

# Feasibility Study for Marysville Virtual Microgrid

**Dr. Tony Richardson**  
**Murrindindi Climate Network**



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# 1. Overview

With an increasing emphasis on the need to reduce greenhouse gas emissions in order to limit the damaging effects of climate change, the area which has seen most activity has probably been energy production and consumption. Considerable attention, worldwide, has been on limiting, and eventually eliminating, the use of fossil fuels, and replacing them with various forms of renewable energy. This has been occurring at various scales, from local community projects up to large-scale industrial projects.

The current project is at the lower end of the scale, concentrating on the development of a MicroGrid for the township of Marysville, 100km north-east of Melbourne. The objective of the MicroGrid is to allow properties within Marysville to share electricity which they have jointly produced, before buying or selling electricity with the National Electricity Grid. In addition, the MicroGrid should have the capacity to “island” itself from the National Grid in times of emergency, so that the community can continue to function without buying or selling electricity with the National Grid.

The purpose of this study is to examine the feasibility of such an islanded MicroGrid to function within Marysville, using just the electricity produced on properties within Marysville. This study is not a full economic or financial evaluation of such a proposal (that will come in a future report). Rather it is trying to establish whether such an islanded Microgrid is even possible, and indicating the scale of any required investment in electricity production and storage.

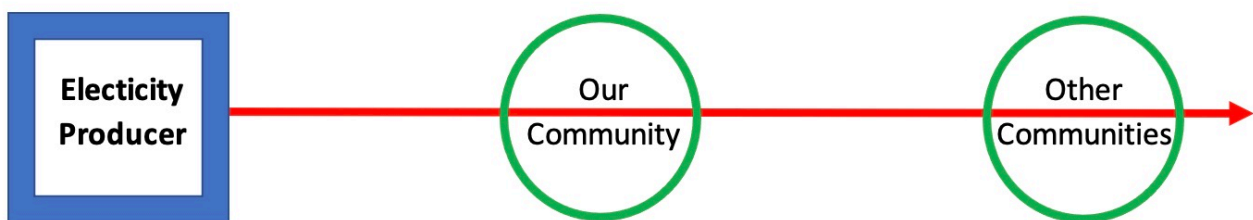
## 2. What is a MicroGrid?

Before delving into the details of this particular study, it is important to address one specific question. What is a MicroGrid? While many definitions exist in the literature, there are two features that are common to most of these definitions, in that a MicroGrid should contain:

- (a) the ability for participants (e.g. households, businesses etc) to produce electricity and to share that electricity with other participants in the MicroGrid
- (b) the ability for the MicroGrid to “island” itself from the Main Electricity Grid in times of emergency, so that the MicroGrid participants can continue to produce and share electricity without being connected to the main Electricity Grid, and without adversely affecting those outside the MicroGrid who remain connected to the Main Electricity Grid.

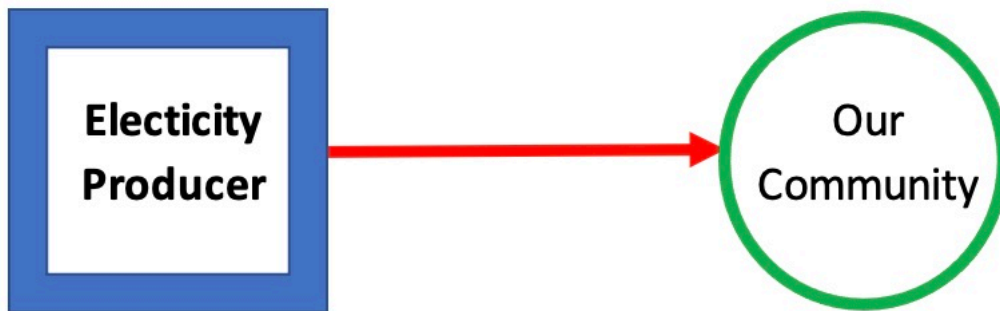
A more complete description of the background to MicroGrids, and other aspects of this study, are contained in a YouTube video produced after an initial Zoom meeting with potential participants in this study (<https://youtu.be/R5EXfZSfJAg>). For the moment, however, two aspects of that presentation are of particular relevance.

Firstly, the second point in the MicroGrid definition above states that islanding should be possible “without adversely affecting those outside the MicroGrid who remain connected to the Main Electricity Grid”. Whether or not this is possible depends to a large extent of the relationship between the community in question and the topographical layout of the electricity distribution network. For example, if the distribution system enters the community on one side and leaves on the other side to serve other communities (as shown in Figure 2.1), then islanding is problematic, since disconnecting Our Community from the Main Grid Electricity Producer would also disconnect Other (downstream) Communities, who may not have the ability to island their electricity system.



**Figure 2.1 An Un-Islandable Network Configuration**

On the other hand, if Our Community is at the “end of the line” as shown in Figure 2.2, then it would be possible to island Our Community because there are no downstream communities who would also be cut off from the Main Grid Electricity Producer. If there are any upstream communities between the Electricity Producer and Our Community then they could remain connected to the Main Grid Electricity Producer, unaffected by our islanding.



**Figure 2.2 An Islandable Network Configuration**



Fortunately, Marysville is in just that network situation as shown in Figure 2.3.

**Figure 2.3 The Marysville Network Configuration**

Marysville (and Narbethong) are both in “end of the line” network situations, with no network connections to the south of the townships. Either of them could be islanded by cutting the main network connection just south of Buxton (although it would be better to make the islanding point closer to the towns to minimise the risk of a network failure occurring inside the island).

The second major issue raised in the video presentation is the nature of the MicroGrid itself, and whether it employs real-time or retrospective sharing of electricity. Before explaining this aspect, it is important to realise that all electricity production and consumption abides by the “bathtub” analogy principle. No producer or consumer can specify exactly where their electricity goes to or comes from. Rather, all electricity produced is emptied into a “bathtub” containing the electricity produced by all producers connected to that network, no matter how they are produced (be it fossil fuels or renewable power). All consumers simply take a ladle of electricity from that bathtub, and get a mixture of all the different types of electricity poured into the bathtub. All “sharing” of electricity between specific producers and consumers is simply an accounting procedure, where sales from a producer are matched with purchases by a consumer. Examples of such situations are Power Purchase Agreements (PPAs) and MicroGrids. Because of their smaller scale, MicroGrids give greater confidence in where purchased electricity has come from, especially in an islanded situation.

Given the above, MicroGrids can have two major types of “accounting systems”; real-time and retrospective. Real-time systems employ electronic control systems to monitor who is producing electricity at a specific time and who is consuming electricity at that same time. They then use real-time matching to join each unit of electricity produced with each unit consumed. Thus, each unit of electricity has a specific seller and buyer. Retrospective systems use data that is already recorded (in Victoria, at least) via SmartMeters, which record all electricity purchased and sold by connected properties in half-hourly periods. Such data can be used retrospectively (say one day later) to match sellers and buyers in each half hour period, and thereby each unit of electricity will have a specific seller and buyer. Such a system has been well developed as Powertracer software by Enosi Australia and is currently used by a number of retailers (e.g. Energy Locals) to reflect the sharing of electricity in periodic bills received by prosumers.

Because the retrospective system requires no further expenditure by participants (e.g. for additional hardware), and because real-time systems have been extensively tested by others, the current study uses retrospective accounting to match buyers and sellers. Also, such a retrospective accounting system has already been developed by Murrindindi Climate Network for a prior project.

### 3. Methodology and Data Sources

This report covers Stages 1&2 of a three-stage project. Stage 1 covered the analysis of NMI (National Meter Identifier) data, and the use of such data to match a sample of buyers and sellers of renewable electricity in Marysville. Stage 2 examines the effect of augmenting the current uptake of solar energy in Marysville, via a hypothetical solar farm with battery storage, to examine what would be required to make islanding a potential reality (Stage 2 also includes financial modelling of the proposal, but this is not yet included in this report and will be issued as an Addendum). Stage 3 (possibly supported by ARENA funding) will cover the design and implementation of such a system.

Stage 1 of this project (to be described in the next chapter) used NMI data from a sample of 13 volunteer participants in the Marysville and Triangle district. They each obtained NMI data for their properties for a two-year period (July 2019 to June 2021) from Ausnet Services (the electricity distributor in this region), and they then provided their data for use in the project. Eight of the participants were households with solar panels (average size 4-5kW and no batteries), four had no solar panels, and the other was a community facility with a significant solar panel installation (35kW).

One important thing to note about the NMI data is that while the data files say that the data are “consumption” and “generation”, that is not the case. In fact, they are “purchases” from the grid and “sales” to the grid. Only in the case of non-solar households are their “purchases” also their “consumption” (and they have no “sales” or “generation”). For solar properties, their “purchases” are less than their “consumption” by the amount they have been able to cover via their own generation of solar power. Similarly, their “sales” are less than their “generation” by the amount of solar power that they have consumed themselves. It seems that Ausnet have not updated their labels to reflect the new solar environment. Care needs to be taken when interpreting the results to ensure that they refer to “sales” and “purchases” and not “generation” and “consumption”.

The NMI data was first analysed to develop profiles of sales and purchases for each of the three groups. The data was then used, in half-hourly periods, to examine the extent to which buyers could be matched with sellers in that half-hour. If there was more offered for sale than required to be purchased, the

surplus was sold to the grid. If there was less offered for sale than required to be purchased, the deficit was purchased from the grid. This initial matching, among the 13 volunteer participants, gave some idea of the extent to which electricity sales and purchase could be matched.

Stage 2 of the project expanded the population from the 13 volunteers to the total population of Marysville, to obtain an idea of the scale of the surpluses and deficits that might be obtained in practice. The home production of electricity was then augmented by electricity from a solar farm with batteries, to determine how much augmentation would be required to make Marysville a feasible islanding proposition. A range of solar farm sizes were tested, in conjunction with a range of battery capacities.

Because of the previous distinction between sales/generation and purchases/consumption, a different methodology was required for Stage 2. In order to estimate the electricity that could be generated from solar farms of different sizes (at different times of the day and seasons of the year) it was necessary to go back to basics and use a modelling approach previously developed by MCN (the Solar Electricity Production and Consumption (SEPAC) Model) to estimate the solar power generation by the solar farm.

## 4. NMI Analysis

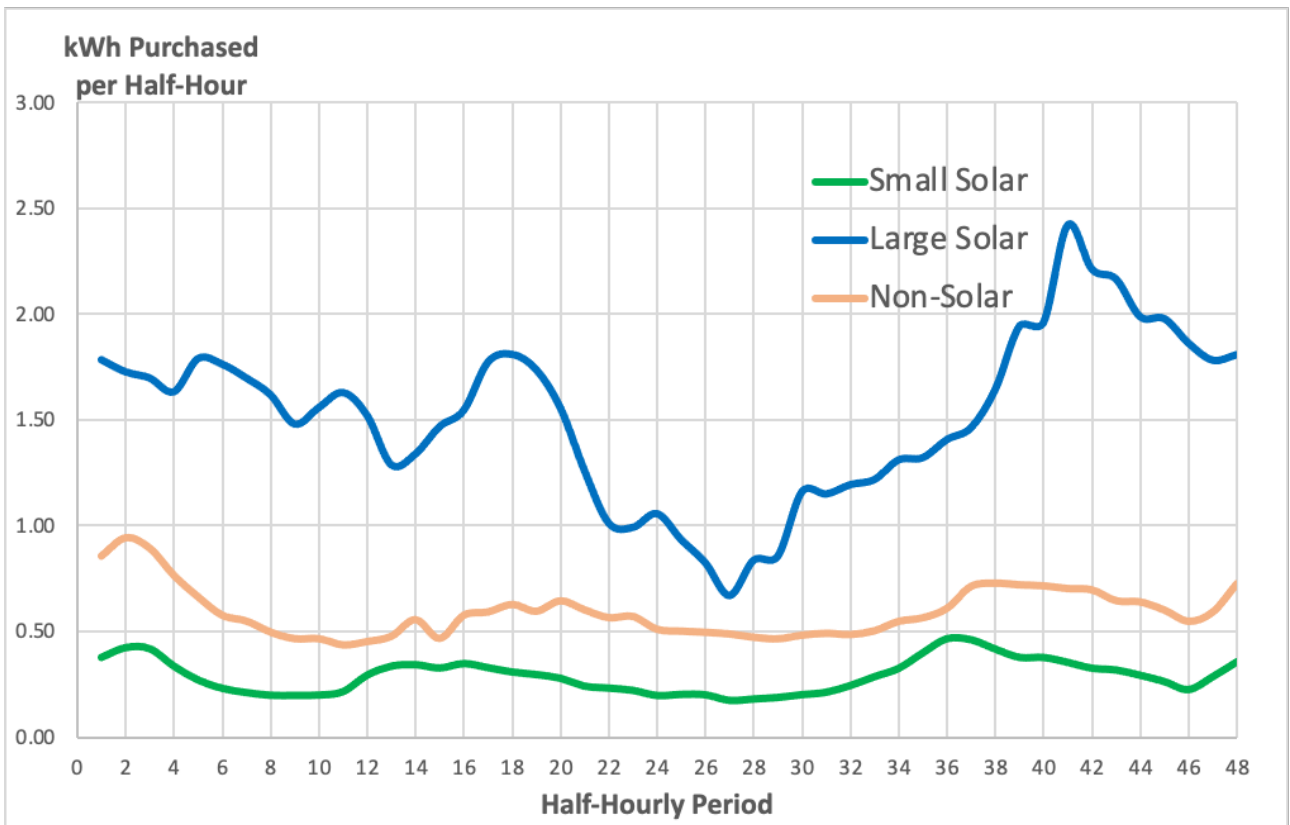
The NMI data for each of the 13 Stage 1 participants contained 2 years of purchases data and (if relevant) 2 years of sales data. The data was meant to cover the period from 1 July 2019 to 30 June 2021. However, the data recovery routine from Ausnet only covered 2 years of data ending on the day when the data was requested online. Since some participants took longer than others to retrieve their data, this meant that some (for example) had data from September 2019 to August 2021. In such cases, the data from 1 July 2021 to the end of their file was transposed to the start of their file as if it were data from 2019. This will introduce a small error, but will still ensure two full years of seasonal data. Unfortunately the Ausnet website underwent a major re-design in September 2021, and the NMI data download was not available for an extended period (meaning that some people were unable to download their NMI data).

The first (tedious) task was to convert all the NMI files into a standard format, with a single column of data and 140,352 rows of data, consisting of 48 half-hour periods over 731 days for four types of data (Consumption, Controlled Load, Generation and Total Consumption (= Consumption + Controlled Load)). The participants were then split into three groups (Small Solar (4-5kw), Large Solar (35kw) and Non-Solar). Daily purchase patterns were then graphed for each half-hour and each of the four seasons, as shown in Figures 4.1 - 4.4. It is important to remember at this stage that we are talking about Purchases, and not Consumption (except for the Non-Solar households).

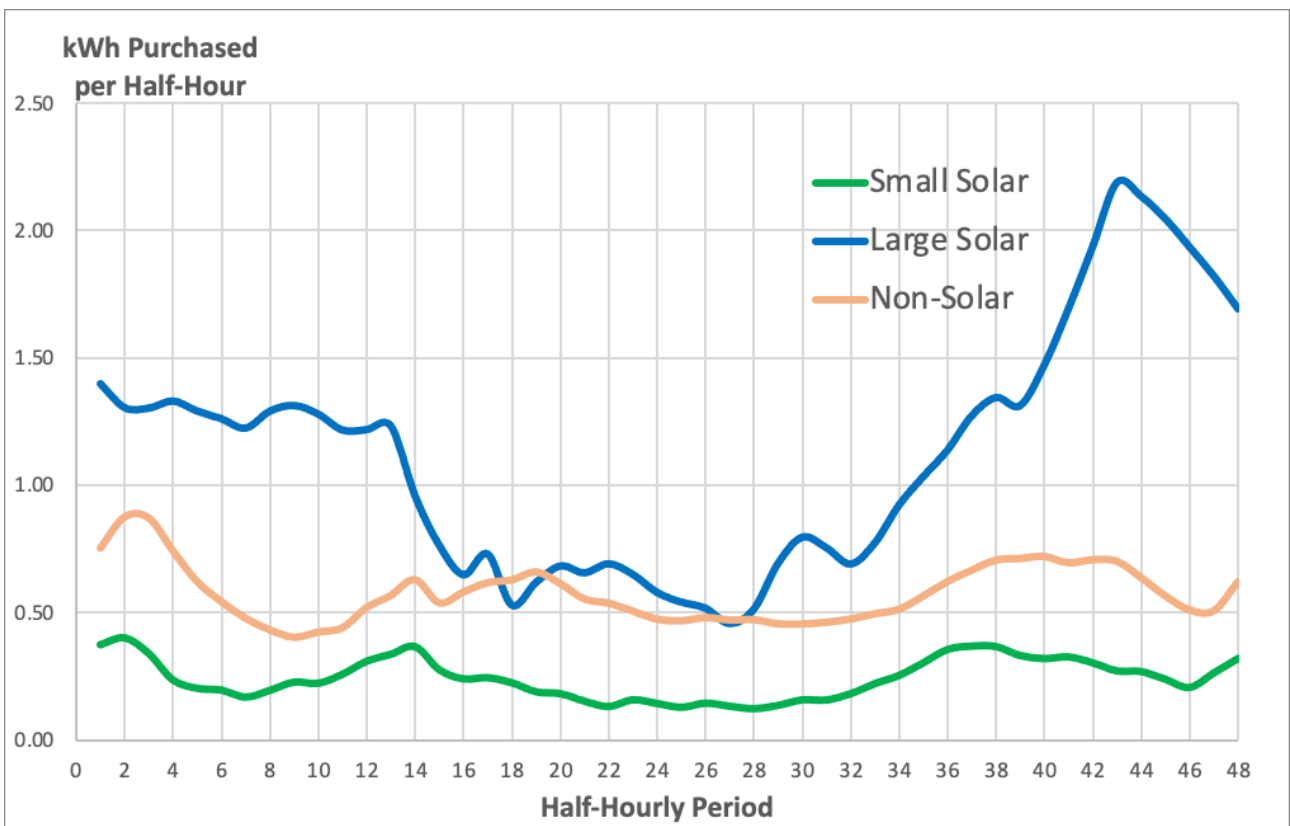
The average grid purchases per day for each of the groups for each of the four seasons is shown in Table 4.1. For the solar and non-solar households, winter has most electricity purchases from the grid, and summer has the least. Autumn and spring are in the middle ranges. Unsurprisingly, Small Solar households buy less from the grid than Non-Solar Households in all seasons. The Large Solar property (a golf course) has very different patterns, as will be explained below.

**Table 4.1 Average Daily Purchases (kWH) by Season**

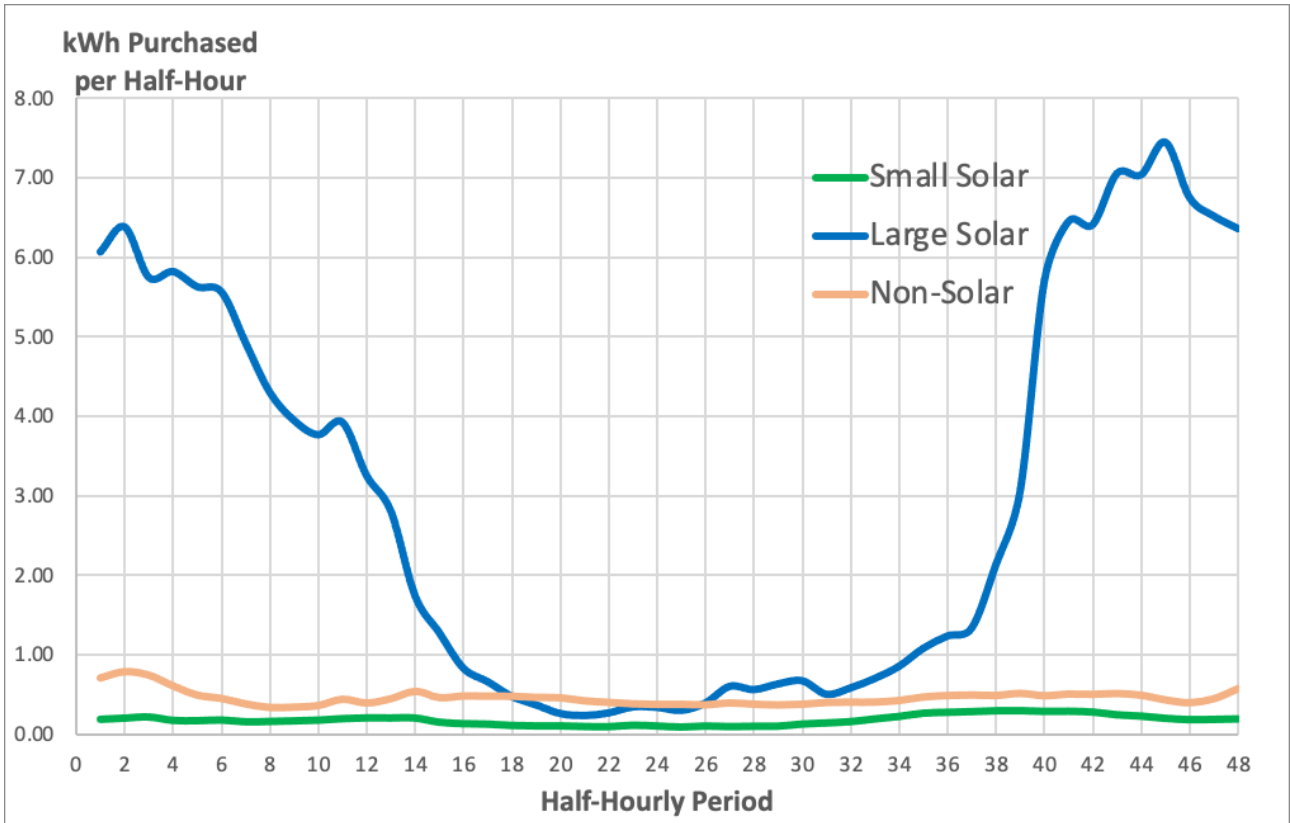
	Non-Solar	Small Solar	Large Solar
Autumn	29	14	73
Winter	39	20	60
Spring	28	12	54
Summer	22	9	143



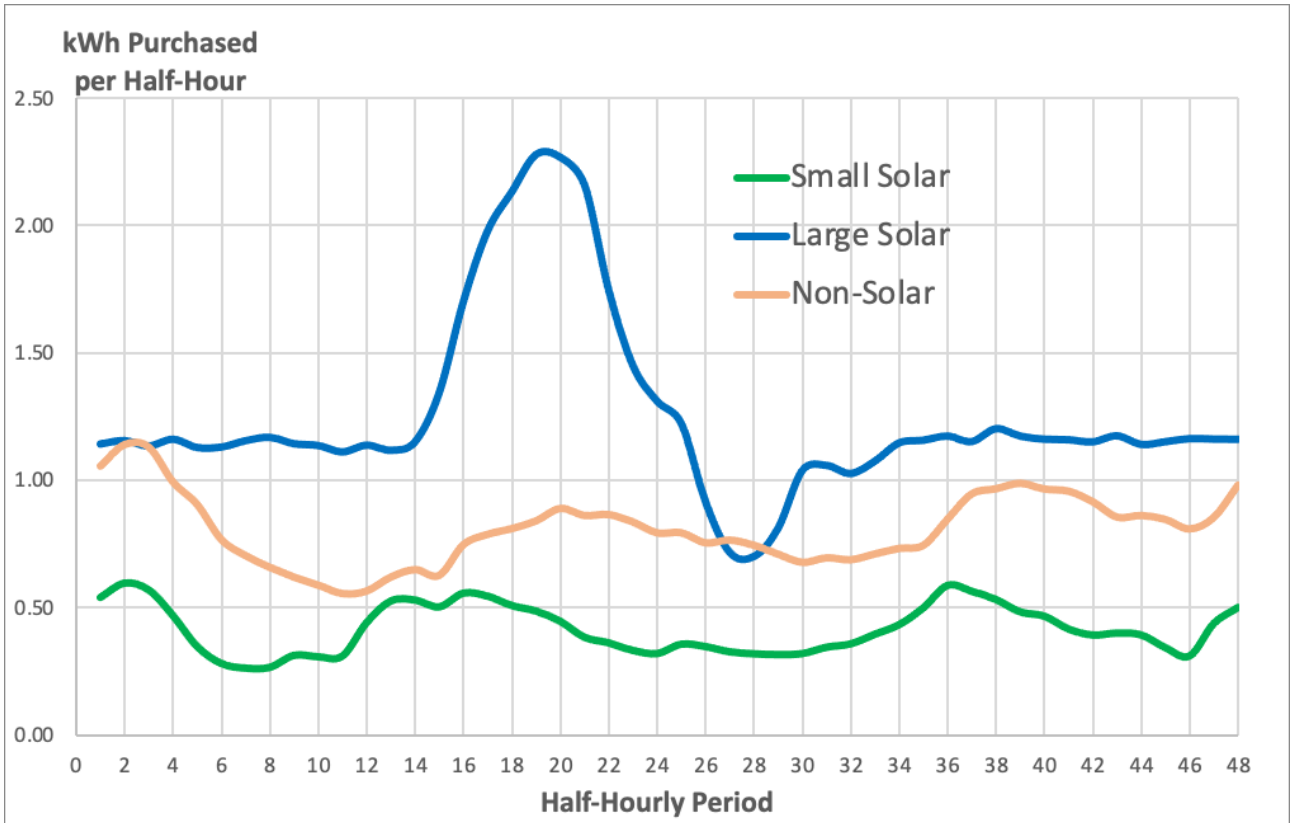
**Figure 4.1 Half-Hourly Grid Purchases in Autumn by Property Type**



**Figure 4.2 Half-Hourly Grid Purchases in Spring by Property Type**



**Figure 4.3 Half-Hourly Grid Purchases in Summer by Property Type**



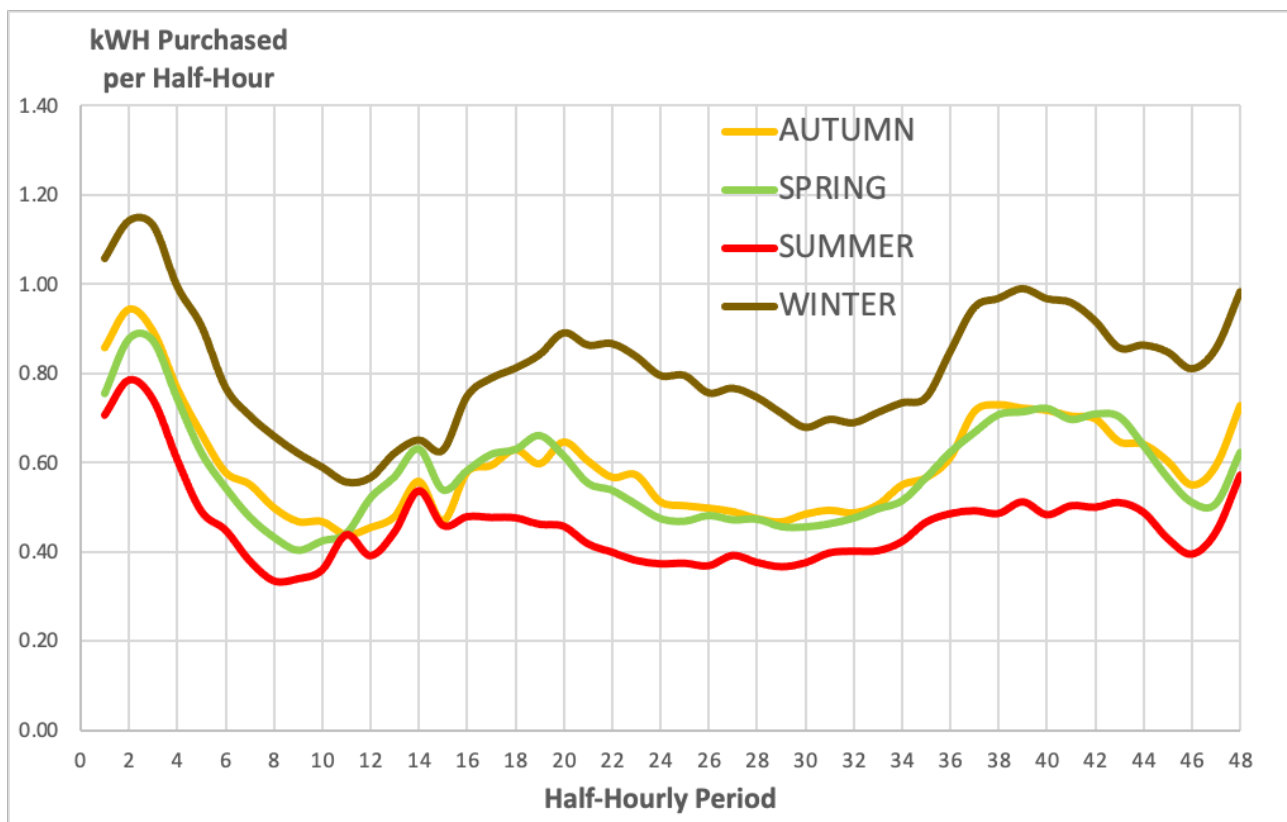
**Figure 4.4 Half-Hourly Grid Purchases in Winter by Property Type**

Figures 4.1 and 4.2 show that Autumn and Spring have very similar grid purchasing patterns, with the Non-Solar and Small Solar households having the typical daily pattern for older couples without kids. The Non-Solar households have about twice the grid purchases per half hour as the Small Solar households. The Large Solar golf club has fairly comparable grid purchases during the middle of the day as the Non-Solar households, but much higher grid purchases in the late evening and early morning when the golf course is being watered.

This effect is shown more clearly in Figure 4.3, where the overnight summer golf course watering requires nearly ten times the grid purchases as during the day.

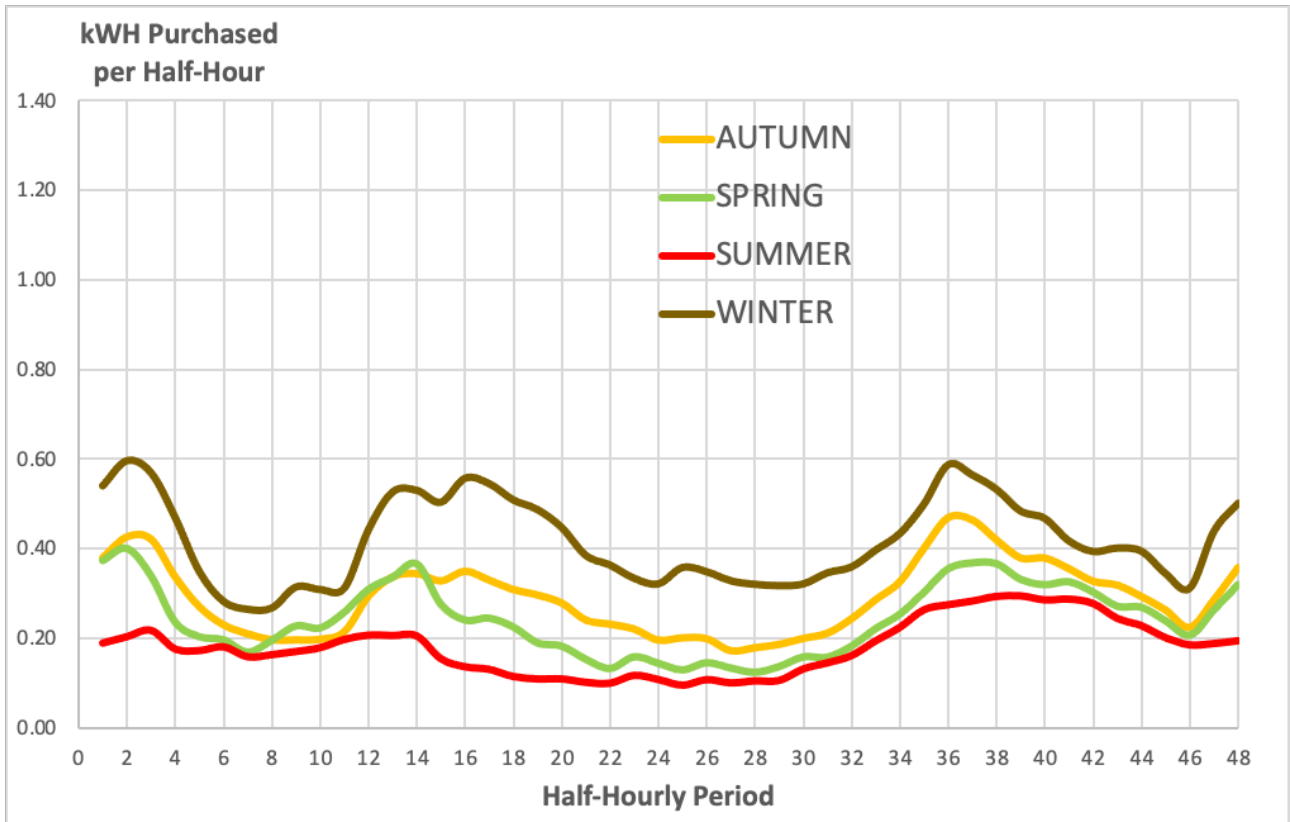
During winter, as shown in Figure 4.4, the golf course is not watered overnight, due to the generally higher levels of rainfall during this season.

Another way of looking at these patterns is to look at the seasonal differences within each of the property types, as shown in Figure 4.5 through 4.7.

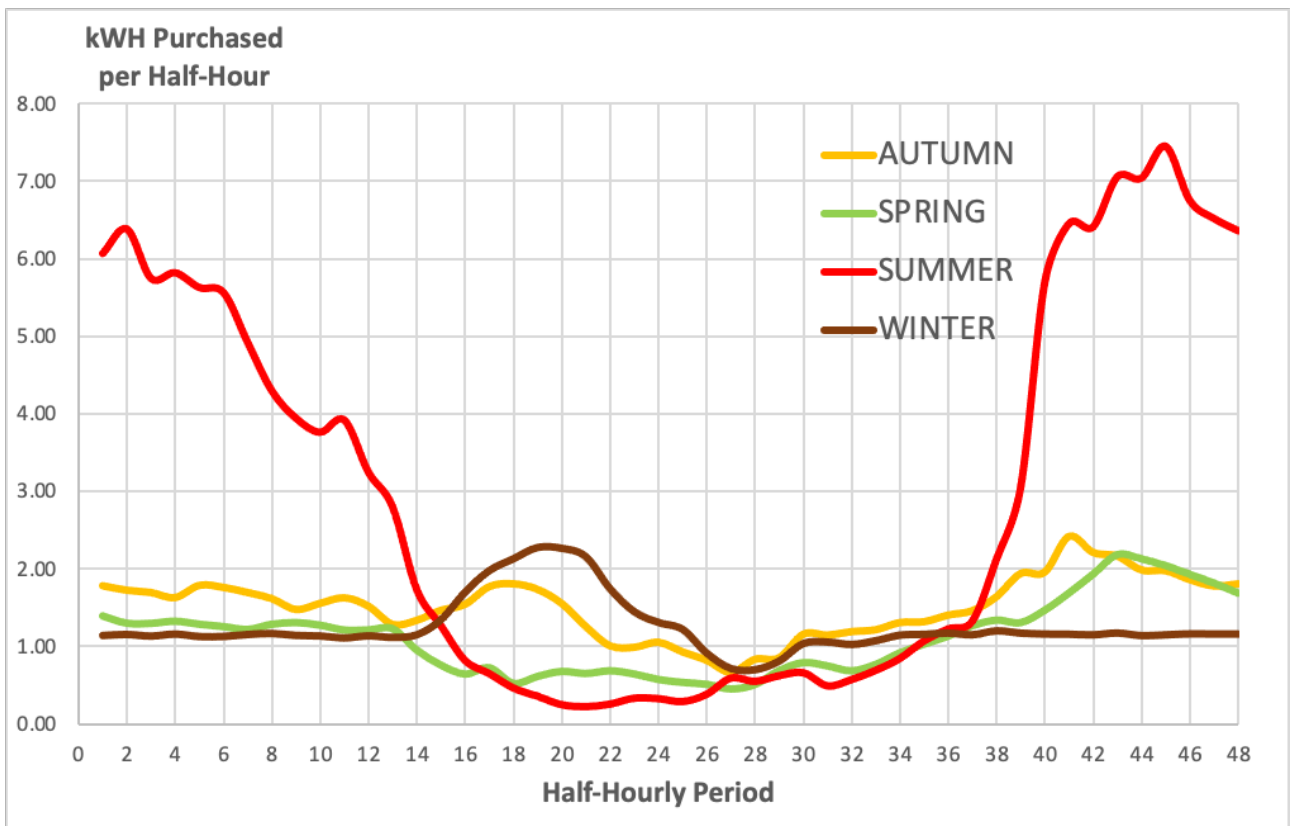


**Figure 4.5 Half-Hourly Grid Purchases for Non-Solar Households**

Figure 4.5 for Non-Solar households shows the same general daily pattern across all seasons, but at different levels. The morning energy peak shifts later in the cooler seasons, perhaps because of the later rising of the sun. Figure 4.6 shows a similar result, but at lower levels than the Non-Solar households.



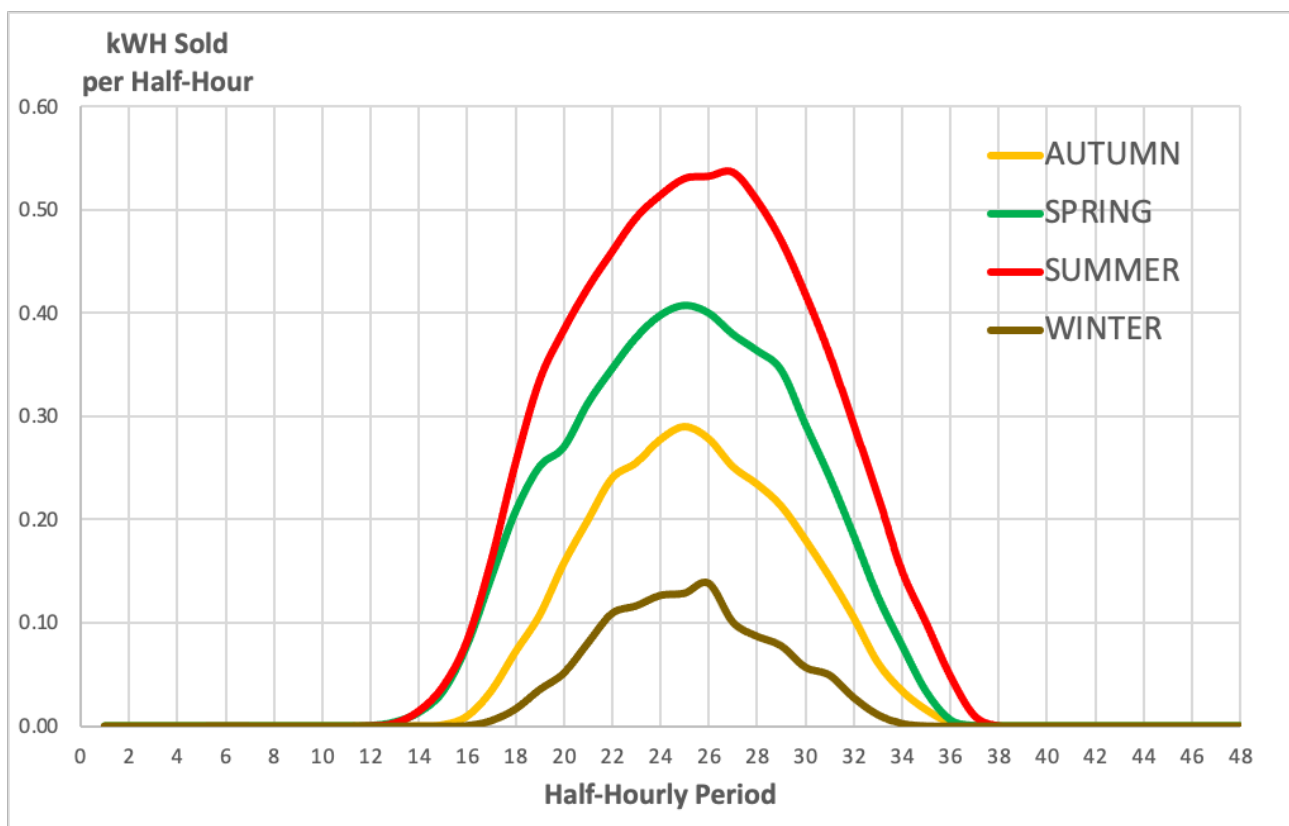
**Figure 4.6 Half-Hourly Grid Purchases for Small Solar Households**



**Figure 4.7 Half-Hourly Grid Purchases for Large Solar Property**

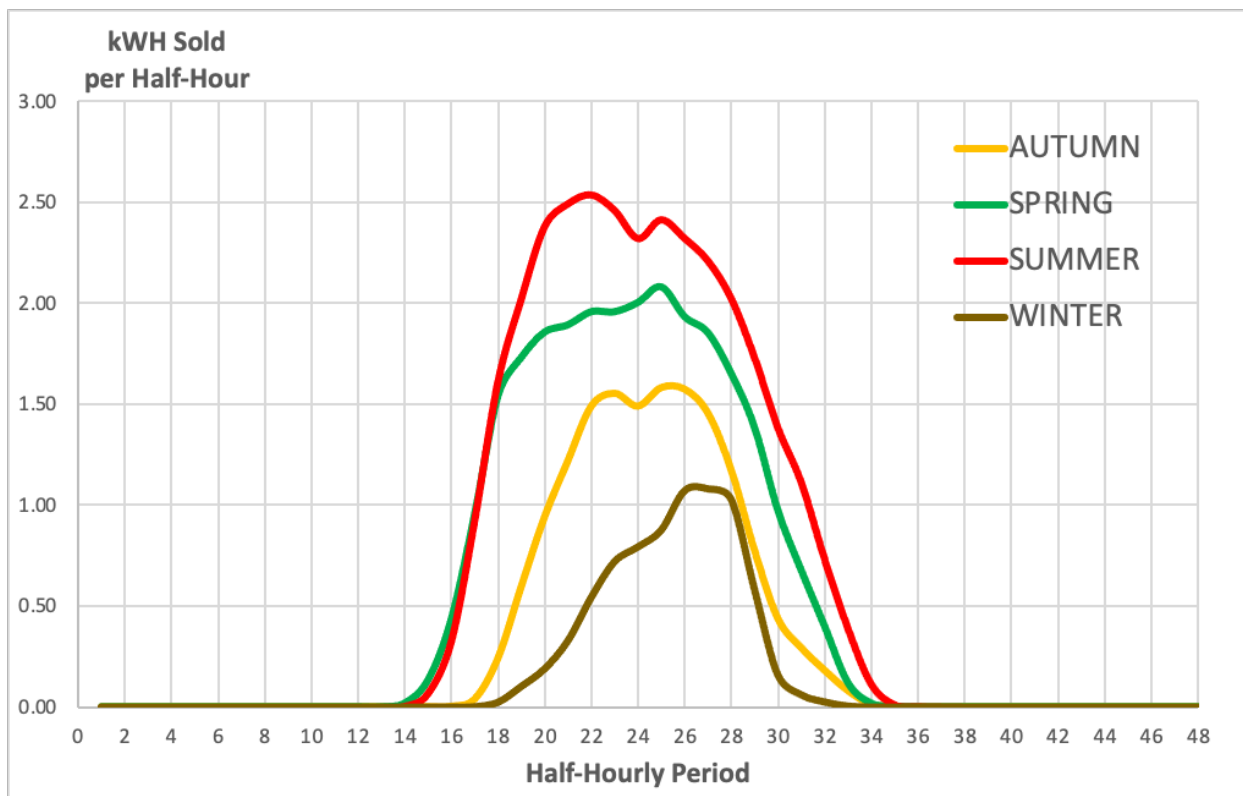
Figure 4.7 for the Large Solar golf course property shows moderate variations across the day in Autumn, Spring and Winter. It also clearly shows the massive night-time Grid purchases in Summer for the purpose of watering the golf-course. This result highlights the unique characteristics of commercial and large scale properties, and the need to treat them individually in any further studies.

The previous paragraphs have considered the electricity purchases made from the Grid by different property types over the different seasons. The other side of the coin is to consider the electricity sold to the Grid by properties with solar panels. Figure 4,7 shows the sales made by Small Solar households, while Figure 4.9 shows the sales made by the Large Solar property.



**Figure 4.8 Half-Hourly Sales to the Grid by Small Solar Households**

It can be seen in Figure 4.8 that the highest sales are made in the middle of the day during summer, while the lowest sales are during winter. It can also be seen that the period of time during which sales are made is longest during summer and shortest during winter. The same patterns are demonstrated for the Large Solar property in Figure 4.9. The only major difference is the scale of the sales because of the bigger capacity of the solar panel array at the Large Solar property. There is also some difference in the shape of the curves, and this may be due to the precise location and orientation of panels at the various properties.



**Figure 4.9 Half-Hourly Sales to the Grid by Large Solar Property**

### 4.1 NMI Matching

Having gained an appreciation of the nature and veracity of the NMI data for the different types of property, the next step is to examine the extent to which participants may have been able to share electricity sales and purchases between themselves, before resorting to sales or purchases with the Main Grid. This is done by matching sales and purchases during each half-hour period, using a pseudo-Powertracer procedure.

This analysis is not exactly the same as Powertracer because it does not need to create matches between specific buyers and sellers. It just needs to determine if there is sufficient electricity for sale in a half-hour period to meet the demand from buyers in that period, or if there are sufficient buyers for the quantity of electricity offered for sale. In a real Powertracer application, shortages in sellers or buyers require decisions to be made about how the shortage will be handled. For example, if there is a shortage of electricity being offered for sale within the MicroGrid then a decision needs to be made as to which buyers will receive the electricity. Numerous rules have been developed such as equal proportions of demand being met for each buyer, equal amounts being allocated to each buyer, a first-come first-served approach, and a range of other strategies. Similar rules can be applied to buyers when there is a shortage of demand.

In the current study, such allocation rules are not required because the aim of the study is simply to see whether there is more demand than supply, or more supply than demand, in each half-hour period. At the moment, non-solar households are buying all their electricity from the Main Grid; how much could they have bought from other MicroGrid participants? Solar properties are currently selling their excess electricity to the Main Grid; how much could they have sold to other MicroGrid participants?

For the moment, we will ignore the question of the prices at which MicroGrid transactions take place. For example, could buyers buy electricity from other MicroGrid participants more cheaply than from the Main Grid, and could sellers sell their excess electricity to MicroGrid participants at a higher price than selling to the Main Grid? These questions will be addressed in a subsequent report about the economics of the MicroGrid.

A short extract from the matching table, shown in Table 4.2, will illustrate how the process works.

**Table 4.2 Extract from the MicroGrid Matching Table**

Year	Season	Month	Day	Period	Total Sales (kWH)	Total Purchases (kWH)	VMG Trades	Grid Sales	Grid Purchases
2021	SUM	1	9	16	1.347	2.928	1.347	0	1.581
2021	SUM	1	9	17	3.304	2.602	2.602	0.702	0

Table 4.2 shows just two rows from the matching table that contains 35,088 rows (half-hourly time periods). They show electricity flows for one hour in the morning of 9 January 2021. Between 8.00am and 8.30am, the solar properties sold a total of 1.347 kWH of electricity to the Main Grid, while all the MicroGrid properties bought a total of 2.928 kWH from the Main Grid. Of this amount, 1.347 kWH could have been bought from the MicroGrid solar properties as a Virtual MicroGrid (VMG) trade, with the remaining 1.581kWH being bought from the Main Grid. Between 8.30am and 9.00am, as the sun rose a little more, the solar properties sold a total of 3.304 kWH of electricity to the Main Grid, while all the MicroGrid properties bought a total of 2.602 kWH from the Main Grid. The MicroGrid solar properties could have supplied all of the 2.602 kWH required by the other MicroGrid properties, with the remaining 0.702 kWH being sold to the Main Grid.

If one applies the logic shown in Table 4.2 to all 35,088 time periods in the 2019-2021 study period, the overall results, stratified by season, are as shown in Table 4.3.

**Table 4.3 Overall Results of Matching Process, stratified by Season**

Season	Total Sales	Total Purchases	VMG Trades	Sales to Grid	Purchases from Grid	% VMG Sales	% VMG Purchases
Autumn	7,371	54,344	4,712	2,659	49,632	64%	9%
Winter	3,155	68,540	2,952	204	65,588	94%	4%
Spring	12,363	46,885	6,463	5,900	40,421	52%	14%
Summer	16,450	54,651	7,184	9,267	47,467	44%	13%
All Year	39,341	224,419	21,311	18,030	203,108	54%	9%

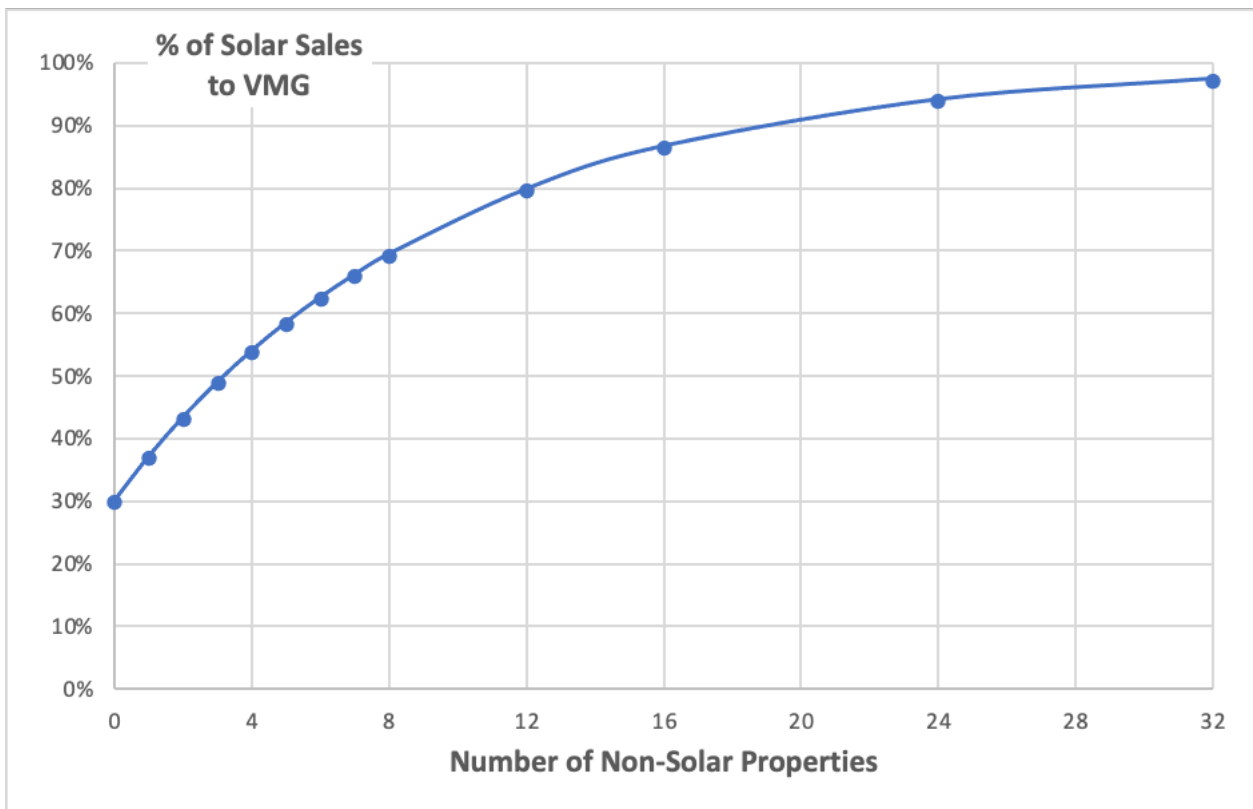
It can be seen in Table 4.3 that exports of excess electricity are highest in Summer and lowest in Winter. Imports of electricity are highest in Winter and lowest in Spring. Trades between VMG participants are highest in Summer and lowest in Winter. Sales to the Main Grid are highest in Summer and lowest in Winter. Purchases from the Main Grid are highest in Winter and lowest in Spring. Across the entire year, 54% of sales of excess solar electricity could have been bought by other VMG participants, with this figure rising to 94% in Winter and falling to 44% in Summer. Across the entire year, 9% of purchases of electricity could have been bought from other VMG participants, with this figure rising to 14% in Spring and falling 4% in Winter. Thus, within this group of 9 solar properties and 4 non-solar properties, it seems that solar properties are much more likely to sell their excess electricity to other VMG participants than non-solar properties are able to buy their electricity from other VMG participants.

While the main emphasis of this study is the sharing of electricity produced by solar properties, one cannot ignore the significant impact of non-solar properties on the feasibility of a MicroGrid. Without non-solar properties, the opportunities for solar properties to sell their excess solar electricity could be greatly reduced. To test this hypothesis, a series of scenarios were modelled with different numbers of non-solar households (keeping the number of solar properties constant across all scenarios). The results of these tests are shown in Table 4.4, with the current situation shown in *italics*, and the main results are summarised in Figures 4.10 and 4.11. It can be seen in Table 4.4 that as the number of non-solar households increases, the total purchases increase while the total sales stays constant. The VMG Trades and Grid Purchases increase, while the Grid Sales decrease.

**Table 4.4 Scenarios with different numbers of Non-Solar Properties**

# Small Solar	# Non-Solar	# Large Solar	Total Sales	Total Purchases	VMG Trades	Grid Sales	Grid Purchases	% VMG Sales	% VMG Purchases
8	0	1	39341	139168	11910	27430	127257	30%	8.6%
8	1	1	39341	160481	14686	24655	145795	37%	9.2%
8	2	1	39341	181793	17146	22195	164648	44%	9.4%
8	3	1	39341	203106	19345	19996	183761	49%	9.5%
8	4	1	39341	224419	21311	18030	203108	54%	9.5%
8	5	1	39341	245732	23073	16268	222659	59%	9.4%
8	6	1	39341	267045	24656	14685	242389	63%	9.2%
8	7	1	39341	288358	26082	13258	262275	66%	9.0%
8	8	1	39341	309671	27372	11969	282299	70%	8.8%
8	12	1	39341	394922	31447	7893	363475	80%	8.0%
8	16	1	39341	480174	34142	5198	446032	87%	7.1%
8	24	1	39341	650677	37074	2267	613603	94%	5.7%
8	32	1	39341	821180	38373	968	782807	98%	4.7%

The most significant results, however, are summarised in Figures 4.10 and 4.11.

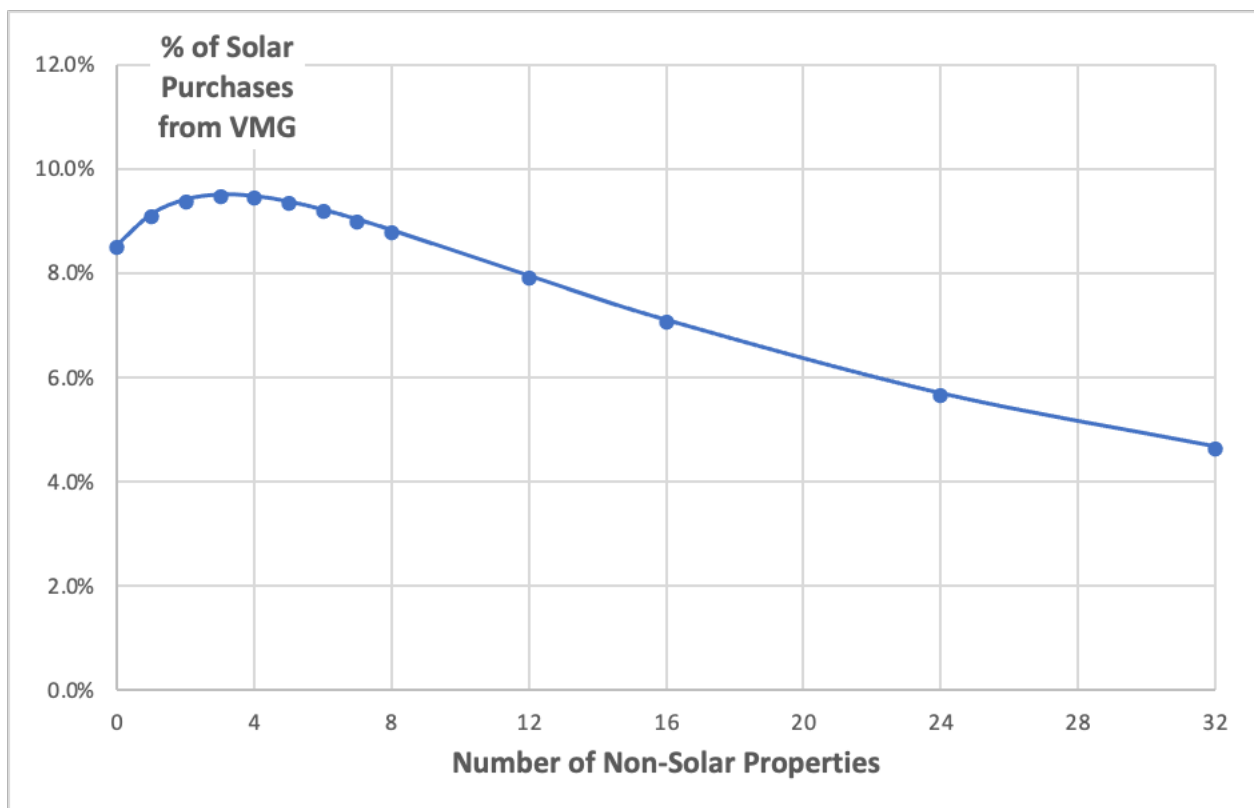


**Figure 4.10 Sales to VMG with differing Non-Solar Property Numbers**

Figure 4.10 shows that with no Non-Solar properties, Solar properties are still able to sell 30% of their excess solar electricity to other (Solar) VMG participants. This is because while all the properties are Solar properties, they are not all producing excess solar electricity at the same time, because of different locations producing solar electricity at different times, and because each property may be using a different amount of their own solar electricity over time.

However, as Non-Solar properties are added to the mix, they represent customers who will not be competing by generating their own solar electricity. Therefore, the percentage of excess solar electricity that can be sold increases with each additional Non-Solar property. In the original scenario, with 4 Non-Solar properties, 54% of the excess solar electricity is sold to the VMG by the Solar properties. As more Non-Solar properties are added, the percent of excess solar electricity sold to the VMG increases, until with 32 Non-Solar properties (compared to the 9 Solar properties), nearly all the excess solar electricity (98%) is sold to the VMG. Thus increasing the Non-Solar properties brings benefits to the Solar properties (especially if those Solar properties can sell their excess solar electric at a better price to the VMG than they can get by selling to the Grid).

The flip side of the coin is shown in Figure 4.11.



**Figure 4.11 Purchases from VMG by Non-Solar Property Numbers**

Figure 4.11 shows the perspective of the Non-Solar households, who are buying the excess solar electricity, as the number of Non-Solar properties increases. After an initial rise in the likelihood of buying excess solar electricity from the VMG as the Non-Solar properties soak up a surplus of excess solar electricity, there comes a point where the increasing numbers of Non-Solar properties are now just sharing a fixed amount of excess solar electricity (because of the constant number of Solar properties). From the perspective of the individual Non-Solar property, it seems that about 15-35% of properties being Non-Solar represents an optimal situation (especially if Non-Solar properties can buy their electricity more cheaply from the VMG than they can from the Grid).

In all the scenarios shown in Table 4.4, the number of Small Solar properties is kept at 8 and the number of Large Solar properties is kept at 1. For completeness, therefore, it is useful to consider the outcomes if those numbers are also changed. Consider, firstly, changing the number of Large Scale Solar properties, as shown in Table 4.5.

**Table 4.5 Different numbers of Large Scale Solar Properties**

# Small Solar	# Non-Solar	# Large Solar	Total Sales	Total Purchases	VMG Trades	Grid Sales	Grid Purchases	% VMG Sales	% VMG Purchases
8	4	0	24806	164327	16624	8182	147703	67%	10.1%
8	4	1	39341	224419	21311	18030	203108	54%	9.5%
8	4	2	53875	284512	23754	30121	260758	44%	8.3%

It can be seen that removing the Large Scale Solar property improves both the percentage of excess solar energy that can be sold to VMG participants and the percentage of purchases that can be made from VMG properties. Increasing the numbers of Large Scale Solar properties reduces both the percentage of excess solar energy that can be sold to VMG participants and the percentage of purchases that can be made from VMG properties. This initially surprising result can be explained by realising that as well as being a Large Scale generator of solar electricity, this property is also a Large Scale consumer of electricity. Thus it is competing with Small Scale solar properties as a supplier of solar electricity and with Non-Solar properties as a consumer of electricity.

Consider now a change in the number of Small Scale Solar properties, as shown in Table 4.6.

**Table 4.6 Different numbers of Small Scale Solar Properties**

# Small Solar	# Non-Solar	# Large Solar	Total Sales	Total Purchases	VMG Trades	Grid Sales	Grid Purchases	% VMG Sales	% VMG Purchases
4	4	1	26938	184882	15751	11186	169130	58%	8.5%
8	4	1	39341	224419	21311	18030	203108	54%	9.5%
12	4	1	51744	263957	26515	25228	237441	51%	10.0%

When the number of Small Scale Solar properties is decreased from the original 8, the percent of sales of excess solar electricity to VMG participants is increased, while the percent of purchases from the VMG is decreased. Conversely, increasing from the original 8 decreases the percent of sales of excess solar electricity to VMG participants, while the percent of purchases from the VMG is increased. Thus having more Small Solar properties increases competition for the sales of excess solar electricity, thereby decreasing the proportion of sales to the VMG for each Small Scale solar property. On the other hand, having more Small Scale solar properties increasing the probability that VMG participants will be able to buy excess solar electricity from the other VMG participants.

Here endeth the reporting of Stage 1 of the project.

## **5. Augmentation with Solar Farm and Battery**

While Stage 1 of the project showed promising results in terms of the ability to share excess solar energy produced by solar properties, it was only a small scale exercise with a sample of 13 properties, and did not show what would be required to make a Marysville MicroGrid a feasible islandable project. Stage 2 of the project will examine that question by expanding the sample to represent the Marysville population, and then considering the incorporation of a Solar Farm and Battery Storage to enable the township to function on internal power sources for an extended period (in cases of emergency, or for economic reasons during times of increasing electricity prices from the Main Grid).

The previous section of this report has relied on NMI data describing the history of electricity sales and purchases to and from the Main Grid. It did not directly address the question of electricity generation or consumption (despite those terms appearing the NMI datafiles). However, in considering the incorporation of a solar farm, whose only purpose is to generate solar electricity, it is necessary to go back to basics and model the generation of solar energy from solar panels. For that purpose, this section of the report will adapt modelling techniques previously developed by Murrindindi Climate Network in the form of the Solar Electricity Production and Consumption Model (SEPAC) to estimate the solar power generation by the solar farm.

### **5.1 Solar Electricity Production and Consumption Model (SEPAC)**

The SEPAC Model, as originally developed, included a wide array of modules, including:

- Prediction of Energy Consumption Patterns
- Prediction of Solar Panel Energy Capture

Because the proposed Solar Farm has no significant consumption of electricity, only the Solar Panel Energy Capture module (as described below) will be used (and adapted) for this study.

### 5.1.1 Solar Panel Energy Capture Prediction

The amount of energy captured by solar panels depends on a number of factors:

- The location latitude/longitude, and hence the path of the sun through the sky
- The number and size of panels installed
- The type of solar panel installed
- The orientation of the panel
- The tilt of the panel.

#### *The path of the sun through the sky*

The path of the sun through the sky is described in terms of two angles: the Elevation of the sun (how high above the horizon is the sun), with  $0^\circ$  being on the horizon and  $90^\circ$  being straight up; and the Azimuth of the sun (which compass direction is the sun shining from), with  $0^\circ$  being due north,  $90^\circ$  being due east, and  $-90^\circ$  being due west. The path through the sky will depend on the latitude/longitude of the location and the day of the year. For reasons of data availability, the location of the MicroGrid is assumed to be Lake Eildon (the nearest weather station to Marysville). While this difference in location makes a small difference to the calculations, the difference is of no practical significance.

The Elevation and Azimuth vary throughout the day, and across the seasons of the year. Figure 5.1 shows the Elevation across the day on the summer and winter solstice days and the spring and autumn equinox days, while Figure 5.2 shows the same for the Azimuth.

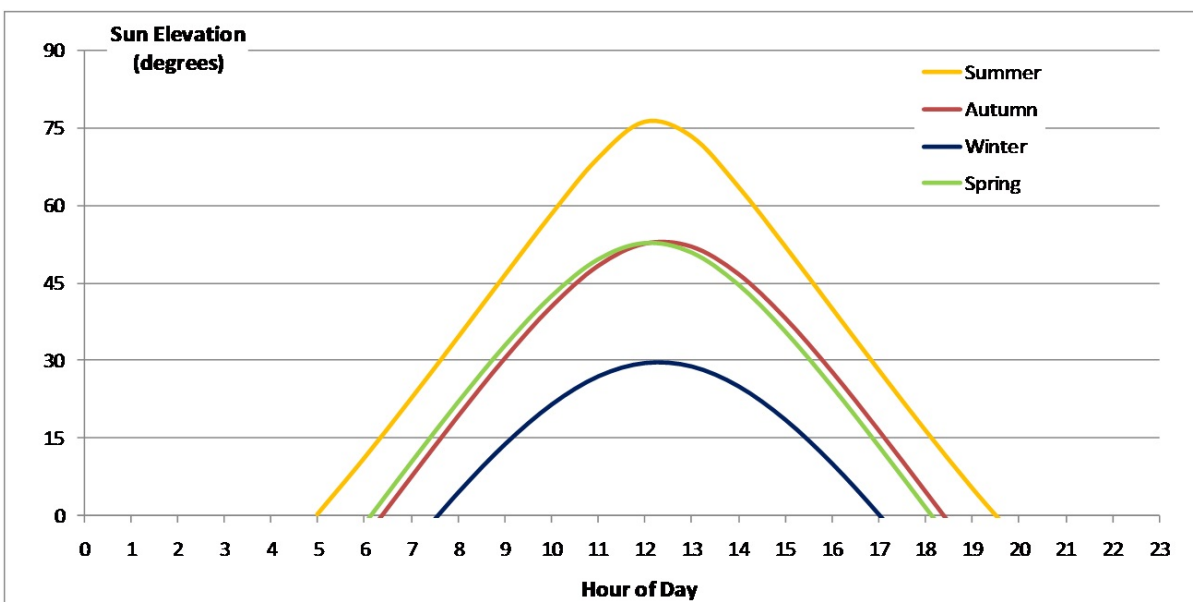
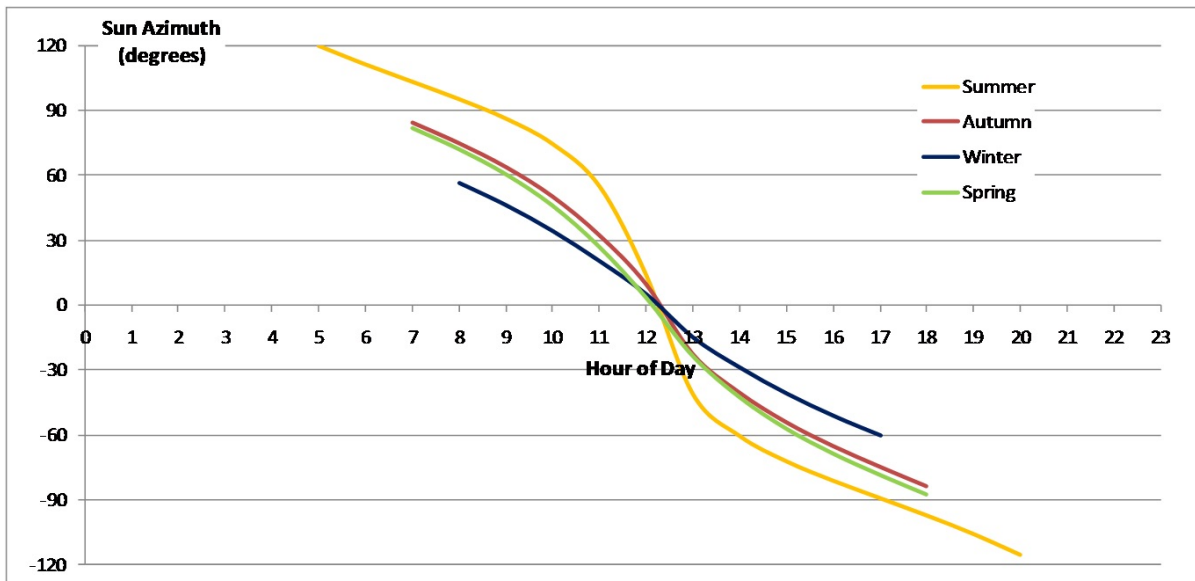


Figure 5.1 Sun Elevation by Hour of Day by Season

Figure 5.1 shows the timing of sunrise when the Elevation is zero in the morning and sunset when the Elevation is zero in the evening. During the day, the sun Elevation rises to a maximum around noon, with a higher maximum in summer ( $75^\circ$ ), compared to spring/autumn ( $52^\circ$ ) and winter ( $30^\circ$ ).



**Figure 5.2 Sun Azimuth by Hour of Day by Season**

In Figure 5.2, it can be seen that in summer the sun rises with an Azimuth of  $120^\circ$  (i.e.  $30^\circ$  south of due east) and sets with an Azimuth of  $-120^\circ$  (i.e.  $30^\circ$  south of due west). On the other hand, in winter the sun rises with an Azimuth of  $60^\circ$  (i.e.  $30^\circ$  north of due east) and sets with an Azimuth of  $-60^\circ$  (i.e.  $30^\circ$  north of due west).

These systematic changes of the position of the sun in the sky have a direct effect on the design of the solar panel installation, because to capture the most direct solar exposure, the panel should be pointing at (at right angles to) the direction of the sun. Since the sun's position is continually changing, the panel should be continually moving to face the sun, and some 3D tracking systems actually do that (but they are expensive). Alternatively, if a fixed solar panel is to be used, then an optimum compromise Tilt and Orientation must be devised.

Conventional wisdom has it that, in the southern hemisphere, the panel should face north and be at a tilt angle equal to the latitude ( $37^\circ$  for Marysville) in order to capture the maximum solar energy over the day across the year. This may have been best when the capture of direct solar radiation was the objective, and when the feed-in tariff was so high that the main objective was to collect and sell as much electricity to the grid as possible. However, this design is rarely optimum these days for two main reasons:

1. In addition to Direct solar energy (coming directly from the direction of the sun), there is also Diffuse solar energy, that has been scattered by clouds and dust particles, and that arrives at the solar panel from all directions. While earlier solar panels concentrated on collecting Direct solar energy, modern solar panels can collect both Direct and Diffuse solar energy.
2. While the north-facing, latitude-tilt might collect the maximum Direct solar energy over the course of the entire day (e.g. if all that energy was to be sold to the grid), households without batteries need to immediately self-consume as much of the collected solar energy before selling the remainder to the grid, because self-consumption saves the cost of buying a kWh from the grid, while selling that kWh to the grid only yields a much lower feed-in tariff. If the householders are not at home during the day, then it might be better to collect solar energy in the morning (from an east-facing panel) and in the evening (from a west-facing panel) which they can consume immediately.

The extent of deviation from a north-facing, latitude-tilt panel will depend on the proportion of Diffuse solar energy that might be collected, and also the consumption Load Profile of the consumers across the day. Although a 3D tracking system might be advantageous for a Solar Farm wishing to capture as much solar energy as possible (for storage and eventual sale), this study assumes a fixed orientation and tilt for the solar panels.

### ***The number and size of panels installed***

The number of solar panels to be installed will generally depend on four factors:

- The available area for the panels
- The available budget
- Any limitations imposed by regulatory authorities
- The marginal economic benefit of installing additional panels

While area available for panels may sometimes limit the number of panels that can be installed, for this feasibility study it will not be considered to be a binding constraint to the size of the Solar Farm. However, it is worth bearing in mind that 1000kW of solar panels can cover a ground area of approximately 2-3 ha.

Similarly, the available budget is something that must be considered later, after seeing the results of the analysis to follow, and considering the available funding sources.

The first major regulatory limitation for a Solar Farm would be 100kW capacity, after which special permissions need to be obtained. It is clear from preliminary estimates that the VMG Solar Farm will likely be well over that 100kW limit. Careful technical design will therefore be required to ensure that the Solar Farm does not overload the network. It will be assumed that such technical challenges can be overcome to provide the required Solar Farm size.

The marginal economic benefit will be the focus of the economic evaluation described later in an Addendum to this report, and will determine if less than the allowable number of panels should be installed.

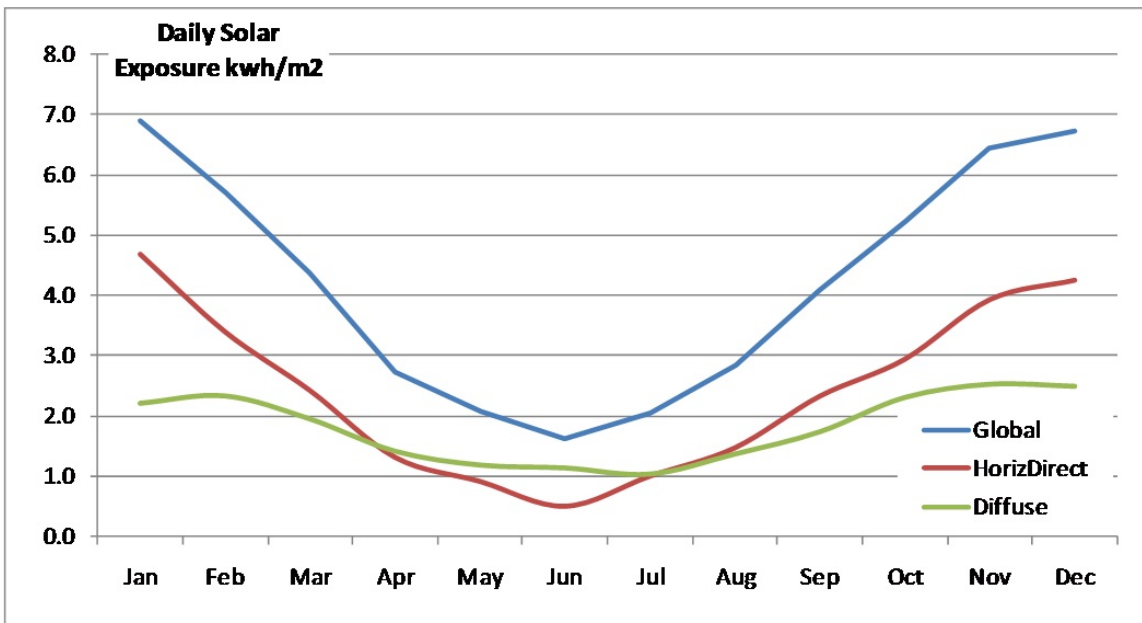
### ***The type of solar panel installed***

It is assumed that the panels to be installed will collect both Direct and Diffuse solar energy. This decision is based on the fact that Marysville is in a temperate mountainous area, where winter energy consumption predominates, and that Diffuse solar energy is more likely in winter. Therefore, having solar panels that can collect this type of solar energy when it is most needed is important.

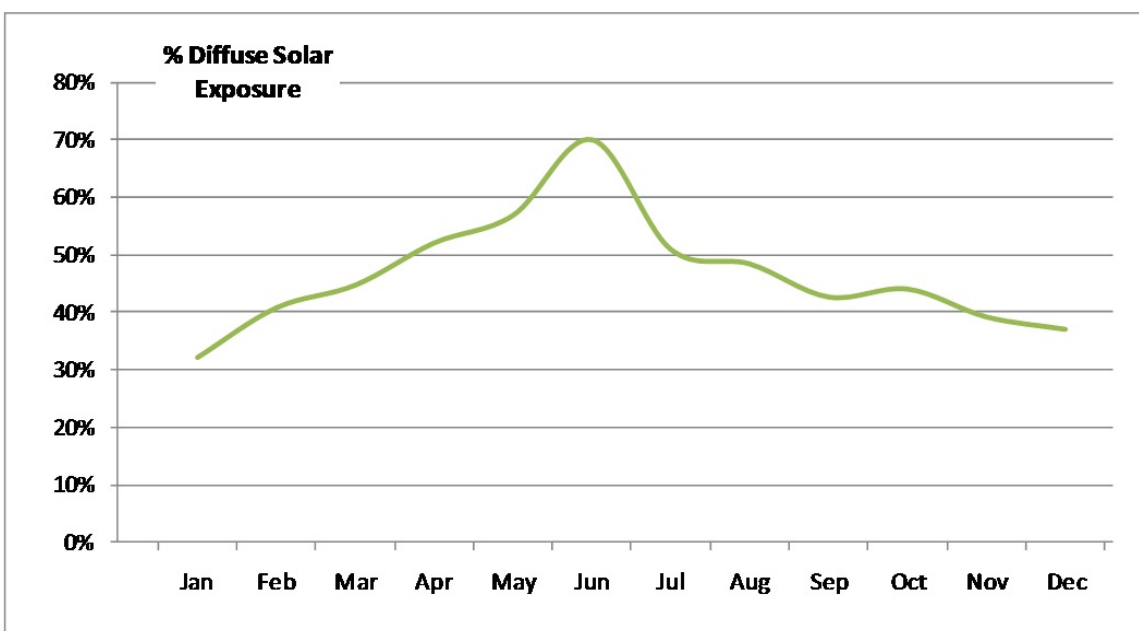
As will be seen later, considerable use is made of historic solar exposure data collected by the Bureau of Meteorology (BOM). Most of the available BOM solar exposure data is in the form of average daily solar exposure (which was used to scale the modelled solar exposure to match the actual solar exposure for each day of 2017 - when the original SEPAC modelling was performed). However, BOM also provides a data service containing minute-by-minute solar exposure data, which contain Diffuse as well as Direct solar exposure data. This data set has two major advantages:

1. The inclusion of separate measurements of Direct and Diffuse solar exposure allows a better calculation of optimum Tilt and Orientation of the solar panel.
2. The minute-by-minute solar exposure data enables a more realistic solar exposure profile over the course of the day, enabling it to be matched to the half-hourly electricity purchases and sales provided by AusNet in their NMI files, thereby enabling more accurate estimates to be made of solar power excesses (for sale to the VMG or the Grid) and solar power deficits (requiring purchases from the VMG or the Grid). Unfortunately, BOM have delayed updating of the minute-by-minute data for 2020 onwards, and so some work-around procedures will be adopted in this study.

An analysis of one complete year (2014) of this one-minute solar exposure data allows many interesting findings to be revealed. Figure 5.3 shows the amount of solar exposure by type by month of the year, while Figure 5.4 shows the percentage of solar exposure that is Diffuse, by month of the year.



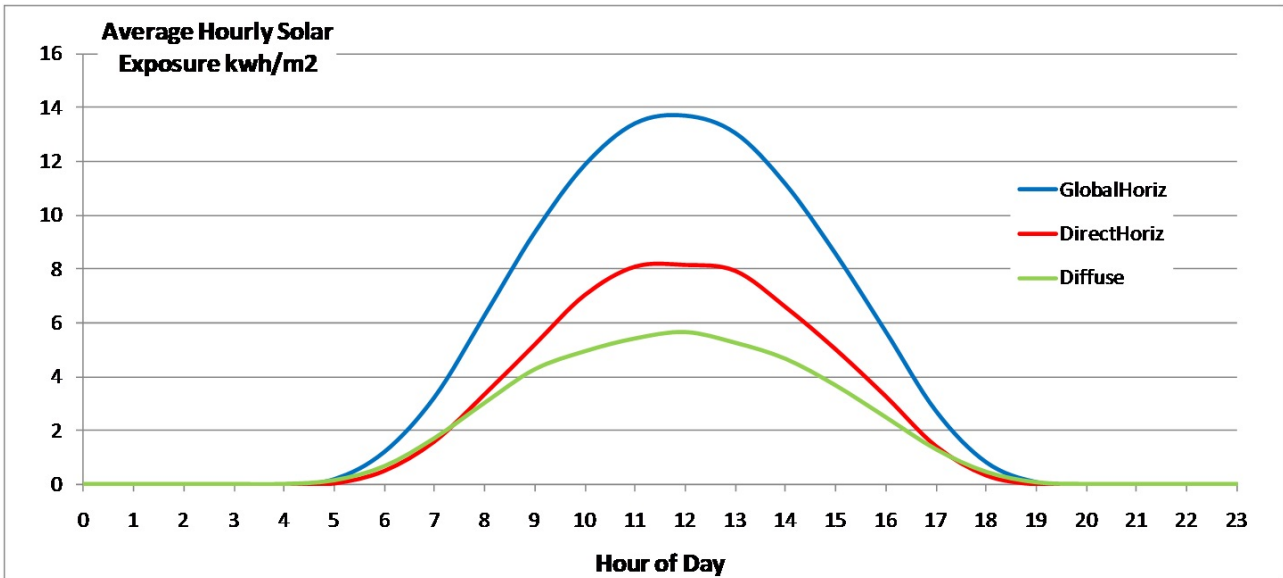
**Figure 5.3 Solar Exposure by Type by Month of Year**



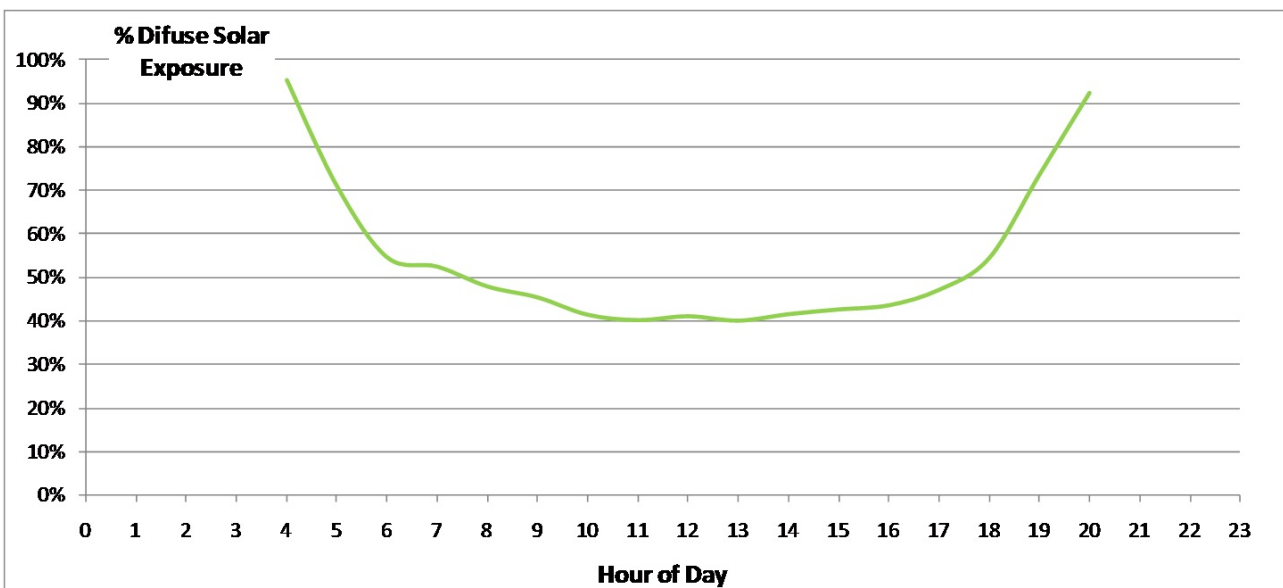
**Figure 5.4 % Diffuse Solar Exposure by Month of Year**

Figure 5.3 shows, as expected, that solar exposure is highest during summer months and lowest during winter months. While this is true for both Direct and Diffuse solar exposure, the extent of the variation differs. Diffuse solar exposure is less susceptible to seasonal variation, and indeed during the winter months Diffuse solar exposure is higher than Direct solar exposure, rising to 70% of Global solar exposure as shown in Figure 5.4.

Direct and Diffuse solar exposure also vary across the hours of the day, as shown in Figures 5.5 and 5.6. The average hourly values for Direct, Diffuse and Global exposure (on a horizontal surface) are shown in Figure 5.5. As expected, the exposures peak during the middle of the day, with Direct exposure higher than Diffuse exposure during the middle of the day, and about the same at the start and end of the day, as shown in Figure 5.6.



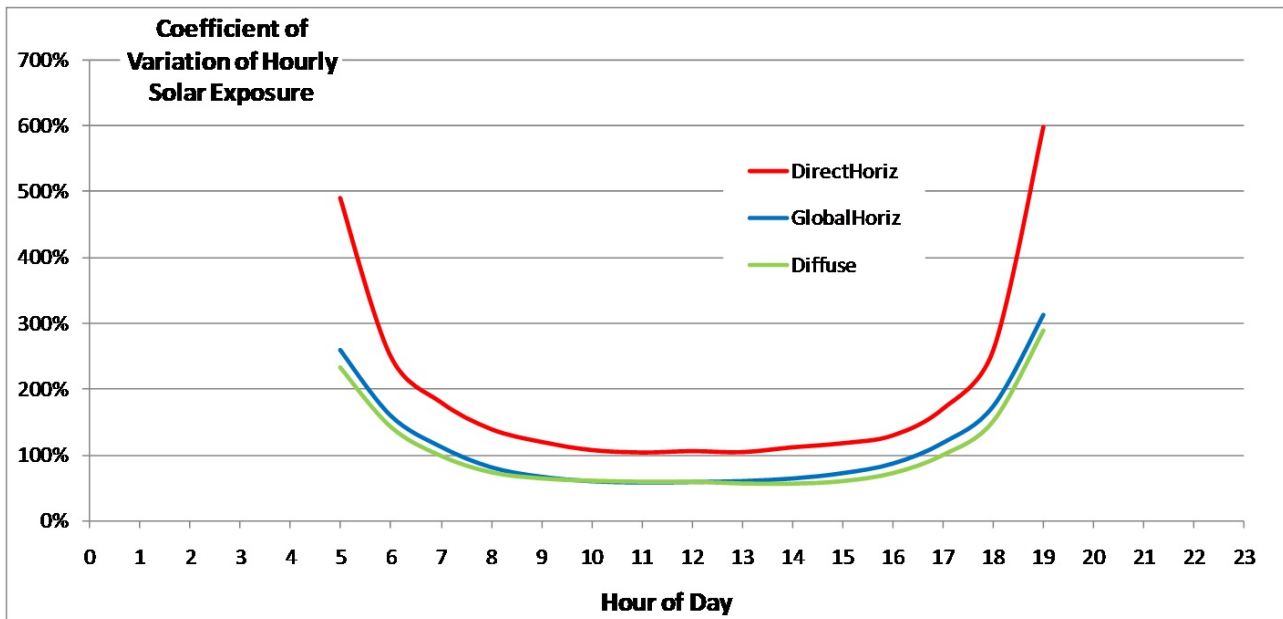
**Figure 5.5 Hourly Solar Exposure by Hour of Day**



**Figure 5.6 % Difuse Solar Exposure by Hour of Day**

The variations across the day shown in Figures 5.5 and 5.6 look very orderly, suggesting that the changes in solar radiation across any given day would be gradual and predictable. However, the values given in Figures 5.5 and 5.6 are average annual values, which hide a lot of variation between and within days. Figure 5.7 gives one indication of the extent of such hourly variation, with the Coefficient of Variation (= Standard Deviation/Mean) of the hourly values across

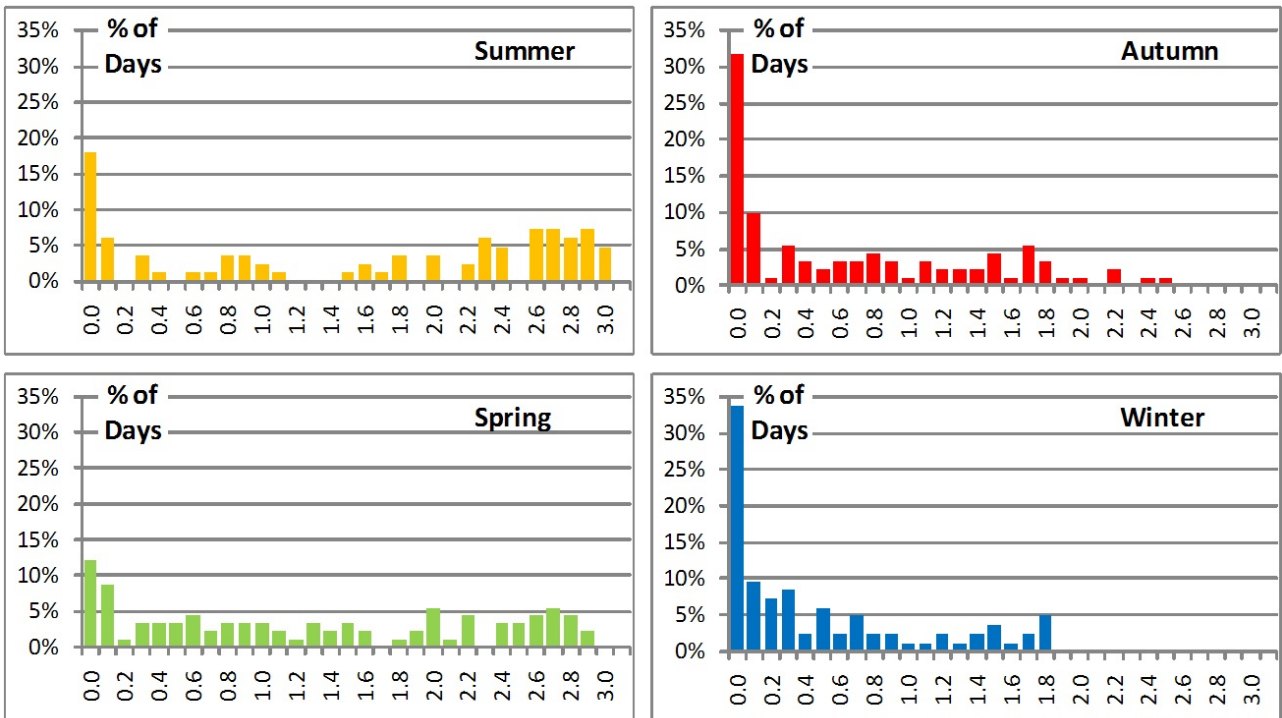
all 365 days of the year. It can be seen that the Direct Horizontal Exposure (i.e. the Direct solar exposure from the sun, landing on a Horizontal surface) has about twice the amount of variability as the Diffuse exposure (landing on a Horizontal surface) at any time of the day.



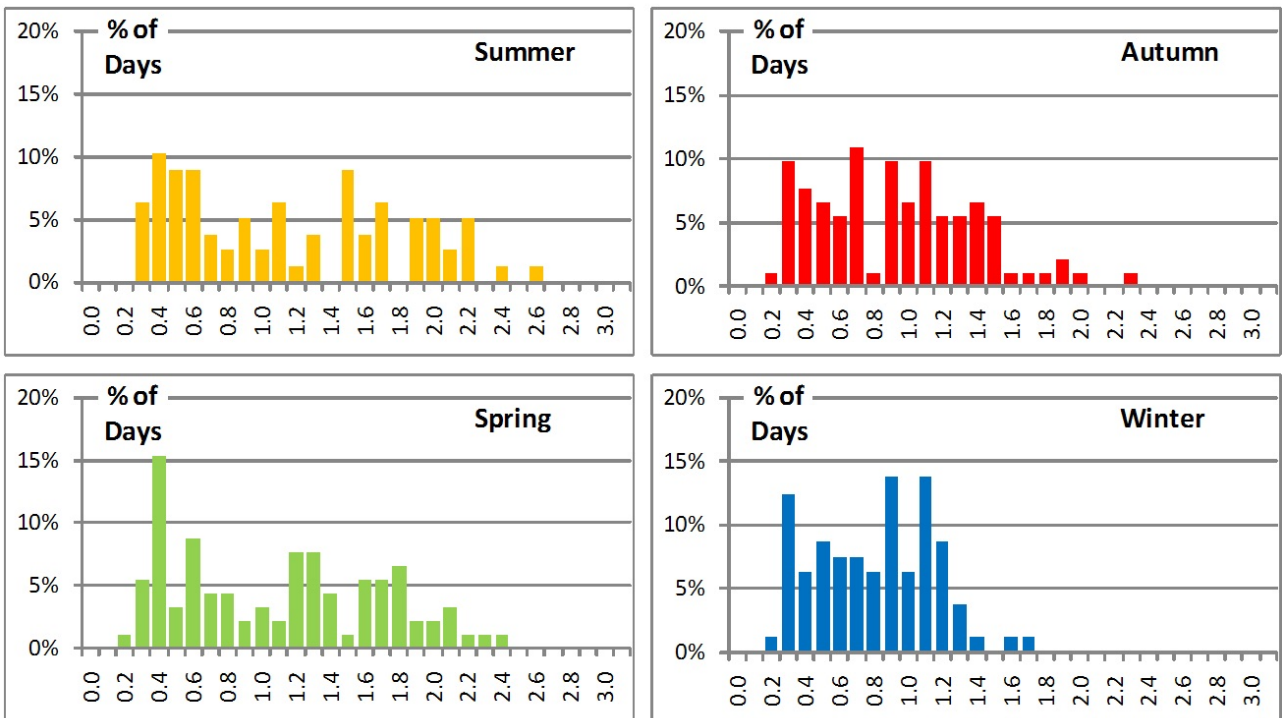
**Figure 5.7 Variability of Solar Exposure by Hour of Day**

Another way of looking at the variability is to compare each day's exposure at that hour of the day with the annual average exposure for that same hour, via the ratio of a specific day's noon exposure to the average exposure at noon for that season. This is shown in Figure 5.8 for Direct Horizontal Exposure, and in Figure 5.9 for Diffuse Exposure, for Solar Exposure between noon and 1pm for each of the four seasons. In Figure 5.8, it can be seen that Summer and Spring have similar distributions, ranging from zero Direct Horizontal Exposure up to 3.0 times the mean. Autumn and Winter, on the other hand rarely go above 1.8 times the mean and have a much higher proportion of zero exposure days. What this means is that in Autumn and Winter there are over 30% of days with no Direct Horizontal Exposure at noon (the peak solar period) because of heavy cloud cover. Even in Summer, there are 18% of days with no Direct Horizontal Exposure at noon, while in Spring the figure is 12%.

Figure 5.9 shows that the variability of the Diffuse Solar Exposure is much less, with a more compact distribution. There are no days in any season with zero Diffuse Exposure at noon, with the minimum values across the seasons of effectively 30% of the mean. Summer and Spring again have longer tails to their distributions with values up to about 250% of the mean, while Autumn and Winter top out at about twice the mean.



**Figure 5.8 Ratio of Noon DirectHoriz Exposure to Average Noon DirectHoriz Exposure**



**Figure 5.9 Ratio of Noon Diffuse Exposure to Average Noon Diffuse Exposure**

What the above discussion of variability means for Solar Farm design is that even in the middle of the day, when solar capture is expected to be at a maximum, there can be many days when solar capture (especially Direct solar energy) is zero or very low. In that case, it may be necessary to buy electricity from the grid (perhaps at peak rates), or to draw power from batteries, to

service consumption demands at that time of day. Such variability in solar capture and demand must therefore be taken into account in the design of the overall Solar Farm system, especially the inclusion of a big battery to store energy for overnight and overcast conditions.

All of the above discussion has been on the basis of solar energy landing on a Horizontal surface (effectively a solar panel lying flat). However, most solar panels will not lie flat, but will be raised at an angle (the Tilt) and pointed in a specific direction (the Orientation). Direct solar energy is most effectively captured when the solar panel is pointed towards the sun (i.e. at right angles to the sun). Diffuse solar energy however is most effectively captured when the solar panel is actually lying flat (because diffuse solar energy is incoming from all directions); raising the panel at an angle will reduce Diffuse energy collection from that part of the sky that is now “behind” the solar panel. Given that Direct and Diffuse solar energy are both substantial components of total solar energy at all times of the year and day (see Figures 5.4 and 5.6), it therefore appears that there must be a compromise Tilt and Orientation to maximise the collection of Global solar energy on an inclined surface.

To find the optimal Tilt and Orientation, the SEPAC model was run with the Direct Horizontal and Diffuse solar capture figures from above, being intercepted by a solar panel at a range of Tilts and Orientations. The results of these experiments, showing solar exposure on the 1m<sup>2</sup> panel, are shown in Tables 5.1 and 5.2 below. It can be seen in Table 5.1 that the optimal Tilt (for a north-facing panel) is lower in the warmer months and higher in the cooler months (as shown by the numbers highlighted in green). Across the year, the optimal Tilt is 15°, but there is relatively little difference between 10° and 20°. Given that the panels for the Solar Farm can be installed at virtually any Tilt (because they are on a ground frame), it has been assumed that the panels will be installed at a fixed Tilt of 15°.

Using a Tilt of 15°, the Orientation was then varied from due West to due East, as shown in Table 5.2. The optimal Orientation during the warmer months is North-East, while the optimal Orientation during the cooler months is due North. Over the entire year, the optimal Orientation is North-East. However, given that winter solar energy capture is likely to be more important for Marysville, the chosen orientation is due North.

Table 5.1 Daily Global Solar Capture (kWh/m<sup>2</sup>) with Varying Tilt (and north-facing)

Month	Tilt (with north orientation)															
	0	5	10	15	20	25	30	35	40	45	50	55	60	65	70	75
Jan	7.08	7.12	7.11	7.04	6.93	6.77	6.56	6.30	5.99	5.64	5.25	4.81	4.35	3.85	3.33	2.79
Feb	5.51	5.58	5.62	5.62	5.58	5.49	5.37	5.20	4.99	4.75	4.47	4.15	3.81	3.43	3.03	2.61
Mar	4.84	4.94	5.00	5.03	5.01	4.96	4.87	4.75	4.58	4.39	4.16	3.90	3.60	3.28	2.94	2.57
Apr	3.18	3.26	3.32	3.35	3.36	3.34	3.29	3.23	3.13	3.01	2.87	2.71	2.53	2.33	2.11	1.87
May	2.35	2.45	2.54	2.62	2.67	2.70	2.72	2.71	2.68	2.63	2.56	2.47	2.36	2.24	2.10	1.94
Jun	2.02	2.12	2.20	2.27	2.32	2.35	2.36	2.36	2.34	2.30	2.24	2.17	2.08	1.97	1.85	1.71
Jul	1.94	2.06	2.16	2.25	2.32	2.37	2.40	2.42	2.41	2.39	2.35	2.29	2.22	2.13	2.02	1.89
Aug	2.73	2.86	2.96	3.04	3.10	3.14	3.15	3.13	3.09	3.03	2.95	2.84	2.72	2.57	2.40	2.21
Sep	3.74	3.86	3.96	4.02	4.06	4.06	4.04	3.98	3.89	3.77	3.63	3.45	3.25	3.03	2.78	2.51
Oct	5.43	5.50	5.52	5.50	5.44	5.34	5.19	5.01	4.79	4.54	4.26	3.94	3.59	3.22	2.82	2.39
Nov	6.64	6.69	6.69	6.65	6.55	6.40	6.20	5.96	5.68	5.35	4.99	4.59	4.15	3.69	3.19	2.67
Dec	7.51	7.53	7.51	7.43	7.29	7.10	6.86	6.58	6.24	5.86	5.44	4.97	4.47	3.95	3.40	2.83
AVE	4.41	4.50	4.55	4.57	4.55	4.50	4.42	4.30	4.15	3.97	3.76	3.53	3.26	2.97	2.66	2.33

Table 5.2 Daily Global Solar Capture (kWh/m<sup>2</sup>) with Varying Orientation (& 15° Tilt)

Month	Orientation (with 15 degrees tilt)				
	W	NW	N	NE	E
Jan	6.71	6.90	7.04	7.12	7.05
Feb	5.21	5.45	5.62	5.85	5.86
Mar	4.69	4.92	5.03	4.95	4.72
Apr	2.99	3.20	3.35	3.36	3.21
May	2.50	2.59	2.62	2.58	2.36
Jun	1.91	2.12	2.27	2.22	2.02
Jul	1.82	2.08	2.25	2.20	1.96
Aug	2.57	2.85	3.04	3.04	2.81
Sep	3.49	3.80	4.02	4.21	4.07
Oct	5.17	5.37	5.50	5.52	5.39
Nov	6.48	6.62	6.65	6.63	6.59
Dec	7.28	7.40	7.43	7.62	8.07
AVE	4.23	4.44	4.57	4.61	4.51

## 5.2 Augmentation of VMG with Solar Farm and Battery

Given the parameters described above, the SEPAC Solar Energy Capture model was run using the Minute-by-Minute Solar Irradiance data for 2017 (aggregated to half-hour periods), for a 1kW solar panel. This then gave the solar capture on a half-hourly basis for a 1kW solar panel (which can be scaled up as required in subsequent analysis). To make these results more relevant to the current study in 2019-2021, the results for the 2017 calendar year were re-scaled to the actual daily Solar Irradiance data for 2019, 2020, and 2021, which was available from

BOM to the present time. The scaled results for July 2019 to June 2021 were then extracted as a 35088 x 1 matrix, which could then be used in conjunction with the NMI data which was in the same format. This then enabled the matching model to be run with the addition of the Solar Farm (of various sizes) and big Battery (of various sizes). In addition, the sample of 13 properties used in Stage 1 were expanded to the current situation in Marysville, where there are 349 private households (according to the ABS 2021 Community Profile, released 30 June 2022). It has been assumed that the 13 properties are representative of the 349 current dwellings (although it is realised that this is a gross assumption). No specific account has been made of businesses in Marysville, although the inclusion of the Large Scale solar property in the sample of 13 takes some recognition of this. It is assumed that 70% of Marysville dwellings will eventually have solar panels by the time that the MicroGrid might be implemented.

Given all the assumptions listed above (and elsewhere) it is clearly recognised that if this project proceeds to Stage 3 (Design and Implementation) with more significant funding, then all of the assumptions will need to be justified or replaced with more highly-researched analyses.

The Matching Simulation Model is a moderately complex spreadsheet, which incorporates the NMI data for the current Marysville population (scaled up from the sample data in Stage 1), the percentage of properties with solar panels (it is assumed that none also have batteries on-site), the size of the Solar Farm (in kW) and the size of the big Battery (in kWh capacity). It is assumed that the size of the battery is its useable capacity e.g. if the battery has a nominal capacity of 4000kWh and a maximum drawdown of 75%, then the useable capacity is 3000kWh.

An extract from the Matching Simulation Model is shown in Table 5.3 for a segment of the day on 7 March 2021, which demonstrates most of the features of the model (it is displayed sideways on the next page for easier reading; note that the model is designed for use, rather than presentation style). The yellow cells are those requiring user input (the percent of properties with Small Scale Solar, the number of Large Scale Solar properties (e.g. businesses), the size of the Solar Farm in kW, the size of the big Battery in kWh). The green cells are highlighting those entities which generate solar energy for sale to the VMG and the Grid. The extract starts at 3.00am and finishes at 8.30pm.



At 3.00am, no one is producing solar energy (unsurprisingly), but the Small Scale solar properties are buying 38kWH of electricity while the Large Scale solar properties are buying 114kWH and the Non-Solar properties are buying 62 kWH, for a total purchase of 214 kWH. Because of previous activities, the Battery Charge is effectively zero (i.e. it is down to its maximum allowable discharge), and is hence unable to meet the demands placed on it by the various properties. The entire demand (214kWH) must therefore be met by purchases from the Grid.

This situation continues until 6.30am, when the Solar Farm starts to generate its first solar electricity for the day (169kWH). In this half-hour, the total demand has fallen to 112 kWH, so this can be fully supplied from the Solar Farm, and the remaining 57kWH can be stored in the Battery (note: a positive number on the Battery Use column indicates that energy is being withdrawn from the Battery, while a negative number indicates that energy is being deposited into the Battery). No purchases were required from the Grid.

The Battery continues to be charged throughout the morning until 10.30am. At this time, the 4000 kWH Battery is almost fully charged (3598 kWH), and the total solar generation 917 kWH in that period can meet the current half-hourly demand of 69 kWH, fill the Battery to capacity with 402 kWH and sell the remaining generation to the Grid (446 kWH).

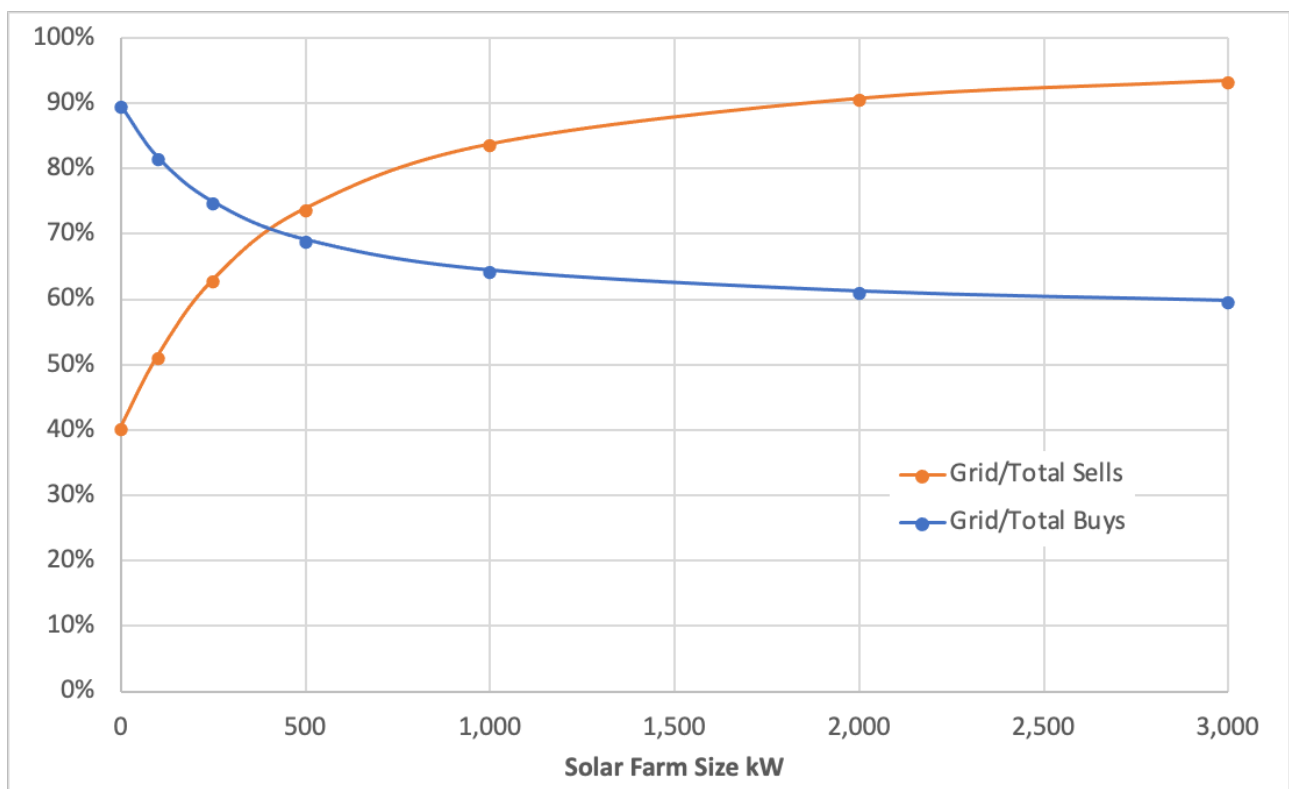
From there until 5.30pm, the Battery remains full, but in Period 35 the total demand (145 kWH) exceeds the total excess generation (99 kWH), and this deficit is met by a withdrawal of 45 kWH from the Battery. This situation continues throughout the evening as the excess generation shrinks to zero with nightfall, while the demand increases to 157 kWH. All of this evening demand is met by withdrawals from the Battery, with no Grid purchases required.

The logic of the model is not particularly complex. The complexity arises from the fact that all the matching of buying and selling must be done within half-hour periods, and often the buying and selling does not match on the timeline because of the time of day, changes in weather conditions, and intermittent surges in demand. One cannot use total buying and selling over extended periods of time (several hours, a day or a week) and hope to get a good estimate of how much electricity can be shared among VMG participants, or how much demand can be met from the Solar Farm. The use of a Battery helps to smooth out demand and supply, but even Batteries become empty and are unable to meet demand after prolonged periods of overcast weather or extended periods of high demand.

The Matching Simulation Model was used to model a variety of scenarios, involving the size of the Solar Farm, the size of the Battery and the proportion of Marysville properties with Small Solar systems. The results of these tests are shown below.

### ***Scenario 1: Increasing the Size of the Solar Farm***

The first, and simplest, scenario is to increase the size (measured in kW) of the Solar Farm, remembering that a 1000 kW Solar Farm requires 2-3 hectares of flat to rolling land with a clear northerly aspect. The results of this scenario testing are shown in Figure 5.10, with Solar Farm sizes from zero to 3000 kW.

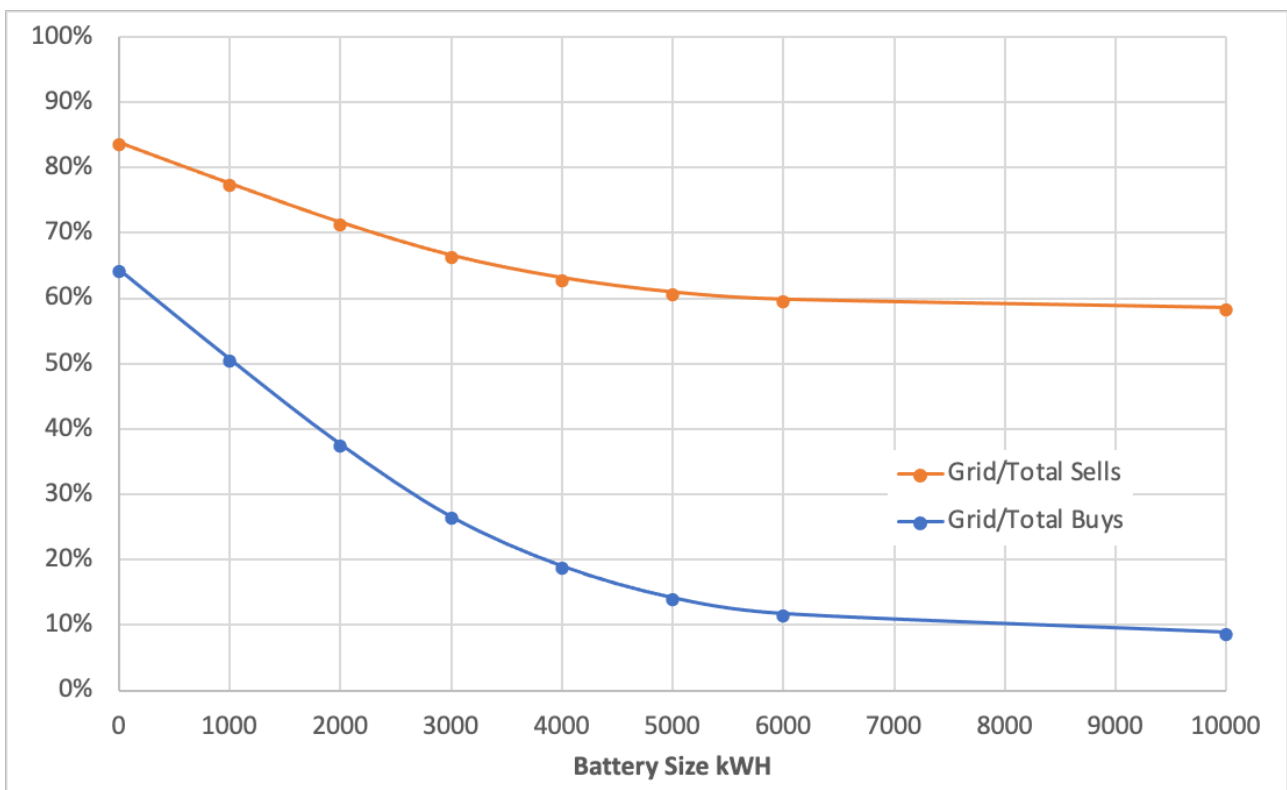


**Figure 5.10 The Effects of Increasing Solar Farm Size**

When there is no Solar Farm (i.e. size = 0 kW), 90% of electricity is bought from the Grid (and hence 10% from within the VMG). At the same time, 40% of the excess solar electricity available for sale is sold to the Grid (and hence 60% is sold within the VMG). As the size of the Solar Farm increases, the percentage bought from the grid decreases while the percentage of excess solar electricity sold to the grid increases. Most of the gains, however, are obtained from the first 1000 kW of Solar Farm; after that, the changes are marginal. However, even with large to very large Solar Farms, the percentage of electricity bought from the Grid is still over 65%, mainly because Solar Farms do not produce electricity at night or (to an extent) on overcast days.

**Scenario 2: Adding a Battery to the Solar Farm**

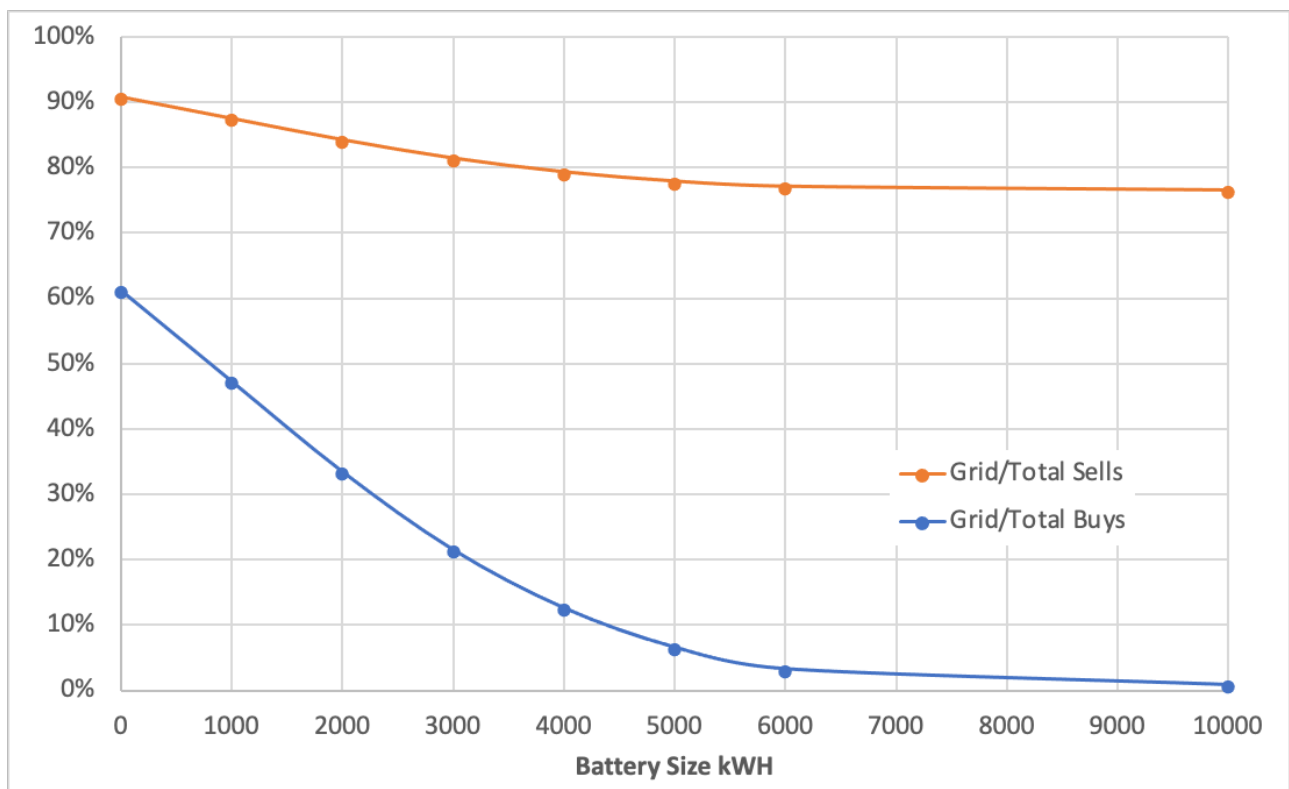
To overcome the problems with Solar Farm electricity generation at certain times of the day and year, one could add a Battery to the Solar Farm and so be able to shift the sale of solar electricity from a high generation period to a low generation period. The results of this scenario testing are shown in Figure 5.11, with Batteries of different sizes being added to a Solar Farm with a size of 1000 kW.



**Figure 5.11 The Effects of Adding Batteries to a 1000kW Solar Farm**

The most striking feature in this scenario is the substantial decrease in electricity that is bought from the Grid, falling from 65% with no Battery to less than 10% with a 10000 kWh Battery. However, once again most of the gains have been achieved with a substantially smaller battery of 5000 kWh. At the same time, the proportion of excess solar electricity sold to the Grid has decreased from 85% to 60%, because a significant proportion of this excess solar energy is now saved to a Battery and later sold within the VMG, rather than selling it to the Grid.

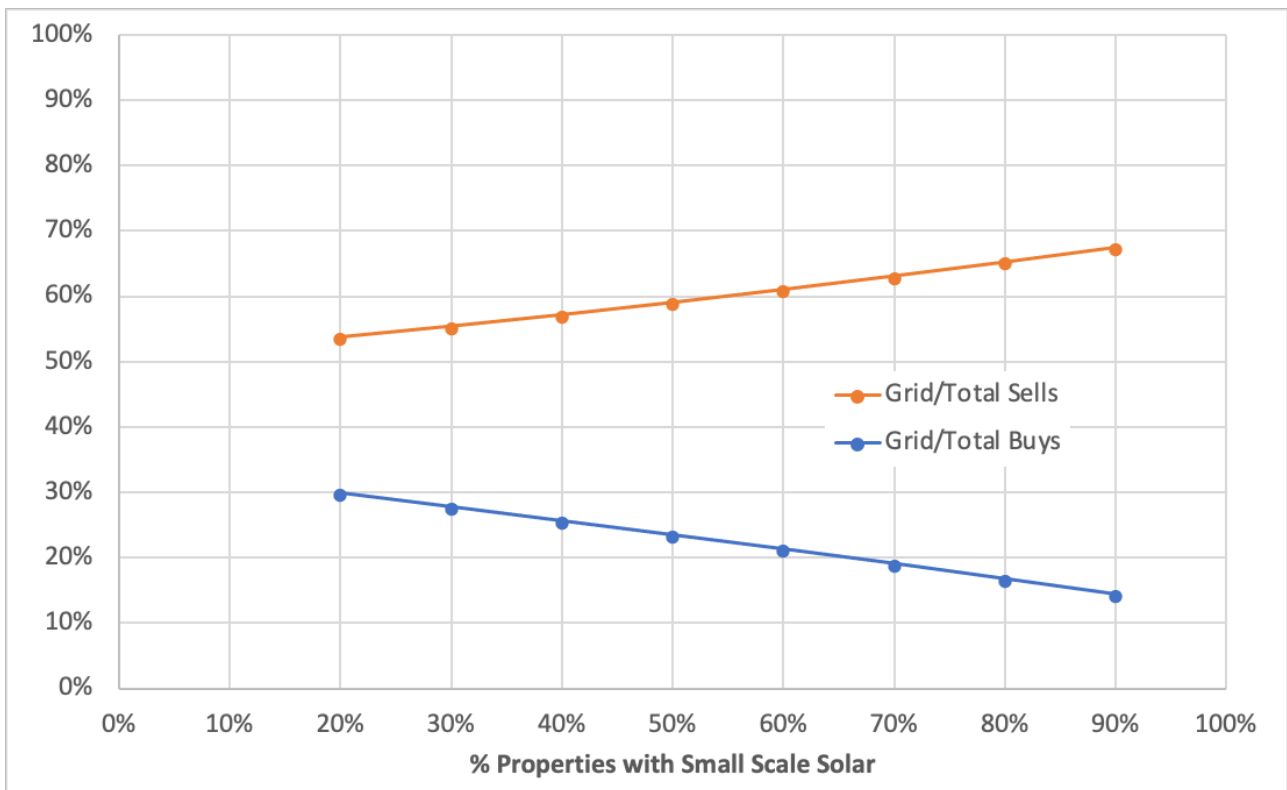
Instead of being content with achieving most of the gains with a smaller solar/ battery installation, one could go "all out" to try and achieve independence from the grid, and as shown in Figure 5.12, where it can be seen that purchases from the Grid have been reduced to virtually zero with a 3000 kW Solar Farm and a 10000 kWh Battery. While such an outcome is possible, the question remains as to whether it is worth the expenditure, or whether such an objective is achievable via alternative methods.



**Figure 5.12 The Effects of Adding Batteries to a 3000kW Solar Farm**

### Scenario 3: Varying the Penetration Rate of Small Scale Solar

The assumption was made earlier that 70% of Marysville properties would have Small Scale Solar before the possible introduction of a MicroGrid. The question remains, however, as to whether that assumption makes a significant difference to the outcomes of the scenario testing. This scenario tests a range of penetration rates and their effect on the results for a 1000 kW Solar Farm with a 4000 kWh Battery, as shown in Figure 5.13.

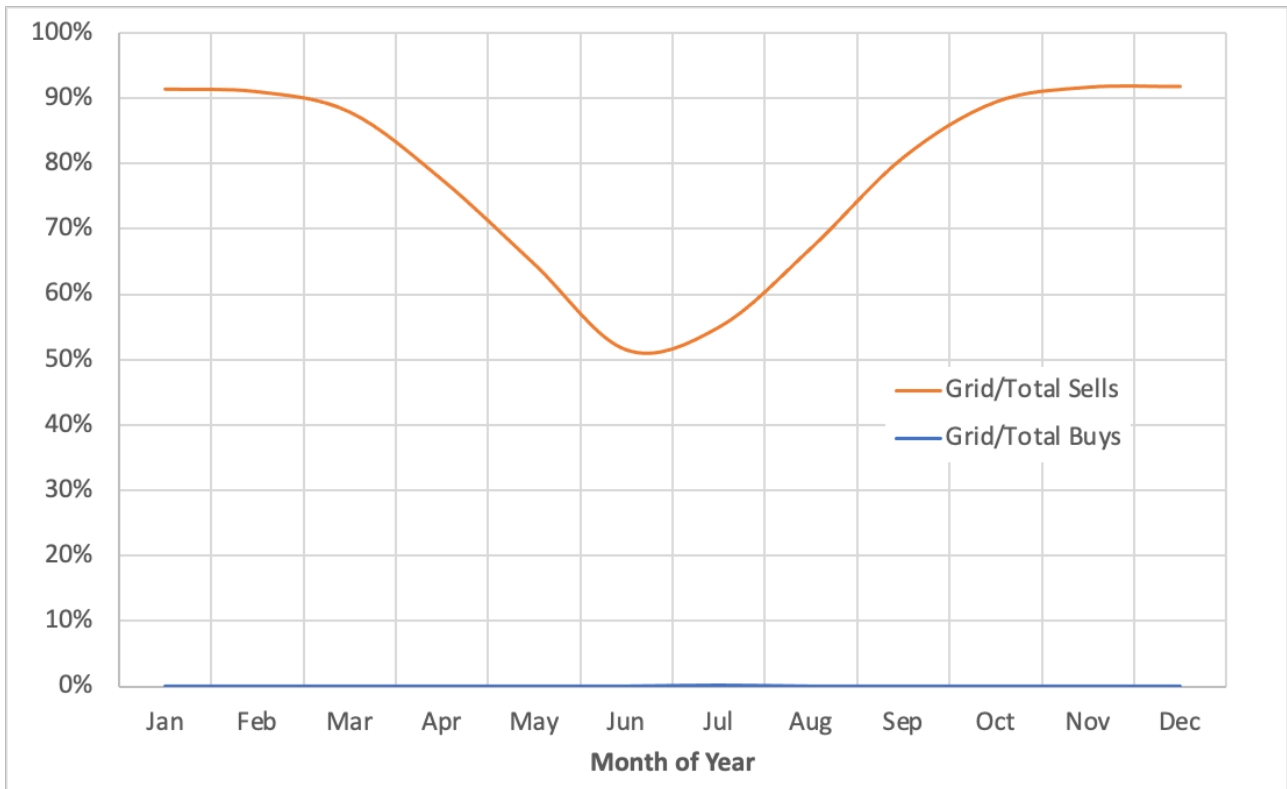


**Figure 5.13 The Effects of Different Penetration Rates for Small Scale Solar**

It can be seen that higher initial penetration rates bring about higher proportions of excess solar electricity being sold to the Grid, simply because more properties are generating solar electricity for a limited VMG market. At the same time, higher penetration rates bring about lower purchases of electricity from the Grid because the properties are now generating and consuming their own solar electricity. However, within a 20% range either side of the assumed 70%, the difference in outcomes is only +/- 5%.

### Scenario 4: Seasonal Difference in Outcomes

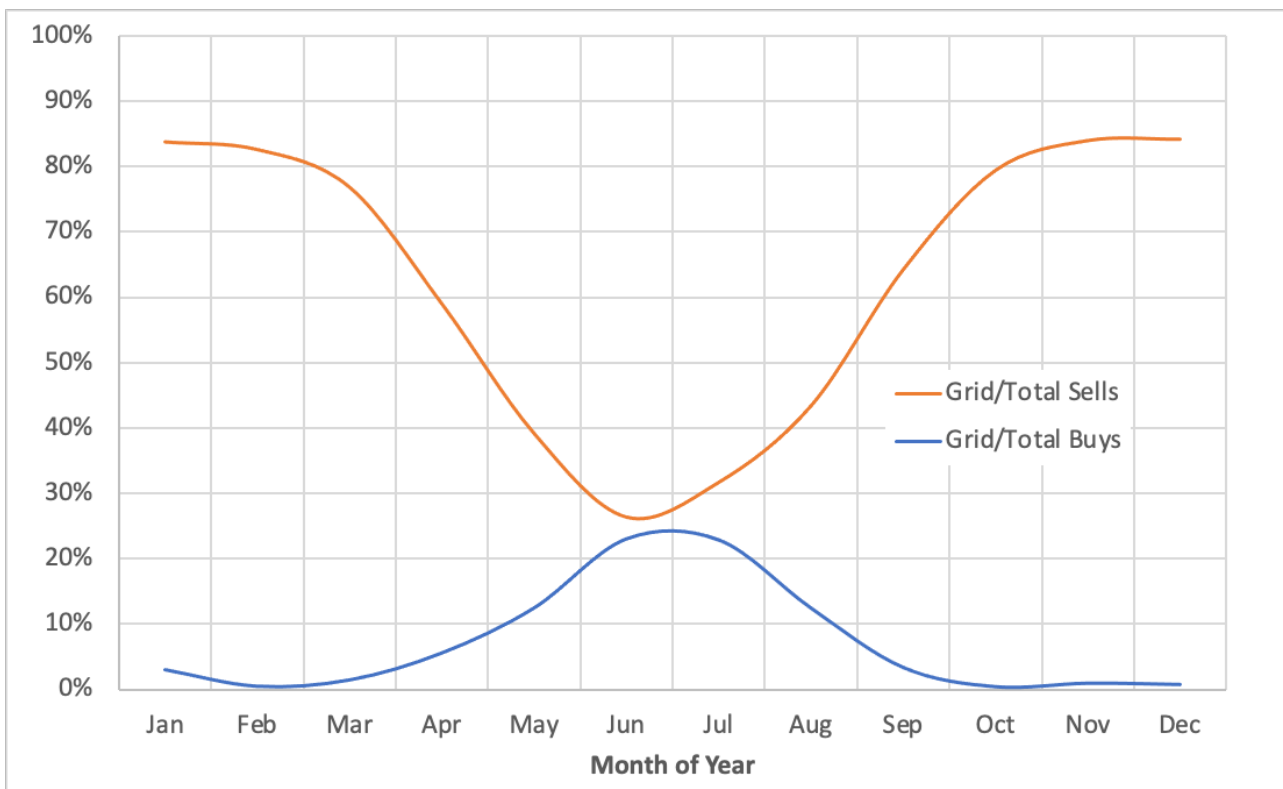
It was noted above in Scenario 2 that it would be possible to achieve zero purchases from the Grid with a sufficiently large Solar Farm (3000 kW) and Battery (10000 kWh). If one considers the outcomes for each month of the year, then they would be as shown in Figure 5.14.



**Figure 5.14 Seasonal Variations in Outcomes (3000kW, 10000kWH)**

While the percentage of excess solar electricity sold to the Grid dips during the cooler months, the percentage of electricity purchased from the Grid flatlines at zero across the entire year. While this has achieved the independence objective required for an islandable MicroGrid, is it an overkill? Could independence be achieved in another way which would still allow Marysville to be islanded?

For example, if the size of the Solar Farm was halved to 1500 kW and the size of the Battery was halved to 5000 kWh, then the seasonal variation in the outcomes would be as shown in Figure 5.15.



**Figure 5.15 Seasonal Variations in Outcomes (1500kW, 5000kWH)**

It can be seen that during the warmer months (October through March) the percentage of electricity bought from the Grid is in the range of 1% to 3%, which is still effectively independence from the Grid. During the cooler months, the percentage of electricity bought from the Grid is in the range of 5% to 25%. Two questions therefore arise. Firstly is Grid independence required for every month of the year. If not, when is islandability most required? Is it in the warmer months when the threats of bushfires are most apparent, or is it in the cooler months when floods and storms might be more frequent? A thorough investigation of the timing of power outages and emergency events over the course of many years would be required to answer such questions.

Secondly, if Grid purchases seem to be essential in the cooler months, is there any way that islandability could still be achieved (if required) during those cooler months? For example, could demand management be employed when islanding is required, such that the demand for electricity could be reduced to only what could be provided from internal sources when islanded? Alternatively, could other creators of electricity be employed (such as biofuel generators) as a substitute for the Grid electricity during these islanding events?

## 6. Conclusions

This study has considered the feasibility of an islandable Microgrid for the town of Marysville. Stage 1 of the project looked at the electricity purchase and sale records of a sample of 13 residents via their NMI data obtained from Ausnet Services. This examination showed that power sharing was possible, and demonstrated the important role that non-solar properties could play in such a Microgrid. Importantly the electricity network configuration for Marysville is conducive to creation of an islandable MicroGrid.

However, to be islandable, the township must be able to produce and deploy sufficient electricity within its own boundaries such that it can become effectively independent from the Main Electricity Grid. For this reason, Stage 2 of the project examined augmentation of the power generation ability of the residents by the inclusion of a Solar Farm and Battery in the town's power generation capabilities.

It was shown that it would be possible to achieve Grid independence by the installation of a suitably sized solar array and battery. However, the question remained as to whether the cost of such an installation was justified by the outcomes.

As in many studies, every answer found raises more questions, and this study was no different. Within the time and budget constraints of the study, not all questions could be addressed. Among the most important questions still to be addressed are:

- What are the economic costs and benefits of such a proposal? (this question will be addressed in an Addendum to this report)
- What are situations which would most demand islanding of the MicroGrid?
- What is the value of a reduction in power outages to residents and businesses in Marysville?
- Are there alternative ways of achieving the objectives of an islanded Microgrid?
- Should electricity trading within a MicroGrid be encouraged by special tariffs which provide MicroGrid buyers and sellers with better prices than when trading with the Grid?
- What are the technical issues that need to be resolved when establishing an islandable Microgrid?