Table 25 presents a summary of the financial performance of this proposed installation. These analyses are presented using the low, medium and high TCRs stated in Table 48 of 1880, 2500 and 3130 $/kW ex GST respectively. Also shown in bold is the TCR required for the proposed installation to have NPV=0, i.e. the *marginal installation cost*. Only installations cheaper than this can potentially make sense for Corrigan's Produce Farm.

Should Corrigan's be able to install and operate a solar PV plant for less than 2331 $/kW ex GST (i.e. 1766$/kW less STCs and ex GST), then this investment may be attractive, if fully debt financed over 10 years.

	Low TCR	TCR NPV=0	Medium TCR	High TCR
Total Capital Required ($/kW)	1880	**2331**	2500	3130
Total Capital Required less STCs ($/kW)	1315	**1766**	1935	2565
Payback period (years)	8.1	**10.6**	11.5	15.0
NPV ($)	34,915	**0**	-13,082	-61,854
IRR (nominal, %)	13.3%	**10.0%**	9.1%	6.6%
LCOE ($/MWh)	109	**147**	161	214

Table 25: Financial performance of a proposed 100kW capacity solar PV plant at Corrigan's Produce Farm. (Analysis is ex GST and assumes 100% debt financing.)

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3.3.2 Simple and co-generation using an LPG fuelled reciprocating engine generator

The financial performance of two different engine driven plants was considered for Corrigan's Produce Farm. These plants both operate on natural gas and have the following features.

1. Simple generation plant: This plant generates electricity only, with the plant's inputs stated in Table 26 for the medium TCR case of 1200$/kWe ex GST. This plant displaces *grid electricity only*. It has a capacity of 80kWe, which is Corrigan's baseload electricity consumption, and so is sized to operate 24/7/365 in order to maximise equipment utilisation. Its capacity factor of 80% means that it generates 64kWe on average.
2. Cogeneration plant: This plant generates electricity and cooling for Corrigan's cool rooms, the latter via engine waste heat recovery and an absorption chiller. The plant's inputs are stated in Table 27 for the medium TCR case of 1440$/kWe ex GST. This plant displaces grid electricity, where that electricity would have been otherwise used for any purpose, including driving the existing refrigeration plant. The cogeneration plant has a capacity of 60kWe and a capacity factor of 80%. This means that the average network electricity displaced is 68kWe, which is the sum of 48kWe from the generator and 20kWe from use of the absorption chiller rather than a refrigeration plant. Once again, this plant sizing was chosen to operate 24/7/365 in order to maximise equipment utilisation.

Cogeneration of electricity and heat is not examined since Corrigan's doesn't have significant requirements for process heat. Of further note are the following.

- Whilst these plants may be able to feed-in electricity to the network, this is unlikely to be financially attractive because the feed-in tariff that Corrigan's Produce Farm would get is likely lower than the price of their displaced network electricity.
- In contrast to the analysis for the solar plant, the average price of the displaced network electricity assumes that both the simple and cogeneration plants operate at the same power output across the entire week. This means that the average price of the displaced network electricity is now simply weighted by the proportion of hours per week with peak, shoulder and off-peak tariffs, giving an average electricity price of 12.7c/kWh.

Table 28 presents a summary of the financial performance of the proposed simple generation plant using the low, medium and high TCRs stated in Table 50 of 900, 1200 and 1500 $/kW ex GST respectively. The fuel price was calculated by setting NPV=0 for a given TCR. As such, natural gas must be cheaper than this in order to achieve a positive NPV and therefore an IRR of at least 10% nominal. Similar analysis is also shown for the proposed cogeneration (electricity and cooling) plant at Corrigan's in Table 29. As with the other case studies, this marginal fuel price depends only weakly on the TCRs of both the simple generation plant and the cogeneration plant.

Capacity and capital required		
Plant Capacity (MWe)	0.02	
Total Capital Required ($/kWe)	1200	ex GST
Other technical inputs		
Engine capacity factor (%)	80.0%	
Engine efficiency (%)	35.0%	
Electricity prices		
Displaced elec. price ($/MWh)	127	ex GST

Table 26: Inputs for potential 60kWe capacity simple electrical generator at Corrigan's Produce Farm. (All other inputs are shown in Table 50 in the Appendix.)

Capacity and capital required		
Plant Capacity (MWe)	0.015	
Total Capital Required ($/kWe)	1440	ex GST
Other technical inputs		
Engine capacity factor (%)	80.0%	
Engine efficiency (%)	35.0%	
Heat recovery efficiency (%)	80.0%	
Chiller COP	0.7	
Refrigerator COP	2.5	
Electricity prices		
Displaced elec. price ($/MWh)	127	ex GST

Table 27: Inputs for potential 60kWe capacity cogeneration (electricity and cooling) plant at Corrigan's Produce Farm. (All other inputs are shown in Table 51 in the Appendix.)

The annual natural gas consumption of these plants is in the range of 4-6 TJ. This places Corrigan's as a larger of the so-called 'small commercial customers' of the major energy retailers, and below the commonly used 10 TJ threshold for 'large commercial customers'. Whilst the gas price that Corrigan's can obtain requires negotiation with different retailers in addition to paying for gas network connection, our own discussions with a major energy retailer suggest that current natural gas contracts for customers of this size are roughly 10 $/GJ [14]. This in turn suggests that the simple generation of electricity is marginally viable at best but that the cogeneration of electricity and cooling may be viable.

	Low TCR	Med TCR	High TCR
Total Capital Required ($/kW)	900	1200	1500
Fuel price ($/GJ)	10	10	9
Payback period (years)	9.2	9.6	9.9
NPV ($)	0	0	0
IRR (nominal, %)	10.0	10.0	10.0
LCOE ($/MWh)	127	127	127

Table 28: Fuel price required to achieve NPV=0 for a potential 80kWe capacity electrical generator at Corrigan's Produce Farm. (All prices are ex GST and assume 100% debt financing.)

	Low TCR	Med TCR	High TCR
Total Capital Required ($/kW)	1080	1440	1800
Fuel price ($/GJ)	15	14	14
Payback period (years)	8.9	9.4	9.7
NPV ($)	0	0	0
IRR (nominal, %)	10.0	10.0	10.0

Table 29: Fuel price required to achieve NPV=0 for a potential 60kWe capacity cogeneration (electricity and cooling) plant at Corrigan's Produce Farm. (All prices are ex GST and assume 100% debt financing.)

A key uncertainty to the financial performance of cogeneration at Corrigan's Produce Farm is therefore the cost of natural gas network connection. The maximum allowable cost of this connection can be estimated by assuming that Corrigan's can obtain a gas contract for 10 $/GJ. The (positive) NPV that results can then be considered to be the maximum allowable cost of network connection, as shown in Table 30.

There is a high pressure, 5” gas main running underground and along the road at the front of the property. Connecting a cogeneration plant to this main will involve installation of a pipe of order 100m length, as well as the installation of a gas meter and regulator. Our discussions with a major energy retailer [14] suggested that the total cost of this connection would be very likely to be less than the maximum allowable costs shown in Table 30. Thus, cogeneration including network connection appears to be feasible. However, binding quotes on the gas price, network connection charges and on-site plant investment would be required in order to be confident of these costs.

	Low TCR	Med TCR	High TCR
Total Capital Required ($/kW)	1080	1440	1800
NPV ($)	174,084	157,362	140,641

Table 30: NPV of a potential 60kWe capacity cogeneration (electricity and cooling) plant at Corrigan’s Produce Farm with a fuel price of 10$/GJ. (All prices are ex GST and assume 100% debt financing.)

3.4 Conclusion

This case study analysed two forms of on-site power generation for Corrigan’s Produce Farm.

Should Corrigan’s be able to install and operate a solar PV plant for less than 2331 $/kW ex GST (i.e. 1766$/kW less STCs and ex GST), then this investment would achieve an IRR of at least 10% nominal. Compared to several of the other growers examined in this report, this is relatively attractive performance, and arises because of Corrigan’s relatively high metered electricity price as well as their high electricity consumption on each day of the year. This plant cost is close to the medium current price of solar installations estimated in Australia.

Our analysis also suggested that the use of network delivered natural gas and a simple engine generator is likely not viable, but that cogeneration of electricity and cooling may be viable. In the case of simple generation, the calculated fuel prices without including the cost of gas network connection were in the range of current contracts with natural gas retailers for customers of this size. As such, including the cost of network connection would likely result in negative NPVs. However, with the same natural gas contracts, cogeneration of electricity and cooling is potentially viable even when the cost of network connection is included. However, binding quotes on the gas price, network connection charges and on-site plant investment are required in order to be confident of these costs.

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4. *Kalfresh: Exploring on-site generation at Kalbar, Queensland*

Vegetable production company, Kalfresh, is a large consumer of electricity at its processing facilities at Kalbar. They are interested in exploring whether on-site power generation makes economic sense as a strategy to protect against possible future increases in power prices.

4.1 Background on Kalbar operations

Kalfresh is a vegetable growing business that has expanded over time to become a major vegetable production company. Kalfresh has around 1500 acres under cultivation in the Fassifern and Lockyer valleys growing carrots, beans and pumpkin. However, it is now primarily a packing, distribution and marketing company that works closely with a network of Queensland growers to supply major retailers and the central market system [67,69,71].

Kalfresh's main product lines are carrots (70-80%), green beans (5-10%), onions (10-15%) and pumpkin (5%) [68]. The business is highly seasonal, with Figure 25 below showing availability for Kalfresh vegetables. Since carrots represent the majority of the business, the 'high season' runs from June to December with the facilities operating 6 days/week over 2 shifts, for up to 22 hours each day. The highest consumption period is October to December when all major lines are operating. Operation during the 'low season' is 5 days/week mostly with a single line operating at one facility. It is estimated that during peak season (June to December), Kalfresh would supply up to 80% of the carrots consumed in Australia's eastern states [68].

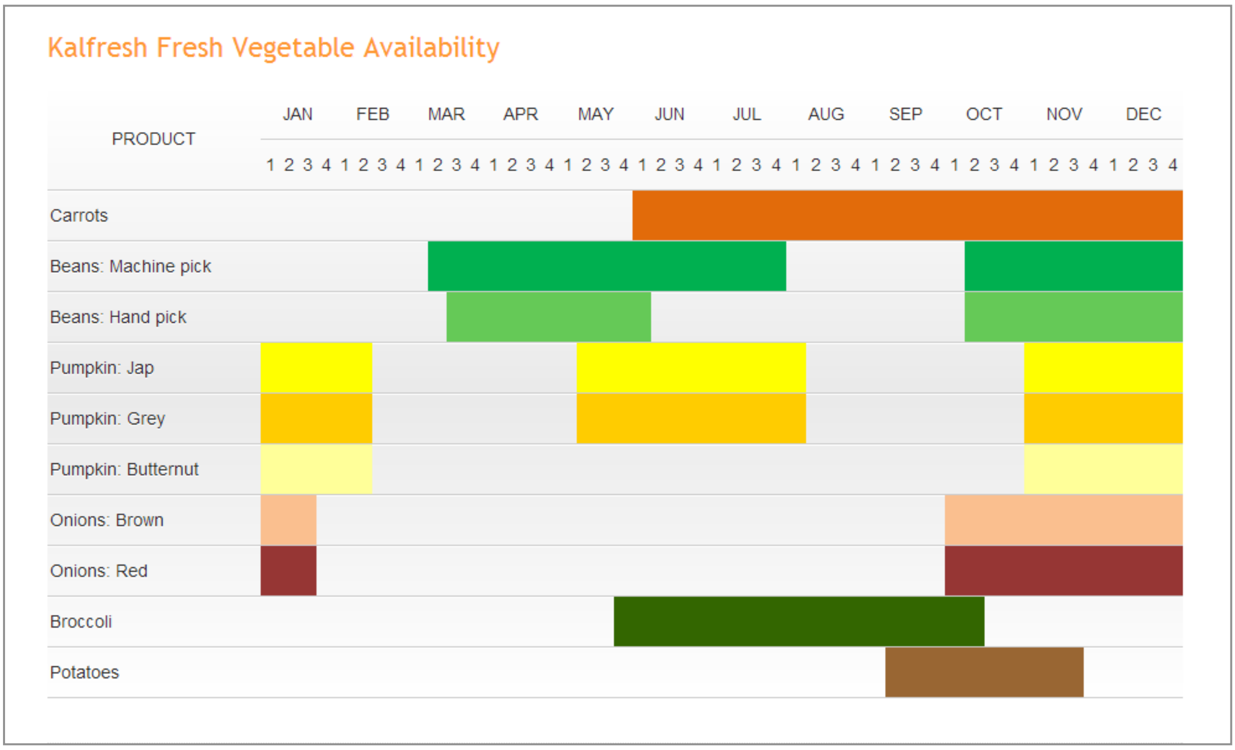

Figure 25: Kalfresh Vegetable Availability [72]

There are two processing facilities on the Kalbar site. The main processing facility is used to process carrots, beans, pumpkins and broccoli. Energy consuming processes within the facility include:

- Washing for each of the vegetable lines
- Hydro-cooling for the carrot and bean lines
- Sorting and grading for all of the vegetable lines
- Packaging and packing for all of the vegetable lines

The onion facility facing the main factory is used for drying, sorting and packing of onions only.

There are cool rooms for short-term storage of some products but the business aims to process only what can be sold hence products are generally transported directly after packing via refrigerated trucks [69]. It is estimated that around 60% of power consumed is used in hydro-cooling or refrigeration processes [68].

At the growing sites, there are irrigation and pumping processes which operate only over the growing seasons and intermittently depending on local rainfall and crop needs.

There is relatively little waste produced by the packing facility at Kalbar since the aim is to process and sell the whole crop. For example, carrots not destined for retail sale may be chopped and sold to the food service industry, food manufacturers or pet food processors. Any genuine biomass waste from the operations is composted or used as stock feed [67,68].

4.2 Energy consumption and needs

The focus of the energy analysis and case study was on the processing and packing facilities at Kalbar since they consume more than 95% of the power across the business. In addition, the irrigation requirements for Kalfresh farms are generally intermittent so it would be difficult to justify the investment in power generation plant. Power consumption at other farms which supply Kalfresh is not known.

There are two metered connections at the Kalbar site, one for main carrot, bean and pumpkin processing facility and the other for the onion facility.

4.2.1 Energy consumption at the main processing facility

Annual energy consumption for 2013 at the main processing facility was approximately 2060MWh, with just over 60% consumed as peak energy. High season accounts for roughly 90% of annual kWh and peak demand is also high at 700-800kW each month [70]. Baseload demand during high season is around 100kW. October and November are the highest months for power consumption with all lines running at capacity. In the low season, the facility operates with much lower loads and consumption. Peak demand at this time is around 100-200kW each month and baseload at nights and on weekends is only 5-15kW [70].

Figure 26 below shows indicative annual electricity consumption across peak and off-period periods for the main processing facility as well as monthly peak demand.

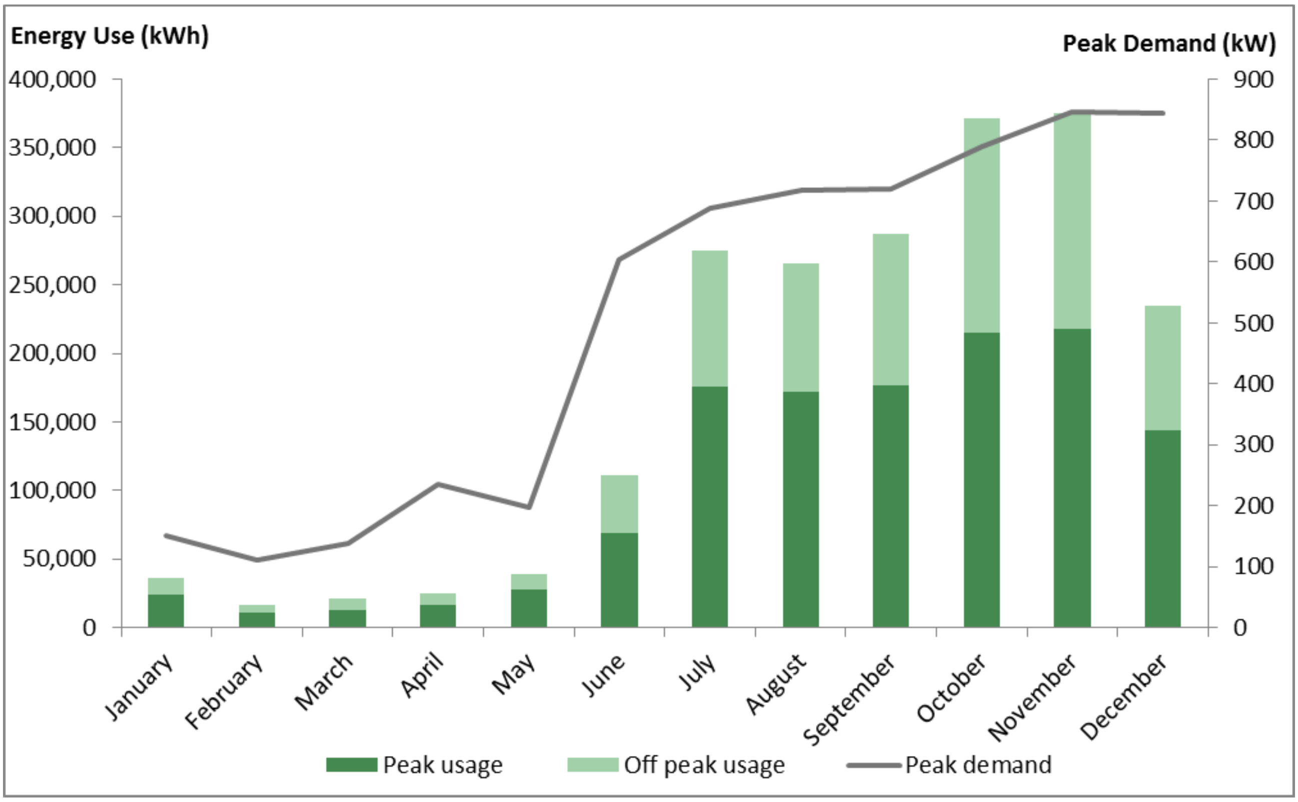

Figure 26: Monthly electricity usage (kWh) and peak demand (kW)

The peak demand billed varies from month to month between 110-850kW, with average annual peak demand of 526kW. The average during the high season is 744kW and during the low season is 167kW [70]. The time of day for peak demand varies from month to month as shown in Table 31 below.

	Time of day for monthly peak demand
January	11.00am
February	11.00am
March	2.30pm
April	2.40pm
May	2.30pm
June	11.30am
July	3.00pm
August	2.30pm
September	3.00pm
October	4.00pm
November	12.30pm
December	4.00pm

Table 31: Time of day for monthly peak demand by month

Whilst peak demand often occurs during the middle of the day, this is not consistently the case and examination of detailed demand data highlights that demand is also high early or late in the day at some point during any month. Figure 27 below for an indicative high season month highlights this pattern which is important when considering the economics of solar PV. In this month, the peak demand of 847W was reached at 12.30pm i.e. the middle of the day. However, demand also exceeded 800kW at several other times during the month, with time of day ranging from 10.30am to 5pm on separate days [70].

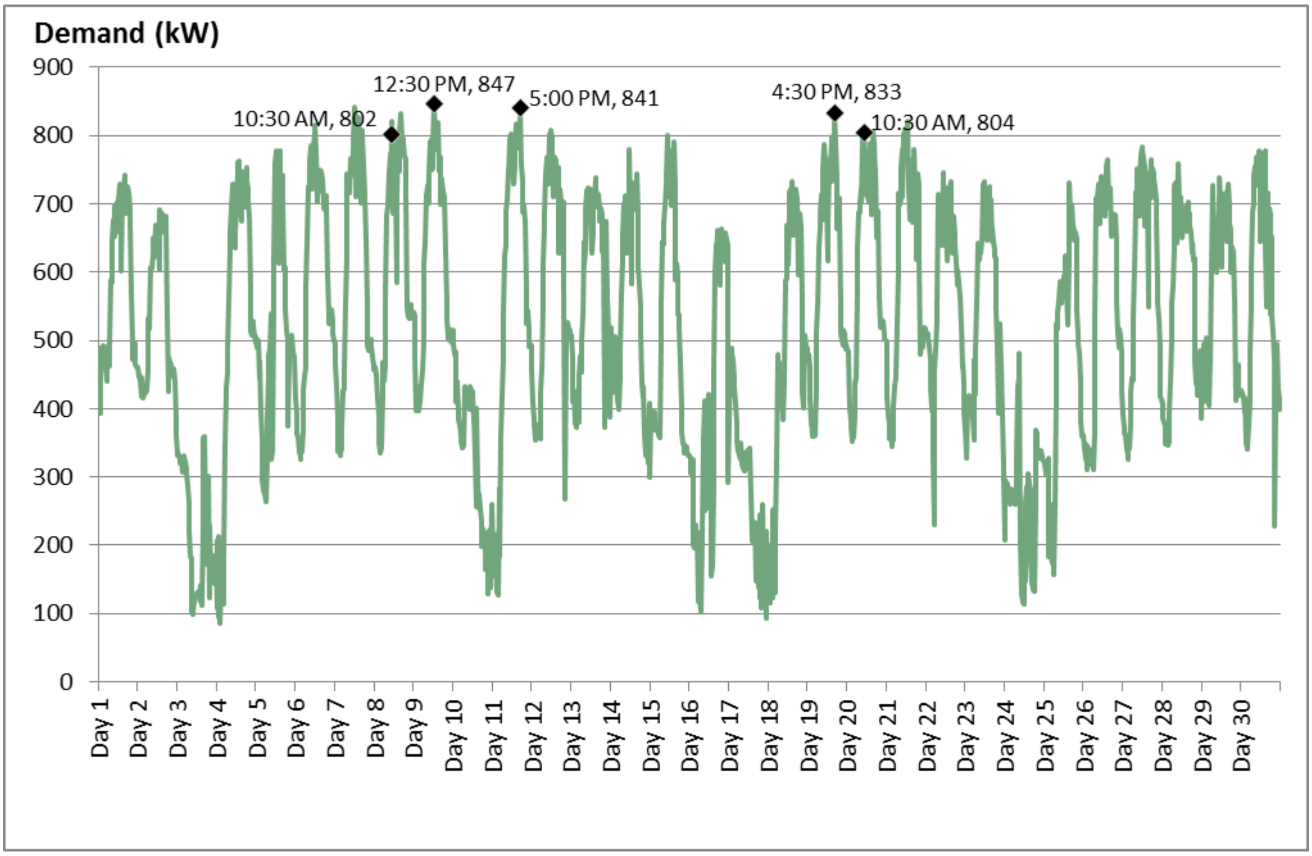

Figure 27: Demand (kW) over an indicative month

Based on the data from Table 31 and Figure 27 above, it is not reasonable to assume that network demand charges would be lower after installation of a solar system considering time of day for peak solar PV output as well as variability in solar output. Similarly, monthly fixed charges would not be affected by installation of on-site power generation since the grower remains grid connected. Hence cost comparison of solar PV vs. current electricity prices should be made only on the basis of the charges driven by kWh.

As a larger customer on a contestable contract, Kalbar has been able to negotiate lower rates than other growers for its main processing facility. Key components of the bills are energy charges (with different rates for peak and off-peak consumption), network charges (which are dominated by demand charges for monthly peak demand), and other environmental, market, fixed supply and metering charges. In essence, there are four cost drivers:

- 9.1c/kWh for peak consumption (7am-11pm weekdays),
- 7.5c/kWh for off-peak consumption (all other times),
- $19/kW for peak monthly demand and
- $45.36/day.

Total annual electricity cost for the main processing facility is approx. $300,000 excluding GST of which energy charges account for just over 40% and network charges almost 50%. Peak demand charges represent just over 35% of annual spend.

4.2.2 Energy consumption at the onion processing facility

The onion facility consumes 90-95MWh each year (grid electricity) of which 40% is consumed during November and December. During these busy months, Kalfresh also hires a 150kVA diesel generator to supply additional power to the onion facility for 8 weeks to ensure the site does not exceed its maximum power capacity. Cost for grid power to the onion facility is around $22,000 each year, based on a flat rate of 23.2c/kWh and daily supply charges [70]. Indicative monthly consumption is shown in Figure 28 below. Data on the demand profile for this site is not available.

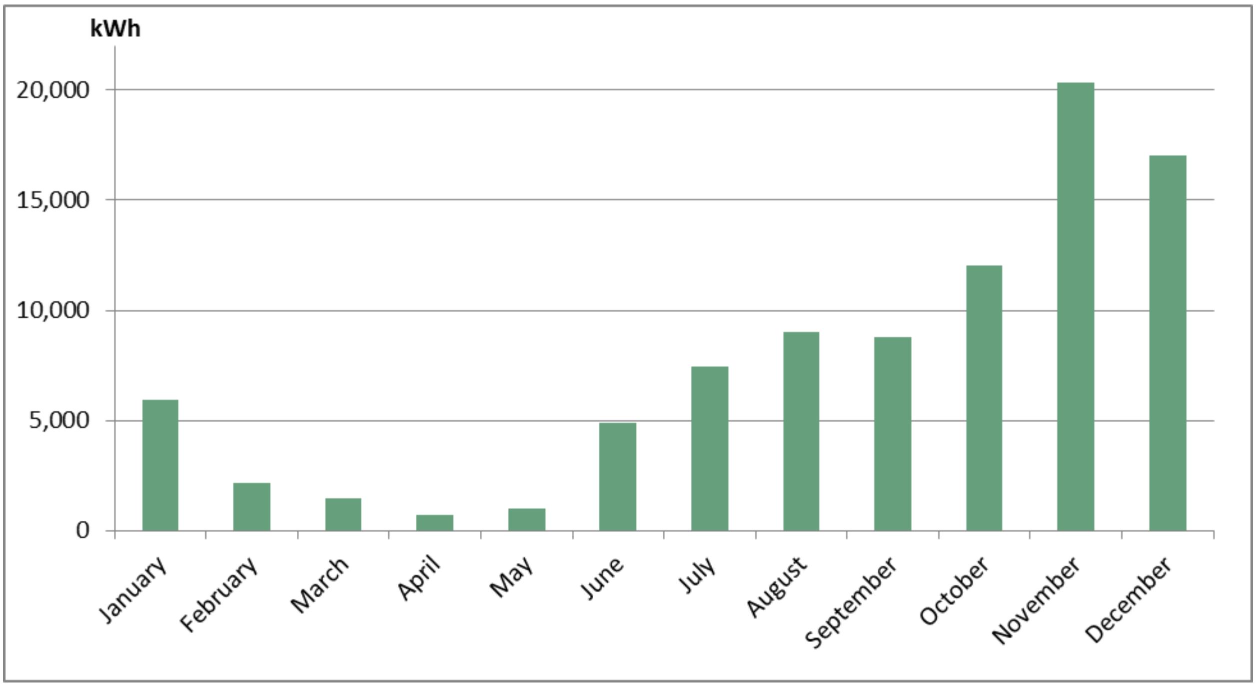

Figure 28: Indicative monthly consumption (kWh) for Kalfresh onion facility

4.3 Feasibility of potential on farm power generation technologies

The analysis of options at Kalbar focused on solar PV and simple generation from LPG or natural gas for the following reasons:

- Kalfresh has been approached several times regarding installation of solar PV panels on the large roof space on the processing facilities. However, given the large variation in load from the high season to low season, this has never appeared to be feasible. We examined whether and how this might work for both the carrot and bean processing factory as well as the onion factory.
- Since Kalfresh already hires a generator at peak season, it is worth investigating whether it would make sense to purchase and install a generator and operate it to displace electrical load year round.

Other possible options have been excluded from the analysis since energy resources are not attractive.

- *Biomass generation*: Little biomass waste is generated at the facility. There are no other known local sources of biomass that could be used to cheaply fuel a biomass generator.
- *Wind power*: Average annual wind speeds in the area are estimated to be 2-4m/s [73,26,74], below the recommended minimum of 4.5-5m/s for consideration of wind power [23,24].

4.3.1 Solar PV

The financial performance of three potential rooftop solar PV installations at Kalfresh was considered:

1. *A potential 100kW capacity solar PV plant located on Kalfresh's main processing facility (*Table 32*).*

   Most network service providers no longer allow electricity to be fed into the network from solar systems of 100kW capacity. In this case, any electricity that cannot be consumed on-site does not generate any income through feed-in-tariffs (FiTs), and so reduces the financial performance of the installation. Kalfresh's main processing facility has a baseload power consumption of about 15kW over nights and weekends for six months of the year, and then 100kW for the remaining six months. Using the method presented under Task 3 of this report, this means that only approximately 82% of the solar electricity (kWh) generated during the quieter six months can be used since export to the network is unlikely. All of the solar energy generated during the busier six months will be consumed on site.

   This translates to loss of only 9% of potential energy generation across the year. Thus, a 100kW capacity plant appears to be appropriate for Kalfresh because it is the largest installation that can earn STCs up front (and thus avoid the complexities of larger installations and LGCs), in turn enabling the largest practical displacement of network electricity during weekdays when network delivered electricity is at its most expensive.

   Kalfresh's main processing facility has peak and off-peak metered network electricity prices of 9.1c/kWh and 7.5c/kWh respectively, covering the daylight hours of weekdays and weekends. This results in a weighted average displaced electricity price of 8.8c/kWh. The analysis assumes that there is no reduction in network demand charges as a result of solar PV installation, since these charges are driven by peak monthly metered demand (in kW) and the peak monthly demand may not coincide with solar output as discussed above. Due to this uncertainty, it is prudent to exclude any possible reduction in demand charges from decision making.

2. *A potential 30kW capacity solar PV plant located on Kalfresh's onion processing facility (*Table 33*).*

   This plant was chosen since network service providers typically allow feed-in from solar PV plants

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with capacities of up to 30kW.
The energy consumption on Kalfresh's onion processing facility is highly seasonal, as shown in Figure 28. Applying the method presented in Section 2 to each month's average power consumption, and assuming single shift, 5 days per week consumption from February to September and single shift, 7 days per week consumption from October to January, results in 65% on-site consumption of the electricity generated by this 30kW capacity solar plant, with 35% exported to the network. Whilst we acknowledge shortcomings in this method for estimating the proportions of on-site and exported electricity, more rigorous analysis is not possible without time-of-use consumption data. Such data is not available from the meter for this site.
Kalfresh's onion processing facility has a flat, electricity price of 23.2c/kWh.

3. *A potential 15kW capacity solar PV plant located on Kalfresh's onion processing facility.*
   This plant was chosen as a comparison to the 30kW plant above. Using the method detailed above results in 72% on-site consumption and 28% feed-in from the solar generated electricity. All inputs for this proposed 15kW capacity facility are the same as that for the 30kW facility, as shown in Table 33.

In all three cases, of further note is that the capacity factor and STC income are calculated using the procedure specified by the Federal Government's Clean Energy Regulator [4]. This classifies Kalfresh as being in zone 3, earning the stated STCs and having a capacity factor of 15.8%.

Capacity and capital required		
Plant Capacity (MW)	0.1	
STC related inputs		
STC price ($/MWh)	35	with GST
STC zone rating (MWh/kW)	1.382	
STCs (MWh)	2073	
STC income ($)	72555	with GST
Other technical inputs		
Capacity Factor (%)	15.8%	
Lost energy without feed-in	9.0%	
Electricity prices		
feed-in tariff ($/MWh)	0	ex GST
displaced elec. price ($/MWh)	88	ex GST
Other financial inputs		
Debt Percentage (%)	100.0%	

Table 32: Inputs for a potential 100kW capacity solar PV plant on the main processing facility at Kalfresh. (All other inputs are shown in Table 48 in the Appendix.)

Capacity and capital required		
Plant Capacity (MW)	0.03	
STC related inputs		
STC price ($/MWh)	35	with GST
STC zone rating (MWh/kW)	1.382	
STCs (MWh)	2073	
STC income ($)	72555	with GST
Other technical inputs		
Capacity Factor (%)	15.8%	
Proportion fed-in	35%	
On-site consumption	65%	
Electricity prices		
feed-in tariff ($/MWh)	55	ex GST
displaced elec. price ($/MWh)	232	ex GST
Other financial inputs		
Debt Percentage (%)	100.0%	

Table 33: Inputs for a potential 30kW capacity solar PV plant on the onion processing facility at Kalfresh. (All other inputs are shown in Table 48 in the Appendix.)

Table 34 presents a summary of the financial performance of the proposed 100kW capacity solar PV plant on Kalfresh's main processing facility. These analyses are presented using the low, medium and high Total Capital Required (TCR) stated in Table 48 of 1880, 2500 and 3130 $/kW ex GST respectively, and all show a negative NPV. This demonstrates that solar PV is not likely to be an attractive option for the main processing facility unless fully installed capital costs for a solar PV plant are very competitive.

The key to the poor performance of solar PV in this instance is the low price of Kalfresh's electricity excluding demand charges (Table 32). This is in contrast to several of the other case studies presented in this report.

	Low TCR	Med TCR	High TCR
Total Capital Required ($/kW)	1880	2500	3130
Total Capital Required less STC ($/kW)	1220	1840	2470
Payback period (years)	11.0	16.3	22.3
NPV ($)	-4,980	-52,977	-101,479
IRR (nominal, %)	9.4%	5.8%	3.7%
LCOE ($/MWh)	93	142	192

Table 34: Financial performance of the potential 100kW capacity solar PV plant on the main processing facility at Kalfresh. (All prices are ex GST and assume 100% debt financing.)

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Table 35 and Table 36 present summaries of the financial performance of the proposed 30kW and 15kW capacity solar PV plants on Kalfresh's onion processing facility. Once again, these analyses are presented using the low, medium and high TCRs stated in Table 48 of 1880, 2500 and 3130 $/kW ex GST respectively. Also shown in bold in Table 35 is the TCR required for the proposed installation to have NPV=0, i.e. the *marginal installation cost*. All of the proposed 30kW installations that are cheaper than this, as well as all of the proposed 15kW installations, have a positive NPV. The smaller of the two units should perform better in terms of IRR and payback period, since it uses a greater proportion of its generation to displace the more expensive network electricity rather than export at lower prices. Nonetheless, for a given TCR with positive NPV, the 30kW plant has a greater NPV since the bigger unit generates more electricity and thus more income. Overall, both cases perform relatively well because the displaced electricity is relatively expensive.

	Low TCR	Medium TCR	TCR for NPV=0	High TCR
Total Capital Required ($/kW)	1880	2500	**3059**	3130
Total Capital Required less STC ($/kW)	1220	1840	**2399**	2470
Payback period (years)	5.8	8.3	**10.6**	10.9
NPV ($)	27,392	12,993	**0**	-1,639
IRR (nominal, %)	18.7%	12.9%	**10.0%**	9.7%
LCOE ($/MWh)	n/a	n/a	**n/a**	n/a

Table 35: Financial performance of the potential 30kW capacity solar PV plant on the onion processing facility at Kalfresh. (All prices are ex GST and assume 100% debt financing.)

	Low TCR	Med TCR	High TCR
Total Capital Required ($/kW)	1880	2500	3130
Payback period (years)	5.5	8.9	10.2
NPV ($)	15,680	8,481	1,165
IRR (nominal, %)	19.9%	13.8%	10.4%
LCOE ($/MWh)	n/a	n/a	n/a

Table 36: Financial performance of the potential 15kW capacity solar PV plant on the onion processing facility at Kalfresh. (All prices are ex GST and assume 100% debt financing.)

The best choice between these two solar PV plants, or indeed some other plant with a different capacity, therefore depends on what the business owners most value. For example, if maximising the company's value is the sole intent, then a 30kW plant may be preferred. However, this is also a more risky investment, in particular if the installed performance is not as modelled, since then the potential losses are greater.

If Kalfresh decides to invest in roof-top solar PV for the onion facility, we would advise further analysis of the facility's load profile and electricity consumption if data can be obtained. This would allow modelling of the optimal size of the installation.

4.3.2 Simple and Co-generation using an LPG fuelled reciprocating engine generator

The financial performance of an electrical generator is now considered for Kalfresh. This plant operates on LPG, with the plant's inputs stated in Table 37 for the medium TCR case of 1200$/kWe ex GST. The plant displaces *grid electricity only* for the main processing facility. It has a capacity of 100kWe, which is Kalfresh's baseload electricity consumption during the busiest 6 months of their main processing facility. It can also be turned down to produce 15kWe during the quieter six months, giving an overall annual capacity factor of 47.5%.

- Whilst this plant may be able to feed-in to the network, this is unlikely to be financially attractive. This is because the feed-in tariff that Kalfresh would get is likely lower than the price of the displaced network electricity.
- In contrast to the analysis for Kalfresh's potential solar plants, the average price of the displaced network electricity assumes that both the simple and cogeneration plants operate at the same power output across the entire week. This means that the average price of the displaced network electricity is now simply weighted by the proportion of hours per week with peak and off-peak tariffs, giving an average electricity price of 8.3c/kWh.

Capacity and capital required		
Plant Capacity (MWe)	0.1	
Total Capital Required ($/kWe)	1200	ex GST
Other technical inputs		
Engine capacity factor (%)	47.5%	
Engine efficiency (%)	35.0%	
Electricity prices		
Displaced elec. price ($/MWh)	83	ex GST
Fuel price		
Fuel price ($/GJ)	55	ex GST
Fuel price ($/MWh)	198	ex GST

Table 37: Inputs for potential 100kWe capacity electrical generator at Kalfresh. (All other inputs are shown in Table 50 in the Appendix.)

Table 38 presents a summary of the financial performance of this proposed simple generation plant using the low, medium and high TCRs of 900, 1200 and 1500 $/kW ex GST respectively. It is clear that all of these proposed plants perform very poorly on all metrics. This is because of the high price of the LPG available to Kalfresh. Further, the large, negative NPVs of all plants in Table 38 show that the TCR has only a minor effect on the financial performance. The relatively low displaced electricity price and the high fuel price dominate the financial performance in all cases. Indeed, the LCOEs presented in Table 38 show that the displaced electricity prices must be substantially higher than that metered at either the main processing facility or the onion processing facility.

Finally, cogeneration of either process heat or cooling must also be similarly uneconomic given these high fuel prices. Further analysis of cogeneration for Kalfresh was therefore not performed.

	Low TCR	Med TCR	High TCR
Total Capital Required ($/kW)	900	1200	1500
Payback period (years)	n/a	n/a	n/a
NPV ($)	-1,726,471	-1,749,696	-1,772,920
IRR (nominal, %)	n/a	n/a	n/a
LCOE ($/MWh)	618	625	633

Table 38: Financial performance of the potential 100kWe capacity simple generation plant (i.e. electricity only) at Kalfresh. (All prices are ex GST and assume 100% debt financing.)

4.4 Conclusion

Analysis of the financial performance of two forms of on-site power generation on Kalfresh's premises obtained the following results.

1. *Solar PV*

   Whilst we had limited data on the energy consumption of Kalfresh's onion processing facility, it appears that solar PV is potentially economic at this site. Plants of 30kW capacity or smaller are expected to be able to export to the network at times of low facility consumption, and thus earn feed-in tariffs, whilst displacing network electricity at other times. In most cases, these plants have a positive NPV as well as favourable payback periods and IRRs. The best choice in plant size depends on what the owner most values. For example, if maximising the company's present value is the sole intent, then a 30kW plant – the likely largest capacity plant that is allowed to export to the network – may be preferred.

   Solar PV on the onion processing facility performs relatively well because the displaced electricity is relatively expensive. This is consistent with the result for the proposed 100kW plant on the main processing facility, where the low metered electricity price results in negative NPVs in all cases.

2. *Simple and cogeneration using an LPG fuelled reciprocating engine generator*

   Our analysis found that a LPG fuelled, reciprocating engine generator will demonstrate very poor financial performance at either of Kalfesh's facilities. This is because of the high price of the LPG available to Kalfresh. Further, the large, negative NPVs of all plants demonstrate that the capital expenditure and installation costs have only a minor effect on financial performance. The high fuel price dominates the financial performance in all cases.

   Similarly, cogeneration of either process heat or cooling must also be uneconomic given these high fuel prices. Further analysis of these options for Kalfresh was therefore not performed.

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5. Austchilli: Exploring Solar PV and Co-generation in Bundaberg

Austchilli is a vertically integrated vegetable & herb grower and innovative processing company based in Bundaberg. It is committed to reducing its environmental footprint and hence energy costs to protect their business from future energy price rises. Austchilli is researching a broad range of options for on-site generation with a focus on innovative cost-effective solutions delivering short term pay-back.

5.1 Background on Austchilli operations

Austchilli is one of Australia's largest chilli growers, supplying a wide variety of fresh chillis year round to major supermarkets in Australia. In addition, the business produces and supplies aseptic chilli, vegetable and herb purees to food manufacturers and the food service sector [50]. Chillis and herbs for the purees are grown on Austchilli plantations. Austchilli also provides high pressure processing (HPP) facilities, primarily used to produce AvoFresh, for sister company Pressure Fresh Australia [51].

Biomass waste from the processing facility can be significant for some processes. For example HP processing of avocado results in half of the weight of the avocado in waste (primarily skin and pit). This waste is taken by a local compost supplier who supplies Austchilli plantations with compost needed to optimise soil health [47].

5.2 Energy consumption and needs

There are 7 metered electricity connections to Austchilli operations: one at the processing plant and six connections metering irrigation and pumping for crops. The processing facility is the major consumer of electricity, accounting for more than 90% of the 950MWh used across Austchilli annually. Irrigation meters consume less than 100MWh/year between them and were excluded from this analysis [49].

Annual energy consumption at the processing facility was approximately 865MWh, with just over 60% consumed during peak periods [49]. Electricity at the factory drives a number of processes including:

- Fresh chilli packing – washing, sorting and packing (low energy consumption)
- Ultra-high temperature (UHT) processing line for purees – washing, chopping/slicing, UHT treatment, hydro-cooling (high energy consumption)
- HPP line – chopping, cold pasteurisation by high pressure processing unit, packaging, hydro-cooling (high energy consumption)
- Cooling and refrigeration – cool rooms for food storage, chillers and hydro coolers used in processing lines (high energy consumption)

Processing lines operate over 2 shifts, 5 days a week year round although the time of operation and volume for each of the three lines can fluctuate day to day and month to month [47,48]. The plant also runs on selected weekends as needed; in 2013 the plant operated on average for 2 weekend days each month. Cool rooms and refrigeration are run 24/7 and provide a baseload demand of around 40kW [49].

Figure 29 below shows indicative annual electricity consumption across peak and off-period periods for the processing facility as well as monthly peak demand.

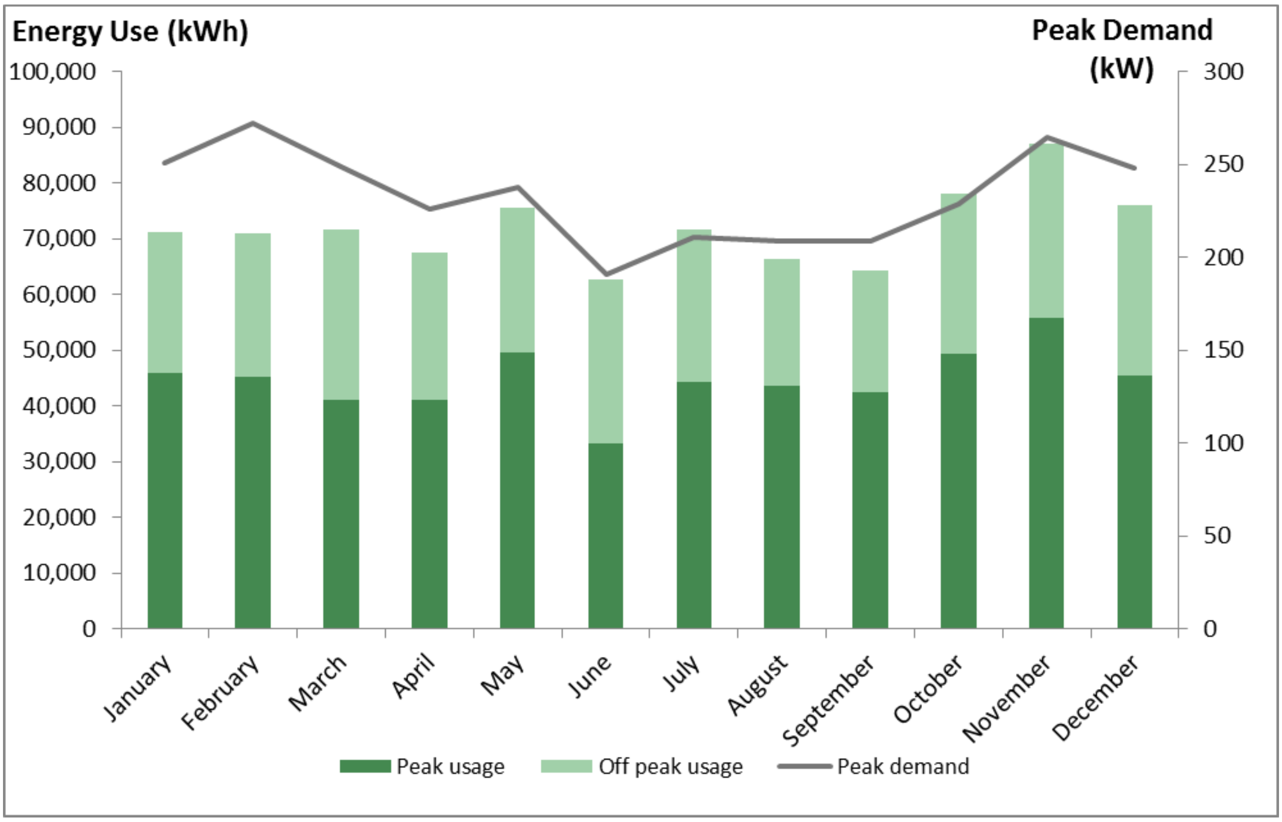

Figure 29: Monthly electricity usage (kWh) and peak demand (kW)

The peak demand billed varies from month to month between 190-270kW, with average peak demand of 233kW [49]. Time of day for peak demand varies from month to month as shown in Table 39 below.

	Time of day for monthly peak demand
January	9:00
February	13:30
March	13:00
April	13:30
May	13:30
June	13:00
July	12:00
August	16:00
September	13:30
October	14:30
November	15:30
December	16:30

Table 39: Time of day for monthly peak demand by month

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Whilst peak demand often occurs during the middle of the day, this is not consistently the case and examination of detailed demand data highlights that demand is also high early or late in the day at some point during any month. Figure 30 below for an indicative month highlights this pattern, which is particularly important when considering the economics of solar PV. In this month, the peak demand of 209kW was reached at 1.30pm i.e. close to the middle of the day. However, demand also exceeded 200kW at other times during the month, with the time of day ranging from 9am to 5.30pm on separate days [49].

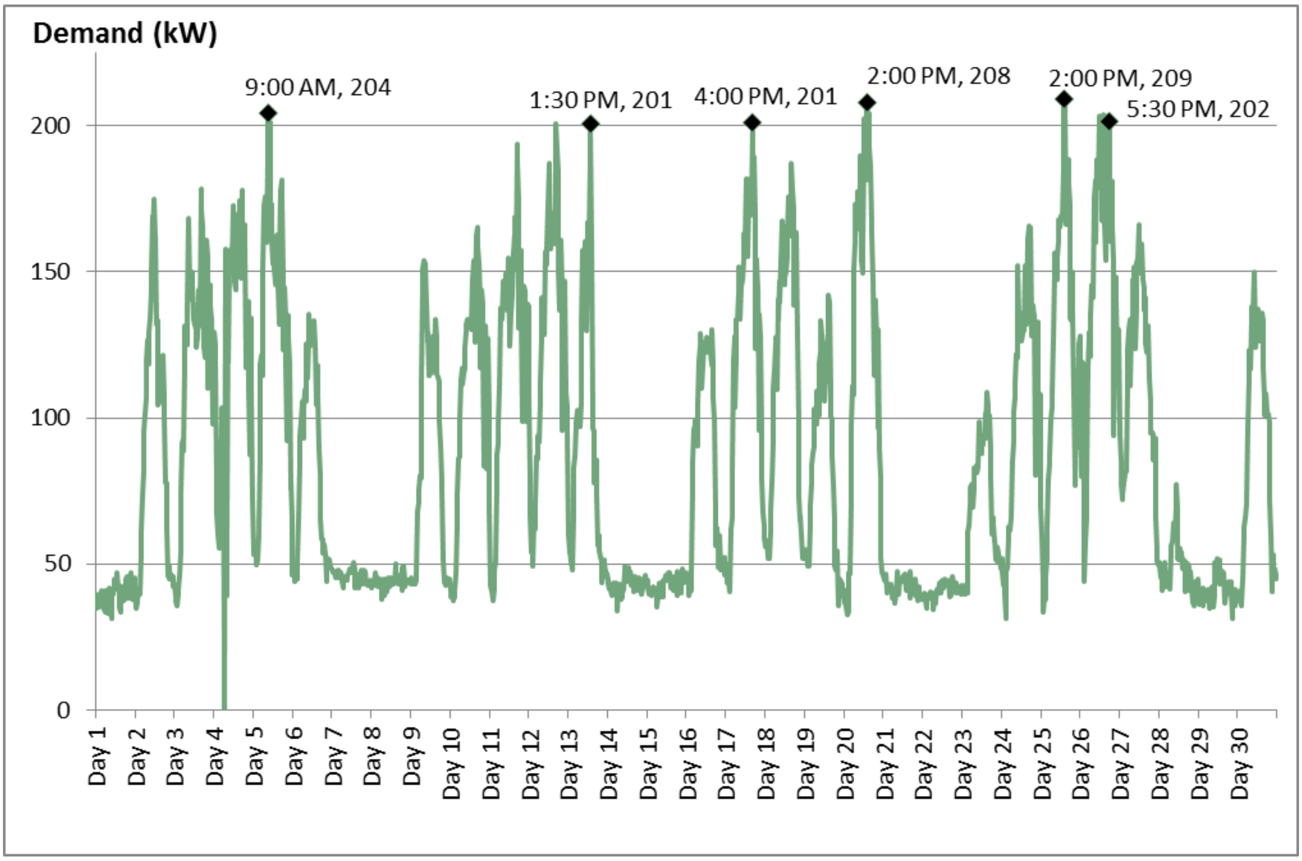

Figure 30: Demand (kW) over an indicative month

As a larger customer, Austchilli is on a contestable contract. Key drivers of the Austchilli bills are energy charges (with different rates for peak and off-peak consumption), network charges (which are dominated by demand charges for monthly peak demand), and other environmental, fixed supply and metering charges. In essence, there are four cost components:

- 12.1c/kWh for peak consumption (7am-11pm weekdays),
- 8.4c/kWh for off-peak consumption (all other times),
- $27.50/kW for peak monthly demand and
- $32.88/day [49].

Total annual electricity cost is around $174,000 excluding GST of which energy charges account for a quarter and the demand component of the network charges more than 40% as can be seen below in Figure 31 [49]. It is important to note from the figure that only around 50% of the total cost is variable by kWh. This is critical when considering the economics of solar PV generation in particular.

Based on the data from Table 39 and Figure 30 above, it is not reasonable to assume that network demand charges would be lower after installation of a solar system considering time of day for peak solar PV output as well as variability in solar output. Similarly, monthly fixed charges would not be affected by installation of on-site power generation if the grower remains grid connected. Hence cost comparison of solar PV vs. current electricity prices should be made only on the basis of the charges driven by kWh.

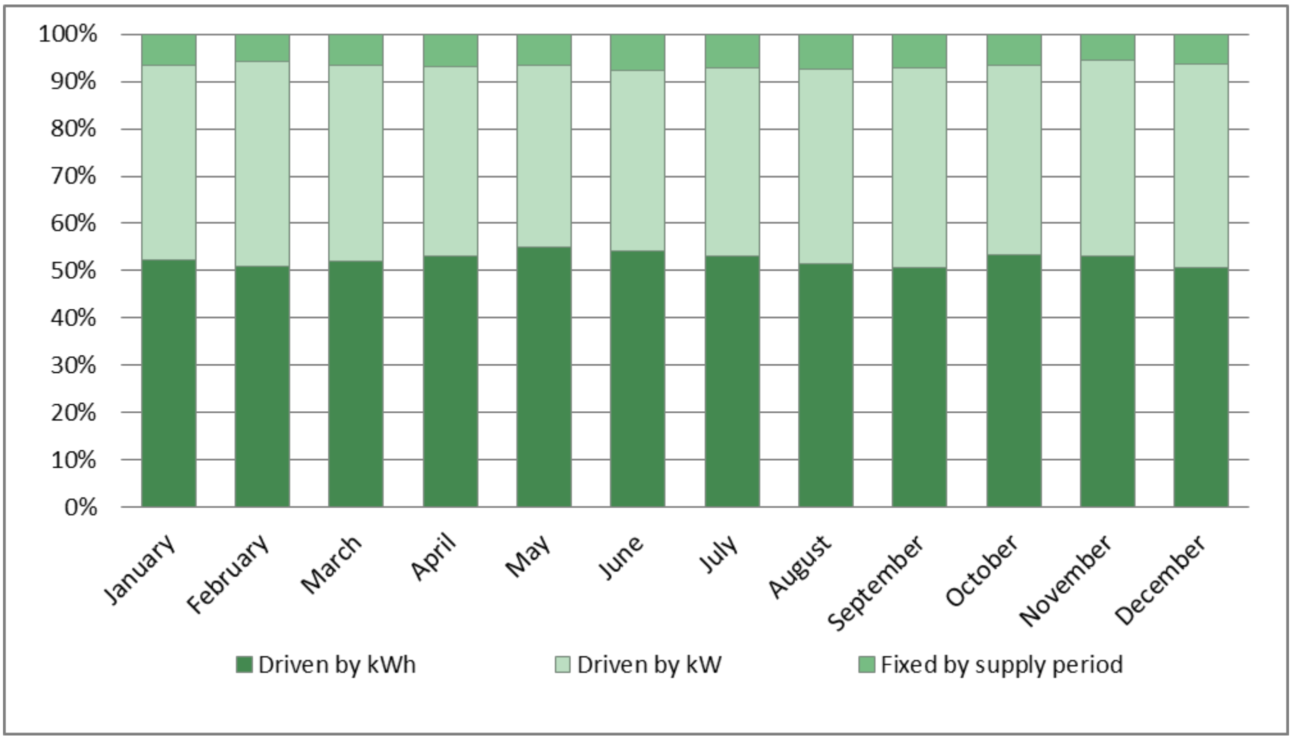

Figure 31: Breakdown of monthly electricity cost by cost driver (% of monthly cost)

In addition to metered electricity, Austchilli also runs a 1MW boiler that provides steam for the UHT processing line. This boiler usually runs on LPG although it can also run on diesel. In 2009, Austchilli ran a trial to grow biodiesel from sunflower and mustard seeds grown alongside their chillis [57]. Whilst the crops were grown successfully, the quality of the biodiesel produced was not sufficient to enable it to be used in the boiler as planned. The boiler consumes roughly 100,000L of LPG each year at an average cost of $0.90/L. However, LPG costs have risen sharply in recent months and many expect further price increases.

Austchilli maintains a diesel emergency generator on-site. In addition to quarterly tests, this run 2-3 times each year during power outages although with the growth in demand at the processing plant in recent years, the 160kW genset can no longer power all of the processing lines at once.

5.3 Feasibility of potential on farm power generation technologies

The analysis of options at Austchilli focused on solar PV and simple and co-generation from LPG or natural gas for the following reasons:

- Austchilli is already interested in solar PV. Given their operation is over daylight hours, they are confident that solar generation will match consumption reasonably well. In addition, there is significant roof space on the processing factory. Since they operate 5-6 days/week, they may lose some of the solar generation when the plant is not operating at full capacity.

- Co-generation should be explored since the processing plant has significant heating and cooling loads in addition to power needs. With no natural gas connection available nearby, LPG and diesel-fuelled generation were analysed.

Biomass and wind generation have been excluded due to significant uncertainty about their feasibility:

- *Woody biomass generation*: The major woody biomass source available locally is bagasse from sugar cane. However this is already used by Bundaberg sugar in biomass co-generation facilities which power and provide heat to their factories [54]. An alternative biomass fuel source could be macadamia shells from local Bundaberg growers. Macadamia shells have been used to power the 1.4MW Suncoast Gold Macadamias biomass co-generation power plant in Gympie, which supplies steam and power to the Suncoast facility as well as power to the grid [52,53]. However, local supply of macadamia nut shells, both in terms of volume and price, is uncertain.
- *Wind power*: The Bundaberg area appears to have reasonable wind resources with estimates for average annual wind speed ranging from 4m/s to 5.5m/s [55,26,56]. However, the bottom end of this range is outside the recommended minimum for wind power installation of 4.5-5m/s [23,24], so there is uncertainty about the viability of investing in wind power. If this option is of interest to Austchilli, we would advise proper monitoring of wind speeds at the site which would also take into account the effect of nearby buildings and trees on wind speed.

5.3.1 Solar PV

We now consider the financial performance of a proposed 100kW capacity solar PV installation at Austchilli. The specific inputs are stated in Table 40. Of particular note are the following.

- Since Austchilli is yet to install the solar plant, the estimated low, medium and high Total Capital Required (TCR) in Table 48 are used to estimate the likely financial performance. Table 40 shows these inputs for the medium TCR of 2500$/kW ex GST.
- The capacity factor and Small-scale Technology Certificate (STC) income are calculated using the procedure specified by the Federal Government's Clean Energy Regulator [4]. This classifies Bundaberg as zone 3, earning the STCs stated in Table 40 and having a capacity factor of 15.8%.
- Most network service providers no longer allow electricity to be fed into the network from solar systems of 100kW capacity. In this case, any electricity that cannot be consumed on-site does not generate any income through feed-in-tariffs (FiTs), and so reduces the financial performance of the installation.
- Austchilli's baseload power consumption is approximately 40kW, which commonly occurs during the night and across the weekends on which the facility doesn't run. Using the method presented in Section 2 of this report, this means that only approximately 73% of the solar electricity (kWh) generated on weekends can be used since export to the network is unlikely.
- This translates to loss of only 8% of potential energy generation across the year, making the conservative assumption that the processing facility does not run on weekends. Thus, a 100kW capacity plant is appears to be appropriate for Austchilli because it is the largest installation that can earn STCs up front (and thus avoid the complexities of larger installations and LGCs), in turn enabling the largest practical displacement of network electricity during weekdays when network delivered electricity is at its most expensive.
- Austchilli's peak and off-peak energy charges are 12.1c/kWh and 8.4c/kWh respectively, covering the daylight hours of weekdays and weekends. This results in a weighted average displaced electricity price of 11.3c/kWh, taking into account complete use of electricity generated on weekdays and 73% use of electricity generated on weekends.

- The analyses assume that there is no reduction in network demand charges as a result of solar PV installation, since these charges are driven by peak monthly metered demand (in kW) and since the peak monthly demand may not coincide with solar output as discussed above. Due to this uncertainty, it is prudent to exclude any possible reduction in demand charges from decision making.

Table 41 presents a summary of the financial performance of this proposed installation. These analyses are presented using the low, medium and high TCRs stated in Table 48 of 1880, 2500 and 3130 $/kW ex GST respectively. Also shown in bold is the TCR required for the proposed installation to have NPV=0, i.e. the *marginal installation cost*. Only installations cheaper than this can potentially make sense for Austchilli. These cheaper installations have payback periods of 8-11 years, which are significantly longer than the 3-5 year payback periods that Austchilli would normally consider acceptable. Nevertheless with 100% debt financing, this investment may be attractive, yielding an internal rate of return of 10-12%.

Relative to some other case studies presented in this report, the key to the less attractive performance of solar PV at this site is the structure of Austchilli's electricity tariff and the low cost for Austchilli's electricity consumption (i.e. the cost components driven by kWh, excluding network demand charges and fixed charges).

Capacity and capital required		
Plant Capacity (MW)	0.1	
Total Capital Required ($/kW)	2500	ex GST
STC related inputs		
STC price ($/MWh)	35	with GST
STC zone rating (MWh/kW)	1.382	
STCs (MWh)	2073	
STC income ($)	72555	with GST
Other technical inputs		
Capacity Factor (%)	15.8%	
Lost energy without feed-in	8.0%	
Electricity prices		
displaced elec. price ($/MWh)	113	ex GST
Other financial inputs		
Debt Percentage (%)	100.0%	

Table 40: Inputs for a potential 100kW capacity solar PV plant at Austchilli.

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	Low TCR	TCR for NPV=0	Medium TCR	High TCR
Total Capital Required ($/kW)	1880	**2147**	2500	3130
Total Capital Required less STC ($/kW)	1220	**1487**	1840	2470
Payback period (years)	8.8	**10.5**	12.8	17.0
NPV ($)	20,646	**0**	-27,351	-76,123
IRR (nominal, %)	12.2%	**10.0%**	7.9%	5.5%
LCOE ($/MWh)	92	**113**	141	190

Table 41: Financial performance of the potential 100kW capacity solar PV plant at Austchilli. (All prices are ex GST and assume 100% debt financing.)

5.3.2 Simple and co-generation using a reciprocating engine generator

The financial performance of three different engine driven plants is now considered for Austchilli. These plants have the following features.

1. Simple generation plant: This plant generates electricity only, with the plant's inputs stated in Table 42 for the medium TCR case of 1200$/kWe ex GST. This plant displaces *network electricity only*. It has a capacity of 40kWe, which is Austchilli's baseload electricity consumption, and so is sized to operate 24/7/365 in order to maximise capital utilisation. Its capacity factor of 80% therefore means that it generates 32kWe on average.
2. Cogeneration plant 1: This plant is similar to the simple generation plant, but also generates heat via engine waste heat recovery. The plant's inputs are again stated in Table 42. This plant displaces *network electricity and some of the LPG currently consumed in Austchilli's boiler*. Since we assume that the UHT processing facility operates for 40 out of a possible 168 hours per week, the engine's waste heat is only used 24% of the time.
3. Cogeneration plant 2: This plant generates electricity and cooling for Austchilli's cool rooms, the latter via engine waste heat recovery and an absorption chiller. The plant's inputs stated in Table 43. This plant displaces network electricity only, where that electricity would have been otherwise used for any purpose, including the existing refrigeration plant. The engine has a capacity of 30kWe. This means that the average network electricity displaced is 34kWe, which is the sum of 24kWe from the generator and 10kWe from use of the absorption chiller rather than a refrigeration plant. Once again, this plant sizing was chosen to operate 24/7/365 in order to maximise capital utilisation.

Of further note are the following:

- In contrast to the analysis for the solar plant, the average price of the displaced network electricity assumes that both the simple and cogeneration plants operate at the same power output across the entire week. This means that the average price of the displaced network electricity is now weighted by the proportion of hours per week with peak and off-peak tariffs, giving an average metered electricity price of 10.2c/kWh.
- This baseload power generation would also reduce Austchilli's demand charges by the average power generated on-site by these plants. However, preliminary analysis indicated that the financial benefits of these reduced demand charges are relatively small and do not change the findings, hence they have been ignored in the financial analysis below.
- Whilst all of these plants would likely be able to feed-in to the network, they are sized not to do so. This is because the feed-in tariff that they would likely get (e.g. roughly 6c/kWh) is likely lower than the price of the displaced network electricity (10.2c/kWh).

Capacity and capital required		
Plant Capacity (MWe)	0.04	
Total Capital Required ($/kWe)	1200	ex GST
Other technical inputs		
Engine capacity factor (%)	80.0%	
Heat utilisation / engine utilisation	23.8%	
Heat recovery capacity factor (%)	19.0%	
Engine efficiency (%)	35.0%	
Electricity prices		
Displaced elec. price ($/MWh)	102	ex GST
Fuel price		
Fuel price ($/GJ)	40	ex GST
Fuel price ($/MWh)	144	ex GST
Other financial inputs		
Debt Percentage (%)	100.0%	

Table 42: Inputs for potential 40kWe capacity simple and cogeneration (electricity and heating) plants at Austchilli.

Table 44 presents a summary of the financial performance of the proposed simple generation plant using the low, medium and high TCRs stated in Table 50 of 900, 1200 and 1500 $/kW ex GST respectively, as well as Austchilli's current LPG price. It is clear that all of these proposed plants perform very poorly on all metrics. This is due to the high price of the LPG available to Austchilli. Further, the large, negative NPVs of all plants in Table 44 show that the TCR has only a minor effect on the financial performance. The fuel price dominates this analysis. Further, the high LCOEs of simple generation – more than four times the displaced electricity price – suggest that using engine driven plants to offset network demand charges is unlikely to be attractive.

Table 45 and Table 46 present summaries of the financial performance of proposed cogeneration plants 1 and 2. As with the simple generation plant, financial performance is very poor due to the high LPG price.

Table 47 then shows the required fuel price in order to obtain NPV=0 for this proposed cogeneration plant. These prices of 11-12 $/GJ translate to roughly 0.3 $/lt of LPG and 0.4 $/lt of diesel. Both of these prices are very unlikely to be achievable, even using biodiesel sourced on site as Austchilli has done previously. Thus, cogeneration of electricity and cooling – the most viable of the engine based options considered – is very unlikely to be viable under any circumstances. It therefore appears that use of either LPG or diesel, including potential biodiesel sources that Austchilli has considered, is better used in Austchilli's boiler or for transport rather than in a new cogeneration plant.

Capacity and capital required		
Plant Capacity (MWe)	0.03	
Total Capital Required ($/kWe)	1440	ex GST
Other technical inputs		
Engine capacity factor (%)	80.0%	
Heat utilisation / engine utilisation	100.0%	
Heat recovery capacity factor (%)	80.0%	
Engine efficiency (%)	35.0%	
Chiller COP	0.7	
Refrigerator COP	2.5	
Electricity prices		
Displaced elec. price ($/MWh)	102	ex GST
Fuel price		
Fuel price ($/GJ)	40	ex GST
Fuel price ($/MWh)	144	ex GST
Other financial inputs		
Debt Percentage (%)	100.0%	

Table 43: Inputs for a potential 30kWe capacity cogeneration (electricity and cooling) plant at Austchilli.

	Low TCR	Med TCR	High TCR
Total Capital Required ($/kW)	900	1200	1500
Payback period (years)	n/a	n/a	n/a
NPV ($)	-747,311	-756,601	-765,891
IRR (nominal, %)	n/a	n/a	n/a
LCOE ($/MWh)	446	450	454

Table 44: Financial performance of the potential 40kWe capacity simple generation plant (i.e. electricity only) at Austchilli. (All prices are ex GST and assume 80% capacity factor and 100% debt financing.)

	Low TCR	Med TCR	High TCR
Total Capital Required ($/kW)	900	1200	1500
Payback period (years)	n/a	n/a	n/a
NPV ($)	-608,924	-618,214	-627,504
IRR (nominal, %)	n/a	n/a	n/a
LCOE ($/MWh)	n/a	n/a	n/a

Table 45: Financial performance of the potential 40kWe capacity cogeneration plant (i.e. electricity and heat) at Austchilli. (All prices are ex GST and assume 80% engine capacity factor, 19% heat recovery capacity factor and 100% debt financing.)

	Low TCR	Med TCR	High TCR
Total Capital Required ($/kW)	1080	1440	1800
Payback period (years)	n/a	n/a	n/a
NPV ($)	-495,498	-503,859	-512,220
IRR (nominal, %)	n/a	n/a	n/a
LCOE ($/MWh)	n/a	n/a	n/a

Table 46: Financial performance of the potential 30kWe capacity cogeneration plant (i.e. electricity and cooling) at Austchilli. (All prices are ex GST and assume 80% engine capacity factor, 80% heat recovery capacity factor and 100% debt financing.)

	Low TCR	Med TCR	High TCR
Total Capital Required ($/kW)	1080	1440	1800
Fuel price ($/GJ)	12	11	11
Payback period (years)	9.3	9.7	9.9
NPV ($)	0	0	0
IRR (nominal, %)	10.0	10.0	10.0
LCOE ($/MWh)	n/a	n/a	n/a

Table 47: Fuel price required to obtain NPV=0 for the potential 30kWe capacity cogeneration plant (i.e. electricity and cooling) at Austchilli. (All prices are ex GST and assume 80% engine capacity factor, 80% heat recovery capacity factor and 100% debt financing.)

5.4 Conclusion

Analysis of solar PV generation for Austchilli identified that installation of a 100kW roof-top system may be an attractive investment for the business if the *fully installed and operating* cost for the solar system is less than 2150 $/kW ex GST (i.e. 1490 $/kW ex GST after taking into account the effective capital cost discount from STCs). This *installed and operating* price is estimated to be in the lower range of currently feasible prices but it is similar to some of the initial quotes that Austchilli has recently obtained from solar installers.

Whilst the pay-back periods for these installations may be longer than those usually acceptable to Austchilli, if Austchilli is able to install and operate a solar PV plant for less than the price above, the investment would deliver an internal rate of return of at least 10% and is worth consideration.

Analysis found that simple and cogeneration using an LPG fuelled reciprocating engine generator performed very poorly in all cases. Analyses included simple electricity generation, the cogeneration of electricity and heat, as well as cogeneration of electricity and cooling. This poor performance was due to the high price of the fuel available to Austchilli relative to the price of their network delivered electricity. Further, when using reasonable fuel prices, the large, negative NPVs of all plants showed that the TCR has only a minor effect on the financial performance. Similarly, very low fuel prices are required in order for any plant to be financially viable. It therefore appears that LPG or diesel, including potential biodiesel sources that Austchilli has considered, is better used in Austchilli's boiler or for transport rather than in a new electricity generation or cogeneration plant.

6. Wind power on vegetable farms in Tasmania, NSW and WA

Four vegetable growers interviewed during this project have installed wind turbines on their properties in Tasmania, New South Wales and Western Australia. Their varied experiences are described below.

6.1 Wind power on selected Australian vegetable farms

6.1.1 Robert Nichols, Sassafras, Tasmania

Robert Nichols is a poultry producer and grower at Sassafras in Tasmania where he runs Nichols Poultry and grows poppies and vegetables on 620 acres. The on-site poultry processing plant is a significant consumer of energy and after significant research into wind power over a number of years, Rob installed a 225kW wind turbine in 2008 to provide power for his poultry factory [75].

Rob chose to install a second-hand Vestas V27 turbine from Denmark since he estimated that a second hand turbine would have a payback period of around 5 years compared to 15 years for a new turbine. He sourced and dismantled the turbine, and shipped it to Tasmania where it was re-conditioned and re-commissioned.

As is common with embedded wind generation, the location of the turbine was a compromise; the turbine is sited 70 metres from the factory which is not the ideal location for maximum generation but enables the turbine to plug directly into the factory switchboard. Whilst the capacity factor is “not brilliant”, it is still economic for energy generation. Initially the wind turbine supplied around 50% of the energy needs of the factory but as demand has grown at the site, it currently provides around 35% of the energy consumed. Any excess energy not able to be consumed at time of generation is fed into the grid and can be ‘bought back’ when needed, paying the local provider network and distribution charges [75].

Rob has subsequently established another business, Blowing in the Wind Pty Ltd, which procures, constructs and maintains medium scale wind turbine generators. Blowing in the Wind has assisted with installation of three additional turbines, at Sisters Creek, Wesley Vale and on Flinders Island. The business works with clients to procure and construct the turbine as well as securing all approvals and meeting grid and regulatory requirements, and provides ongoing maintenance of the turbines.

6.1.2 Andrew Nichols, Sisters Creek, Tasmania

Andrew Nichols runs a 1500 acre property in Sisters Creek raising chickens and beef cattle, alongside mixed cropping including canola, vegetables and poppies. A significant part of the business is a chicken hatchery which supplies day-old chicks to Nichols Poultry.

In 2012, Andrew and his son, Michael, worked with Blowing in the Wind (Andrew’s brother’s business) to install a single 225kW wind turbine to power chicken sheds, the hatchery and an industrial kitchen. The power needs are significant and across all 24 hours. Andrew was interested in putting in wind power to offset power consumption and reduce power bills.

The turbine tower is a lattice design which is easy and cheap to dismantle and re-assemble. The turbine was installed in 2012 and has been operating for around 18 months.

6.1.3 Michael Cook, Bathurst, NSW

Michael Cook has a 350 acre farm near Bathurst, NSW, growing cabbage, cauliflower, pumpkins and sweet corn and raising cattle. Electricity consumed chiefly drives pumping for irrigation.

In 2010/2011, Michael installed a 10kW wind turbine on his property in order to cut electricity costs. The turbine was eligible to participate in the generous NSW Solar Bonus Scheme which closed to new applications in April 2011. This scheme offered a gross feed-in-tariff of 60c/kWh for eligible solar PV and wind power installations connected to the grid by customers consuming less than 160MWh per year [78]. The turbine was connected directly to the grid with the grower paid for *all* electricity generated.

In spite of this generous feed-in-tariff arrangement, the technical and financial performance of the wind turbine was extremely poor. In the first instance, the turbine generated significantly less electricity than was anticipated after installation. The capacity factor is estimated to have been less than 10% during its operation. Further, the turbine operated for 16 months before technical problems were encountered and the generator ceased to function. As the turbine supplier had gone into bankruptcy, the turbine investment was written off and the generator no longer operates. Less than 10% of the cost of the total investment was recovered from feed-in payments for electricity generated during the operation of the turbine [77].

6.1.4 West Hills Farm, Lancelin, Western Australia

Large Western Australian vegetable grower Sumich has installed 5MW capacity at their West Hills Farm near Lancelin. The processing plant at the West Hills Farm processes and packs more than 1000 tonnes of carrots each week and is a significant consumer of energy.

Commissioned in two stages in 2012 and 2013, the wind generation facility comprises ten 500kW Enercon E-40 turbines which were sourced second-hand from Italy when an operating wind farm was being re-powered. The processing plant uses around 80% of the wind power generated on site with any excess exported to the grid or wheeled across the network to other Sumich properties [79].

Sumich worked with Blair Fox, a Perth-based renewable energy project developer, to develop and construct the wind farms. Blair Fox provided project management, including construction of the wind farm, management of the network connection and obtaining all approvals. Blair Fox has an ongoing role in operating the wind farm infrastructure, including maintenance and asset management [80].

Sumich and Blair Fox have also partnered to establish another 5MW wind farm to the east of Lancelin at Karakin. It has a similar configuration to the West Hills farm with the wind farm embedded within an existing agricultural load. However, the turbines sites are leased from local growers. The wind farm consists of 10 Enercon E-40 500kW turbines and electricity is utilised by local properties [79,80].

6.2 Performance and cost

Detailed data on cost and financial performance or the operating performance of the wind turbines were not provided by growers. Using estimates obtained from some of the growers and public sources, we examine key elements of cost and financial performance below.

6.2.1 Capital cost

For the second-hand, reconditioned 225kW turbine installations in Tasmania, total capital required as reported by growers and installers appears to be in the range $1330-1780/kW [75,76,81]. The 10kW turbine installed in NSW was considerably more expensive at $6000-7000/kW [77].

In 2010, a report on Embedded Wind Generation in Tasmania estimated the fully installed costs for a 225kW turbine at a dairy farm at $390,000 or $1730/kW [82]. This report also notes that the installed cost for a comparable new wind turbine would be about twice the cost of the refurbished turbine. However, as noted in the report, new turbines have other advantages such as a warranty, higher operating efficiency, lower maintenance costs, and a longer assumed operational life [82].

6.2.2 Performance and payback periods

There is limited data on the generation and actual financial performance of the turbines. The Tasmanian turbines appear to be operating as anticipated; we understand the capacity factors of the turbines to be 15-20%. Larger turbines installed at sites with excellent wind resources can achieve 35%+ capacity factor.

All of the currently operating wind turbines described above create tradeable Large-Scale Generation Certificates (LGCs) on electricity generated. The LGCs are traded by the growers themselves to realise additional income with LGC price typically $35-38/MWh [83]. Income from LGCs will vary with capacity factor and LGC income could be expected to be a significant part of the expected return for the wind turbine. For example, for a 225kW turbine with capacity factor of 15-20%, the LGCs would be worth $11-15,000 per annum. This could represent up to 25% of the total value of energy generated for the grower in each year. Growers estimate that the pay-back period would be an additional 2 years without RECs and that they would have ‘thought twice’ about whether to proceed should LGC income not be available.

For the wind turbine installed at Sassafras by Rob Nichols, the investment has been positive with pay-back on the initial investment over 5 years. Without LGCs, Rob estimates that the pay-back period would have been an additional 18-24 months.

At the Sister Creek installation, the turbine has been operating for less than 2 years, hence it is too early to predict the pay-back period with confidence. However, the turbine has reduced energy consumption at the switchboard significantly with savings of $3,000-4,000 per month. Michael anticipates that the pay-back period will be around 5-6 years at current performance [76]. The value of the energy generated by the wind turbine has three components: expenses avoided by offsetting power consumed from the grid (valued at 12-15c/kWh), revenue from exporting energy not consumed on site (attracting the wholesale rate for electricity exports of around 4c/kWh) and the income from trading LGCs created on the total electricity generated.

However, as noted above, not all growers who have installed wind power on-site have had positive experiences. The NSW turbine had both poor generation and poor economic performance with the investment resulting in a significant financial loss.

6.3 Practical considerations and feasibility of wind power

6.3.1 Suitability of load for wind power

It is most economical for most vegetable growers to install small to medium scale wind turbines for self-consumption. This embedded wind generation is most suitable for growers with significant loads on site which can be offset by wind generation where the demand is consistent throughout the year and where power requirements are around-the-clock. This may not be the case for many vegetable growers particularly if electricity chiefly drives pumping for irrigation.

6.3.2 Wind resource and turbine site

In addition, the feasibility of wind power is dependent on there being a suitably windy site for the turbine close to the switchboard for the load. Whilst some farms may have reasonable wind resources at some points on their property, if the sites are not close enough to the meter, cost of connection between the turbine and the meter could be uneconomic. For example, after the cost of the turbines, the single largest cost involved in the installation of the wind turbine at Sisters Creek in 2012 was to lay a 350m underground cable from tower to the meter which cost around $50,000 [76].

Assessment of the wind resource at potential sites on the property is an important part of determining the feasibility of wind power. Typically growers and their advisers use public data available for sites near their farms to understand the wind potential before conducting more detailed wind monitoring. The Bureau of Meteorology (BOM) publishes a suite of climate data for different BOM weather stations across Australia. By selecting the station nearest to the potential site, growers are able to understand the wind potential in their *area*. As a rule of thumb, average annual wind speeds of 4.5-5m/s are recommended as the minimum at which wind power would be considered viable [23,24].

Once growers have identified that there is sufficient wind potential at their site, they typically conduct an in-depth wind assessment to look at feasibility as well as the optimal site for the turbine. The assessment usually involves on-site monitoring of wind speeds over at least a 12–month period and will take into account the impact of local topology to measure actual wind resource and its variability over a year. However, not all of the growers interviewed undertook wind monitoring before proceeding with their investment [84].

6.3.3 Sourcing the turbines

It is interesting to note that three of the four growers we interviewed have installed re-conditioned second-hand turbines. They stated that installation of new turbines would not have been economic for them. Wind farms in several European countries, including Denmark, are being 're-powered'. This means that installed turbines are being replaced with newer turbines of greater capacity or efficiency to boost generation on the site. This has created a healthy market for medium scale second-hand wind turbines. In both Tasmania and Western Australia, growers worked with local energy experts to source the turbines and project manage their installation and connection to the grid.

The experience of the NSW grower underscores the importance of sourcing a turbine from a well-established and reputable company if the turbine does not operate as advised.

6.3.4 Financing wind power installations

Two of the growers interviewed accessed low interest government 'green loans' or grants. For the turbine at Sassafras, Robert Nichols obtained a Clean Biz grant which contributed $65,000 towards cost of turbine installation [84]. The Sisters Creek wind turbine project was able to access a Renewable Energy Loans Scheme loan to provide low interest financing for purchase of the wind turbine [85,86].

6.3.5 Approvals and grid connection

Wind power generation generally requires two different forms of approval: planning approval and approval to connect to the grid. Planning approval must be sought from local government with the requirements varying by locality. Preparation of the necessary documents and supporting evidence is often a time-consuming process. Typically development applications will need to address visual impact, noise impact, and the environmental impact (including the impact on plants and local animals). Further, during the local approval process, proposals can be challenged and local community, environmental or other objections can force the proponent to invest in costly and extensive impact studies which renders the project financially unattractive.

One of the growers we interviewed abandoned a planned site for a turbine due to objections from environmentalists. He emphasised that environmental objections to the installation of wind turbines can be a major disincentive to invest in on farm wind generation. In addition, advisers and installers who work with growers to project manage their wind power installations highlighted that since requirements change between councils and since each development is unique, there is no consistent set of guidelines that can be followed which adds significant cost and uncertainty to obtaining approvals.

Grid connection requirements are governed by the National Electricity Rules [61]. Customers must apply to the local Network Service Provider (NSP) for grid connection of embedded generation. The NSP will certify the technical performance of the plant and possibly conduct a network study. In the case of Robert Nichols, negotiating the grid connection agreement for his wind generator at Sassafras was not straightforward. There were delays in receiving approval and tight technical specifications had to be met and new metering installed in order to connect the second-hand turbine to the grid [84]. We nonetheless emphasise that these issues with NSPs are not particular to wind turbines, but are common across all forms of larger scale, embedded generation.

6.4 Conclusion

This case study reviewed four wind turbine installations on vegetable-growing sites. Whilst data on the financial and technical performance of the wind turbines was not available, it is possible to identify likely attractiveness of the investment for two of the sites. The NSW installation had very poor outcomes, ceasing operation after 16 months due to technical issues. The Nichols Poultry installation appears to have had very good outcomes with pay-back of the initial capital investment within 5 years. It is too early to understand the likely outcomes for the two more recent installations in Tasmania and WA, particularly without detailed data on capital and ongoing operating costs as well as electricity generation and electricity tariffs at the sites.

Nonetheless, it appears that wind power may be an attractive option for some vegetable growers where the wind resource is good, where the load is significant and consistent around-the-clock, where reliable turbines can be sourced economically and where there are unlikely to be local or environmental objections to turbine installation.

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Appendix

Input assumptions for the analysis of different forms of on-site power generation

This appendix details the input assumptions for analysing each form of on-site power generation considered in this report. Unless specified otherwise for a given case study, these assumptions are always used in this report. Where there are multiple values for the Total Capital Required (TCR), these figures represent low, medium and high estimates.

Capacity and capital required		
Plant Capacity (MW)	0.1	
Total Capital Required ($/kW)	1880, 2500, 3130	ex GST
STC related inputs		
STC price ($/MWh)	35	with GST
STC zone rating (MWh/kW)	1.382	zone 3, 1.185 for zone 4.
Other technical inputs		
Fixed O&M ($/kW.yr)	10	
Variable O&M ($/MWh)	0	
Capacity Factor (%)	15.8%	zone 3, 13.5% for zone 4.
Annual loss in performance (%)	0.5%	
Proportion fed-in	0.0%	
On-site consumption	100.0%	
Lost energy without feed-in	0.0%	
Electricity prices		
feed-in tariff ($/MWh)	0	ex GST
displaced elec. price ($/MWh)	150	ex GST
Other financial inputs		
Discount rate (real %)	7.1%	
Cost of Debt (nominal, %)	6.5%	
Inflation (CPI %)	2.7%	
Cost of Debt (real, %)	3.7%	
Debt Percentage (%)	100.0%	
Plant life (years)	25	
Book life (years)	20	
Debt life (years)	10	
Company tax rate	30.0%	

Table 48: Typical input assumptions for solar PV plant.

Capacity and capital required		
Allowable depth of discharge	80.0%	
Total Capital Required ($/kWh)	800	ex GST
Other technical inputs		
Charge/discharge cycles (#/yr)	365.3	
Fixed O&M ($/kW.yr)	25	
Variable O&M ($/kWh)	0.001	
Annual loss in performance (%)	0.5%	
Electricity prices		
Displaced elec. price ($/MWh)	150	ex GST
Other financial inputs		
Discount rate (real %)	7.1%	
Cost of Debt (nominal, %)	6.5%	
Inflation (CPI %)	2.7%	
Cost of Debt (real, %)	3.7%	
Debt Percentage (%)	100.0%	
Principal ($)	212000	ex GST
Equity investment ($)	0	ex GST
Plant life (years)	15	
Book life (years)	15	
Debt life (years)	10	
Company tax rate	30.0%	

Table 49: Typical input assumptions for battery plant.

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Capacity and capital required		
Total Capital Required ($/kWe)	900, 1200, 1500	ex GST
Other technical inputs		
Fixed O&M ($/kWe.yr)	25	
Variable O&M ($/MWhe)	0	
Engine capacity factor (%)	80.0%	
Heat utilisation / engine utilisation	100.0%	
Heat recovery capacity factor (%)	22.0%	
Engine efficiency (%)	35.0%	
Heat recovery efficiency (%)	80.0%	
Boiler efficiency (%)	80.0%	
Annual loss in performance (%)	0.5%	
Electricity prices		
Displaced elec. price ($/MWh)	150	ex GST
Fuel price		
Fuel price ($/GJ)	10	ex GST
Fuel price ($/MWh)	36	ex GST
Other financial inputs		
Discount rate (real %)	7.1%	
Cost of Debt (nominal, %)	6.5%	
Inflation (CPI %)	2.7%	
Cost of Debt (real, %)	3.7%	
Debt Percentage (%)	100.0%	
Plant life (years)	25	
Book life (years)	20	
Debt life (years)	10	
Company tax rate	30.0%	

Table 50: Typical input assumptions for cogeneration (electricity and heat) plant. Note that simple electricity generation is obtained by setting the 'Heat utilisation / engine utilisation' to 0%.

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Capacity and capital required		
Total Capital Required ($/kWe)	1080, 1440, 1800	ex GST
Other technical inputs		
Fixed O&M ($/kWe.yr)	25	
Variable O&M ($/MWhe)	0	
Engine capacity factor (%)	80.0%	
Heat utilisation / engine utilisation	100.0%	
Heat recovery capacity factor (%)	22.0%	
Engine efficiency (%)	35.0%	
Heat recovery efficiency (%)	80.0%	
Chiller COP	0.7	
Refrigerator COP	2.5	
Annual loss in performance (%)	0.5%	
Electricity prices		
Displaced elec. price ($/MWh)	150	ex GST
Fuel price		
Fuel price ($/GJ)	10	ex GST
Fuel price ($/MWh)	36	ex GST
Other financial inputs		
Discount rate (real %)	7.1%	
Cost of Debt (nominal, %)	6.5%	
Inflation (CPI %)	2.7%	
Cost of Debt (real, %)	3.7%	
Debt Percentage (%)	100.0%	
Plant life (years)	25	
Book life (years)	20	
Debt life (years)	10	
Company tax rate	30.0%	

Table 51: Typical input assumptions for cogeneration (electricity and cooling) plant.

Task 3: Economic analysis of the feasibility of different technologies at different scales

Summary

This report presents a generalised economic analysis of the viability of different on-site power generation options for vegetable growers, using a required internal rate of return (IRR). We also discuss the different incentives and regulations that affect on-site energy generation.

By technology, our findings for the economic analysis are summarised as follows:

1. *Solar photovoltaics (PV)*

   We find that solar PV should be viable for most growers, including those in less sunny regions, if the Renewable Energy Target (RET) and its Small-Scale Technology Certificates (STCs) remain. For example, depending on the region, a solar PV plant with a total capital expenditure of $2500 per kW of capacity can be viable with a 10% nominal IRR if it displaces network electricity with a price of at least 12-15 c/kWh. A key consideration in this analysis is the appropriate sizing of the plant such that roughly 10% or less of the potentially generated electricity is not consumed on-site. Should the RET be repealed, this same solar PV plant then requires the displaced network electricity to have a price of at least 19-22 c/kWh, which is expected to be the case for some growers. Thus, solar PV may remain financially viable for some growers even if the RET is repealed.

2. *Battery storage*

   Our analysis finds that the viable financial performance of batteries is at present unlikely. For example, for a highly utilised (i.e. daily charging/discharging) battery storage system with a total capital expenditure of $800 per kWh, a 10% nominal IRR requires the displaced network electricity to have a price higher than about 35 c/kWh. This required displaced network electricity price is unlikely in most cases, and becomes higher if the battery storage system is less utilised. Further, given the significant uncertainty in the full cost of battery storage systems, we recommend that growers do not consider the installation of battery storage at present.

3. *Simple and cogeneration using reciprocating engine generator*

   This report considered three types of on-site power generation using reciprocating engines: simple generation (i.e. electricity only), cogeneration of electricity and process heat and cogeneration of electricity and process cooling. Our analysis found that simple or cogeneration requires fuel prices that can plausibly compete against network delivered electricity on its own, with additional heating or cooling then providing additional potential benefit. The required IRR is less of an issue for engine driven plant since the cost of fuel, rather than the plant cost, dominates their financial performance.

   In practice, the fuel must likely to be network delivered is natural gas, since this is the only fuel priced to plausibly displace that of network delivered electricity in most cases. For example, an engine driven plant of appropriate capacity (and hence a capacity factor of 50% or more) should be viable when displacing network delivered electricity of at least 10c/kWh provided that it consumes fuel with a price of 10 $/GJ or less. Nonetheless, on-site engine generation will be unviable for many growers, since network delivered natural gas is simply not available to them.

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4. *Wind turbines*

Our analysis of wind turbines focused on the use of intermediate scale (i.e. 50-500kW capacity) second hand plant since this plant has been used by growers in Australia, for good reason. Despite significant uncertainty about the total capital required to install a second hand wind turbine, it appears that they will be viable in many cases because they are significantly cheaper than new plant.

For example, requiring a 10% nominal IRR should result in a financially viable, second hand wind turbine with total capital expenditure of 1750 $/kW provided that LGCs with current prices are generated, on-site consumption is high, the displaced electricity is more than about 10c/kWh, and the capacity factor is about 20% or higher. Such capacity factors should be achievable at better sites. Cheaper installations may be viable at capacity factors below 20%, particularly if the displaced electricity price is relatively high. Obtaining reasonable estimates of the capacity factor is hence a priority prior to making investment decisions.

Further, compared to solar PV, the repeal of the RET appears likely to have a weaker impact on the financial viability of wind. For example, the wind turbine example discussed above becomes viable if the displaced electricity price is at least 12c/kWh when LGCs are removed. Thus, it is likely that second hand wind turbines will remain an attractive investment for some growers, regardless of the future of the RET. Nonetheless, since wind is intermittent across the entire day, growers need to have an electrical load that is also across the day to ensure high levels of on-site consumption of the electricity generated.

5. *Woody biomass*

On-site power generation using woody biomass was not analysed since it does not appear to be a significant resource for the large majority of growers, and because the performance of electricity generating plant that consumes this fuel is poor at the scale of individual growers. The most common method of generating electricity from woody biomass involves its direct combustion to drive a steam turbine. At scales of order 100kW and below, these steam plants tend to have significantly lower thermal efficiencies than, for example, the reciprocating engines discussed above. Thus, unless the fuel has a very low price and is readily available – which doesn't appear to be so for many growers – power generation from woody biomass is expected to be unviable.

Regarding incentives, the schemes currently in place include the Renewable Energy Target (RET) and feed-in-tariffs. The RET can provide growers with financial incentives for installing eligible renewable energy power plant via creation and sales of renewable energy certificates either upfront (STCs for smaller systems) or annually (LGCs for larger systems). As discussed above, STCs are likely required for the viability of solar PV installations for many growers. Changes to the RET recommended recently by the RET Review could therefore have a significant impact on the viability of on farm power generation options.

Feed-in-tariffs vary by jurisdiction. With the exception of the Northern Territory and some parts of Western Australia, mandatory minimum feed-in-tariffs have been significantly reduced from previously high levels or scrapped altogether. The remaining mandated and voluntary feed-in-tariffs offered by retailers are typically 5-8c/kWh for net export from small to medium scale systems. Since feed-in-tariffs are often significantly below growers' electricity tariffs, consuming most of the power generated on-site is much more important to a system's economic viability than generating income from feed-in-tariffs.

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Regulatory requirements to install and operate on farm power generation can be complex, onerous, time-consuming and costly. These requirements differ by type of generation as well as by location. There are three key types of requirements relevant for on farm power generation installations:

1. *Grid connection and technical requirements*

   Installation and grid connection for embedded generation plant needs to be approved by the distribution network service provider (DNSP), who will certify the technical performance of the plant. For medium and larger scale installations, the DNSP will conduct a network connection study to identify technical issues and any constraints on grid connection. Requirements for small scale generation (below 5-10kW) are typically more streamlined, particularly for rooftop solar PV installations. It is important to initiate discussions with the DNSP about feasibility of a proposed system as early as possible.

2. *Planning and development approval*

   Growers need to approach their local government or council to understand planning and development requirements for different technologies on their site. Planning and/or building permits may be required before construction and installation can commence, even for solar PV installations in some locations.

   Typically, planning and development approvals are required for wind power and some stationary power plant. Preparation of the necessary documents and supporting evidence is often time-consuming. Requirements differ between councils so there is no consistent set of guidelines to follow, adding significant cost and uncertainty to obtaining approvals. Further, environmental objections to the installation of turbines can be a major disincentive to invest in on farm wind generation.

3. *Engine fuels and emissions standards*

   Additional standards and regulations must be met where an engine is fuelled by natural gas, LPG, biogas, petrol or diesel. These include standards governing the fuel and the appliance, regulations regarding atmospheric and noise emissions, and OH&S standards for workplaces and hazardous areas. The associated processes are administered by different State environmental and OH&S agencies.

Economic analysis methodology

All analysis in this report assumes that *a company* purchases any of the discussed forms of on-site power generation. This is the same as the approach taken in our second report, and means that the following apply.

- Purchase of any form of on-site power generation can increase the company's income in three ways:
  - by displacing electricity that would have otherwise been purchased from the network;
  - (where relevant) by being paid a feed-in tariff for electricity sold into the network; and
  - (where relevant) by receiving payment for the generation of small-scale technology certificates (STCs) and large-scale generation certificates (LGCs) as part of the Federal Government's Renewable Energy Target (RET) [1].
- All purchased plant is depreciated over a stated book life. This means that, in a given year, acquisition of the plant can reduce *the company's overall* taxable income and thus reduce its tax repayments in that year. Note that the Australian Tax Office's (ATO's) method for *diminishing value depreciation* [2] is used.
- Interest payments on debt financing also reduce the company's taxable income.
- All analysis is done *excluding* GST. This assumes that the company claims a GST credit on any purchases, and pays GST on feed-in tariffs and STCs/LGCs.
- STCs are not taxed however LGC income is taxed.

However, the analysis in this third report differs from our second report in a key aspect – it presents analysis that allows the reader to estimate the conditions under which a given form of on-site power generation is financially viable. In doing so, this report answers the following question.

*"What is the **maximum** allowable cost of installing a plant in order for it to be a sound investment?"*

This maximum allowable cost of installing a plant will be called the marginal total capital required - the 'marginal TCR'. Then, any installation that can be completed for less than the marginal TCR should be a sound investment.

We ask this question since the TCR required to obtain an operating plant is usually the most uncertain parameter for all forms of on-site power generation considered. It is therefore the key parameter that growers need to know prior to installation in order to minimise investment risk. The TCR is the cost of obtaining *a fully installed and operating plant*, and can be significantly higher than uninstalled plant costs or the costs of major plant components.

The marginal TCR for any plant depends on numerous inputs. The most important of these are:

- the price of the displaced network electricity;
- (where relevant) the feed-in tariff;
- (where relevant) the price of the fuel used;
- (where relevant) the STCs or LGCs generated and their price;
- the proportion of generated electricity that is used on-site; and
- the various measures of a plant's financial performance used by different growers.

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Finally, we note that our analysis presents marginal TCRs on a per unit capacity basis ($/kW or $/kWh), rather than assuming a particular plant capacity. This is because growers will be interested in a wide range of plant capacities. In so doing, we note that the sizing of any plant is an involved task that depends on several aspects of a given installation, and so is outside the scope of this report.

Measures of plant financial performance

We present analysis using two different measures of a plant's financial performance as follows.

1. Internal rates of return (IRR) of 5%, 10% and 15% nominal: This is the rate of return on the initial capital investment that plant operation over its lifetime achieves for the company. Once again, this return is defined in terms of the change in the company's cash flows that result from operating a given plant.
2. (For solar PV only) Payback periods of 3, 5 and 10 years: This is the time required for the company's increased cash flows arising from plant operation to offset the total costs of installing and operating that plant. Note that the payback period is calculated using *undiscounted* cash flows.

Note the following regarding these measures:

- They include the tax benefits of interest repayments and depreciation.
- They are formulated in terms of *the change in* the company's cash flows due to operation of a given form of on-site power generation. As such, all analysis is done on a company basis and not in terms of the cash flows to equity or debt holders.
- A 10% nominal IRR is consistent with the discount rate obtained by studies into consumer purchasing behaviour for solar PV in Australia [3]. Thus, much of this report uses a 10% nominal IRR as a reference, which is 7.1% real using the 10 year Australian average CPI of 2.7% [2].
- The Levelised Cost of Electricity (LCOE) is not presented in this report. This is because electricity prices are an input to this analysis rather than an output. Further, cogeneration plants do not produce only electricity, and so cannot be analysed using this metric.

Finally, and consistent with our second report, we question the sole use of the payback period as a measure of a plant's financial performance. In particular, enforcing a 3 or 5 year payback period can lead to growers missing significant investment opportunities, since this payback period requirement commonly leads to very low marginal TCRs that cannot be achieved in many cases. This is shown in the section analysing solar PV, and so is not repeated in the analyses of the other technologies. Rather, the IRR is the preferred metric, with 10% to 15% nominal commonly used by investors. IRRs in this range usually result in payback periods of between five and ten years, depending on the plant type and installation.

Calculation of the displaced electricity price

The *displaced electricity price* is the variable component in kWh of the electricity that is not drawn from the network due to the presence of on-site electricity generation. This price depends on when the on-site generation is functioning, and also the peak, shoulder and off-peak tariffs of a given grower. Thus, the displaced electricity price depends on both the technology in question (specifically, when it generates) and a grower's electricity contract.

The methods for calculating the displaced electricity price are as follows for each technology considered.

- Solar PV: Generation is of course during the day. However, this may be at any tariff rate, most likely at peak or shoulder times during the working week and off-peak during the weekend. The displaced electricity price is then the average of the different tariffs weighted by the number of hours per week spent generating at these tariffs.

- Engine driven generation or wind turbines: Electricity generation may not correlate with the time of day, in which case the displaced electricity price is the average of the different tariffs weighted by the number of hours per week spent at these tariffs.
- Batteries: Since the time of battery discharge can be controlled, a simple first estimate is to assume that the displaced electricity price is the peak tariff since this maximises financial performance.

We emphasise that the displaced electricity price is only the variable component in kWh of the total electricity price. The latter can include fixed and other variable charges for the energy consumed, peak demand, network charges and other charges. Whilst on-site generation can reduce peak demand charges, this effect is expected to be secondary and not guaranteed if the plant is not always generating when expected. The latter is an issue for intermittent plant in particular, like solar PV and wind, but also for engines and batteries during scheduled or unscheduled downtime.

1. Economic analysis

1.1 Solar PV

We first consider the financial performance on on-site electricity generation using solar PV.

A significant determinant in the performance of solar PV is the location of the candidate site. This affects both the capacity factor of the installation, due to environmental effects, as well as the STC payment available to the grower upon installation. The STC payment is calculated by first classifying a given site into an *STC Zone* by its postcode, and then using a formula defined by the Australian Federal Government's Clean Energy Regulator [5] to calculate the STCs generated (MWh). Given the STCs generated, a representative STC price ($/MWh) is then used to calculate the STC payment. Many growers are expected to be in STC Zones 3 and 4. This includes growers in South-Eastern Queensland, South-Western Western Australia, Southern South Australia, Victoria and Tasmania. Growers can quickly confirm their STC zone using their post-code [5].

Our second report considered in some detail the likely range of TCRs for solar PV (Table 52), given various sources and discussions with growers [5,6,7]. This range was significant, and arose from the use of different PV systems, different installers and the varying difficulty of installation at different sites, amongst other factors. Table 52 shows these TCRs without any subsidy and also assuming a representative STC of 35 $/MWh (with GST) for STC Zones 3 and 4 subtracted. The TCR range represents our estimate of the full, *unsubsidised* cost of installing a solar PV plant. The TCRs minus STCs are also shown, since STC payments are often made up-front to the owner by the installer, and so effectively reduce the TCR by the STC subsidy.

	Low $/kW	Medium $/kW	high $/kW
TCR	1880	2500	3130
TCR minus STCs, zone 3	1220	1840	2470
TCR minus STCs, zone 4	1315	1935	2565

Table 52: Low, medium and high TCRs ($/kW, ex GST) assuming a 35 $/MWh STC (with GST) [2] for STC Zones 3 and 4.

In this report, the medium TCR of 2500 $/kW will often feature as a guide to the plausibility of a given marginal TCR obtained.

[2] Note that STC prices are commonly quoted with GST included.

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Reference example

We first give a reference example for a hypothetical solar PV installation in a STC Zone 3 location. This installation has the input assumptions listed in Table 53, and the following features.

- It will be located in a Zone 3 STC region. This affects both the total STC payment and the capacity factor.
- All electricity that it generates is consumed on site, and no energy is fed into the network.
- It has a displaced electricity price of 150 $/MWh = 15 c/kWh, which is a representative displaced electricity price for some of the larger growers considered in our second report.
- The grower requires a 10% nominal internal rate of return (IRR) as his/her measure of the plant's financial performance.

Using these inputs, we obtain a marginal TCR of 2785 $/kW without STCs.

Thus, given the inputs in Table 53, a grower will achieve a financially viable solar PV installation by the stated required measure of a 10% nominal IRR, if he/she ***can install and begin operation*** *of a solar PV plant with a total cost per kW of installed capacity that is equal to or less than 2785 $/kW ex GST.*

STC related inputs		
STC price ($/MWh)	35	with GST
STC zone rating (MWh/kW)	1.382	zone 3
Other technical inputs		
Fixed O&M ($/kW.yr)	10	
Variable O&M ($/MWh)	0	
Capacity Factor (%)	15.8%	zone 3
Annual loss in performance (%)	0.5%	
Proportion fed-in	0.0%	
Lost energy without feed-in	0.0%	
Electricity prices		
feed-in tariff ($/MWh)	0	with GST
feed-in tariff ($/MWh)	0	ex GST
displaced elec. price ($/MWh)	150	ex GST
Other financial inputs		
IRR (real %)	7.1%	10% nominal
Cost of Debt (nominal, %)	6.5%	
Inflation (CPI %)	2.7%	
Debt Percentage (%)	100.0%	
Plant life (years)	25	
Book life (years)	20	
Debt life (years)	10	
Company tax rate	30.0%	

Table 53: Inputs for the STC Zone 3 reference example

Effect of different input parameters

The effect of feed into the network with a stated feed-in tariff

The amount of energy fed into the network depends on the capacity of the solar installation, the local environmental conditions (and thus electricity generation) and the profile of on-site consumption. Our second report discussed how most Network Service Providers (NSPs) currently allow feed-in from solar PV installations with capacities up to 30kW, but not above. We also discussed how feed-in tariffs have reduced significantly in recent years, with 6 c/kWh a representative tariff that may be used for this analysis.

Figure 32 shows the variation of the marginal TCR obtained for varying displaced electricity price, a 10% nominal IRR and varying amounts of annual, on-site energy being fed into the network at a feed-in tariff of 6c/kWh (with GST). As expected, the marginal TCR increases with increasing displaced electricity price. This figure reduces as a greater proportion of the generated electricity is fed into the network, since it then earns income from the lower feed-in tariff. When the displaced and fed-in electricity have the same price, the marginal TCR is the same since electricity displacement and electricity feed-in generate the same income.

Since displaced electricity has a significantly higher price in practice, it is preferable to minimise the amount of electricity fed into the network. This highlights the importance of plant sizing. Figure 32 shows this by demonstrating that *a plant with a medium TCR* may be a good investment provided that the displaced electricity price is more than roughly 13 c/kWh in Zone 3 (or 16 c/kWh in Zone 4, see Figure 36) and feed-in is less than 10% of the annual electricity generation. *It is expected that many growers could meet these conditions with an appropriately sized PV system.*

The effect of non-utilisation of electricity that can be generated on-site

Network feed-in is not guaranteed in some applications, most commonly when the capacity of the solar installation is greater than 30kW. Also, some Network Service Providers may allow network connection, but won't give a feed-in tariff. In such cases, any electricity that cannot be consumed on site then doesn't generate any income. Figure 33 shows the financial performance of installations with varying proportions of lost energy. These results are similar to those with network feed-in, particularly for low proportions of lost energy and feed-in. Since lost energy does not generate any income, the marginal TCRs for a given displaced electricity price is higher than the equivalent case with a feed-in tariff.

Of particular interest are cases with higher proportions of lost energy, such as the 50% case shown. These proportions of lost energy result in very low marginal TCRs, such that the likelihood of the installation being economic is lowered. Once again, this highlights the importance of plant sizing and maintaining high levels of on-site consumption of the solar generated electricity.

The effect of different payback periods

Figure 34 shows the effect of different required payback periods on the marginal TCR. This shows that enforcing a 3 year payback requires a displaced electricity price of greater than 50 c/kWh for a solar PV plant with a medium TCR. This price is much higher than any seen in Australian electricity markets, thereby demonstrating that requiring a 3 year payback does not accord with the massive recent growth in solar PV installations nationally. A 5 year payback is also a challenging target, with only one grower in our second report – Loose Leaf Lettuce - meeting this given their high displaced electricity prices of greater than 30 c/kWh. Figure 34 also shows that installations with low to medium TCRs and a displaced electricity price of 10-20 c/kWh should have 5-10 year payback periods, which we expect to cover most cases of interest.

The effect of different internal rates of return (IRR)

Arguably, the internal rate of return (IRR) is a more useful measure by which to decide on investment. Figure 35 shows the effect of different IRRs on the marginal TCR, with 10%-15% nominal IRRs a common range used by investors. Figure 35 shows that imposition of such IRRs should result in viable solar PV installations in the low to medium TCR range. For example, for a medium TCR installation, a 10% nominal IRR is viable if the displaced electricity price is greater than about 12 c/kWh, whilst a 15% nominal IRR requires electricity to be more than about 20 c/kWh. However, a low TCR installation (Table 52) can achieve at least 10% and 15% nominal IRRs respectively for about 9 and 14 c/kWh respectively. Of course, determination of the required IRR can only be done by the grower, ideally taking into account this IRR relative to other investments that he/she makes.

The effect of capacity factor and STC zone

As discussed earlier, the location of a proposed solar plant affects the capacity factor and thus the STC payment received by the plant owner. We can therefore study the effects of capacity factor and STC payment by STC zone, since zones are categorised by approximate capacity factor and are used to calculate the STC payment.

Figure 36 shows the effect of varying the STC Zone on the marginal TCR. Zone 3 includes growers in South-Eastern Queensland, South-Western Western Australia and Southern South Australia, whilst Zone 4 includes growers in Victoria and Tasmania. The marginal TCRs for Zone 3 are higher than Zone 4 for a given STC price (35 $/MWh in this instance). This is because Zone 3 plants have higher capacity factor (15.8% for Zone 3, 13.5% for Zone 4), and so generate more renewable energy per unit plant capacity, and also because the STC payment is higher.

It then follows that, for a given cost of installation, the lowest viable displaced electricity price must be lower in Zone 3 than in Zone 4, as Figure 36 shows. We nonetheless emphasise that viable Zone 4 displaced electricity prices are still within the range experienced by many growers.

The effect of RET repeal

Figure 36 also allows us to examine the effect of repealing the RET and thus removing STC payments on a new installation. For example, with a medium TCR of 2500 $/kW, Figure 36 shows that RET repeal increases the lowest viable displaced electricity price from roughly 13c/kWh to 19c/kWh for a Zone 3 plant, and from 16c/kWh to 22c/kWh for a Zone 4 plant.

Whilst this is a significant increase in the required displaced electricity price, solar PV is still expected to be viable for some growers given current tariffs should the RET be repealed.

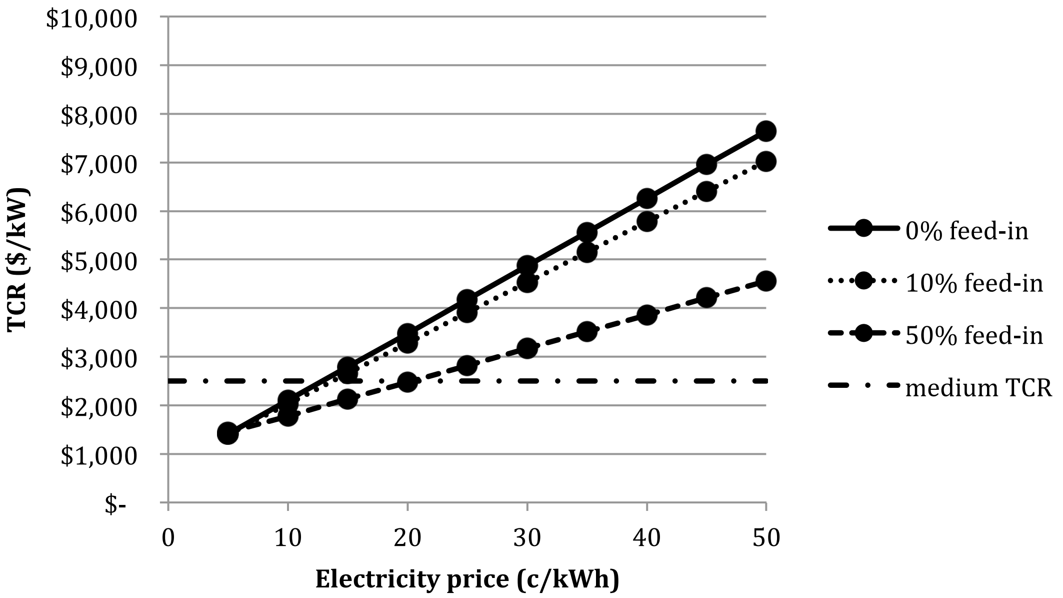

Figure 32: Marginal TCR ($/kW) versus displaced electricity price for IRR=10% nominal and 0%, 10% and 50% of annual, on-site energy being fed into the network at 6c/kWh (w/ GST). Also shown is a medium TCR of 2500 $/kW. Analysis assumes a Zone 3 STC region with all other assumptions in Table 53.

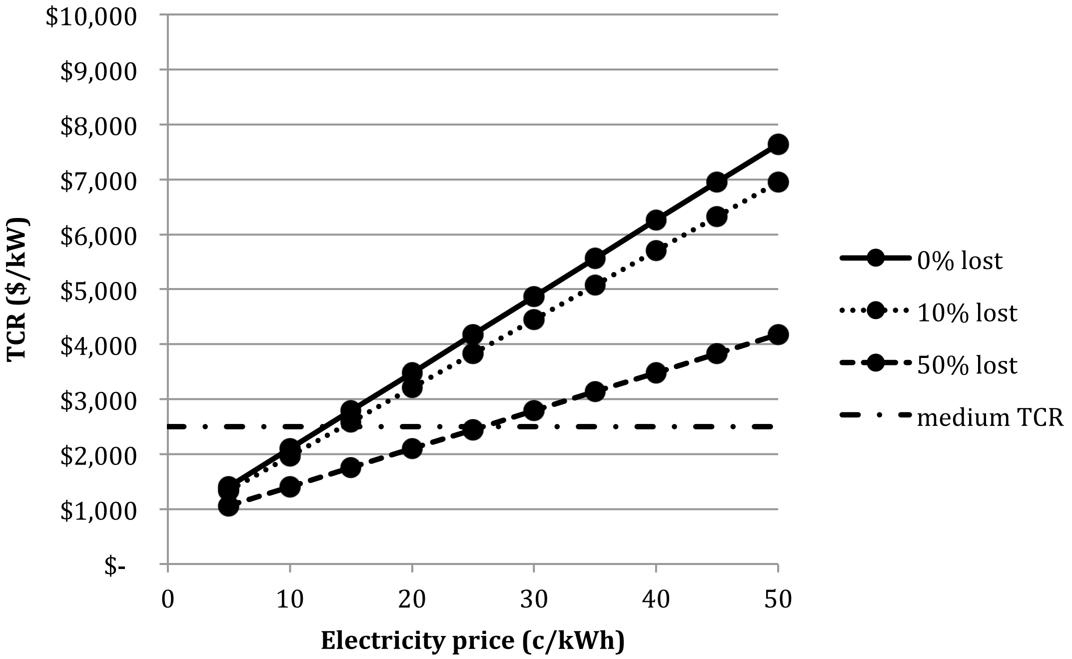

Figure 33: Marginal TCR ($/kW) versus displaced electricity price for IRR=10% nominal and 0%, 10% and 50% of lost annual, on-site energy generation. Also shown is the medium TCR of 2500 $/kW. Analysis assumes a Zone 3 STC region with all other assumptions in Table 53.

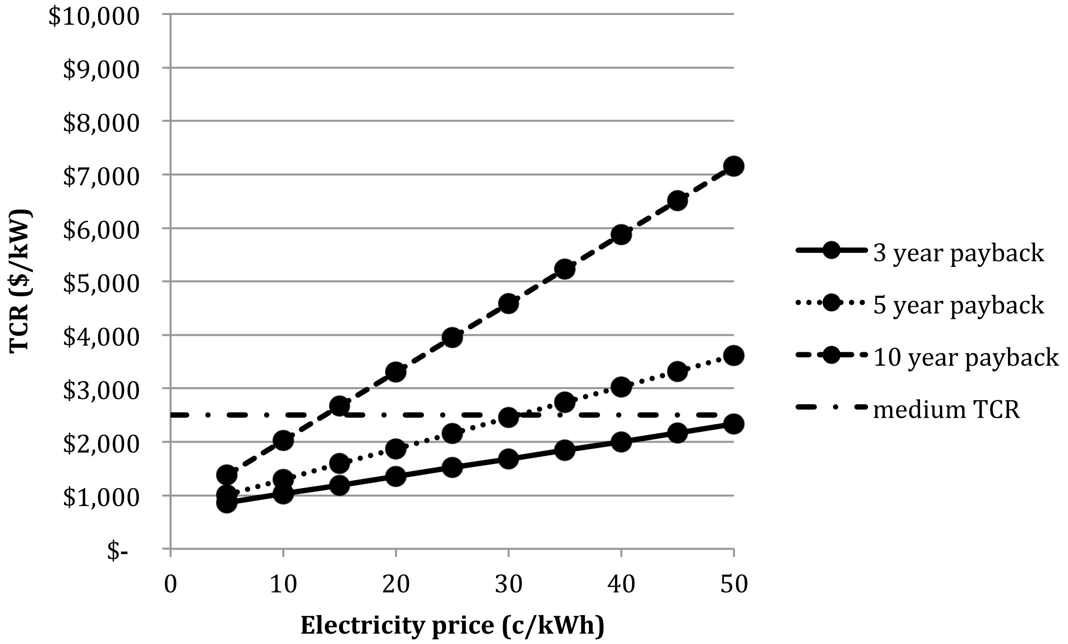

Figure 34: Marginal TCR ($/kW) versus displaced electricity price for 3, 5 and 10 year payback periods. Also shown is the medium TCR of 2500 $/kW. Analysis assumes no energy lost or fed into the network, a Zone 3 STC region and all other assumptions in Table 53.

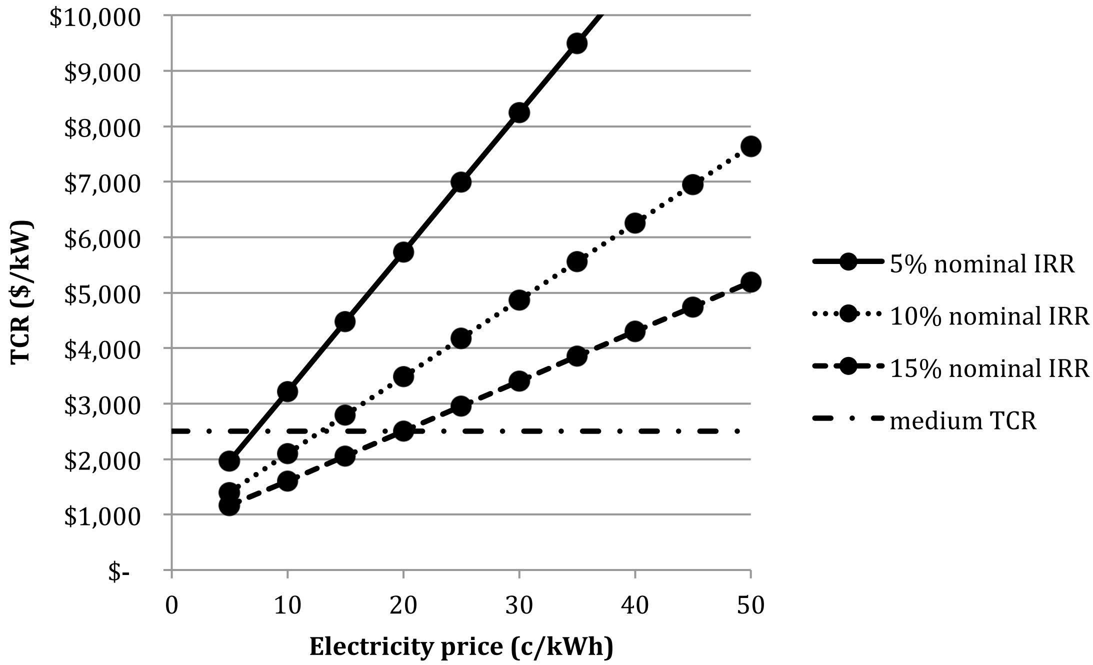

Figure 35: Marginal TCR ($/kW) versus displaced electricity price for 5%, 10% and 15% nominal IRRs. Also shown is the medium TCR of 2500 $/kW. Analysis assumes no energy lost or fed into the network, a Zone 3 STC region and all other assumptions in Table 53.

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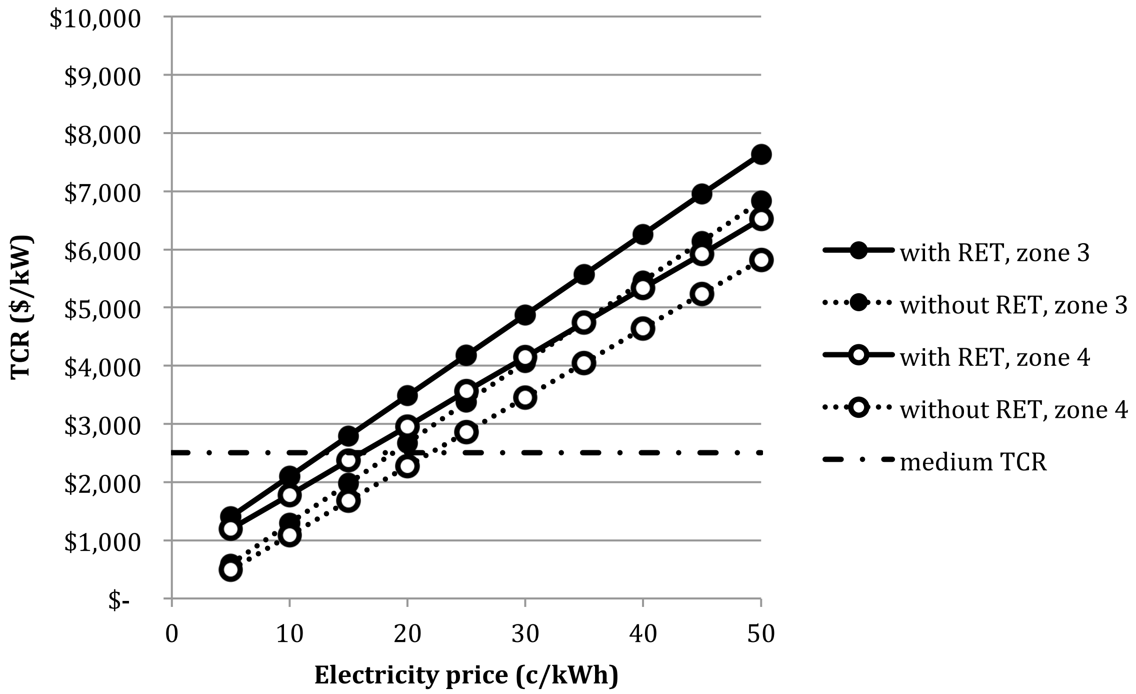

Figure 36: Marginal TCR ($/kW) versus displaced electricity price for STC Zones 3 and 4 with IRR=10% nominal, with and without the RET. Also shown is the medium TCR of 2500 $/kW. Analysis assumes no energy lost or fed into the network and all other assumptions in Table 53.

1.2 Battery storage

The financial performance on on-site battery storage is now considered. Our second report discussed in some detail the likely range of TCRs for battery storage. This range was large, reflecting the very limited experience with battery storage systems in both Australia and internationally.

The most comprehensive and independent, recent study of energy storage technologies was undertaken by a consortium led by the Sandia National Laboratories in the US [9]. This study states that battery storage at a scale that is appropriate for growers currently has TCRs that vary from roughly 550$/kWh to several thousands of $/kWh (at full discharge), and that lead-acid based storage systems are generally cheaper than Li-ion based systems. Other, less comprehensive studies suggest that the TCR of Li-ion battery systems is 700-800 $/kWh [10,11,12]. Further, all of these reported TCRs do not include the cost of battery replacement. The Sandia study [9] reports 8 years to be a typical battery life and 15 years as the typical life of the rest of the plant. Other studies tend to suggest longer battery lives (e.g. 10-12 years in [10,11,12]). If battery replacement is included in the analysis, then the total, lifetime cost of the storage system is significantly higher than these reported figures above.

Some of the analysis presented in this report uses an estimated TCR of 800$/kWh for battery storage. This figure is reasonably often quoted in the industry (e.g. [10,11,12]). Nonetheless, the uncertainty in this figure must be acknowledged and so should be considered to be only indicative.

We also assume a price of zero for the electricity that charges the battery. The most likely example of when this would arise is when the battery is charged from an already financially viable form of on-site power generation, using electricity that would not otherwise be consumed on-site. An example of this would be a solar PV plant that is already viable for less than 100% on-site utilisation, with the otherwise unutilised electricity being stored in the battery and discharged at some other time.

In principle, we could also consider the displaced electricity price in the following analysis to be the difference between the price of the network electricity actually displaced and the price of that purchased and used to charge the battery. This is an example of what is called *arbitrage*, and could occur by purchasing electricity at the off-peak rate and storing it for use during peak rate times. Of course, the difference between the peak and off-peak rates is always lower than the peak rate itself. Thus, arbitrage can only be potentially viable if a battery storage system is already viable whilst charging at zero electricity price and discharging at the peak rate. Since we find that this is unlikely to be the case in practice, financially viable arbitrage using battery storage is more unlikely and is not analysed below.

Reference example

We now give a reference example for a hypothetical battery storage system. This installation has the input assumptions listed in Table 54 and the following features:

- It is charged by electricity that is generated on-site at zero price.
- It is charged and discharged daily to 80% depth of discharge.
- It has a displaced electricity price of 150 $/MWh = 15 c/kWh, which is representative of some of the larger growers considered in our second report.
- All electricity that it discharges is consumed on site, and no energy is fed into the network.
- The grower requires a 10% nominal internal rate of return (IRR) as his/her measure of the plant's financial performance.

Using these inputs, we obtain a marginal TCR of 299 $/kWh, which is significantly lower than the estimated, required TCR of 800 $/kWh for an installed system. *Thus, given the inputs in Table 54, it is very unlikely that battery storage will be viable for this hypothetical example.*

Technical inputs		
Allowable depth of discharge	80%	
Charge/discharge cycles (#/yr)	365.25	
Fixed O&M ($/kW.yr)	25	
Variable O&M ($/kWh)	0.001	
Annual loss in performance (%)	0.5%	
Electricity prices		
displaced elec. price ($/MWh)	150	ex GST
Other financial inputs		
Discount rate (real %)	7.1%	
Cost of Debt (nominal, %)	6.5%	
Inflation (CPI %)	2.7%	
Debt Percentage (%)	100.0%	
Plant life (years)	15	
Book life (years)	15	
Debt life (years)	10	
Company tax rate	30.0%	

Table 54: Inputs for the reference example

Effect of different input parameters

We now consider the effect of different input parameters.

The effect of different internal rates of return (IRR)

Figure 37 shows the effect of different IRRs on the marginal TCR of a battery system that is fully charged and discharged daily. Once again, 10% to 15% nominal IRRs is a common range used by investors. Figure 37 shows that these IRRs should only result in viable battery installations for high displaced electricity prices: IRRs of 10% and 15% nominal are only estimated to be viable for displaced electricity that has a higher price than about 35 c/kWh and 50 c/kWh respectively. These displaced electricity prices are high, with prices higher than 35c/kWh likely in only rare cases.

The effect of non-utilisation of electricity that can be generated on-site

Of course, when the battery system is not fully utilised, its financial performance can only deteriorate. Figure 38 illustrates this for cases with a 10% nominal IRR and where charging/discharging is on weekdays (i.e. 5/7 of all days) and weekends (i.e. 2/7 of all days). Given the very high, required displaced electricity prices discussed previously, these less utilised systems are likely to be unviable.

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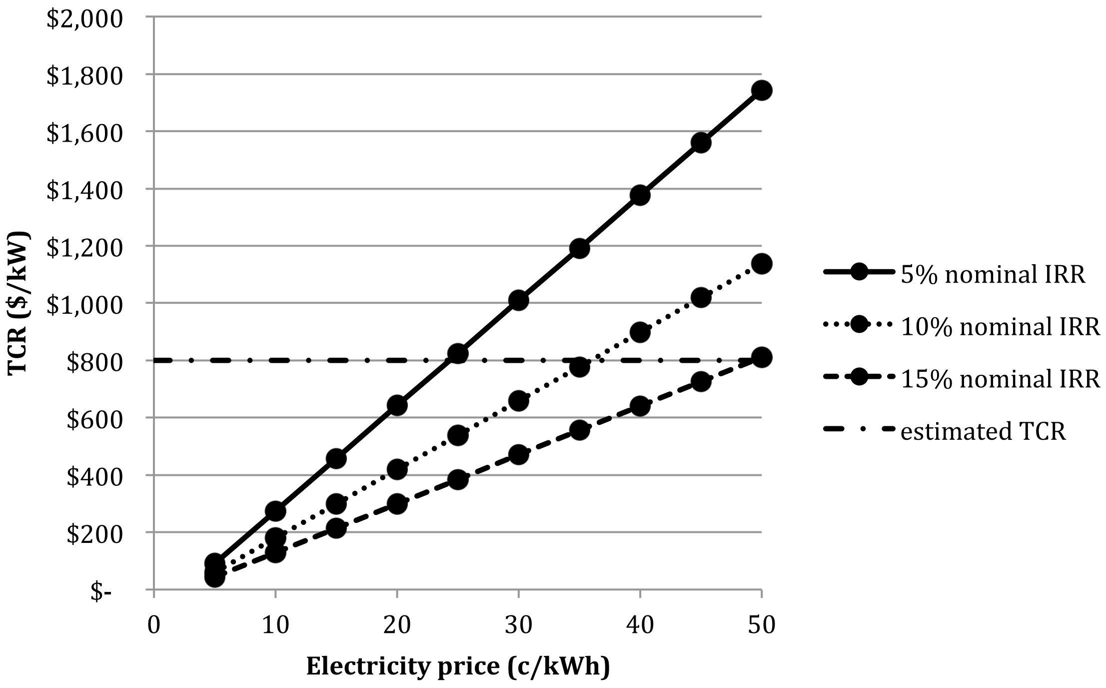

Figure 37: Marginal TCR ($/kW) versus displaced electricity price for 5%, 10% and 15% nominal IRRs. Also shown is the estimated TCR of 800 $/kW. Analysis assumes daily full charge/discharge by zero price electricity, with all other assumptions in Table 54.

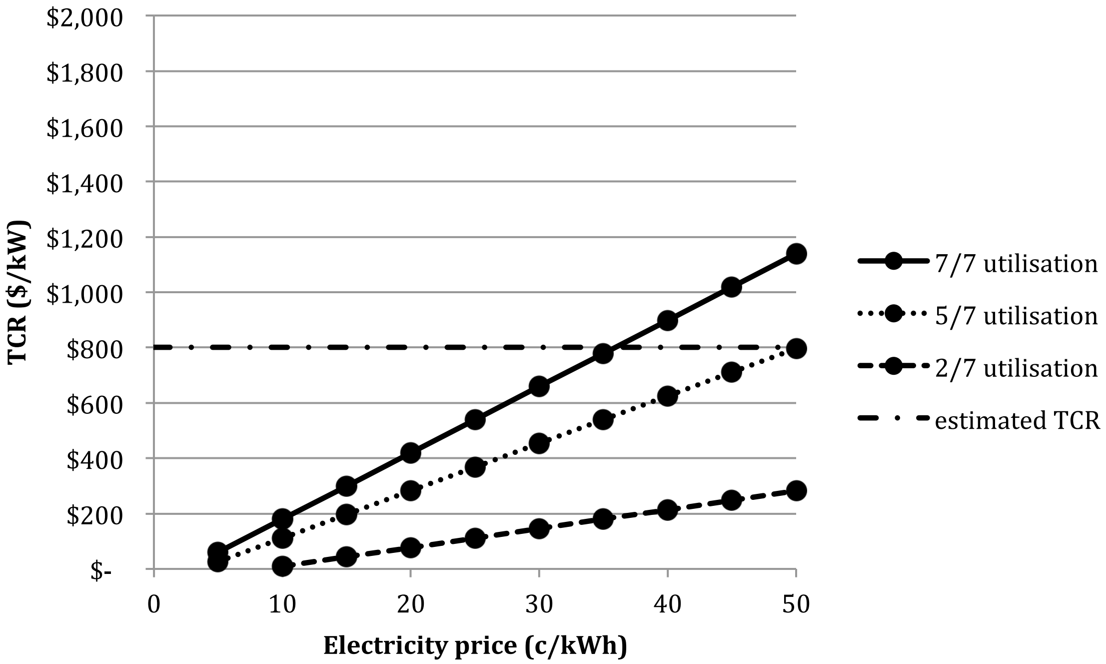

Figure 38: Marginal TCR ($/kW) versus displaced electricity price for 10% nominal IRR and daily (7/7), weekday (5/7) and weekend (2/7) full charge/discharge. Also shown is the estimated TCR of 800

$/kW. Analysis assumes that battery is charged by zero price electricity, with all other assumptions in Table 54.

1.3 Engines

As in our second report, we consider three types of on-site generation with reciprocating engines.

1. Simple generation: This features a reciprocating engine connected to an electrical generator only.
2. Cogeneration of electricity and process heat: This features a reciprocating engine connected to an electrical generator, with the waste heat from the engine's cooling system and exhaust recovered via heat exchangers. This waste heat is used for process heating.
3. Cogeneration of electricity and process cooling: This is similar to the cogeneration plant above, but features an absorption chiller that uses the engine's waste heat to generate process cooling.

Table 55 shows the estimated range of TCRs for these systems. As our second report discusses in detail, simple and cogeneration systems are mature technologies for which *uninstalled* plant costs are readily available. Further, whilst different manufacturers can have significantly different uninstalled plant costs, financial analysis of simple and cogeneration systems demonstrates that the TCR is normally a relatively small part of the total operating cost, with the price of fuel dominating. It therefore important to choose a system of appropriate size that has high efficiency and reliability, rather than one with the lowest TCR. Finally, given the maturity of these technologies, the stated uncertainty in the TCR relates primarily to the difficulty of installation rather than the uninstalled plant cost.

	Low TCR $/kW	**Medium TCR $/kW**	**High TCR $/kW**
Simple generation	900	1200	1500
Cogeneration with heating	900	1200	1500
Cogeneration with cooling	1080	1440	1800

Table 55: Estimated low, medium and high TCRs ($/kWe, ex GST) for the three simple and cogeneration systems examined in this report.

Reference example 1 – simple generation and cogeneration using LPG or diesel

We first give a reference example for a hypothetical simple generation plant. This installation has the input assumptions listed in Table 56, and the following features.

- All electricity that it generates is consumed on site, and no energy is fed into the network.
- It has a displaced electricity price of 150 $/MWh = 15 c/kWh, which is representative of that some of the larger growers considered in our second report.
- It has a fuel price of 40 $/GJ, which corresponds to approximately 0.92 $/lt of LPG or 1.36 $/lt of diesel, and is thus representative of delivered prices for these fuels.
- The grower requires a 10% nominal internal rate of return (IRR) as his/her measure of the plant's financial performance.

A meaningful (i.e. positive) TCR is not obtained with these inputs simply because of the relative prices of the fuel and electricity. This is easily understood if we ignore the tax deduction of fuel as an operating expense. In this case, simple generation with an engine of 35% efficiency means that the displaced electricity must cost more than 40$/GJ / 0.35% = 114$/GJ = 41c/kWh *in order to offset the fuel costs only*. Since this is an excessively high electricity price, using fuel of this price to generate electricity is very likely unviable at any site. Further, use of cogeneration (for either heating or cooling) cannot offset this high cost of the fuel through more efficient use of the energy in the fuel, since only some of the fuel energy is used for the heating or cooling and the remaining fuel energy is already uncompetitive against the electricity.

Therefore, simple or cogeneration in practice requires fuel prices that can plausibly compete against network delivered electricity on its own, with additional heating or cooling then providing additional potential benefit.

Technical inputs		
Fixed O&M ($/kWe.yr)	25	
Variable O&M ($/MWhe)	0	
Engine capacity factor (%)	80.0%	
Engine efficiency (%)	35.0%	
Annual loss in performance (%)	0.5%	
Electricity prices		
Displaced elec. price ($/MWh)	150	ex GST
Fuel price		
Fuel price ($/GJ)	40	ex GST
Other financial inputs		
Discount rate (real %)	7.1%	
Cost of Debt (nominal, %)	6.5%	
Inflation (CPI %)	2.7%	
Debt Percentage (%)	100.0%	
Plant life (years)	25	
Book life (years)	20	
Debt life (years)	10	
Company tax rate	30.0%	

Table 56: Inputs for the reference example with simple generation using LPG or diesel

Reference example 2 – simple generation and cogeneration using network delivered natural gas

As we discuss in our second report, network delivered natural gas should cost significantly less than the fuel in Table 56 *if network connection is already existing or straightforward and the supply contact is for large enough quantities* (likely 5 TJ pa or more). In this case, 10 $/GJ or even less for network delivered natural gas is expected to be feasible.

Use of 10 $/GJ for the fuel price and otherwise the same inputs in Table 56 results in a marginal TCR of 2734 $/kWe for simple generation, which is significantly higher than the estimated range shown in Table 55. Thus, simple generation in this case is viable. (Once again, ignoring the tax deduction of fuel as an operating expense, the displaced electricity price must now be at least 10$/GJ / 0.35% = 28.6$/GJ = 10c/kWh to offset the fuel costs only. The modelled electricity price of 15c/kWh in Table 56 clearly meets this.)

We now consider the cogeneration of electricity and process cooling, since many growers have significant and continuous electricity consumption from refrigeration plant on cool rooms. In this case, a fuel price of 10 $/GJ is used with the other inputs in Table 56, as well as additional inputs in Table 57 that describe the performance of the absorption chiller and a potentially existing, electrically driven refrigeration system that the absorption chiller displaces. In this case, the cogeneration plant has a marginal TCR of 7114 $/kWe, which is *far above* the estimated ranges shown in Table 55, and so again viable.

Viewed together, reference examples 1 and 2 demonstrate the importance of fuel price in determining the viability of on-site generation using reciprocating engine generators. These examples also show that, in practice, the fuel must very likely be network delivered natural gas, since this is the only fuel that has a price that can plausibly displace that of network delivered electricity. This means that on-site engine generation will be unviable for many growers, since network delivered natural gas is simply not available to them.

Heat utilisation / engine utilisation	100.0%
Heat recovery capacity factor (%)	80.0%
Heat recovery efficiency (%)	80.0%
Chiller COP	0.7
Refrigerator COP	2.5

Table 57: Additional inputs for the reference example with cogeneration of electricity and processing cooling

Effect of different input parameters on the cogeneration of electricity and process cooling

We now consider the effect of different input parameters on the financial performance of the cogeneration of electricity and process cooling. This is once again since many growers have significant and continuous electricity consumption from refrigeration plant on cool rooms.

The effect of different internal rates of return (IRR)

Figure 39 shows the variation of the marginal TCR for different IRRs and a representative network delivered natural gas price of 10 $/GJ. Relative to other technologies studied in this report, variations in the IRR have a relatively weak effect on the marginal TCR. As discussed previously, this is because the financial performance of cogeneration is dominated by the fuel price.

Thus, Figure 39 shows that, largely regardless of the specified IRR, the displaced electricity must be more than about 10 c/kWh if this cogeneration plant is to be viable. This is only expected to be likely for most growers, *if they can obtain the network delivered natural gas at approximately 10 $/GJ or less.*

The effect of fuel price

Figure 40 then shows the variation of the marginal TCR for different fuel prices and a fixed nominal IRR of 10%. The dominance of the fuel price on the plant's financial performance is clear. Importantly, most growers are expected to have access only to LPG or diesel, which is likely to cost 40 $/GJ or more. If this is the case, then Figure 40 shows that the displaced electricity price must be more than 30 c/kWh in order for the cogeneration plant to be viable.

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The effect of plant capacity factor

Finally, Figure 41 shows the variation of the marginal TCR for different plant capacity factors, a fixed nominal IRR of 10% and a fuel price of 10 $/GJ. The capacity factor of any plant should be maximised in order to maximise its financial performance. An 80% capacity factor for these plants is a reasonable upper limit in practice, and a 50% capacity factor can still give reasonable financial performance. However, the financial performance diminishes at lower capacity factors, highlighting the importance of plant sizing relative to the on-site electricity and cooling demand, as well as sound maintenance practices that ensure reasonable capacity factors.

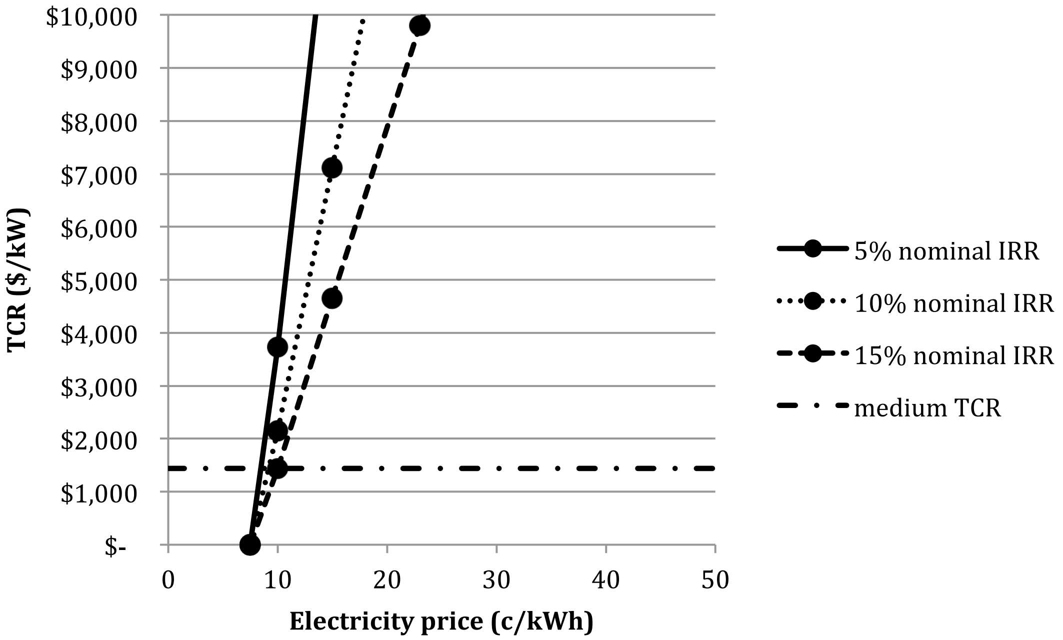

Figure 39: Marginal TCR ($/kW) versus displaced electricity price for fuel at 10$/GJ and 5%, 10% and 15% nominal IRRs. Also shown is the estimated medium TCR of 1440 $/kW, and other assumptions in Table 53.

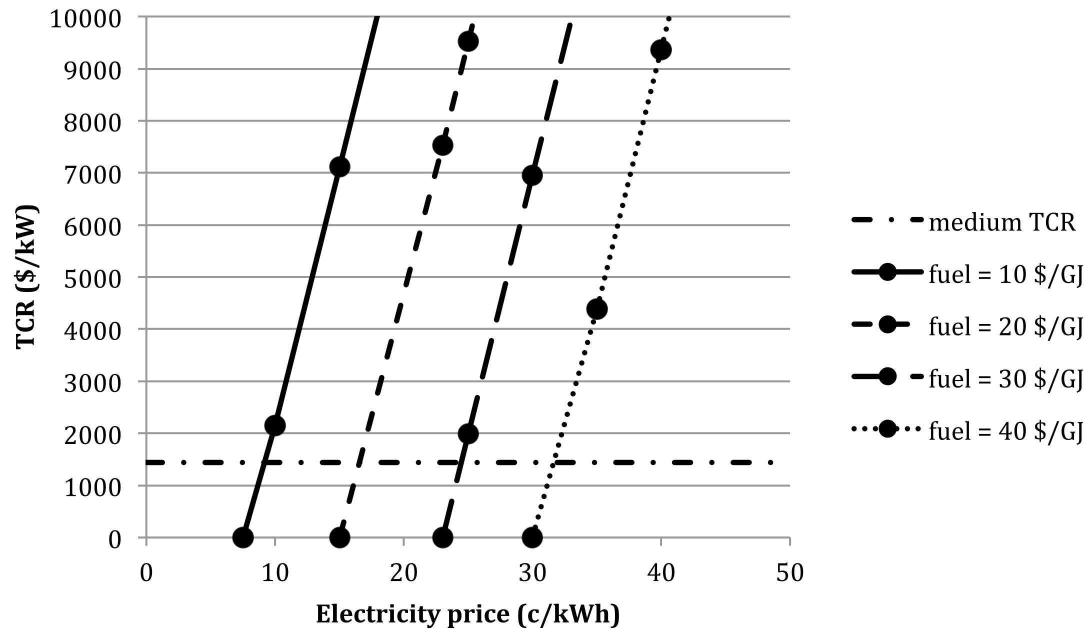

Figure 40: Marginal TCR ($/kW) versus displaced electricity price for 10% nominal IRR and different fuel prices. Also shown is the estimated medium TCR of 1440 $/kW, and other assumptions in Table 56.

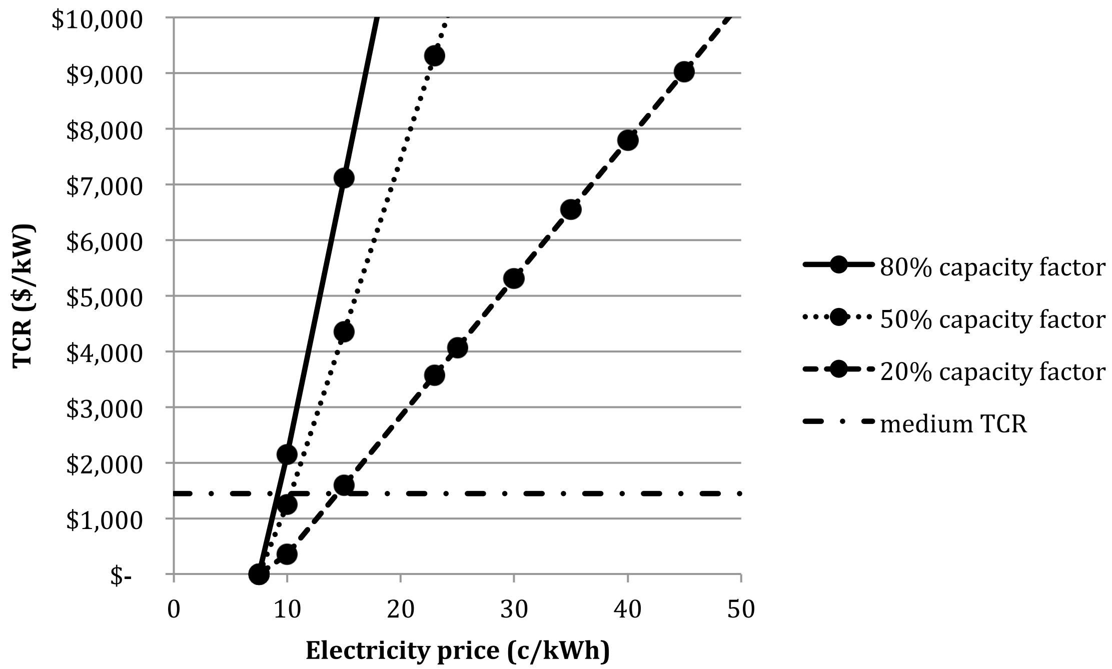

Figure 41: Marginal TCR ($/kW) versus displaced electricity price for 10% nominal IRR and different capacity factors. Also shown is the estimated medium TCR of 1440 $/kW, and other assumptions in Table 56.

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1.4 Wind turbines

We now consider on-site power generation using wind turbines. As we discuss in Task 2, Australian growers have already installed wind turbines, with individual turbines ranging in capacity from 10kW (i.e. small scale turbines) to 500kW (i.e. larger, intermediate scale turbines). In one case, a particular grower has installed ten 500 kW turbines on one site, resulting in a wind farm of 5MW capacity.

The grower with 5MW of installed wind capacity, and therefore roughly 500kW to 1MW of average wind power generation, had substantial electricity needs around the clock. It is expected that most growers would not consume this much electricity, with a single or a few, intermediate scale turbines (of say 50-500kW total capacity or 10-100kW average power generation) being most relevant. We have therefore analysed intermediate scale wind turbines.

Under Task 2 we presented a range of likely TCRs for installed wind turbines of small and intermediate scales. A key feature of the turbines that had been installed already was that most were second hand. The reason for this was straightforward; those interviewed found that second hand turbines were required in order to make the installation financially viable, with the TCR reported by these growers and installers in the range 1330-1780 $/kW. Nonetheless, there is some uncertainty in these estimates by growers, as it was unclear whether they included *all* the costs of turbine installation. As a result, we suggest that a reasonable range of TCRs for second hand, intermediate scale wind turbines is 1500-2000 $/kW, with a medium TCR of 1750 $/kW (Table 58).

Low TCR $/kW	Medium TCR $/kW	High TCR $/kW
1500	1750	2000

Table 58: Estimated low, medium and high TCRs ($/kWe, ex GST) for intermediate scale (50-500kW), second hand wind turbines examined in this report.

Further, this range of TCRs for *second hand*, intermediate scale wind turbines appears reasonable, since *new* turbines of intermediate scale should cost more per kW than large scale turbines and be cheaper than new, small scale turbines. Of note then is the following.

- The TCR of a new, large scale (100MW) wind farm is estimated by the Bureau of Resource and Energy Economics (BREE) to be 2530 $/kW, with an uncertainty of +/- 20% [14].
- The TCR of new, 10kW capacity turbines appears to be in the range of several '000s $/kW, with our second report finding one instance of a small turbine with a TCR of 6000-7000 $/kW.

This suggests that new, intermediate scale turbines may have TCRS of 3000-4000 $/kW, with their second hand equivalents having TCRs as per Table 58. If so, *new* wind turbines of small or intermediate scale are then likely less attractive than solar PV since capital expenditure is a large part of the total cost of ownership of any renewable plant. Similarly, *second hand* intermediate scale turbines can potentially be more attractive than solar PV. This is consistent with the fact that, compared with solar PV, there are negligible registered wind turbine installations generating STCs (i.e. turbines of 10kW capacity of less) [15].

Also, as defined by the Clean Energy Regulator [13], the threshold between generating small-scale technology certificates (STCs) and large-scale generation certificates (LGCs) from wind turbines is a system of 10kW capacity and a total annual electricity output of 25 MWh. A key difference between LGCs and STCs is that the former are generated annually, whereas the latter are created for the entire plant's life upon installation. Because of this, LGC income generated in a future year should be taxed and then discounted to a present value. Since the RET currently runs to 2030, we assume that LGCs are

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generated for the first 15 years of the operating life of a wind turbine, which corresponds to a commencement of generation on 1 January, 2016.

Reference example

We first give a reference example for a hypothetical wind turbine. This installation has the input assumptions listed in Table 59, and the following features.

- All electricity that it generates is consumed on site, and no energy is fed into the network.
- It has a displaced electricity price of 150 $/MWh = 15 c/kWh, which is representative of that some of the larger growers considered in our second report.
- The grower requires a 10% nominal internal rate of return (IRR) as his/her measure of the plant's financial performance.

When LGCs are included, the marginal TCR is 2560 $/kW, showing that any second hand, wind turbine within the range quoted in Table 58 should be viable. Importantly, this remains to be the case even if the RET is repealed (i.e. LGCs are ignored), in which case the marginal TCR is 2120 $/kW.

This simple analysis therefore highlights the financial attractiveness of using second hand wind turbines, particularly given the significant likelihood that LGCs may not be available shortly.

LGC price ($/MWh)	35	with GST
Technical inputs		
Fixed O&M ($/kW.yr)	32.5	
Variable O&M ($/MWh)	10	
Capacity Factor (%)	20%	
Annual loss in performance (%)	0.5%	
Proportion fed-in	0.0%	
Lost energy without feed-in	0.0%	
Electricity prices		
displaced elec. price ($/MWh)	150	ex GST
Other financial inputs		
Discount rate (real %)	7.1%	
Cost of Debt (nominal, %)	6.5%	
Inflation (CPI %)	2.7%	
Debt Percentage (%)	100.0%	
Plant life (years)	25	
Book life (years)	20	
Debt life (years)	10	
Company tax rate	30.0%	

Table 59: Inputs for the reference example

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Effect of different input parameters on the cogeneration of electricity and process cooling

We now consider the effect of different input parameters on the financial performance of on-site electricity generation from wind turbines.

The effect of lost energy generation

Figure 42 shows the variation of the marginal TCR obtained for varying displaced electricity price, a 10% nominal IRR and varying amounts of annual, on-site energy being lost. This lost energy represents the situation where the network service provider does not allow feed into the network. Of course, feed-in tariffs may feature in some cases, but these generally have a small impact on the plant's financial performance since these tariffs are now generally quite small, as the analysis of solar PV showed.

As with a solar PV plant, the marginal TCR reduces as a greater proportion of the potentially generated electricity is lost. This again highlights the importance of plant sizing. Importantly, Figure 42 shows that a second hand wind turbine of medium TCR is viable provided that the displaced electricity costs more than about 10c/kWh and 10% or less of the potentially generated electricity is lost. Since wind power is both intermittent and unpredictable, growers would likely need a significant and round-the-clock electricity load to ensure minimal electricity is lost. It is expected that some growers will meet these conditions with an appropriately sized, second hand wind plant, provided that a reasonable capacity factor (assumed to be 20% in this case) is achieved at their site.

The effect of different internal rates of return (IRR)

Figure 43 shows the effect of different IRRs on the marginal TCR, with 10%-15% nominal IRRs a common range used by investors. This again shows that imposition of a 10% nominal IRR should result in a financially viable, second hand wind turbine of medium TCR provided that the displaced electricity is more than about 10c/kWh, and the capacity factor is again reasonable, i.e. about 20% or higher. Importantly, if the displaced electricity price is higher than 15c/kWh, an IRR higher than 15% nominal is plausible, which should be considered a very strong investment.

The effect of RET repeal

Figure 44 shows the variation of the marginal TCR with displaced electricity price for the same installation, again with a 20% capacity factor and 10% IRR nominal, both with and without the RET in place. As found previously, a second hand wind turbine of medium TCR is viable for displaced electricity prices about roughly 10c/kWh with the RET in place and a representative LGC price of 35 $/MWh. Importantly, this required displaced electricity price only rises to about 12c/kWh when the RET is repealed, which is still below the displaced electricity price of many growers.

Importantly, repeal of the RET appears to have a weaker adverse impact on the viability of intermediate scale wind turbines than for solar PV. This is because LGCs are generated yearly, and so as discussed earlier, they are taxed and then discounted to a present value, i.e. LGCs of a given price in $/MWh presently have lower value than STCs of the same price.

Thus, it is likely that second hand wind turbines will remain an attractive investment for many growers, irrespective of the future of the RET, since their low TCR makes them attractive and they are less sensitive to RET repeal than solar PV.

The effect of plant capacity factor

Finally, Figure 45 shows the strong effect of the capacity factor on the marginal TCR. It is expected that most growers will have intermediate scale wind turbines with a capacity factor in the range 10-20%. Figure 45 shows that a second hand wind turbine of medium TCR and a capacity factor of 20% requires a displaced electricity price of at least roughly 10c/kWh. Similarly, a second hand wind turbine of medium TCR and a capacity factor of 10% requires a displaced electricity price of at least roughly 22c/kWh.

This range of displaced electricity prices spans the likely range of many growers. In particular, capacity factors below 20% may be viable if the displaced electricity price is higher, say 20-25 c/kWh or more.

Regardless, having a good estimate of the capacity factor prior to investment is important. For large scale wind farms, capacity factors are usually estimated using detailed wind measurements as part of the wind farm's feasibility study, and these measurements are usually conducted over several years. Whilst such detailed measurements are likely unaffordable to most growers, more limited measurements by credible consultants are nonetheless strongly recommended in order to reduce the chances of making a poor investment.

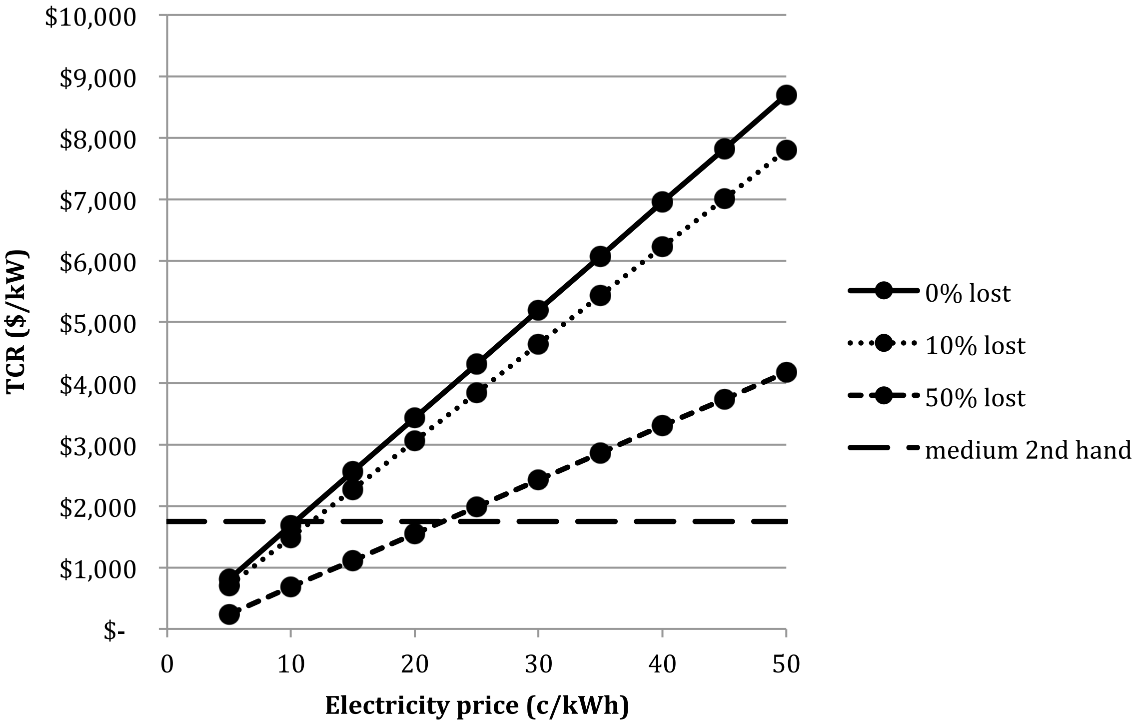

Figure 42: Marginal TCR ($/kW) vs displaced electricity price for 0%, 10% and 50% of lost, on-site energy generation, with other inputs as per Table 59. Also shown are medium TCRs for new and 2nd hand plant.

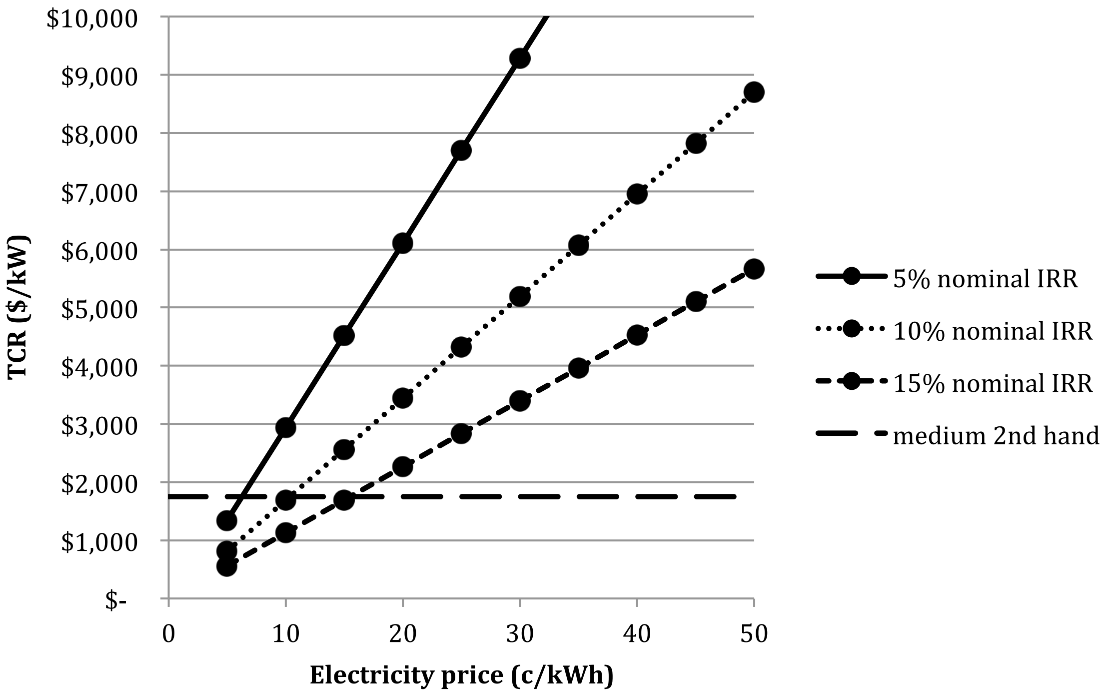

Figure 43: Marginal TCR ($/kW) versus displaced electricity price for 5%, 10% and 15% nominal IRRs, with other inputs as per Table 59. Also shown are medium TCRs for new and 2nd hand plant

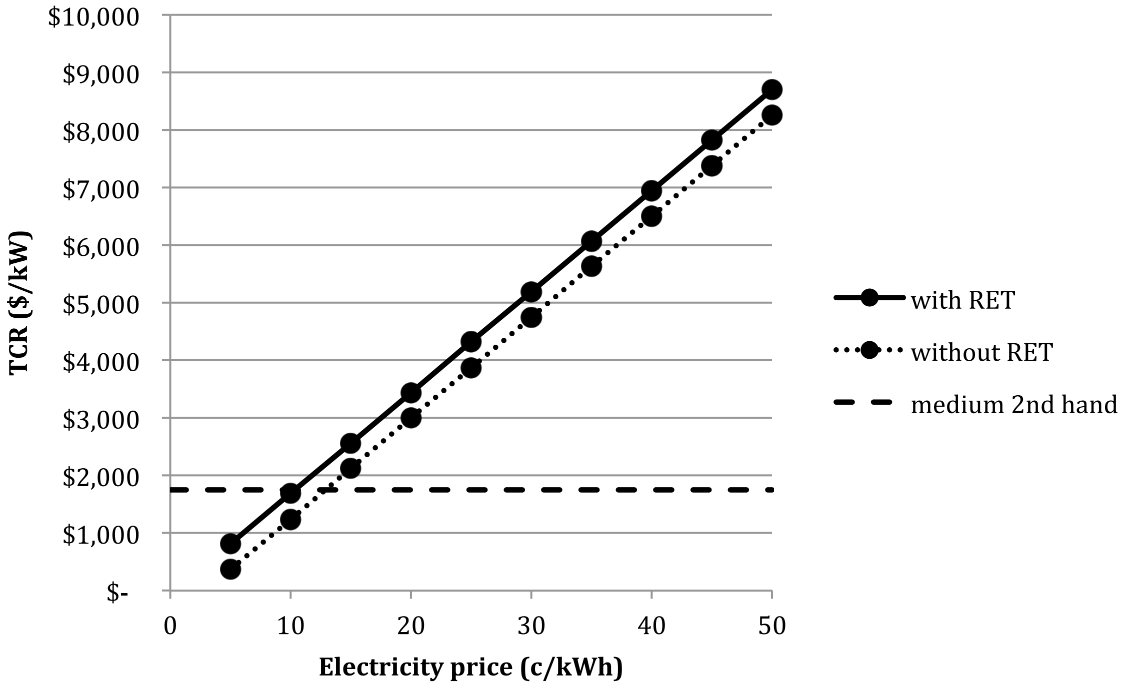

Figure 44: Marginal TCR ($/kW) versus displaced electricity price with and without LGCs at 35 $/MWh, with other inputs as per Table 59. Also shown are medium TCRs for new and 2nd hand plant.

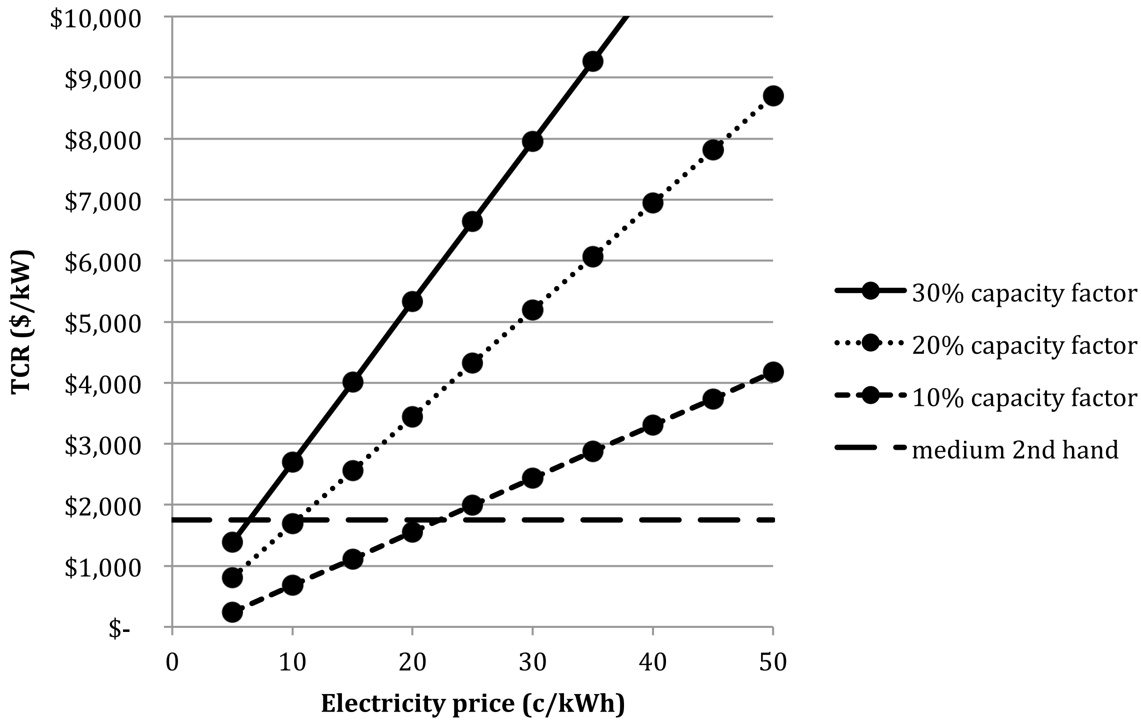

Figure 45: Marginal TCR ($/kW) versus displaced electricity price for capacity factors of 10%, 20% and 30%, with other inputs as per Table 59. Also shown are medium TCRs for new and 2nd hand plant.

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Task 4: Incentives and regulation for on farm power generation

In this section, we consider key regulatory and policy arrangements that will affect the attractiveness and implementation of on farm power generation for growers. Specifically, we reviewed regulated incentives schemes, namely the Renewable Energy Target and feed-in-tariffs. In addition, we present an overview of the regulatory requirements that must be addressed to install and operate key technologies.

1. The Renewable Energy Target

The Renewable Energy Target (RET) is an Australian government scheme designed to reduce greenhouse gas emissions from the electricity sector. The RET was established to encourage installation of renewable energy generation capacity by providing financial incentives for renewable energy generation [16].

After its establishment, the RET was split into two different schemes covering small scale and large scale generation. Each of these schemes, described in greater detail below, create tradable certificates based on generation (MWh) by renewable power plant and an obligation for liable market participants to purchase and surrender a certain number of these certificates each year. The certificates typically trade around $35-40/MWh although can vary from $10-60/MWh on a daily basis [17].

The Small-scale Renewable Energy Scheme (SRES) creates financial incentives for householders and businesses to install eligible small-scale renewable power systems. Eligible systems include solar PV installations up to 100kW in capacity, small-scale wind systems up to 10kW in capacity and small-scale hydro systems up to 6.4kW in capacity. Systems can create tradable Small-Scale Technology Certificates (STCs) which can be claimed 'up-front' once the system is installed by an accredited installer [18,20].

The number of STCs that a given system can create is based on the expected electricity generation (in MWh) by the system over the course of its lifetime up to 15 years [18]. For a solar system of a given capacity, the number of STCs varies depending on the incident solar radiation with four distinct zones defined across Australia. As noted in previous reports, the Clean Energy Regulator website includes a calculator for owners to work out the number of STCs that they would be eligible to create, based on system type, size and location. Owners of the system may assign the STCs to their installer or agent in return for a 'discount' on the cost of the system, or can choose to create and trade their STCs themselves. However, given administrative complexity, most owners do not choose this approach.

The Large-Scale Renewable Energy Target (LRET) operates to encourage establishment and electricity generation by renewable energy power stations, such as large-scale solar, wind and hydro power. Large-scale Generation Certificates (LGCs) are created by eligible power stations based on their actual renewable energy production in MWh and sold or traded to liable entities such as electricity retailers [19]. The LRET places a legal obligation on liable entities to purchase a set number of LGCs each year. A key difference between LGCs and STCs, as discussed earlier, is that STCs are created and their value is realised at the establishment of the renewable power system whilst LGCs are created and traded over the life of the power plant (and the LRET scheme). A number of growers profiled in our second report create and trade LGCs.

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In February 2014, the Australian Government commissioned a Review into the Renewable Energy Target (the RET Review). The RET Review released its report and recommendations in late August 2014[3]. In brief, the RET Review recommendations included that:

- The LRET is either closed to new entrants (and existing arrangements 'grandfathered') or that the annual target is set to allocate a share of growth in electricity demand to renewables (i.e. increases in the target are contingent on growth in electricity demand).
- The SRES is either abolished or changed in key respects, including bringing forward the phase-out of SRES from 2030 to 2020, reducing the deeming period for roof-top solar from 15 years to 10 years and then each year until the 2020 deeming period is 5 years, and lowering the eligibility threshold for solar PV systems from 100kW to 10kW.
- The changes to the deeming rate and the eligibility threshold are implemented regardless of any other changes to the RET [21,22,23].

If implemented in full, these proposals would have significant affect the economics of on farm power generation options. However, the Australian Government has not announced their response to the RET Review findings. Given the uncertainty about the Government's position and, further, whether the Senate would pass all of the amendments in this term, it is too early to be definitive as to the RET's future.

2. *Feed-in-tariffs*

As noted in previous reports, feed-in-tariff arrangements vary by jurisdiction and have changed significantly over time. Historically, differences between states and territories have been large and some have operated very generous feed-in-tariff schemes. However, most (though not all) jurisdictions have significantly reduced or scrapped their mandatory minimum feed-in-tariffs and remaining mandated rates are typically 5-8c/kWh for net export across most of Australia. In many locations, customers who wish to export excess renewable energy to the grid must negotiate with retailers regarding compensation. These are known as *voluntary feed-in-tariffs*.

Nonetheless, there are differences in rates and eligibility by jurisdiction as detailed below. It was not our intention to review previous feed-in-tariff regimes or schemes which still operate but are closed to new entrants or investors. Instead we reviewed schemes that are currently open to new customers in each jurisdiction and any known or anticipated changes to these schemes. Schemes and rates can change, however. Investors and other readers should therefore check on the rates being offered in their jurisdiction prior to making decisions and investments.

2.1. Victoria

The Essential Services Commission in Victoria regulates the minimum feed-in-tariff that energy retailers must offer to Victorian customers who install renewable or low emissions energy systems below 100kW in capacity. These systems can include roof-top solar PV, ground-mounted solar, wind and hydro systems. Low emissions systems fuelled by fossil fuels may also be eligible to participate if their emissions intensity is below 0.4 t CO_2-e/MWh [23]. The feed-in-tariff rate for excess energy fed into the grid is 8c/kWh for 2014 [24] and 6.2c/kWh for 2015 [25].

2.2. NSW

There is no mandatory regulated feed-in-tariff in NSW for new customers who install small-scale generation. However, each year, the Independent Pricing and Regulatory Tribunal publishes a determination on a fair and reasonable value for small-scale solar electricity fed into the grid. The

[3] https://retreview.dpmc.gov.au/sites/default/files/files/RET_Review_Report.pdf accessed 4/11/2014

benchmark range for 2014/15 for the unsubsidised feed-in tariffs that retailers may voluntarily offer solar PV customers who are not part of the Solar Bonus Scheme is 4.9 to 9.3 c/kWh with a median of 5.6 c/kWh [26].

2.3. ACT

Similar to NSW, ACT does not regulate feed-in-tariffs for small scale solar systems [27]. Electricity retailers may offer voluntary feed-in-tariffs to customers who wish to export excess energy from their solar systems.

2.4. Queensland

As discussed in our previous reports, the generous Solar Bonus Scheme offering a feed-in-tariff of 44 c/kWh runs until 2028 but is not open to new customers [28,31]. For new customers in Queensland installing a small-scale solar PV system, the feed-in-tariff arrangement depends on the location of the customer.

Customers in south-east Queensland (covered by the Energex network) are not covered by a government-mandated tariff from July 2014. Instead, electricity retailers offer voluntary feed-in-tariffs and customers must negotiate with retailers to secure a feed-in-tariff [28,31,32].

For new customers in regional Queensland (outside the Energex supply network), the Queensland Competition Authority (QCA) sets regulated feed-in-tariff rates annually which cover systems up to 5kW in capacity. Until September 11, 2014, the mandated feed-in-tariff is 9.07c/kWh [29]; from 11 September 2014 until 30 June 2015, the rate drops to 6.53c/kWh [30]. For systems over 5kW in capacity, customers must negotiate with their retailer regarding a voluntary feed-in-tariff [33].

2.5. South Australia

As in other states, generous feed-in-tariff schemes still operating in South Australia are now closed to new entrants. For customers with small scale solar systems who meet eligibility criteria[4], there is a minimum payment that their retailer must pay them for excess electricity exported to the grid [35]. This minimum retailer payment is determined each year by the South Australian regulator (the Essential Services Commission of South Australia, or ESCOSA) and is designed to reflect a fair and reasonable value of fed-in electricity to energy retailers. From 1 July 2014 to 31 December 2014, the rate is 6c/kWh [34]. However, the 'retailer feed-in-tariff' or R-FiT which customers receive may be above the minimum payment.

2.6. Tasmania

The regulated feed-in-tariff rate for Tasmanian small scale customers with renewable energy generation is currently 5.551c/kWh (excl GST) [36,37,38]. This rate is in place until 30 June 2015. These rates apply to net exported electricity fed into the grid by residential and small business customers with a renewable generation system up to 10kW in capacity and who consume less than 150MWh per annum [38].

2.7. Western Australia

[4] "All customers consuming less than 160MWh per annum with a solar system up to 10kVA (single phase) or 30kVA (three phase) may be eligible for a minimum payment from their electricity retailer for any excess electricity they export to the grid" from http://www.sa.gov.au

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The current Western Australian feed-in-tariff scheme is closed to new applicants. Instead, customers who install eligible renewable energy generation and export excess energy to the grid may be compensated via the Renewable Energy Buyback Scheme (REBS) [39]. Under this scheme, government owned retailers (namely Synergy for the South West Interconnected System – or SWIS – and Horizon Power for the rest of the state) must pay residents, schools and non-profit organisations for net electricity exports. Each retailer establishes its own terms and conditions, including rates, for the REBS which are approved by the Public Utilities Office [39].

Synergy offers residential customers 8.8529c/kWh excl GST for electricity exports to the grid where their system is less than 5kW in capacity [40]. Educational and non-profit organisations are also compensated but at widely different rates, depending on their tariff [40]. It is unlikely that growers would be eligible under these conditions so these are not discussed further. Synergy does not offer a REBS rate for commercial customers [41].

Horizon Power, on the other hand, offers REBS payments to all customers, both residential and commercial, depending on location and eligibility [42]. Horizon Power REBS rates vary widely with minimum payments of 10c/kWh up to a maximum of 50c/kWh [43]. The REBS pricelist published on the Horizon Power website shows the rates by locality; growers should be aware that commercial contracts are not offered in some areas [44]. Horizon Power also notes that some commercial customers have negotiated a bespoke buyback price. Further, commercial customers with systems above 50kW in capacity may not be eligible for the Commercial REBS rate. If the renewable energy generated is more than 20% above existing consumption, the customer will be required to negotiate a Power Purchase Agreement (PPA) which would cover electricity tariffs and potentially buyback rates [44].

2.8. Northern Territory

Jacana Energy, the government-owned Northern Territory electricity retailer, offers its customers solar buyback rates. These rates are subject to regulatory approval and may be changed but essentially match the relevant electricity tariff (i.e. generation offsets consumption) [45,46]. From 1 August 2014, export of energy from solar systems up to 30kVA attracts the following feed-in-tariffs: for domestic customers 25.6c/kWh and for commercial customers 29.79c/kWh [45]. Customers with solar systems larger than 30kVA or consuming at least 750MWh can negotiate a customised rate with Jacana Energy [45]. It should be noted that commercial customers with systems larger than 4.5kW may be required to install ‘zero-export devices’ (or reverse power protection) which will mean than the system does not export excess energy to the grid [46].

3. Implementation requirements and regulation associated with installation and operation of power generation plant

Regulatory requirements to install and operate on farm power generation can be numerous, onerous, time-consuming and costly. The requirements differ both by type of generation as well as by location. For any grower considering implementation of on farm power generation, there will be a complex set of requirements and regulations set and enacted by network service providers (for distribution and/or transmission systems), electricity market operators and environmental bodies as well as Commonwealth, State/Territory and local Government standards, laws and regulations.

This section aims to provide growers with an *overview* of these regulations and requirements illustrated by examples where appropriate. It does not constitute an exhaustive examination of the requirements nor should it be used as a technical guide. There are a number of comprehensive reports and other sources that provide further detail and most of these references are listed at the end of this section. Readers should also be aware that regulations and requirements are reviewed and changed from time to time, and whilst every effort has been made to ensure the accuracy of information included in this section, growers should make their own enquiries about requirements governing their proposed installation.

We describe three types of requirements relevant for potential on farm power generation installations:

1. Grid connection and technical requirements
2. Planning and development approval
3. Engine fuels and emissions standards

3.1. Grid connection and technical requirements

Grid connection requirements are governed by the National Electricity Rules [61] or other technical rules for jurisdictions not part of the National Electricity Market. For Western Australia, grid connection requirements are spelt out in the technical rules for the different power systems, e.g. South West Interconnected System (SWIS), North-West Interconnected System (NWIS) and regional non-interconnected systems (RNIS) [48]. For Northern Territory customers, the Power and Water Corporation determines grid connection requirements [47]. Installation and grid connection for embedded generation plant needs to be approved by the distribution network service provider (DNSP) who will certify the technical performance of the plant and may conduct a network study.

Requirements for small scale generation (below 5-10kW) are typically more streamlined in most jurisdictions, particularly for rooftop solar PV installations [48]. However, this is not the case in all states or localities so growers need to understand their local requirements for grid connection. For example, some DNSPs in Victoria require technical pre-approval checks regardless of solar system size; others only require these checks for systems larger than 4.6kW [49].

A typical, simplified grid connection process for small-scale solar systems would include the following steps:

- Seek approval from DNSP to connect system to the grid – this may be managed by the solar PV provider
- After installation, solar PV provider and DNSP arrange new metering if required and system connection
- DNSP informs electricity retailer about connection; owner may need to negotiate with electricity retailer regarding potential feed-in-tariff [50]

For solar PV installations in the range 10kW to 100kW, this process will be expanded to include discussions on feasibility with the DNSP about the proposed installation as well as a technical connection study that the DNSP will conduct to identify likely issues and any constraints to be imposed on grid connection (e.g., zero export). Commonly, systems above 30kW in capacity are required to install reverse power protection to prevent export to the grid.

Requirements for grid connection of larger scale, embedded generation are typically more involved. The Clean Energy Council's "Embedded Generation Connection Guide" summarises the process well [51] and highlights key differences between jurisdictions for systems of scale 100kW-5MW. The 11-stage process is reproduced in Table 60 below. Early engagement with the DNSP about proposed generation is key to successful navigation of the process. Since DNSPs are responsible for the safe and reliable supply of electricity to all customers, their role in the process is to ensure that any new grid connected generators will not compromise this responsibility and they can indicate likely technical constraints or connection issues.

Stage	Key activities
Preliminary connection discussion	The proponent approaches the DNSP with the concept of what they are trying to achieve, where and by when.
Connection enquiry	The proponent approaches the DNSP with a formal document outlining the basic information about their proposed project.
Response to connection enquiry	The DNSP responds with details about the information required for a connection application, and the application fee.
Connection application	The proponent completes and submits the connection application as per the DNSPs requirements, and pays the application fee. Connection studies would usually be completed as part of the connection application if being completed by the proponent.
Negotiation	The proponent and DNSP negotiate as to the details of the connection. This will involve negotiation of technical design, as well as commercial details. Connection studies may be undertaken at this stage if being completed by the DNSP.
Offer to connect	The DNSP makes an offer to connect once all of the technical parameters and commercial details have been agreed.
Connection agreement	The proponent accepts the offer to connect by signing it and this offer then becomes the connection agreement.
Registration and licencing	The proponent registers (or obtains registration exemption) with the appropriate market operator and secures any jurisdictional licences required.
Construction/implementation	The connection assets and the project are physically constructed.
Commissioning and testing	Following required testing, the plant will be commissioned and connected to the network.
Maintenance	The proponent will need to demonstrate sufficient ongoing maintenance to meet safety and reliability requirements.

Table 60: Overview of the connection process for medium scale embedded generation [51]

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3.2. Planning and development approval

Growers need to approach their local governments or councils to understand planning and development requirements for different technologies on their site. Planning and/or building permits may be required before construction and installation can commence, even for solar PV installations in some locations. Planning and development approvals may be required for some technologies, including wind power and some stationary power plant.

Installation of wind turbines commonly requires submission of a planning application. Whilst there is no common process or consistency in what councils require, development applications will typically examine:

- visual impact,
- noise impact,
- environmental impact (including the impact on plants and animals)
- and, for stationary power plant, air quality impact.

Preparation of the necessary documents and supporting evidence is often a time-consuming process. In addition, during the planning process, proposals can be challenged and local community or other objections can force the proponent to invest in costly and extensive impact studies which renders the project financially unattractive.

One of the growers we interviewed abandoned a planned site for a wind turbine due to objections from environmentalists. He emphasised that environmental objections to the installation of wind turbines can be a major disincentive to invest in on farm wind generation. In addition, advisers and installers who work with growers to project manage their wind power installations highlighted that since requirements change between councils and since each development is unique, there is no consistent set of guidelines that can be followed which adds significant cost and uncertainty to obtaining approvals.

3.3. Engine fuels and emissions standards

Where an engine or other generating plant is fuelled by natural gas, LPG, biogas, petrol, or diesel fuel, there are additional standards and regulations which must be met. These may include, but are not limited to:

- Australian standards governing the fuel itself (e.g. Gas installation code AG601),
- Australian standards governing industrial and commercial gas-fired appliances (AG501),
- State and Territory regulations regarding atmospheric and noise emissions (typically regulated by State-based Environmental Protection Authorities or equivalent)
- State-based fire and emergency services requirements
- State-based occupational health and safety standards for workplaces, and
- Australian standards for Hazardous Areas and ventilation

Typically, the organisation who is installing the power generation equipment can assist the grower to understand and meet these standards. However, whilst many of these requirements are national standards and hence consistent across jurisdictions, there are others which vary by state or within state. For example, there are no national emission limits for stationary power sources; state by state measures vary and are being revised at the moment. In addition, there are also variations within states for air quality emissions requirements. For example in NSW, there are more stringent NO emission standards for natural gas fired co-generation plants in the Sydney and Wollongong Metropolitan Area and Wollondilly Local Government Area than the rest of NSW (250mg/m^3 vs 450mg/m^3) to address air quality issues in these regions [52].

Further reading

The Clean Energy Council has a series of excellent guides regarding grid connection for embedded generation of different scales. These guides also outline requirements by jurisdiction. The series of guides for small scale systems, provided through the Solar Accreditation website, the Clean Energy Council's "Embedded Generation Connection Guide" and Sustainability Victoria "Guide to Connecting a Distributed Generator in Victoria" for medium scale installations are recommended to growers. They can be found at http://www.cleanenergycouncil.org.au/technologies/grid/grid-connection.html

The Clean Energy Council has also published a useful guide for businesses on solar PV. See: http://www.solaraccreditation.com.au/consumers/purchasing-your-solar-pv-system/solar-pv-guide-for-businesses.html

State and Territory Governments commonly publish guides and requirements regarding installation and connection of embedded generation. The table below includes a selection of resources that growers may find useful. Many of these can be found through the Clean Energy Council website, or by searching the websites for relevant Government departments and/or electricity distributors and retailers.

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Task 5: Communication of on farm power generation options

The outcomes of the project were communicated to Australian vegetable growers using the following methods:

Factsheets

A series of four factsheets which summarise the main findings described in Tasks 1-4 were produced. The titles of the 3-4 page factsheets are:

1. **On farm power generation: Vegetable growers**. This 3-page factsheet summarises the main findings of the whole project in a broad overview. It is intended to provide general information to growers who are in the early stages of considering on farm power generation.

2. **On farm power generation: Solar photovoltaics (PV**). This 4-page factsheet is specifically about solar PV. It outlines the outcomes of the case studies, and provides quantitative tools which growers can use to help them decide whether solar is likely to be technically feasible and economically viable for their location and pattern of power usage.

3. **On farm power generation: Wind power**. This 3-page factsheet is specifically about wind generation. It provides quantitative tools which growers can use to help them decide whether wind is likely to be technically feasible and economically viable for their location and pattern of power usage.

4. **On farm power generation: Gas fuelled power generation.** This 3-page factsheet is specific about gas fuelled generation and cogeneration. It outlines the outcomes of the case studies, and provides quantitative tools which growers can use to help them decide whether gas is likely to be technically feasible and economically viable for their location and pattern of power usage.

The factsheets are available in electronic and printed form.

Workshops

A series of five workshops were conducted in conjunction with John Cumming (InfoTech Research). These workshops presented the results of the on farm power generation project as well as project VG13054 ***Energy audits and energy efficiency case studies***. The combination was excellent, and added value to both projects for the growers and others who attended the workshops.

The Gatton, Bundaberg and Perth workshops were also attended by the growers who were the subject of the case studies, and they spoke about their experiences with on farm power generation.

The growers who gave the presentations were:

- **Ian Gaffel,** AustChili, Bunaberg, Qld
- **Angus Stainlay,** KalFresh, Kalbar, Qld
- **Maureen Dobra**, Loose Leaf Lettuce Company, Gin Gin, WA

The workshops were held in the following locations:

- **Melbourne, Victoria**: Thursday 25 September 2014, 1-4pm. Settlers Run Golf Club, 1 Settlers Run Botanic Ridge
- **Shepparton, Victoria**: Friday 26 September 2014, 7pm, Westside Performing Arts Centre, Echuca Road, Mooroopna
- **Bundaberg Queensland**: Tuesday 30 September 2014, 1-4pm, Bundaberg Research Station, 49 Ashfield Road, Bundaberg
- **Gatton Queensland**: Wednesday 1 October 2014, 1-4pm, Gatton Research Station, Warrego Highway, Gatton
- **Perth Western Australia**: Thursday 9 October 2014, 1-4pm, Kingsway Football and Sporting Club, Cnr Spectator Drive & Sporting Drive, Madeley

A further workshop was requested by growers in Tasmania and will be conducted at:

- **Launceston, Tasmania**: Friday 20 November 2014, 1-4pm, at the ServeAG office, 6181 Frankford Road, Bellfield

Evaluation sheets were distributed at the workshops, and these are reported in the evaluation section of this report.

Video presentation of the workshops via YouTube

While the workshops were very well regarded by growers and other who attended, it was difficult to attract growers to attend these meetings, despite the information being highly relevant and well presented. The workshops were well advertised and promoted via the AUGVEG weekly updates, media releases to local and specialist publications, and personally via direct contact with growers by AHR and InfoTech Research.

We have decided to produce a series of short, 5-7 minute video presentations on key sections of the workshops. These will be made from a professional video recording of the Gatton workshop, made available through ***YouTube***, and promoted with assistance from AUSVEG in November 2014.

The electronic versions of the factsheets will be linked to video and made available via the AHR and AUSVEG websites.

Presentations

Gordon Rogers gave a presentation about on farm power to an EnviroVeg meeting in Coffs Harbour on Wednesday 17 September, 2014.

Articles

An AUSVEG VegeNote on the project will be published.

In addition, AUSVEG will be producing a special 2-3 page paper on the project to be distributed to all growers and will feature the YouTube video presentations and electronic factsheets.

Radio interviews

Gordon Rogers gave a radio interview to promote the workshops and the project, one of which was aired by ABC Rural in Queensland on 1 October 2014.

Newspaper articles

Gordon Rogers was interviewed by the Bundaberg News on 30 September, 2014.

Outputs

The project team produced the following outputs:

1. Six detailed case studies of the feasibility of on farm power generation options on Australian vegetable farms.
2. Detailed analysis of the economic feasibility of on farm power generation
3. A series of six regional workshops
4. A series of four factsheets
    a. On farm power generation: Vegetable growers
    b. On farm power generation: Solar photovoltaics (PV)
    c. On farm power generation: Wind
    d. On farm power generation: Gas fuelled power generation
5. Video series of presentations for YouTube
6. On Farm Power Generation – Assessment of viability
7. Two articles for AUSVEG: VegeNote plus one other
8. One radio interview
9. One newspaper interview
10. Power point presentation On Farm Power viability
11. Final report

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Outcomes

The growers involved, and the attendees of workshops found the project to be very useful.

In total 196 people attended presentations or workshops, or were sent information directly. Of the five direct case study growers, one who did not already have on farm power generation is now installing solar PV. One other has seriously considered it as a result of the project but will focus more on improving energy efficiencies. One other grower would have invested in solar PV but the medium term future of the farm in its current location makes the investment decision difficult. Another grower was planning to expand the current solar system, but has moved overseas for three years.

The growers with current solar PV and wind generation capacity are all very happy with the investment, apart from one NSW grower (wind) which was a special case.

Several of the major Lockyer valley growers are seriously interested in investing in solar.

Virtually all growers are interested in improving their energy use efficiency as a result of the project.

Evaluation and discussion

Exposure

Forty-one people (mainly growers) attended the workshops, excluding the Tasmanian one which had not been held at the time of writing this report. We are expecting 15 growers to attend, giving a total of 56 for the workshops.

The Shepparton presentation was attended by 120 delegates and was part of the SLAP Tomorrow forum.

The Coffs Harbour presentation was attended by eleven growers plus two AUSVEG staff, giving a total of thirteen.

In addition, seven growers have requested the factsheets and reports.

This puts the total number of people attending presentations or workshops, or being sent information directly at 196.

We expect much larger numbers to view the YouTube, read the articles and take advantage of factsheets accessed via the AUSVEG InfoVeg website or the AHR website.

Feedback on the workshops

The workshop evaluation forms were completed by a total of 31 attendees.

The reaction to the workshops by the growers and others who did attend was overwhelmingly positive. Seventy-five percent of attendees completed evaluation forms. Of these, 96% would recommend the workshop to other growers.

All respondents rated the workshop as either very beneficial (29%) or beneficial (71%), Figure 46.

Nearly all respondents would recommend the workshop to other growers (98%), Figure 47.

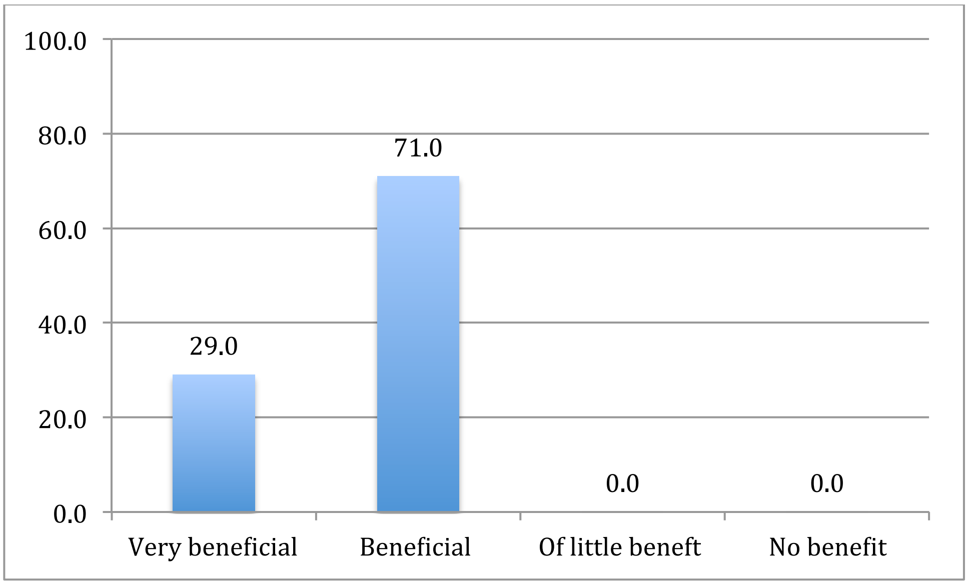

Figure 46 Rating by workshop attendees on benefit of the workshops (percentage of respondents).

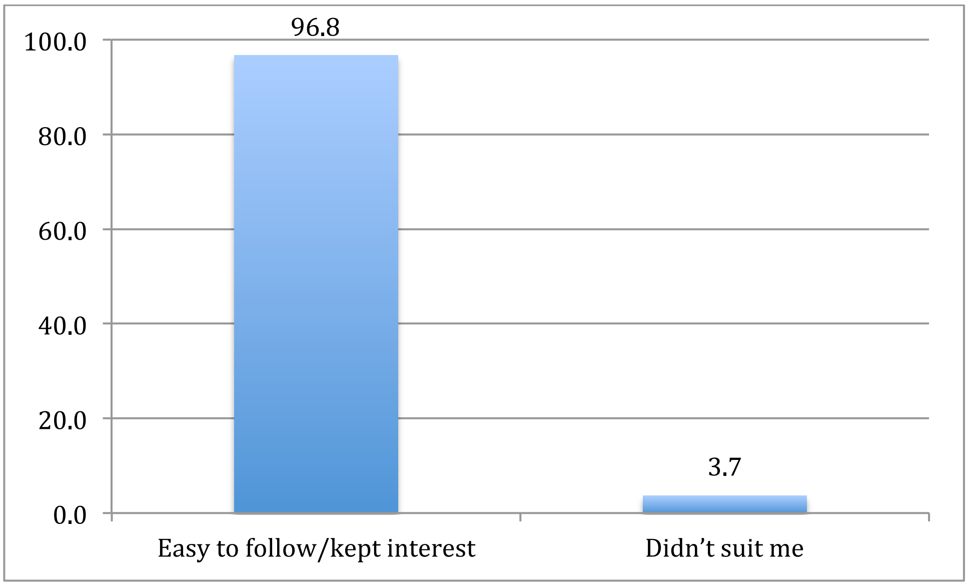

Figure 47 Rating by workshop attendees on the presentation style (percentage of respondents).

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Recommendations

1. Promote the YouTube video presentation, factsheets and self-assessment tool through articles in state-based grower magazines, Vegetables Australia/VegeNote and via the InfoVeg and AHR websites.
2. Encourage growers interested in pursuing installations of on farm power to seek the assistance of an appropriate energy consultant and accounts to assess proposed installations with full assessment of costs and benefits.
3. AHR present feedback from Parkside energy, case study growers and workshop attendees to the design team.

IP/Commercialisation

No IP issues.

References

All references are cited under Tasks 1, 2 and 3.

Acknowledgements

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- Vincent Tana, West Hills Farm
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Appendices

On farm power generation and power saving workshop program (Gatton)

Time	Activity
12:45 - 1:00	Arrive and register
1:00 – 1:15	Introductions, interest in this area, and what you would like to get out of the workshops and support material.
1:15 – 1:45	On farm power generation options, case studies and examples: *Gordon Rogers*
1:45 – 2:00	Growers' perspective: *Angus Stainlay (Kalfresh)*
2:00 – 2:15	How to interpret your power bill – How much do you actually pay for electricity? *John Cumming*
2:15 – 2:45	***Discussion:*** • Drivers of change – what factors affect your decision to invest in on farm power, or to make modifications to cool rooms and pumps? • What would clinch it for you? • What do you see as the main opportunities for the future?
2:45 – 3:15	Opportunities for reducing energy use of your farm Learnings from twenty vegetable farm energy audits around Australia: *John Cumming*
3:15 – 3:45	***Feedback session*** • Experiences in saving power on farm • Suggestions for future investment by the vegetable industry in this area? • Strategies to manage power costs
3:45 – 4:00	Wrap up: *Gordon Rogers*
4:00	Close and refreshments

On Farm Power Generation – Assessment of viability

This exercise will give you the opportunity to start assessing the viability of your farming operation for solar PV power generation. The same principles apply to the other forms of generation, and you can use the graphs in the economic analysis document, or the factsheets to guide you.

To complete this activity, you should first fill in the boxes below with some information from your farm. Ie:

1. What is the average price you are currently paying for electricity?	$/MWh
2. What size system do you need?	kW
3. What is your STC zone?	
4. What is your STC rebate?	$/kW
5. How much of the power generated can I use on farm?	%

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Calculations

Question 1. What is the maximum you should be willing to pay (*before subsidies*) for a viable solar PV system given the price you currently pay for your electricity? You can assume a 10% feed in rate if you don't have a better estimate.

$/kW

Question 2. What would be the maximum capital cost you should be willing to pay after subsidies are deducted, in your STC zone?

$/kW

Question 3: What would be the cost of the electricity you could generate on farm assuming your quoted capital cost is $2500/kWh before subsidies (ie medium TCR before subsidies) and a 10%$ feed in rate?

c /kWh

Question 4. For the same $2500 per kW system, how much would the electricity cost if you have to feed in 50% of the power to the grid?

c /kWh

(Note: Questions 1-4 use Figure 1)

Question 5. For the same $2500 per kW system (before subsidies), what would the payback period be for your

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proposed solar system if you were producing power at about 14c/kWh? (use Figure 2)

Years

Question 6. What would be the effect on the cost of power you can produce, of removing the STC subsidies on a medium capital cost (TCR) of $2500 per kWh (before subsidies) in your STC zone? (use Figure 3)

c /kWh

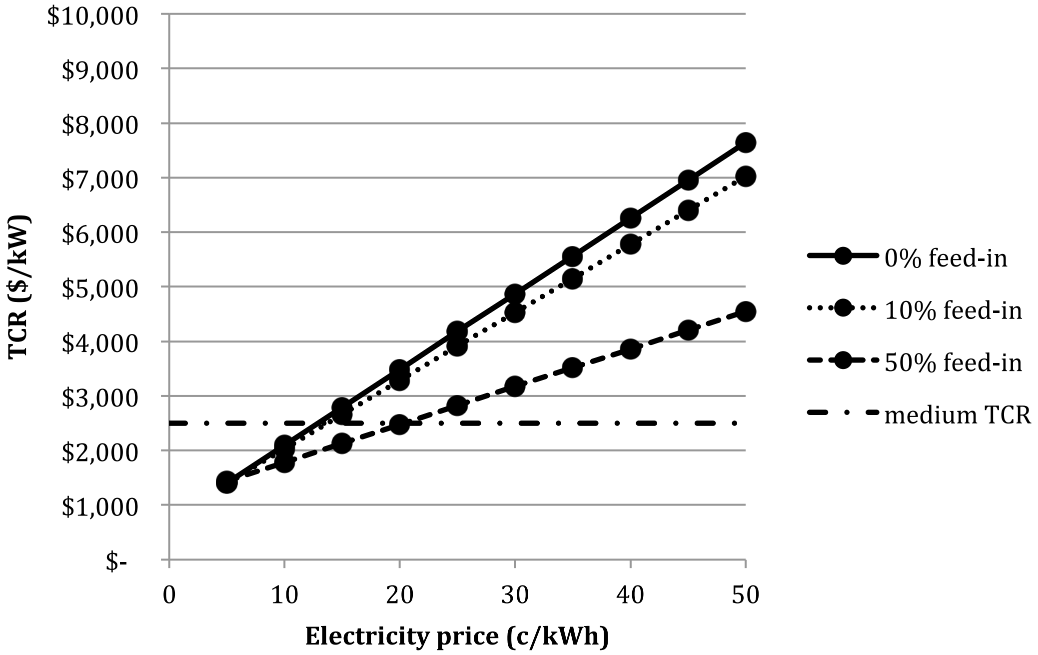

Figure 1: Capital cost ($/kW) excluding STC subsidies, versus displaced electricity price for IRR=10% nominal and 0%, 10% and 50% of annual, on-site energy being fed into the network at 6c/kWh (w/ GST). Also shown is a medium TCR of 2500 $/kW.

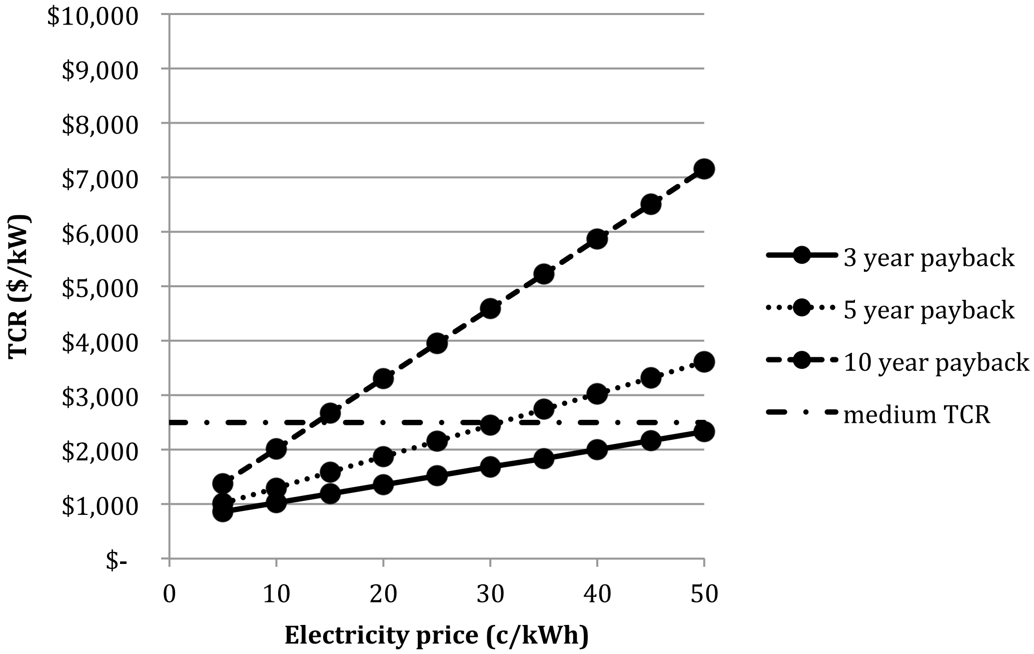

Figure 2: Marginal TCR ($/kW) versus displaced electricity price for 3, 5 and 10 year payback periods. Also shown is the medium TCR of 2500 $/kW. Analysis assumes no energy lost or fed into the network, a Zone 3 STC region

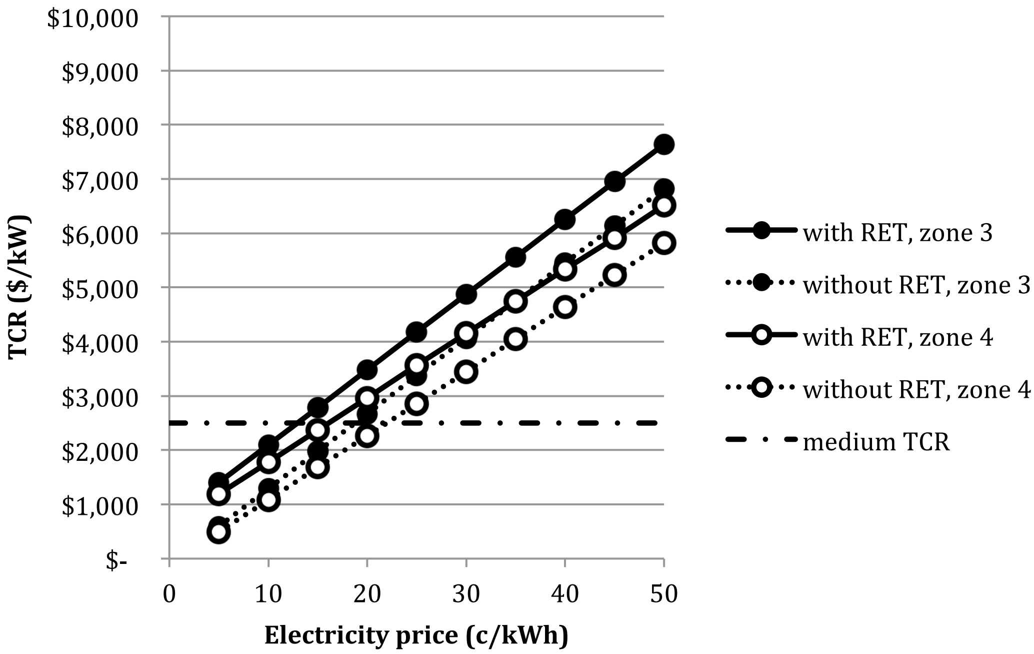

Figure 3: Marginal TCR ($/kW) versus displaced electricity price for STC Zones 3 and 4 with IRR=10%

nominal, with and without the RET. Also shown is the medium TCR of 2500 $/kW.

Assumptions (except for when each item is a variable in estimates)

- Feed in tariff = 6c/kWh
- IRR = 10% (think of this as the value of money in your business)
- Funded by borrowing over 10 years at 6.5% interest

Workshop evaluation sheet

On-farm Power Generation Workshop Evaluation

Workshop date: Tuesday 30th September 2014

Name: *(optional)* ______________________________

Sector of industry: *(please circle)* Grower / Supplier / Research / Extension / Other

1. Was the workshop: *(tick appropriate box)*

Very beneficial [ ] Beneficial [ ] Of little benefit [ ] Of no benefit [ ]

2. Were the presentations/discussions: *(tick appropriate box)*

Easy to follow [ ] Kept my interest [ ] Didn't suit me [ ]

Is there anything that would have assisted your learning on the day (please specify)?

____

3. The workshop improved my understanding of: *(tick appropriate box/boxes)*

Understanding my energy use [ ]

Opportunities for use of alternative energy sources [ ]

Importance of reducing my greenhouse gas emissions [ ]

Other *(please specify)* ______________________________

4. Would you recommend the event to another primary producer? YES [ ] NO [ ]

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5. How did you hear about the field day? AUSVEG [ ] Email from AHR [ ]
Flyer [ ] Direct contact [ ] Other *(please specify)* ________________________________

6. Please provide your thoughts on the presentation/delivery style:

____

____

____

7. Please provide your thoughts on the value of the workshop:

____

____

____

8. Where appropriate, please list the names + addresses of people you think would benefit from future on-farm power generation workshops:

____

____

____

11. Does AHR have your permission to use these comments in future promotions? YES [ ] NO [ ]

________________________________ _________________

Signature Date

We would appreciate your handing this evaluation form in at the end of the day

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