McHenry, M.P. (2012) A technical, economic, and greenhouse gas emission analysis of a homestead-scale grid-connected and stand-alone photovoltaic and diesel systems, against electricity network extension. Renewable Energy, 38 (1). pp. 126-135.

A technical, economic, and greenhouse gas emission analysis of a homestead-scale grid-connected and stand-alone photovoltaic and diesel systems, against electricity network extension.

Mark P McHenry

School of Engineering and Energy, Murdoch University

90 South Street, Murdoch, Western Australia, 6150

+61 430 485 306

mpmchenry@gmail.com

ABSTRACT

This research compares two generation components in grid-connected and stand-alone power supply (SPS) systems (6 kW_p solar photovoltaic array, and a 6 kW_p diesel generator), separately supplying a homestead's electricity load (12 kWh day^{-1} average, 10 kW_p), against a 2 km underground electricity distribution line extension. The technical simulation intervals (15 minute) included realistic peak demand and generation component outputs, based on actual load data collected from an existing homestead and local meteorological data in the southwest of Western Australia. The separate emission and economic calculations incorporated technical simulation data, were based on emission factors for the region, used 2010 market prices for capital and operational costs, all projected over 15 years. The economic model included an 8% real discount rate, and several assumptions customised for each scenario. The results suggest small-scale distributed electricity generation systems are currently unattractive economically when compared to medium distance network extension, and increased the cost of electricity for private individuals (or governments if subsidised) with small mitigation benefits. The scenario results and discussions illuminate the specific

economic barriers for small-scale photovoltaic components in both stand-alone and grid-connected systems in areas proximal to electricity distribution networks in regional Western Australia.

Keywords: photovoltaic; diesel; stand-alone; renewable energy; electricity network.

1. Introduction

Climate change mitigation researchers and policymakers need to address private concerns regarding energy supply security and cost in terms of the context of technical feasibility, financial viability, and community acceptability of clean energy options [1]. Governments, researchers, and innovative businesses will be required to both harness and guide suitable renewable energy options to provide both private and public benefits for specific regions [2], rather than a generalised approach. Research by Sims et al. [3] suggests while there are power limitations, reliability issues, and cost issues with many decentralised energy systems, the general advantages of decentralised energy systems include short capacity construction times, reduced network transmission and distribution power losses, deferral of transmission and distribution upgrades, potential reliability improvements, and increase total energy recovery by being proximal to thermal demands. The magnitude of advantages/disadvantages of decentralisation requires investigation at the local scale to ensure suitable investments occur, taking into account system design and performance, technology alternatives, cost minimisation, and resultant greenhouse gas emission reductions. This work provides a technical, emissions, and economic assessment comparing a 6 kW_p solar photovoltaic (PV) and a 6 kW_p diesel generator components as grid-connected and stand-alone power supply (SPS) systems, against electricity distribution network extension in a regional area in the southwest of Western Australia (WA).

2. Data and methods

Sixty-two years of primary climatic (daily, and monthly mean) data was derived from the Bureau of Meteorology (BOM) ground-station at Albany Airport, WA (Station 009741, Lat.(S): -34.9414, Long.(E): 117.8022, 69 m above sea level). The Albany airport was selected as a quality long-term data set representative of a region exhibiting a temperate climate, a good solar resource (4.32 kWh day^{-1} annual average), in addition to growing electricity distribution network infrastructure deficiencies due to additional demand through population growth. The technical simulations were performed using HOMER version 2.68 beta, which simulates the operation of renewable energy-based systems over selected simulation intervals over a one year period. A 15 minute interval was selected to balance the intermittent nature of the homestead load, climate data, and resultant system performance.

HOMER compared the electricity demand to the electricity the designed system provides, and calculated energy balance calculations of the individual flows to and from each component of the designed system incorporating climatic variables. While HOMER can also estimate the cost of installing and operating the system over the lifetime of the project, an explicit economic model was developed in a spreadsheet to ensure all attributes of the system production, costs, rates, subsidies, assumptions (etc.) could be easily analysed. This simple economic model incorporated technical performance output data from HOMER, and incorporated 2010 market prices projected over a 15 year project lifetime. Each feasibility study contained a number of assumptions and included a real 8% real discount rate, after inflation with details given for each respective scenario. The model was used to calculate a Net Present Value (NPV), or a Net Present Cost (NPC) if the system did not recoup total discounted costs. Whilst these economic methods are well established [4, 5], such methods are not without limitations, as even the most probable NPV for a project (even with a sensitivity analysis) does not recognise the asymmetric probabilities associated with each variable over time [6]. Nonetheless, a region-specific bottom-up analyses are able to account for many detailed features and constraints, and also provide scope for variable assumptions, econometrics applied, and flexible economic and emission baselines [7]. The emission calculations for each system and scenario were based on the concept of the "market mitigation potential", which includes emissions or abatement attributable to specific private activities, calculated using private costs and discount rates expected under forecast market conditions [8, 9].

3. Technical simulation results of the PV SPS system scenario

The basic components of the simulated PV system was a 6 kW_p PV array and a battery bank supplying a homestead electricity load (12 kWh average daily load, 10 kW_p) in parallel through an 11 kW_p stand-alone inverter/rectifier unit , located off-grid to the electricity network. The battery bank nominal capacity was 139 kWh, 83 kWh of useable nominal capacity (with a 60% minimum state of charge) on a 120 V DC bus. Fig. 1 shows the annual and monthly electrical energy simulation results at 15 minute intervals for an average year, with an annual homestead total electricity of demand of 4,380 kWh. The inverter supplied 100% of the load with the electricity originally generated by the PV component, as it was the only generation technology in this simulation. The total annual average output of the PV array was 8,404 kWh.

Fig. 2 shows that 4,611 kWh was supplied to the simulated 95% efficient inverter to provide an average total annual net electricity load of 4,380 kWh. The 3,247 kWh of excess electricity was "dumped" by the PV system over the year due to full battery state of charge and zero load requirements. Therefore, the useful electricity provided by the PV system was 5,157 kWh. The difference between the load (4,380 kWh) and the useful electricity from the PV system was attributable to the losses from the inverter (231 kWh) and the battery bank (546 kWh), with a 90% efficient rectifier from AC to DC (does not sum exactly due to rounding). The battery technology simulated cycle efficiency of 80% was selected to represent an average lead-acid battery, and all capacity and lifetime curve data were derived from a representative available commercial battery. Fig. 3 shows that the battery bank remains at a very high state of charge (>90%) for three quarters of the simulated year. The winter months, with lower PV output and relatively stable load requirements, led to distinct intervals of lower state of charge (in late June to early July, and a shorter interval in early August. Fig. 4 shows the average simulated hourly excess electricity for the system for each month of the year. The monthly differences clearly show the system was over-designed for many months of the year, while providing just enough electricity in months with low solar resources. The stand-alone system supplied 100% of the annual load requirement, and a generous average level of autonomy of 7 days was achieved with the battery bank design. The software simulation estimated the battery bank lifetime of 12 years under the selected management conditions, although this life expectancy was likely to be an overestimate for WA conditions [10]. In any case, no battery bank replacement was included in the model for any of the stand-alone system designs, due to the discounting reducing the present value to a minor concern. Table 1 summarises the annually averaged simulated technical outputs.

[Insert Fig. 1, 2, 3 and 4, and Table 1 approximately here]

To optimise the component sizes, an exploration of various annual angle of the fixed PV array to less than the annually fixed 35^{o} (based on the latitude), aiming to increase winter PV output was undertaken. However, there was an insufficient PV output increase over winter to improve the battery bank state of charge without greater deleterious associated losses in other seasons. This optimisation did not include a seasonal adjustment of the PV array slope to increase annual output in a similar manner to an automated single axis vertical pivoting tracker. (In practice, systems with a PV component often also have an internal combustion engine generator, rather than array tracking systems, as the generator reduces the battery bank, PV array, and often the inverter capacity requirements by providing additional electricity production capacity during high load, or low PV production intervals). However, the various optimised configurations of hybrid PV-internal combustion engine generator systems were superfluous to the objective of comparing the PV and the diesel generator component, against electricity network extension in this research.

4. Technical simulation results of the diesel SPS system scenario

The simulation of the 6 kW_p PV component was compared with a 6 kW_p diesel generator coupled to an identical enabling SPS system. This comparative scenario is similar to the decisions that most SPS system owners located in remote areas of WA make each year. The primary purpose for the inclusion of the diesel generator-only component was to assess actual costs of energy and emissions relative to each other, and relative to the electricity network.

In the diesel SPS system scenario, a well loaded (70% minimum load ratio) AC diesel generator with an average specific fuel consumption of 0.397 L kWh^{-1} supplied the annual 4,380 kWh homestead load requirement. The diesel was restricted to operate only between the hours of 13.00 and 17.00, and forced to operate once a day at hours 13.00 to 15.00, and scheduling was optimised for hours 15.00 to 17.00 to satisfy system control requirements of battery state of charge and load supply. This scheduling did not have a significant negative impact on performance or diesel generator efficiency (see Fig. 5 for the diesel generator efficiency curve), and only served to approximate a realistic preference of off-grid diesel generator operation when an inverter and battery bank are components of the SPS system.

The total simulated annual average electricity produced by the diesel generator to supply the homestead load and to cover associated conversion efficiency losses from enabling equipment (the inverter/rectifier, battery bank, etc.) was 7,121 kWh. The simulated annual average diesel fuel consumption of the system was 2,830 L (Fig. 6). Fig. 7 shows the annual operation of the inverter and rectifier for each 15 minute simulated interval. Fig. 8 shows that the battery bank remains at a very high state of charge (>85%) for 90% of the simulated year.

[Insert Fig. 5, 6, 7 and 8 approximately here]

5. Economic and emission modelling results and discussion of the PV SPS system

Capital costs for all system components including PV module, inverter, battery bank, and balance of system prices were based on the actual costs in 2010. The PV system included a small capital rebate for eligible RECs[a], whereas the diesel SPS system did not. Whilst, there are other existing capital subsidy programmes that subsidise various stand-alone system components and installations in WA, the use of which is more common off the network in remote areas, these were outside the analysis scope.

The single electricity retailer in the regional areas of southwest WA (Synergy) has a combined business and domestic electricity tariff is known as the K1tarrif, which caters for residences with combined domestic and small business operations (such as farms). The 2010 tariff supply charge of AUD0.3823 day^{-1} (including the 10% Goods and Services Tax, or GST), was represented in the economic model as an equivalent average annual daily load cost.

[a] One REC, or Renewable Energy Certificate is equivalent to 1 MWh of renewable energy produced by an accredited renewable energy generator. Australian rebate structures available for solar PV systems are currently based on RECs, and simple deeming calculations which include the quality of solar resource, the rating of the PV component, a deeming period (in this case 15 years), and a “multiplier”, which is essentially a discount rate that gives a higher REC allocation for investments commissioned sooner rather than in a few years. The REC entitlement of the 6 kW_p PV grid-connected system installed in 2010 based over a 15 year deeming period was 213, and at an assumed AUD40 per REC, this AUD8,520 can be used as a capital subsidy, included as such in Table 2 [11].

The 12 kWh average daily load at a cost of AUD0.2083 kWh^{-1} and the daily supply cost was equivalent to an average daily tariff increase of 15.29% to AD0.2401 kWh^{-1}, which was used in the economic analysis. All costs are summarised in Table 2, and were GST inclusive unless otherwise specified. Fig. 9 shows that the NPV does not recoup the initial outlay (technically this is a NPC), and the discounted cost relative to grid-connection, was around AUD80,000 over the 15 year interval. Nonetheless, the total life-cycle market mitigation potential of the system was modelled as 55.188 tCO_2-e, based on a simplified assumption of the 2009 "scope 2" emissions factor for the network of 0.84 $kgCO_2$-e kWh^{-1} remaining stable over the 15 year interval. (This is likely to be an overestimate as the southern WA electricity network emission factor has slowly, and consistently decreased in recent years, reducing the per unit mitigation potential of cleaner electricity options relative to the network.) Furthermore, the market mitigation potential for the simulation was based on the assumption that the electricity exported onto the network does not displace conventional supply, while inverter output to supply homestead load did reduce network electricity demand and associated emissions. Note that this generous assumption that the electricity produced by a single PV SPS system consumed in the homestead resulted in reduced emissions from the network is not realistic in practice.

[Insert Table 2 and Fig. 9 approximately here]

6. Economic and emission modelling results and discussion of the diesel SPS system

The diesel price was based on average current costs of approximately AUD1.20 L^{-1} gross delivered, and the economic model incorporated the Fuel Tax Credit of AUD0.38143 L^{-1}, resulting in a net cost of AUD0.82 L^{-1} (rounded). Therefore, the equivalent electricity price per kWh using a diesel with an average annual efficiency of 0.397 L kWh^{-1} was simulated as AUD0.3255 kWh^{-1}. The capital costs, the minor servicing, and major reconditioning requirements for the diesel generator were estimated and included in the economic model. The associated emissions were calculated using the data in Table 2. The simulated annual average diesel emissions from the combustion of 2,830 L were 7.592 tCO_2-e (2,830 L × 38.6 MJ L^{-1} × 0.0695 $kgCO_2$-e MJ^{-1}). This was around double the emissions associated with supplying the homestead with the network electricity alone for the simulated average year. However, the market mitigation potential difference between the simulated diesel and PV option was 113.811 tCO_2-e over the 15 year life-cycle, a notable difference. Fig. 9 and Table 4 show the discounted cash flow (DCF), NPV, and the total market mitigation potential of the diesel SPS system. The market mitigation potential of the diesel system over the life-cycle was negative, as the system implementation emitted an additional 58.693 tCO_2-e than the baseline electricity grid-connected system. The NPC of the system was AUD-79,693, an expensive option relative to grid-connection, based on an available electricity network line and connection and a network extension cost of zero. However, the diesel SPS system NPV was comparable to the NPV of the 6 kW_p PV SPS system of AUD-79,981. (Table 5).

[Insert Table 3, 4, and 5 approximately here]

7. Economic modelling results and discussion of the network extension scenarios

The economic modelling included two scenarios for the PV SPS system: one without an electricity network extension when the location does have access to the electricity network, but chooses not to connect, and; an underground electricity distribution network extension of 2 km from an existing 240V, 32A two phase metered connection on a rural property, based on actual cost data. The simulated property's underground distribution line extension was modelled as a private cost, undertaken by a qualified electrician, based on 2010 market prices. The diesel SPS system was not included in the network extension scenarios.

Table 6 and Fig. 9 represent the 2 km underground distribution network extension from an existing metered point on the property as a capital cost saving in year zero of AUD45,944. This represented an extension to a homestead which does not currently have the electricity network connected. (As rural properties in WA can require very long (>>10 km) network extensions from the existing network, and the Government of Western Australia's Contributory Extension Scheme has long subsidised construction and maintenance of overground distribution extensions in rural areas [12]. However, due to the relatively short distance of the extension scenario in this analysis, the Scheme's detailed eligibility and subsidy details were deemed to be outside of the scope of this research, and the full commercial underground extension cost was included.) Table 7 summarises the NPV and market mitigation potential of the scenarios, including an equivalent carbon price.

[Insert Table 6 approximately here]

While noting simulation and modelling uncertainties, both the PV SPS and the diesel SPS projects were clearly not commercially feasible with a negative NPV, relative to both the network extension and grid-connection only options. Despite the significant saving of a privately commissioned 2 km distribution extension from the existing network to the homestead, the total project economic viability of a 6 kW_p PV SPS system remained unattractive economically. The analysis showed that the cost of the network extension was an important factor in the decision to commission a SPS system, and from an economic perspective it was more cost-effective to connect to the electricity network, or for short distances of around 3-4 km, extend the network to have access to a relatively inexpensive electricity supply. (A detailed analysis of greater distances of distribution extensions was outside the scope of this work as each location extension capital works costs vary greatly.) The poor economic attractiveness of both the PV SPS system and the grid-connected PV systems, indicate that neither option would effectively reduce costs associated with electricity service provision. The PV SPS system market mitigation potential was the highest possible for homestead load assumptions, although the equivalent carbon price for the SPS and grid-connected system (AUD1,451 tCO_2-e^{-1} and AUD617 tCO_2-e^{-1}, respectively) were well above current market prices paid for carbon mitigation activities. Therefore, extremely high carbon prices would be required to make the PV system economically attractive, despite the known problems associated with assuming small generation systems displace conventional emissions.

8. Conclusions

This research indicates there is little economic (NPV) difference between comparably sized PV and diesel components in SPS systems, despite the existence of the current PV component capital subsidy. The provision of a larger PV component subsidy or a very high carbon price for the difference in total mitigation would be required to make the PV technology a consistent choice over the traditional diesel option. This finding is consistent with previous research undertaken by the author on decision-making for standalone power supply systems in WA over the past decade[10, 13]. While the economics between PV and diesel components over time may be similar, the operational costs and maintenance regimes of the two technology types will be significantly different and for respective technology choices [10], the least being simple grid connection. Furthermore, suitably valued renewable energy subsidies for SPS systems, preferably capital subsidies, will increase the likelihood of individuals choosing PV components, often displacing non-renewable generation, and producing a tangible emission reduction from displacing diesel consumption [10]. This research confirms the attractiveness (and common occurrence) of installing SPS systems when electricity network extension is prohibitively expensive, rather than to reduce the cost of electricity. The additional cost for basic energy services in more remote areas having no government provided network infrastructure justifies the continued subsidies for SPS systems for social equity reasons.

In contrast, the assertion that small-scale grid-connected decentralised renewable energy systems may be commercially viable in smaller electricity networks in rural areas with high network connection costs and abundant renewable energy resources does not hold for the modelled scenarios in the southwest of WA. This research shows that the current PV subsidy available for the 6 kW_p PV grid-connected system is insufficient to equalise the economics of supplying households with network electricity, even if the cost of the unnecessary equipment (battery bank etc.) are excluded. Furthermore, the extremely high market mitigation (AUD $tCO_2\text{-}e^{-1}$) cost calculations in the hundreds to thousands for grid-connected small-scale renewable energy systems over the 15 year NPV scenarios demonstrate the high cost of such mitigation options. Government subsidy programmes may more efficiently reduce emissions and diversify energy supplies by re-allocating funds from small-scale to medium-to-large-scale renewable electricity installations to achieve co-benefits of energy supply diversification at the local or regional level, and greater economies of scale than small-scale systems. Further research is recommended to determine suitable sizes of medium-to-large renewable energy generation technologies that can operate in parallel with existing fossil fuel systems to either defer electricity transmission network augmentation or extension of the distribution network system in regional areas. An analysis of such systems will likely provide an indication of the potential for renewable energy system designs to actually displace fossil fuel generation to achieve real mitigation outcomes.

References

[1] Glover J, Johnson H, Lizzio J, Wesley V, Hattersley P, Knight C. Australia's cropland pastures in a changing climate - can biotechnology help? Canberra, Australia: Bureau of Rural Sciences, Commonwealth of Australia; 2008.

[2] Arundel A, Sawaya D. The bioeconomy to 2030. Designing a policy agenda. Paris, France: Organisation for Economic Cooperation and Development; 2009.

[3] Sims REH, Schock RN, Adegbululgbe A, Fenhann J, Konstantinaviciute I, Moomaw W, Nimir HB, Schlamadinger B, Torres-Martinez J, Turner C, Uchiyama Y, Vuori SJV, Wamukonya N, Zhang X. 2007: Energy supply. Climate Change 2007: Mitigation. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change Cambridge, United Kingdom & New York, USA: Cambridge University Press; 2007.

[4] Parker RH. Discounted cash flow in historical perspective. Journal of Accounting Research 1968;6(1):58-71.

[5] Ljungqvist A, Richardson M. The cash flow, return and risk characteristics of private equity. Working paper 9454. NBER Working Paper Series Cambridge, USA: National Bureau of Economic Research; 2003.

[6] Slater SF, Reddy VK, Zwirlein TJ. Evaluating strategic investments: complimenting discounted cash flow analysis with options analysis. Industrial Marketing Management 1998;27:447-458.

[7] Intergovernmental Panel on Climate Change. Summary for Policymakers. In: Climate Change 2007: Mitigation. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change Cambridge, United Kingdom & New York, USA: Cambridge University Press; 2007.

[8] Intergovernmental Panel on Climate Change. Appendices. In: Climate Change 2007: Synthesis Report. Intergovernmental Panel on Climate Change Fourth Assessment Report Cambridge, United Kingdom: Cambridge University Press; 2007.

[9] McHenry MP. Integrating climate change mitigation and adaptation: Refining theory for a mathematical framework to quantify private and public cost-effectiveness, and carbon emissions for energy and development projects. Renewable Energy 2011;36(4):1166-1176.

[10] McHenry MP. Why are remote Western Australians installing renewable energy technologies in stand-alone power supply systems? Renewable Energy 2009;34:1252-1256.

[11] Office of the Renewable Energy Regulator. Website. Available from: www.orer.gov.au 2010 (accessed 19 August 2010).

[12] Wyder J, Frazer R, Pryor T. Study into Power Provision Policies for Remote Areas in Western Australia. Perth: Murdoch University Energy Research Institute; 1995.

[13] McHenry MP. Remote area power supply system technologies in Western Australia: New developments in 30 years of slow progress. Renewable Energy 2009;34:1348-1353.

Fig. captions.

Fig. 1. Electrical simulation of the homestead's 6 kW_p PV system.

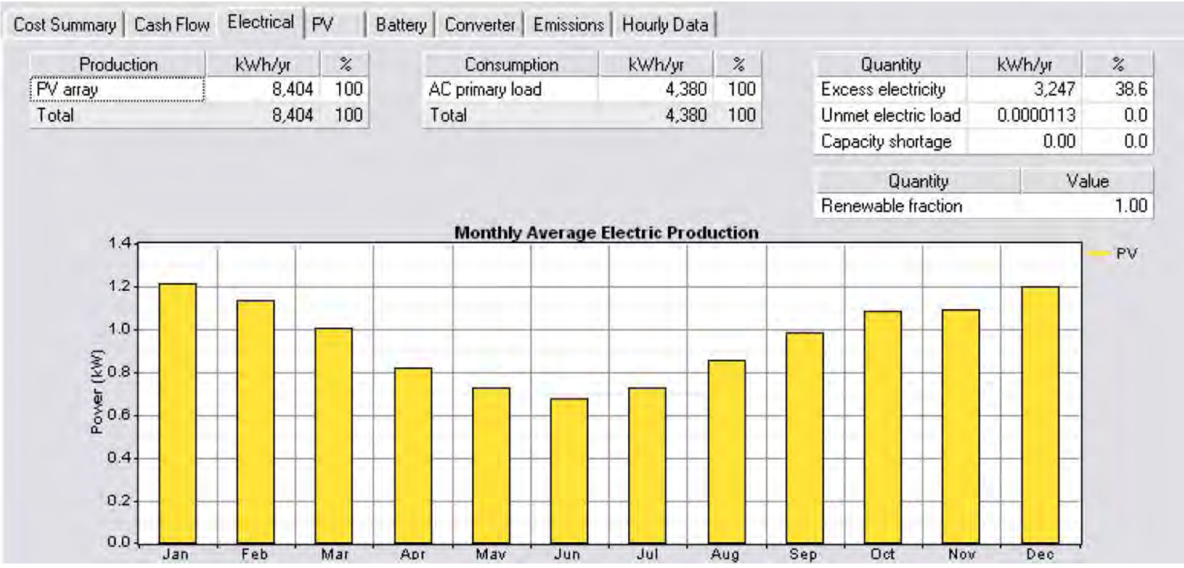


Fig. 2. Inverter annual simulation results for the homestead.

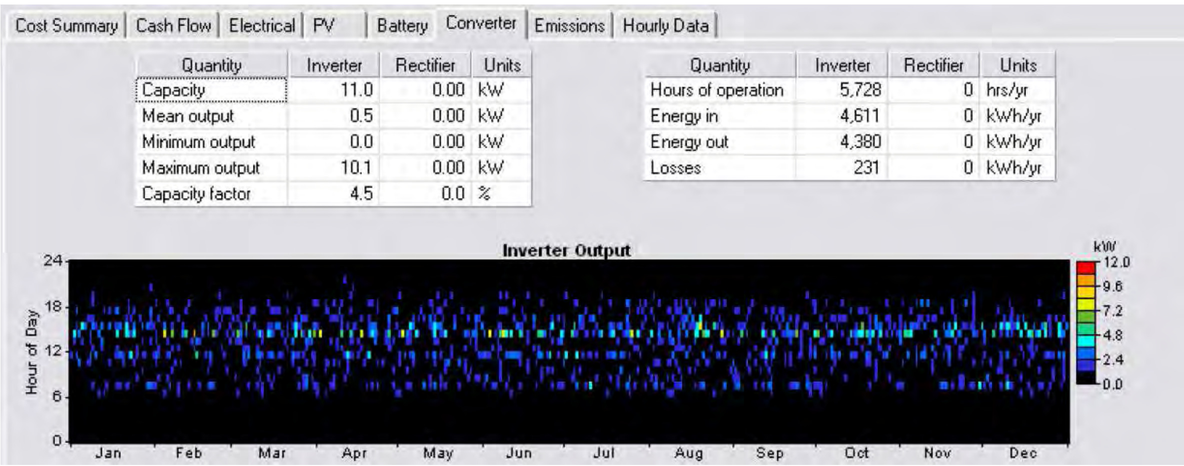


Fig. 3. Battery component annual simulation results for the homestead's input from the 6 kW_p PV and the output to the 11 kW_p inverter.

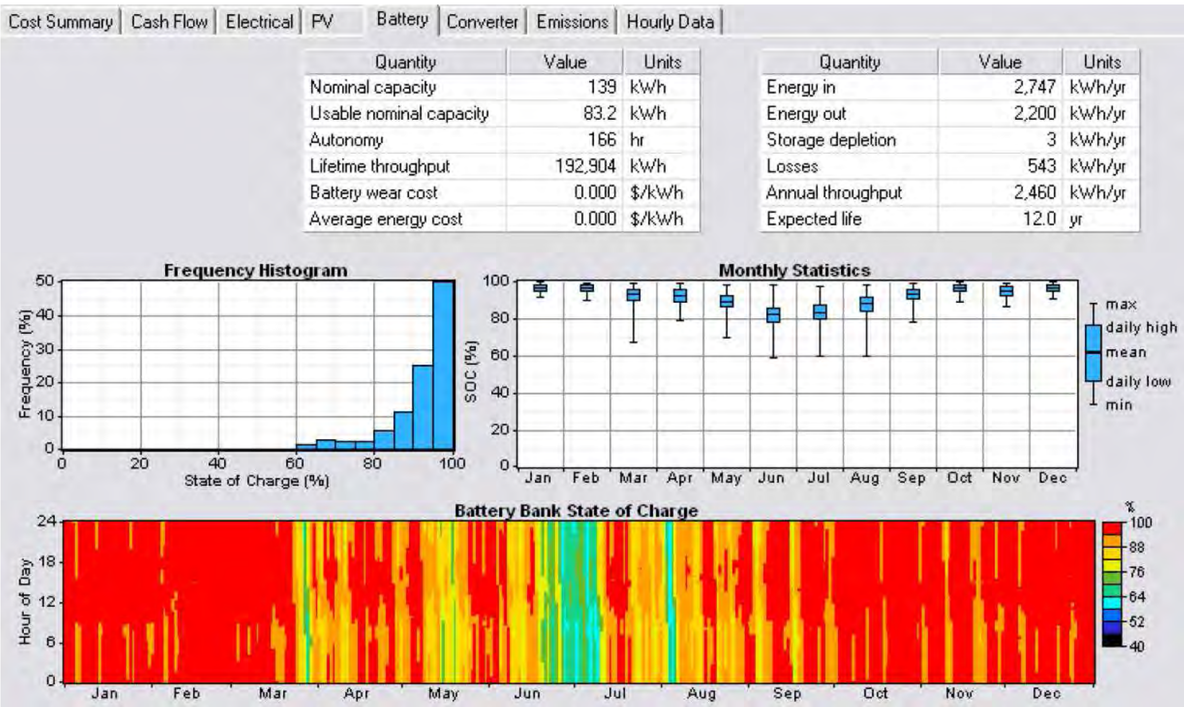


Fig. 4. Monthly average hourly homestead excess electricity from the system for each month.

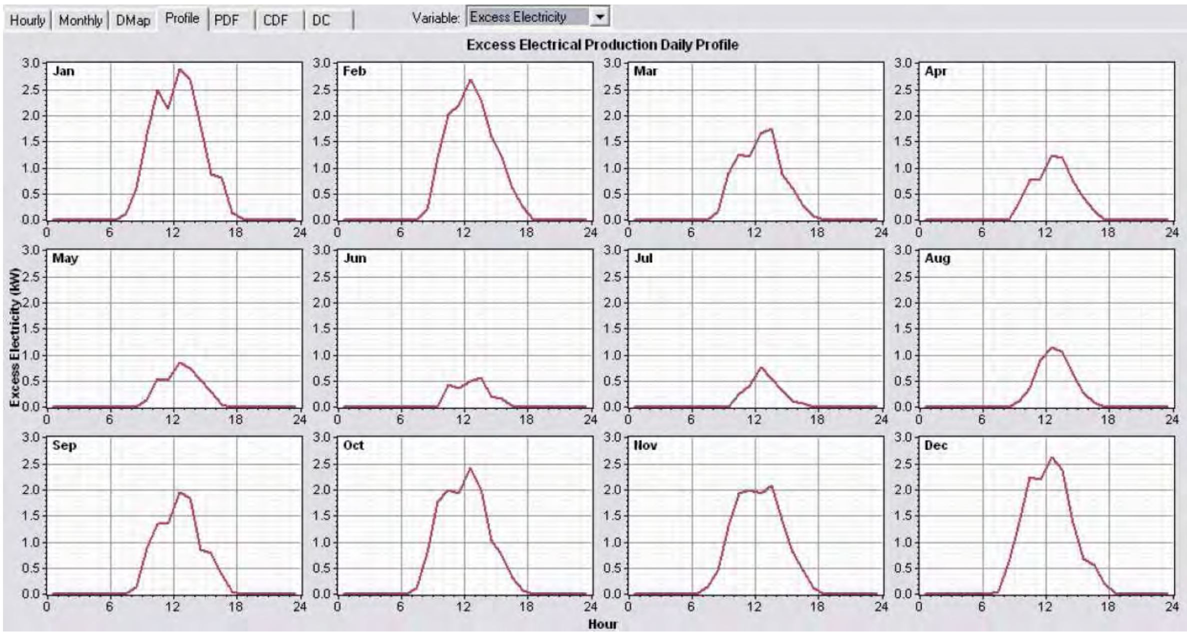


Fig. 5. The efficiency curve of the homestead's 6 kW_p diesel generator.

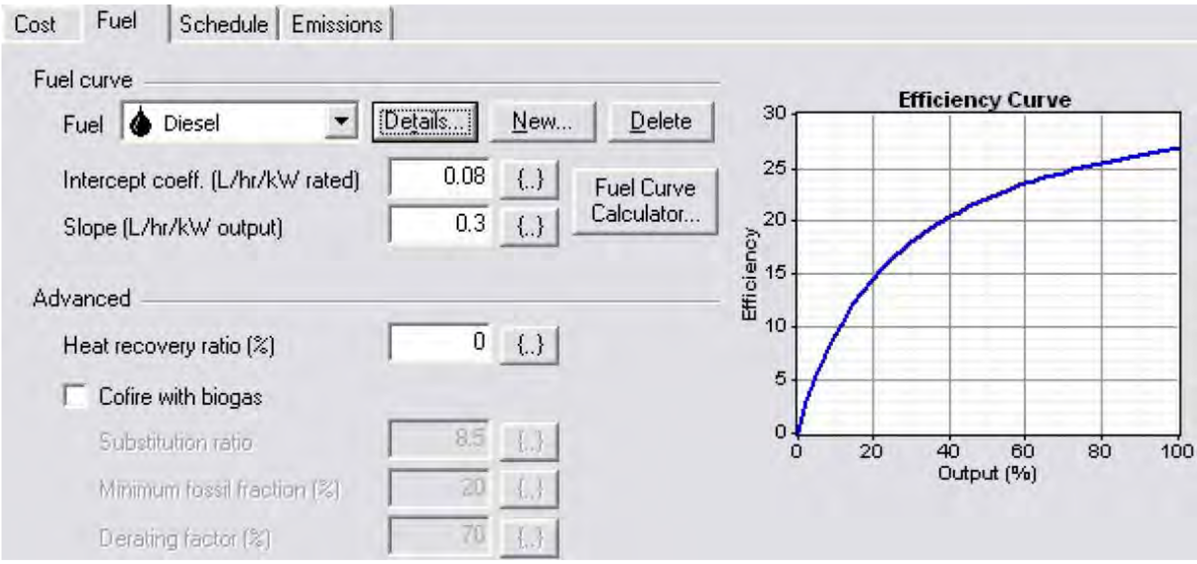


Fig. 6. Electrical simulation results for the homestead's 6 kW_p diesel generator.

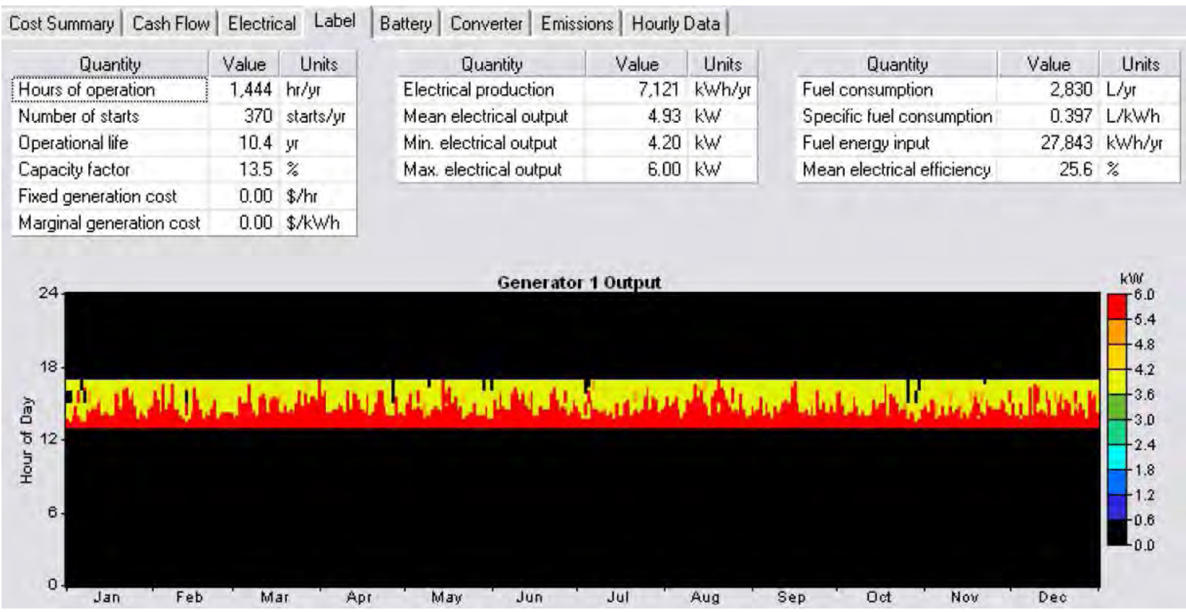
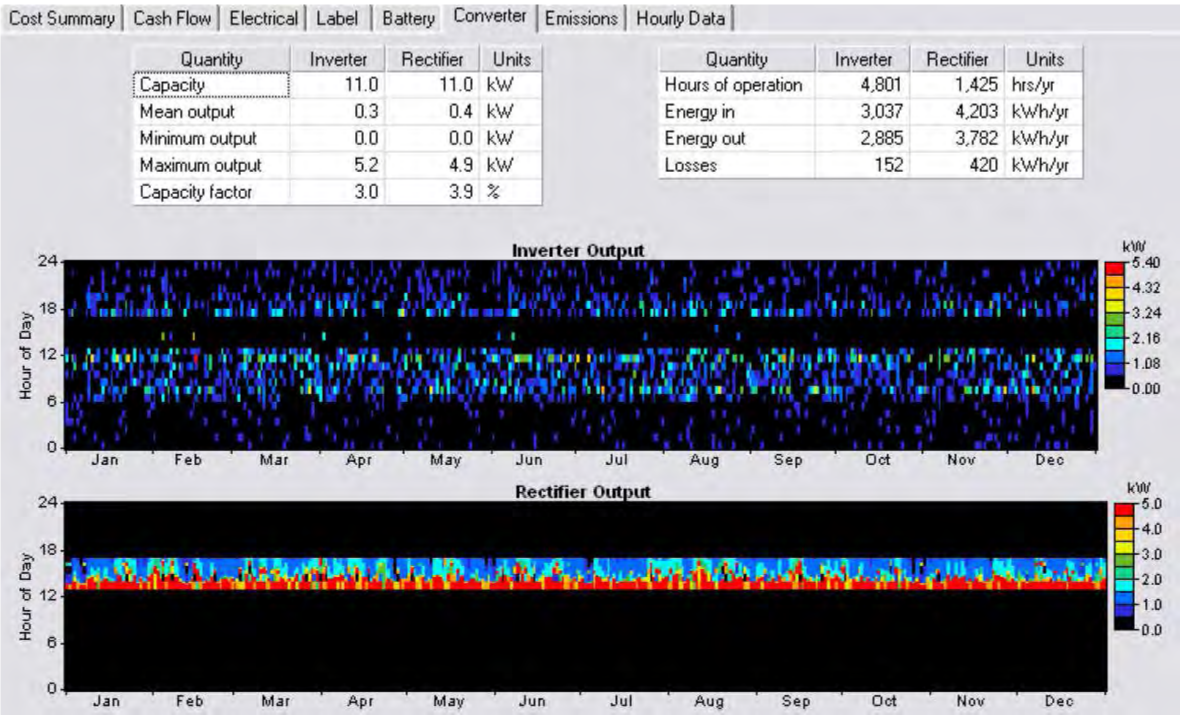


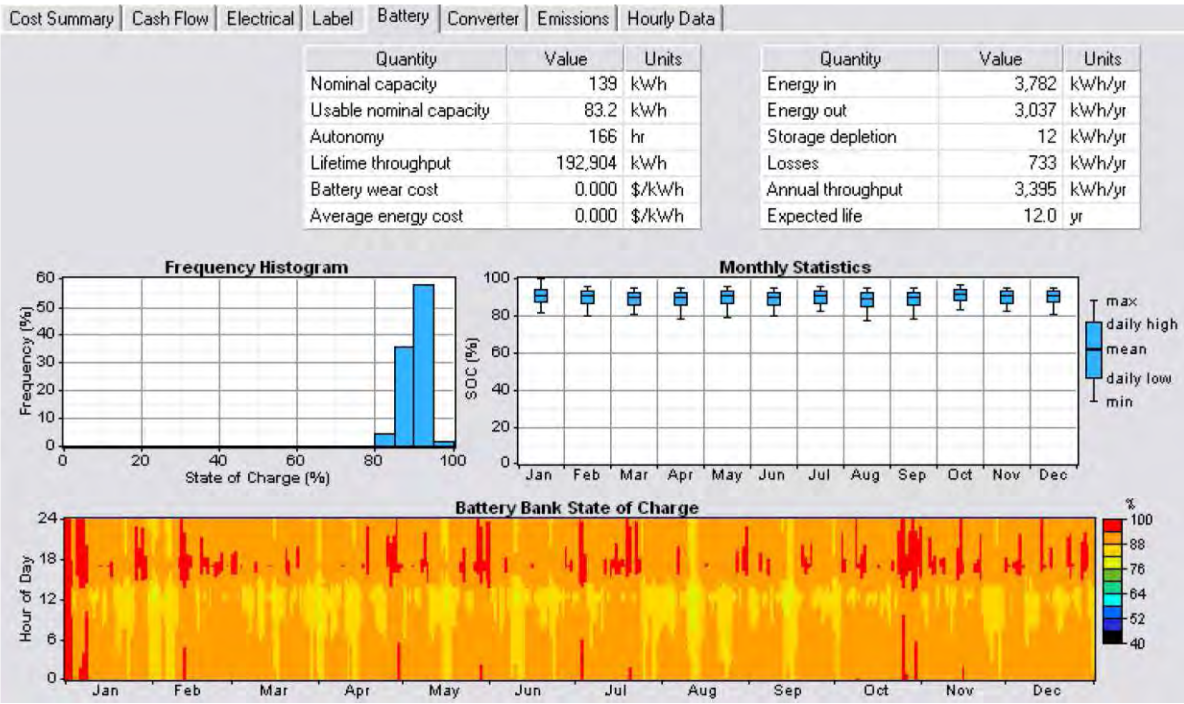
Fig. 7. Inverter annual simulation results for the homestead.



Quantity	Inverter	Rectifier	Units
Capacity	11.0	11.0	kW
Mean output	0.3	0.4	kW
Minimum output	0.0	0.0	kW
Maximum output	5.2	4.9	kW
Capacity factor	3.0	3.9	%

Quantity	Inverter	Rectifier	Units
Hours of operation	4,801	1,425	hrs/yr
Energy in	3,037	4,203	kWh/yr
Energy out	2,885	3,782	kWh/yr
Losses	152	420	kWh/yr

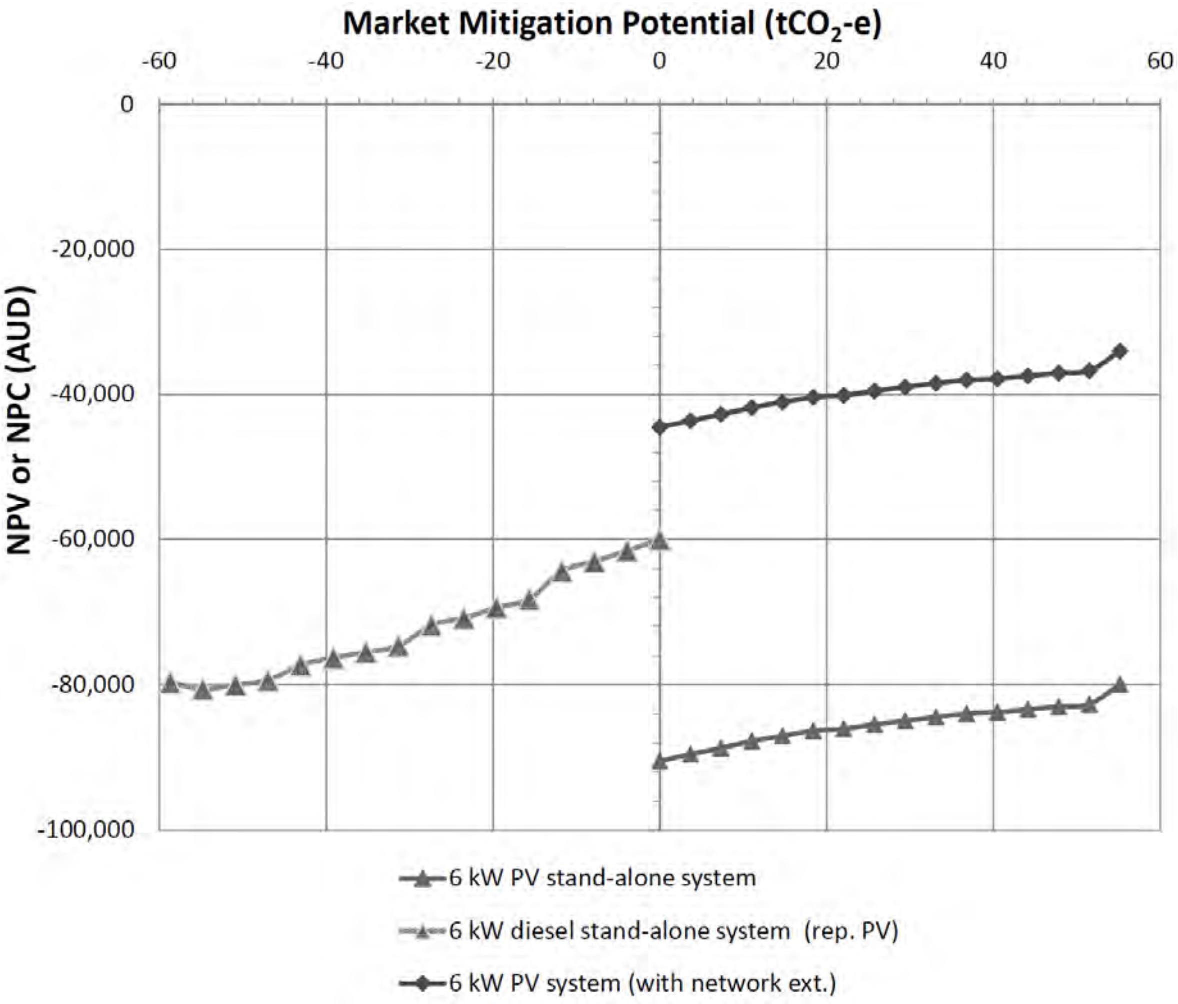
Fig. 8. Battery component annual simulation results for the homestead's input from the 6 kW_p diesel and input/output from/to the 11 kW_p rectifier/inverter.



Quantity	Value	Units
Nominal capacity	139	kWh
Usable nominal capacity	83.2	kWh
Autonomy	166	hr
Lifetime throughput	192,904	kWh
Battery wear cost	0.000	$/kWh
Average energy cost	0.000	$/kWh

Quantity	Value	Units
Energy in	3,782	kWh/yr
Energy out	3,037	kWh/yr
Storage depletion	12	kWh/yr
Losses	733	kWh/yr
Annual throughput	3,395	kWh/yr
Expected life	12.0	yr

Fig. 9. The DCF of the 6 kW$_p$ PV and diesel SPS systems, with the 6 kW$_p$ PV network extension scenario over the 15 year interval.



Tables and Table captions.

Table 1. Summary of annual average simulated technical outputs.

Total homestead electricity consumption from all sources	4,380 kWh $year^{-1}$
Total excess electricity	3,427 kWh $year^{-1}$
Net electricity production from the PV array	8,404 kWh $year^{-1}$
Net electricity production from the inverter	4,380 kWh $year^{-1}$
Net electricity output from battery bank	2,200 kWh $year^{-1}$
% of PV production consumed by the homestead	52.1 %
% of inverter production consumed by the homestead	100%

Table 2. The DCF (discounted cash flow) and emissions calculation results for the 6 kW_p PV stand-alone system over the 15 year interval. The system's NPV is in red.

Initial costs & subsidies		Rates/Prices/Factors		Annual costs & production	
Capital equipment	-$99,000.00	Inflation rate	3.00%	Electricity price for import ($/kWh)	$0.2401
New meter	$0.00	Real discount rate	8.00%	Electricity supply charge saving ($/day)	$0.0000
Capital subsidy	$0.00	Carbon price ($/tCO2-e)	$0.00	Annual electricity generated (kWh)	6,653
REC entitlement	213	Carbon price inflation	0.00%	Annual net electricity used (kWh)	4,380
Total REC value	$8,520.00	REC price	$40.00	Annual supply charge savings	$139.54
Extension cost	$0.00	SWIS (kg CO2-e / kWh)	0.84	Total electricity consumed	4,380
		System insurance	$0.00	Array service (AS)	-$40.00
Total	**-$90,480**	2 km extension cost	$0	Electronics and battery service (EBS)	-$600.00

Yr	Cashflow Data	Costs	Income	Net $ Flow	Cumul. $ Flow	D.Net S Flow	D.Cumul. $ Flow	tCO2 Baseline	tCO2 New	Net. tCO2 Mit.	Cumul. tCO2 Mit.
0	Installation	-$99,000	$8,520	-$90,480	-$90,480	-$90,480	-$90,480	3.679	0.000	0.000	
1	AS	-$40	$1,052	$1,012	-$89,468	$937	-$89,543	3.679	0.000	3.679	3.679
2	AS	-$40	$1,052	$1,012	-$88,457	$867	-$88,676	3.679	0.000	3.679	7.358
3	AS	-$40	$1,191	$1,151	-$87,306	$914	-$87,762	3.679	0.000	3.679	11.038
4	AS	-$40	$1,052	$1,012	-$86,294	$744	-$87,019	3.679	0.000	3.679	14.717
5	AS	-$40	$1,052	$1,012	-$85,282	$689	-$86,330	3.679	0.000	3.679	18.396
6	AS, EBS	-$640	$1,052	$412	-$84,871	$259	-$86,071	3.679	0.000	3.679	22.075
7	AS	-$40	$1,052	$1,012	-$83,859	$590	-$85,480	3.679	0.000	3.679	25.754
8	AS	-$40	$1,052	$1,012	-$82,847	$547	-$84,934	3.679	0.000	3.679	29.434
9	AS	-$40	$1,052	$1,012	-$81,836	$506	-$84,428	3.679	0.000	3.679	33.113
10	AS	-$40	$1,052	$1,012	-$80,824	$469	-$83,959	3.679	0.000	3.679	36.792
11	AS, EBS	-$640	$1,052	$412	-$80,412	$177	-$83,783	3.679	0.000	3.679	40.471
12	AS	-$40	$1,052	$1,012	-$79,401	$402	-$83,381	3.679	0.000	3.679	44.150
13	AS	-$40	$1,052	$1,012	-$78,389	$372	-$83,009	3.679	0.000	3.679	47.830
14	AS	-$40	$1,052	$1,012	-$77,378	$344	-$82,664	3.679	0.000	3.679	51.509
15	AS	-$40	$1,052	$8,512	-$68,866	$2,683	-$79,981	3.679	0.000	3.679	55.188
Remaining System Value			$7,500								

Table 3. 2009 emission factors and energy content of combusted diesel oil fuel in stationary energy systems. (All emission factors have the relevant oxidation factors incorporated).

Emission factor ($kgCO_2$ MJ^{-1})	0.0692
Emission factor ($kgCH_4$ MJ^{-1})	0.0001
Emission factor (kgN_2O MJ^{-1})	0.0002
Emission factor ($kgCO_2$-e MJ^{-1})	0.0695
Energy content factor (MJ L^{-1})	38.6

Table 4. The DCF and emissions results for the 6 kW_p diesel SPS system over the 15 year interval. The system's NPV is in red.

Initial costs & subsidies		**Rates/Prices/Factors**		**Annual costs & production**	
Capital equipment	-$60,000.00	Inflation rate	3.00%	Equivalent electricity price ($/L*0.383L/kWh)	-$0.3256
New meter	$0.00	Real discount rate	8.00%	SWIS baseline incl. Supply costs ($/kWh)	-$0.2401
Capital subsidy	$0.00	Carbon price ($t/CO2-e)	$0.00	Annual electricity generated (kWh)	7,121
REC entitlement	0	Carbon price inflation	0.00%	Annual net electricity used (kWh)	4,380
Total REC value	$0.00	REC price	$0.00	Total diesel consumed (L)	2,380
Extension cost	$0	Annual fuel emissions (kg)	7,592.0	Annual minor diesel servicing costs (mDS)	-$1,100.00
		E.F. (kgCO2-e/MJ)	0.0695	Electronics and battery service (EBS)	-$600.00
Total	**-$60,000**	Energy content (MJ/L)	38.6	Major diesel service (MDS)	-$3,500.00

Yr	Cashflow Data	Service Costs	Fuel Costs	Net $ Flow	Cumul. $ Flow	D.Net S Flow	D.Cumul. $ Flow	tCO2 Baseline	tCO2 New	Net. tCO2 Mit.	Cumul. tCO2 Mit.
0	Installation	-$60,000	$0	-$60,000	-$60,000	-$60,000	-$60,000	3.679	7.592	0.000	
1	mDS	-$1,100	-$608	-$1,708	-$61,708	-$1,582	-$61,582	3.679	7.592	-3.913	-3.913
2	mDS	-$1,100	-$608	-$1,708	-$63,417	-$1,465	-$63,047	3.679	7.592	-3.913	-7.826
3	mDS	-$1,100	-$608	-$1,708	-$65,125	-$1,356	-$64,403	3.679	7.592	-3.913	-11.738
4	mDS, MDS	-$4,600	-$608	-$5,208	-$70,334	-$3,828	-$68,231	3.679	7.592	-3.913	-15.651
5	mDS	-$1,100	-$608	-$1,708	-$72,042	-$1,163	-$69,394	3.679	7.592	-3.913	-19.564
6	mDS, EBS	-$1,700	-$608	-$2,308	-$74,351	-$1,455	-$70,849	3.679	7.592	-3.913	-23.477
7	mDS	-$1,100	-$608	-$1,708	-$76,059	-$997	-$71,845	3.679	7.592	-3.913	-27.390
8	mDS, MDS	-$4,600	-$608	-$5,208	-$81,267	-$2,814	-$74,659	3.679	7.592	-3.913	-31.302
9	mDS	-$1,100	-$608	-$1,708	-$82,976	-$855	-$75,514	3.679	7.592	-3.913	-35.215
10	mDS	-$1,100	-$608	-$1,708	-$84,684	-$791	-$76,305	3.679	7.592	-3.913	-39.128
11	mDS, EBS	-$1,700	-$608	-$2,308	-$86,993	-$990	-$77,295	3.679	7.592	-3.913	-43.041
12	mDS, MDS	-$4,600	-$608	-$5,208	-$92,201	-$2,068	-$79,364	3.679	7.592	-3.913	-46.954
13	mDS	-$1,100	-$608	-$1,708	-$93,909	-$628	-$79,992	3.679	7.592	-3.913	-50.866
14	mDS	-$1,100	-$608	-$1,708	-$95,618	-$582	-$80,573	3.679	7.592	-3.913	-54.779
15	mDS	-$1,100	-$608	$2,792	-$92,826	$880	-$79,693	3.679	7.592	-3.913	-58.692
	Remaining System Value		$4,500								

Table 5. The total market adaptation potential and market mitigation potential of the 6 kW_p diesel and PV SPS systems.

NPV of the diesel SPS system	AUD-79,693
Mitigation (tCO_2-e)	-58.693
NPV of the 6 kW_p PV SPS system	AUD-79,981
Mitigation (tCO_2-e)	55.188

Table 6. The DCF and emissions results for the 6 kW_p PV stand-alone system with the network extension scenario over the 15 year interval. The NPV is in red.

Initial costs & subsidies		Rates/Prices/Factors		Annual costs & production	
Capital equipment	-$99,000.00	Inflation rate	3.00%	Electricity price for import ($/kWh)	$0.2401
New meter	$0.00	Real discount rate	8.00%	Electricity supply charge saving ($/day)	$0.0000
Capital subsidy	$0.00	Carbon price ($/tCO2-e)	$0.00	Annual electricity generated (kWh)	6,653
REC entitlement	213	Carbon price inflation	0.00%	Annual net electricity used (kWh)	4,380
Total REC value	$8,520.00	REC price	$40.00	Annual supply charge savings	$139.54
Extension cost	$45,944.00	SWIS (kg CO2-e / kWh)	0.84	Total electricity consumed	4,380
		System insurance	$0.00	Array service (AS)	-$40.00
Total	**-$44,536**	2 km extension cost	$0.00	Electronics and battery service (EBS)	-$600.00

Yr	Cashflow Data	Costs	Income	Net $ Flow	Cumul. $ Flow	D.Net S Flow	D.Cumul. $ Flow	tCO2 Baseline	tCO2 New	Net. tCO2 Mit.	Cumul. tCO2 Mit.
0	Installation	-$99,000	$54,464	-$44,536	-$44,536	-$44,536	-$44,536	3.679	0.000	0.000	
1	AS	-$40	$1,052	$1,012	-$43,524	$937	-$43,599	3.679	0.000	3.679	3.679
2	AS	-$40	$1,052	$1,012	-$42,513	$867	-$42,732	3.679	0.000	3.679	7.358
3	AS	-$40	$1,191	$1,151	-$41,362	$914	-$41,818	3.679	0.000	3.679	11.038
4	AS	-$40	$1,052	$1,012	-$40,350	$744	-$41,075	3.679	0.000	3.679	14.717
5	AS	-$40	$1,052	$1,012	-$39,338	$689	-$40,386	3.679	0.000	3.679	18.396
6	AS, EBS	-$640	$1,052	$412	-$38,927	$259	-$40,127	3.679	0.000	3.679	22.075
7	AS	-$40	$1,052	$1,012	-$37,915	$590	-$39,536	3.679	0.000	3.679	25.754
8	AS	-$40	$1,052	$1,012	-$36,903	$547	-$38,990	3.679	0.000	3.679	29.434
9	AS	-$40	$1,052	$1,012	-$35,892	$506	-$38,484	3.679	0.000	3.679	33.113
10	AS	-$40	$1,052	$1,012	-$34,880	$469	-$38,015	3.679	0.000	3.679	36.792
11	AS, EBS	-$640	$1,052	$412	-$34,468	$177	-$37,839	3.679	0.000	3.679	40.471
12	AS	-$40	$1,052	$1,012	-$33,457	$402	-$37,437	3.679	0.000	3.679	44.150
13	AS	-$40	$1,052	$1,012	-$32,445	$372	-$37,065	3.679	0.000	3.679	47.830
14	AS	-$40	$1,052	$1,012	-$31,434	$344	-$36,720	3.679	0.000	3.679	51.509
15	AS	-$40	$1,052	$8,512	-$22,922	$2,683	**-$34,037**	3.679	0.000	3.679	55.188
Remaining System Value			$7,500								

Table 7. The NPV of the two 6 kW_p PV SPS system scenarios.

NPV without 2 km network extension	AUD-79,981
NPV including 2 km network extension	AUD-34,037
Mitigation (tCO_2-e)	55.188
Carbon price of the system without the 2 km extension	AUD1,451 $tCO_2\text{-}e^{-1}$
Carbon price of the system with the 2 km extension	AUD617 $tCO_2\text{-}e^{-1}$