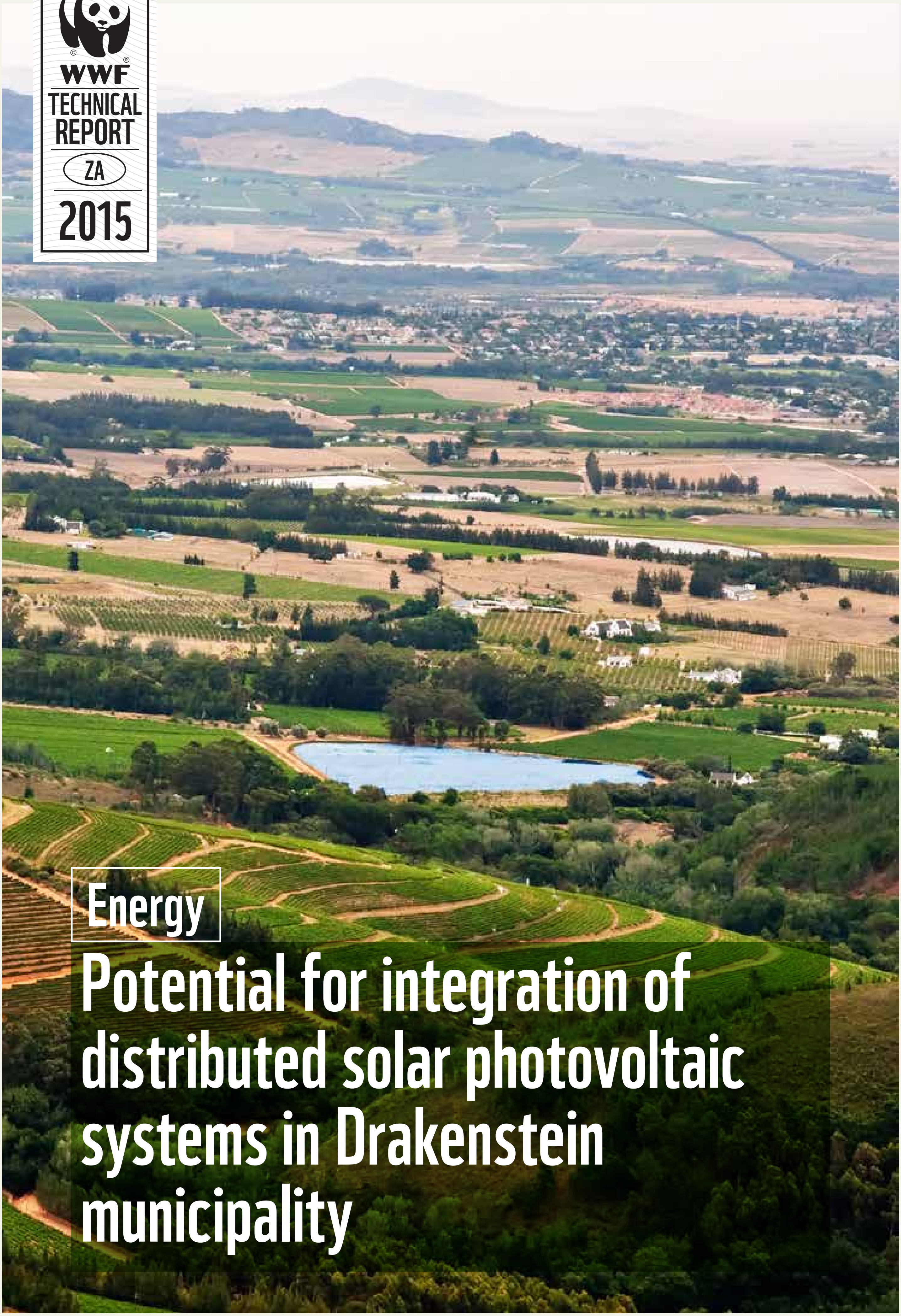
WWF
TECHNICAL REPORT
ZA
2015



Energy

Potential for integration of distributed solar photovoltaic systems in Drakenstein municipality

EXECUTIVE SUMMARY

Using Drakenstein Municipality as a case study, this report analyses the potential impacts of the installation of roof top PV by residential and industrial users on the municipal revenue generated by electricity sales. Secondly, the report investigates the potential for Municipalities to play a more pro-active role in rolling out of distributed energy to address electricity constraints and generate income. This is done through an analysis of three municipal buildings to determine their suitability for rooftop PV followed by a pre-feasibility report (both technical and financial) in respect of the optimal building selected.

The overall analysis of solar potential of the area shows that a typical site within the Drakenstein Municipality has a fair solar resource and PV yield. If a PV array is installed within the municipal area, orientated to the north and inclined at an optimised angle of 29°, a performance ratio of approximately 77% is achieved. The high temperature in the summer months reduces the efficiency of the PV panels and the presence of Paarl Mountain limits the late afternoon generation capacity. However, in comparison to other sites in South Africa, a typical site in the area of focus has a good solar yield.

Using available data from two case studies, one residential and one industrial user, together with an additional analysis, the maximum amount of PV that can be installed in the Drakenstein municipal district before grid studies are needed is quantified. The electricity generated from this calculated installed PV capacity is compared with the load profiles at the substations, where load data was available, to evaluate the impact of such PV installations. A conservative approach based on the electricity load profiles at substation level, indicates that just over 24 MW_p of distributed solar PV could easily be installed in Drakenstein without causing grid instability.

The impact that the installation of 24 MW_p of rooftop PV installations will have on the revenue of Drakenstein municipality will depend on the type of customer installing the rooftop PV as well as the tariff structure that the customers were on before and are on after the installations.

The absolute worst case scenario - when all the customers installing PV are billed on a residential tariff and do not switch to the new SSEG tariff – translates into a net potential loss to the municipality of R 24 million for the 2014/2015 financial year, should these systems have already been installed. This is less than 3% of electricity revenue to Drakenstein. It needs to be pointed out that this high penetration of rooftop PV is highly unlikely in the short and medium term.

After an analysis of three possible municipal sites, the study concludes with a prefeasibility analysis to determine the economic viability of a PV installation on the roof of municipal owned building at 1 Market Street, Paarl. The available solar resources are evaluated, the potential electricity generated and the financial projections for the site are modelled.

In this PV installation pre-feasibility study, a 25 kW_p and a 50 kW_p system are proposed and through financial assessments carried out. The most feasible case found is the 25 kW_p system, where the building remains on the Bulk Time of Use

Medium Voltage tariff. For the 50% grant funded case an IRR of 8.35% is seen, a payback period of 13 years and LCOE of R 1.49. Less savings are seen by the building owners if the building moves over to the proposed embedded generation tariff after the installation of PV on the building's roof top.

It is clear from this study, that potential impact of private PV installation on the municipal income generated from electricity sales will probably have less of an impact than commonly believed in the short term. However, a breakthrough in the costs and practicality of battery storage technology could be a leap enabler, leading to a large scale increase in self-sufficient off-grid consumers. Municipalities will have no choice but to relook their present role of energy distribution in the value chain and develop new business models for local energy systems. The focus of this study was self-generation using PV panels to address energy security and generate revenue, but there are other options that municipalities can explore.

ACKNOWLEDGEMENTS

The authors are grateful to WWF-SA for the financial support provided to undertake this research as well as for inputs provided on the contents of the report.

We also thank the Drakenstein Municipality, and in particular the Manager: Infrastructure, Deon Louw, and the Manager: Electricity, Willie Albertyn, who gave their time and expertise to make this study possible.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF ABBREVIATIONS

AC	Alternating Current
BoS	Balance of System
BoQ	Bill of Quantity
CRSES	Centre for Renewable and Sustainable Energy Studies
CSP	Concentrated Solar Power
DC	Direct Current
DNI	Direct Normal Irradiation
DoE	Department of Energy
EPC	Engineering, Procurement and Construction
EG	Embedded Generation
GHI	Global Horizontal Irradiation
GTI	Global Tilt Irradiation
GW	Gigawatt
GWh	Gigawatt hour
HV	High Voltage
kW	Kilowatt
LCOE	Levelised Cost of Electricity
kWh	Kilowatt hour
kW_p	Kilowatt peak
LV	Low Voltage
MPPT	Maximum Power Point Tracking
MV	Medium Voltage
MW	Megawatt
MWh	Megawatt hour
MW_p	Megawatt peak
MYPD	Multi-Year Price Determination
NERSA	National Energy Regulator of South Africa
NMD	Notified Maximum Demand
O&M	Operation and Maintenance
PPA	Power Purchase Agreement
PR	Performance Ratio
PV	Photovoltaic
RE	Renewable Energy
REIPPPP	Renewable Energy Independent Power Producers Procurement Programme
STC	Standard Testing Conditions
VAT	Value Added Tax
WWF-SA	World Wide Fund for Nature South Africa

INTRODUCTION

The utility scale renewable energy market has achieved much success in the South African energy market and is making a notable difference within the energy mix of South Africa. However, on a much smaller scale, distributed embedded generation such as rooftop PV can also help relieve some of the pressure on the constrained electricity grid. However, in the municipal context, the challenges experienced to manage the uptake embedded RE generation as new plants become operational, and micro or distributed grids emerge, the role of the managing municipality and service requirements of consumers at source needs to be addressed.

Electricity revenue and municipal financial survival are often closely linked in South African municipalities operating as electricity distributors in that surplus electricity revenue is fed into municipal coffers, subsidising a range of other municipal services. In addition, revenue from 'high-end' users (larger residential and other consumers) is routinely used to cross subsidise 'losses' from providing power to poor households which are not fully covered by the national Equitable Share grant[1].

The threat of revenue loss linked to reduced sales from energy efficiency and solar water heating programmes has often resulted in resistance by municipal electricity departments to such initiatives. However, today it is widely accepted that such changes are inevitable, as increasing numbers of consumers are installing electricity saving technologies and even generating their own electricity in response to the high electricity prices and increasing availability of cheaper alternatives (e.g. solar PV).

Although municipalities realise the climate change mitigation potential from renewable energy, they often see private installations as a threat to their revenue from electricity sales, have concerns about electricity supply quality and safety, and fear the possibility of the increased administrative burden[2]. Drakenstein Municipality is no different. Increasingly, it is losing revenue from high-end and/or large consumers that are investing in renewable energy technologies. These customers are key revenue generators for the municipality and important for enabling cross-subsidisation of the ever increasing proportions of poor households.

Existing research[3] shows that municipalities can protect the financial viability of their electricity supply operations by ensuring that the cost of network connectivity of each customer is recovered, even when PV zeroes the net energy consumption, and that the cost at which energy is bought from a PV exporter is no more than the equivalent cost paid by the municipality to Eskom. Drakenstein have taken cognizance of this, but is of the opinion that their future strategy should be more proactive and that they should investigate the potential of a micro and or distributed grid to enable them to also generate their own electricity and on-selling to their consumers. Pursuing such a strategy would not only address decreasing revenue, energy security and climate change, but might also speak to the grid challenges.

---

1 Janish. A. & Others. 2014. The potential impact of efficiency measured and distributed generation on municipal electricity revenue: Doublye whammies and death Spirals.Available at: http://www.cityenergy.org.za/uploads/resource_23.pdf [accessed on 8/92014]

2 http://www.crses.sun.ac.za/files/services/events/forums/services_events_forum_kritzinger(2).pdf

3 CRSES study

The report is divided in three parts. Part A of the report presents two case studies of current instances of installed private PV systems within the Drakenstein municipality. The case studies examine both an industrial and residential case. Extrapolating from these cases, an analysis is carried out to determine the effects the maximum installable amount of PV, before grid studies need to be carried out, will have on the load profiles of the substations in Drakenstein municipality. Typical summer and winter days are examined in detail.

Making use of the results of Part A, Part B indicates the impact that these installations will have on municipal revenue. The monthly electricity usage profiles for electricity users in Drakenstein is then analysed and the financial impact on the municipality is calculated.

Part C of the report identifies opportunities for the municipality to install solar photovoltaic technologies on municipal owned buildings and/or municipal land, based on generic data. The three municipal sites identified are (see Figure 1) the electricity building (1 Jan Van Riebeeck Drive), the Civic Centre (Bergriver Boulevard) and the Civil Engineering building (1 Market Street).

In Part D, a full prefeasibility study is conducted on the 1 Market Street building to determine the viability of installing solar PV. This site was identified in consultation with Drakenstein municipality.

Figure 1: **The location of the three analysed buildings in the PV Opportunities Report**

BACKGROUND

Location

Drakenstein Municipality is a local municipality located within the Cape Winelands District Municipality, in the Western Cape province of South Africa. The municipality covers a total area of 1,538 square kilometres in the valley of the Berg River. It stretches about 75 kilometres from Saron in the north to beyond Paarl in the south. The neighbouring municipalities are the Witzenberg Municipality and Breede Valley Municipality to the east, the Stellenbosch Municipality to the south, the City of Cape Town and the Swartland Municipality to the west, and the Bergrivier Municipality to the north. According to the 2011 census Drakenstein municipality has a population of 251,262 people in 59,774 households.

The principal town and location of the municipal headquarters is Paarl, situated in the south of the municipality, which as of 2011 has a population of 112,045 people. Paarl is the southernmost part of a continuous built-up area along the Berg River which also includes Mbekweni (pop. 30,875) and Wellington (pop. 55,543). In the northern part of the municipality are the smaller towns of Gouda (pop. 3,441) and Saron (pop. 7,843).

The town of Paarl is located at the coordinates of -33.724° S; 18.956° E. Figure 2 shows that the town is located in a valley with Paarl Mountain to the west and Haweqwa mountain range to the east.

Figure 2: **Satellite view of Paarl Town from Google Earth**

Solar PV Production Potential

The solar resource for Paarl town is examined. PV panel power production is directly proportional to the solar irradiance (solar energy) incident on the panel surface. For the suggested type of PV plant, the irradiation component of interest in assessing the solar resource is the Global Tilt Irradiation (GTI). Considering the solar resource and the optimally mounted angle for PV panels at each location, which maximises energy generation, a PV output map can be generated for South Africa, Figure 3.

PV systems' production potential is measured as the amount of electricity (kWh) that can be produced during a year, for the peak amount of PV power installed (kW_p) on the same area. The units for PV production potential (specific yield) are kWh/kW_p per year.

Figure 3: **PV output map for South Africa, measured in annual kWh production per kW_p installed**

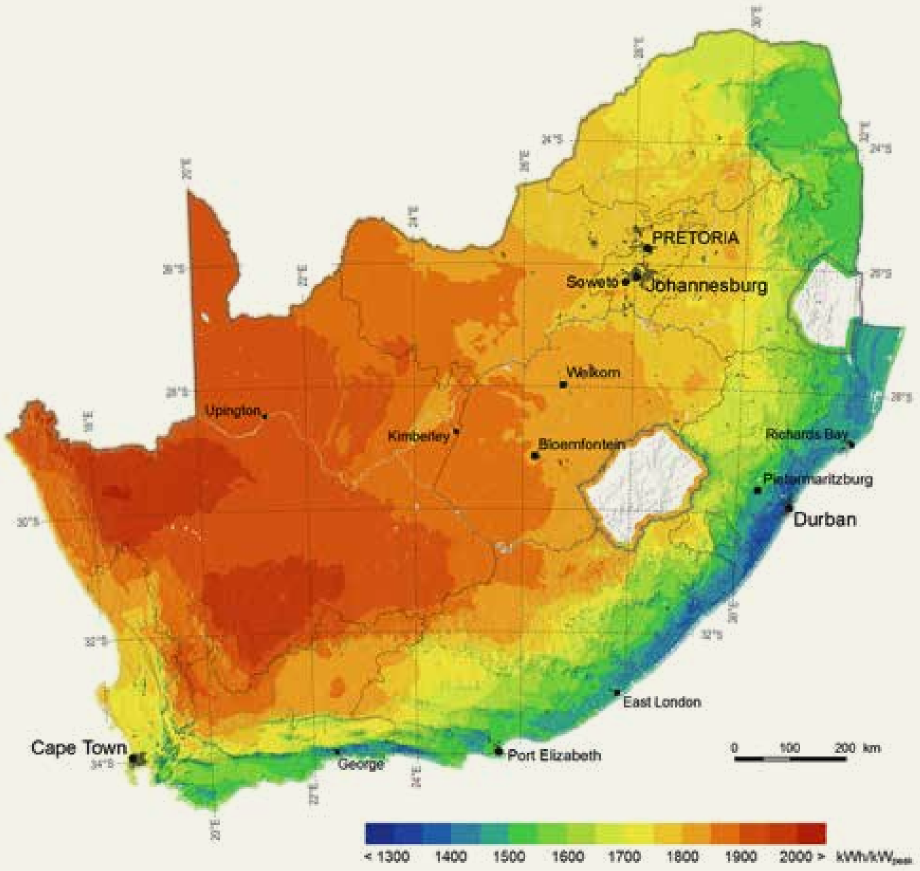


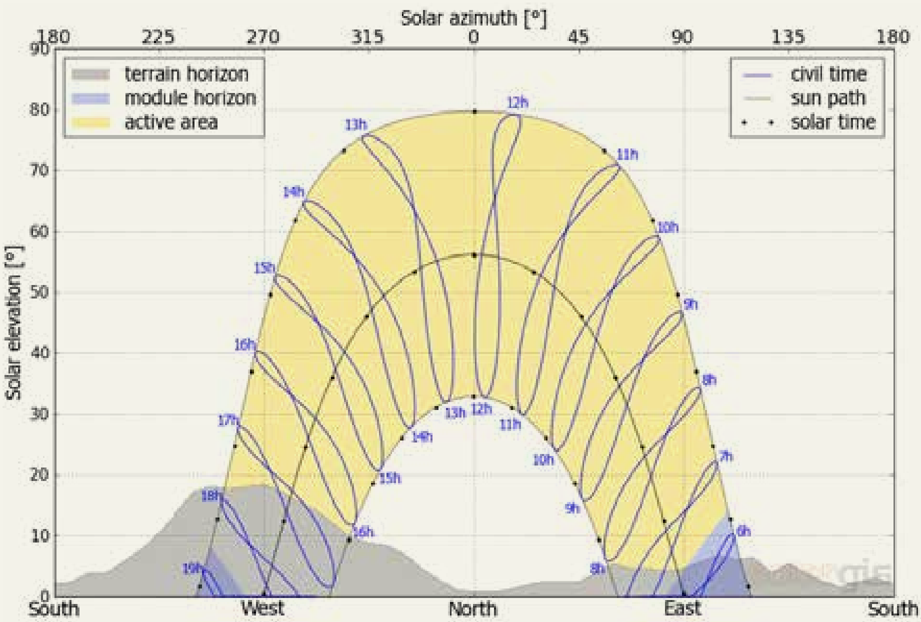
Table 1 shows this output for various locations around South Africa, as obtained from PVPlanner software. Note that this is merely an approximation, as the local shading effects are not taken into account.

Table 1: **PV output comparison across South Africa**[4]

Location	Annual PV output (optimally inclined)
Paarl	1 632 kWh/kW_p
Pretoria	1 731 kWh/kW_p
Kimberley	1 854 kWh/kW_p

The sun path diagram, Figure 4[5], show the shading effects due to the mountains surrounding Paarl. The diagram allows the visual representation of the sun's movement and shading effect on the PV system during different times of the day and different seasons, throughout the year.

Figure 4: **Terrain horizon and day length for 1 Market Street, Paarl**



The effect of the mountain ranges on either side of Paarl town is seen clearly in Figure 4, with the predominant loss of generation in the late afternoon due to shading causes by Paarl Mountain. In summer Paarl mountain will limit PV production from 18:00 (upper curve) and in winter from 16:00 (lower curve). However it must also be noted that even though these shading effects shorten the PV production day, during the late afternoon PV panels will not produce electricity at rated power due to the low incidence angle of the sun on the PV panels. The localised orientation and azimuth effects will be considered when a detailed solar analysis of the building is carried out.

4 Output for various locations around South Africa, as obtained from PVPlanner software. Note that this is merely an approximation, as the local shading effects are not taken into account.

5 Shading diagram produced by PVPlanner software, GeoModel Solar

By sourcing the average yearly data, Table 1, it is found that Paarl has a fair solar resource when compared to other locations in South Africa. In South Africa, projects in the range of 1 600 kWh/kW$_p$ to 1 800 kWh/kW$_p$ per year are considered to be a feasible range for PV projects, above this is considered to be excellent and below is considered to be poor. However, feasible projects have been completed in ranges below 1 600 kWh/kW$_p$, but an extended payback period is seen. It should however be noted here that Germany, the country with the highest penetration of PV in the world, has a PV production (specific yield) of below 1 000 kWh/kW$_p$ per year.

THE POTENTIAL FOR PV IN DRAKENSTEIN

Introduction

The potential for embedded generation solar photovoltaic (PV) technology in Drakenstein by the private sector is investigated.

The following information was received from Drakenstein Municipality to aid in the research;

- Monthly invoices from Eskom for the five substations in Drakenstein
- Load profiles for three of these substations;
- Monthly electricity purchases for all prepaid customers in Drakenstein for July 2012 to February 2015
- Monthly metered electricity statistics for all credit customers in Drakenstein for the period July 2013 to January 2015

The maximum amount of PV that can be installed in Drakenstein before grid studies are required is quantified. The electricity generated from this calculated installed PV capacity is compared to the load profiles at three substations in Drakenstein.

Drakenstein Case Studies

Two case studies of currently installed embedded PV are presented to illustrate the impact of that such installations can possibly have on municipal electricity sales. An industrial and residential installation is examined and represents typical embedded generation installations for these user groups.

Case Study 1: Industrial installation

"Transforming a dumpsite to a Western Cape 'Green Logistics' Landmark"[6]

The offices and warehouses of IMPERIAL Cargo are located on a four hectare site between Paarl and Wellington. The property houses offices for 120 employees, a 2 000 m^2 warehouse, wash bays and a workshop. IMPERIAL Cargo considers this site to be a renewable energy landmark in the logistics sector. The property was developed as a Greenfield project opening its doors in June 2011.

6 For more information see: http://www.imperiallogistics.co.za/documents/IMPERIAL-CARGO-GREEN-HUB.pdf

Figure 5: **Google Earth image of IMPERIAL Cargo site from 1 April 2010**

Figure 6: **Google Earth image of IMPERIAL Cargo site from 31 January 2015**

On top of many other innovative green technologies incorporated in the IMPERIAL Cargo site, including optimal use of natural light, solar geysers, low energy lights and motion sensors, the rooftop of the warehouse also has a 30kW$_p$ PV installation. This was one of the largest PV installations in the Western Cape when it was installed.

The PV system consists of eleven identical subsystems and includes some battery storage. It is thus safe to assume that no electricity is fed back into the grid and all electricity generated is used as self-consumption.

IMPERIAL Cargo purchases its electricity from Drakenstein municipality on the "Commercial 3 phase 150 Amp" tariff structure and purchased 311 081 kWh from Drakenstein municipality in 2014.

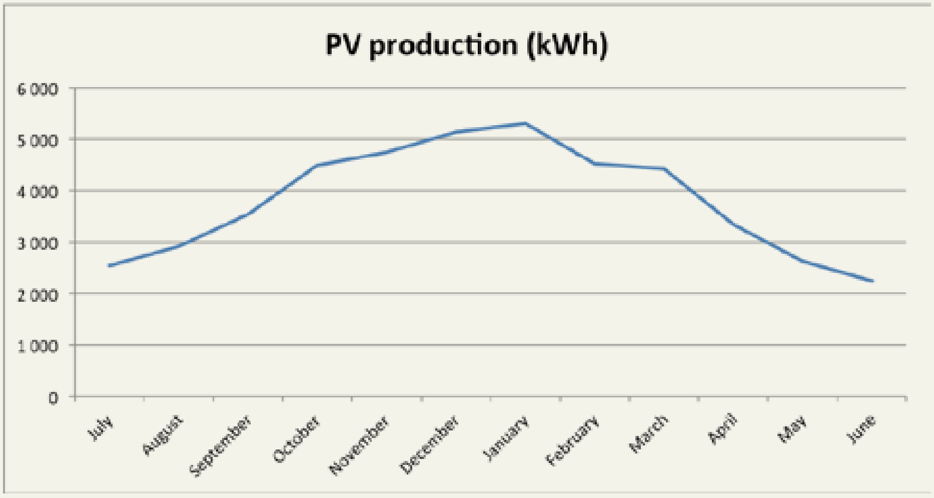
Figure 7: **The 30kW$_p$ PV installation at IMPERIAL Cargo with battery storage**

PVPlanner software[7] was used to calculate the yearly PV production for the IMPERIAL Cargo site. The azimuth used in the software was 305 degrees (northwest)[8], which is the actual orientation of the roof. The inclination was taken as 30 degrees. The specific yield for this site is 1 527 kWh/kW$_p$ per year. For the PV installation of 30 kW$_p$, the average yearly PV electricity generation amounts to 45 810 kWh per year.

The monthly PV electricity generation for this site varies from 2 241 kWh for June to 5 301 kWh for January. The monthly generation of electricity can be seen in Figure 8.

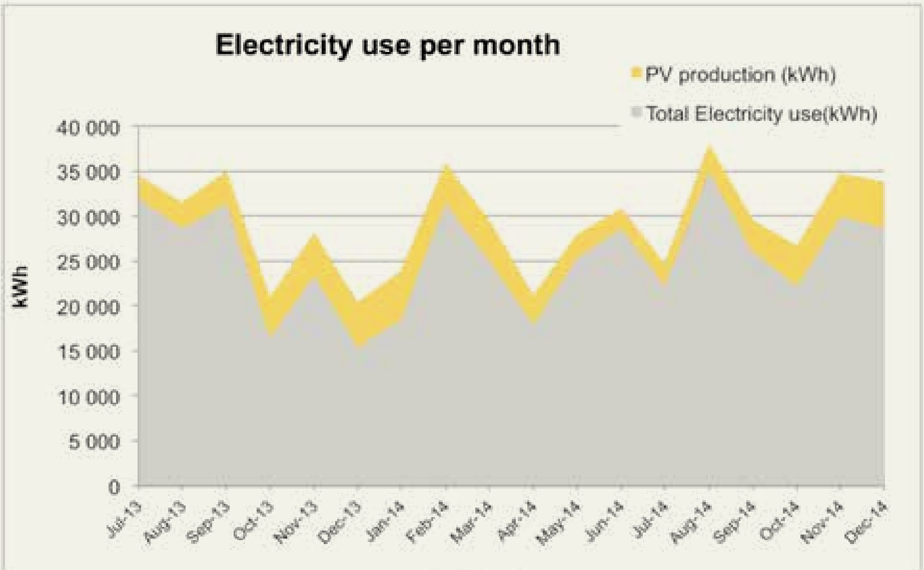
7 http://solargis.info/pvplanner
8 this is 55 degrees West of North

Figure 8: **Monthly PV production for the IMPERIAL Cargo site**



The total electricity use for 2014 for Imperial Cargo is 357 879 kWh: 45 798 kWh form PV and 311 081 kWh purchased from Drakenstein Municipality. The electricity used from the PV and purchased from Drakenstein municipality can be seen in Figure 9.

Figure 9: **Total electricity use per month for IMPERIAL Cargo for 1 July 2013 to 31 December 2014**



The electricity generated by the PV is about 13% of total electricity use for this period. This differs from as high as 22% in the summer months to as low as 7% in the winter months. See Table 2.

Table 2: **Electricity use for IMPERIAL Cargo for 2014**

	Total electricity use	Electricity use from PV (30 kW_p)	PV generation as a percentage of total use
January 2014	23 902	5 301	22%
February 2014	35 935	4 518	13%
March 2014	29 545	4 422	15%
April 2014	21 174	3 336	16%
May 2014	27 921	2 625	9%
June 2014	30 862	2 241	7%
July 2014	24 775	2 544	10%
August 2014	37 928	2 910	8%
September 2014	29 580	3 537	12%
October 2014	26 723	4 491	17%
November 2014	34 726	4 743	14%
December 2014	33 808	5 130	15%
Total for 2014 Jan to Dec	356 879	45 798	12.83%

Case Study 2: Residential Installation

A home owner from Paarl, who wished to remain anonymous, installed a 4.25 kW_p PV system on the roof of his home at the end of 2014.

There is an extended family living on the property and all adults work from home. The family has installed a number of energy efficient and fuel-switching options over the years, as can be seen in Figure 10.

Figure 10: **Fuel switching, energy efficient and renewable energy technologies installed by the home owner as compared to electricity usage averaged over 6 months: 2010 to 2014**

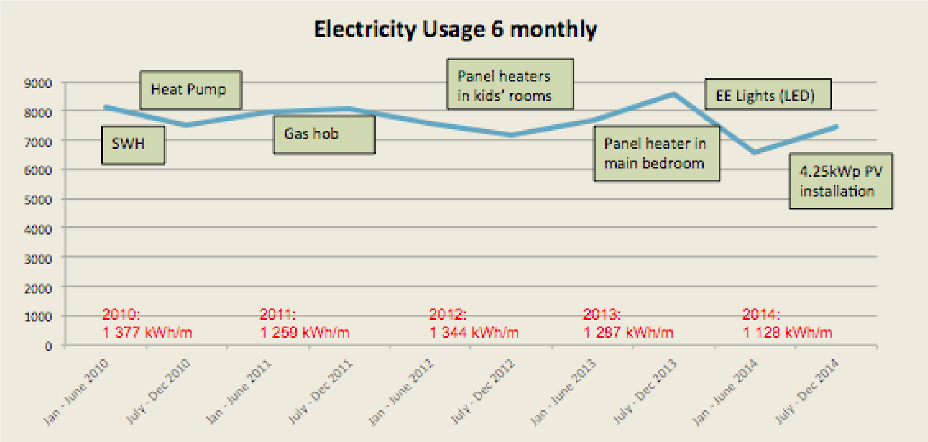


Figure 11: **The 4.25 kW_p installation at a private home in Paarl**

PVPlanner software[9] was used to calculate the yearly PV production for this site. The azimuth used in the software two degrees west of North, which is the actual orientation of the roof. The inclination was taken as 30 degrees. The PV potential production for this site is 1 596 kWh/kW_p/year. For the PV installation of 4.25 kW_p, the average yearly PV electricity generation amounts to 6 758 kWh per year.

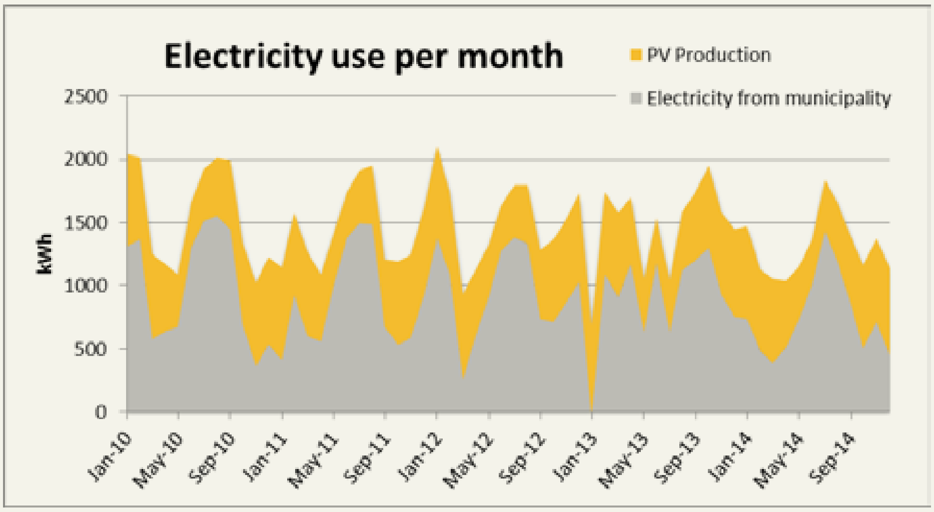
The monthly PV electricity generation for this site varies from 357 kWh for June to 727 kWh for January.

This home owner purchases electricity from Drakenstein Municipality on a credit meter and is on the single phase 160 Amp tariff for residential users. They purchased 15 444 kWh of electricity from Drakenstein Municipality in 2013 and 13 541 kWh for 2014.

9 http://solargis.info/pvplanner

The impact that the PV installation could have had on the monthly electricity bill for this homeowner had it been installed in January 2010 is estimated in Figure 12.

Figure 12: **Total electricity purchased from Drakenstein and consumed from PV generation for the residential user had the PV been installed since January 2010**



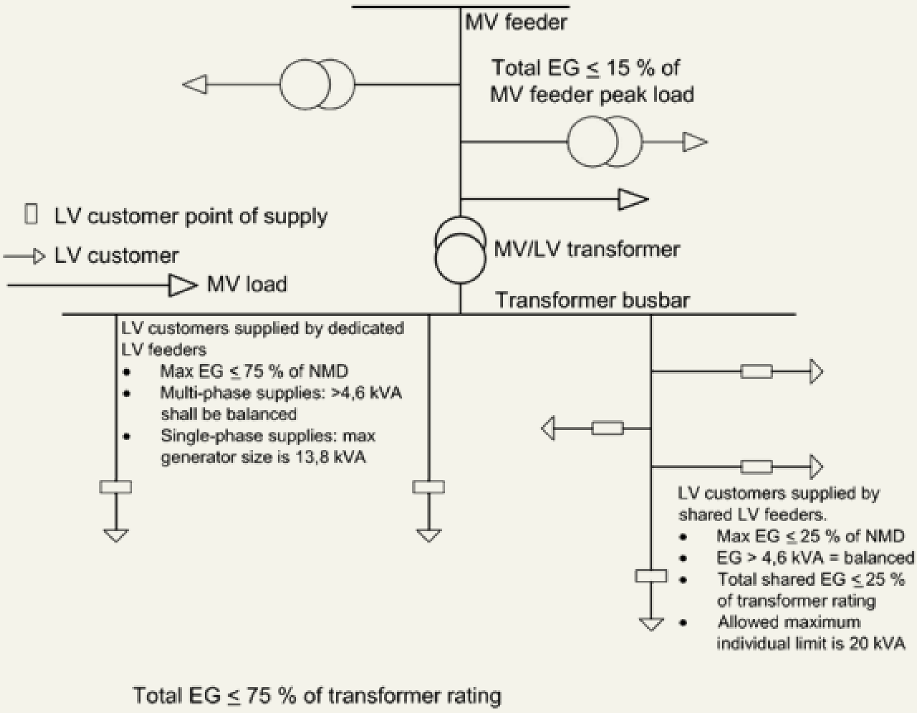
Methodology to calculate maximum installable PV in Drakenstein

Embedded Generation Rules in South Africa

There are no specific standards or regulations currently in place in South Africa for small-scale embedded generation (SSEG), but the National Regulation, NRS 097-2-1:2010, covers the utility interface of grid interconnected embedded generation. In the 2010 edition of the NRS097-2-1 document, the size of an embedded generator is limited to the rating of the supply point on the premises while the NRS097-2-3:2014 specification sets out the technical requirements for the utility interface, the embedded generator and the utility distribution network with respect to embedded generation. The specification applies to embedded generators smaller than 100 kW connected to low-voltage (LV) networks.

Section 4.5 of the NRS097-2-3:2014 specification gives a summary of the connection criteria as shown in Figure 13.

Figure 13: **Summary of simplified connection criteria**



Solar Data

The solar data used in the hind cast model to predict the PV plant production output is sourced from SoDa solar radiation data. The Solar irradiation data that is supplied by SoDa is from the HelioClim database, which combines measurements from ground stations and satellite data, and provides hourly GHI data that is used in the PVsyst software for detailed modelling. The layout of the panels and area covered is determined by the selected equipment and spacing thereof.

PVsyst software is used to model final production estimates. PVsyst software allows for detailed modelling, taking into account the effects of local shading, equipment losses, and panel- and string layouts, among other features. There are standard industry practices used in the report, which will not be described in detail.

In order to model the potential production of a PV array, a specific PV panel and inverter needs to be selected. The choice of reference equipment is based on global statistics on the manufacturers' production volumes, age of the company and the manufacturer having an established presence in South Africa.

The reference PV panel that is used for modelling purposes is the polycrystalline panel available from Yingli Solar, YL250P-29b. Yingli Solar is one of the top global producers of PV panels that has been manufacturing for more than 15 years and fall in the Gigawatt production category. The panels are assumed to be north facing with a tilt angle optimised for maximum annual production. The reference inverter used is a SMA Sunny Boy 2,5 kW inverter. SMA is currently the largest inverter manufacturer globally, with more than 25 years of experience and an established local market. Both of the reference equipment manufacturers are very large globally and in South Africa with proven reliability.

The study and its results are impacted by data inconsistencies, loss assumptions and equipment selection. Owing to the unpredictable nature of the climate and the variety of installation setups, the actual production of the installation can differ from the predicted values. The results of the study is therefore for decision making purposes and should not be used as an accurate prediction of the PV production of the installed system.

Information received from Drakenstein municipality

There are five substations in Drakenstein municipality that are billed monthly by Eskom, namely;

- Dalweiding, 60 000 kVA: Noorder Paarl, Daljosafat Industrial and Paarl East
- Hugenote, 60 000 kVA: Central Business district, Denneburg, Boschenmeer
- Dwarsrivier, 30 000 kVA: Pniel, Hollanse Molen, Victor Verster, Pearl Valley and Val de Vie
- Wellington, 30 000 kVA
- Slot, 30 000 kVA

The Eskom accounts for these substations, the transformer capacity, firm capacity and some hourly load data was made available to this study by Drakenstein Municipality. The maximum load figures were derived from the Eskom accounts. See Appendix 2.

Hourly load data was made available for the following substations;

- Dalweiding: 4 February 2015 to 20 April 2015 in one minute intervals
- Hugenote: 15 April 2014 to 21 April 2015 in half an hour intervals
- Dwarsrivier: 25 January 2015 to 20 April 2015 in one minute intervals

PV potential using NRS097-3 rules

To quantify the maximum installation capacity of PV in Drakenstein, a conservative approach is taken by using 15% of maximum load at the substations. This data is derived from the Eskom accounts and can be seen in Appendix 2. This is the amount of embedded generation capacity that can be installed before a grid study is needed. It is possible that detailed grid studies will reveal that the potential is much higher, but this is the potential that can be installed in a reasonably short time.

Looking at Figure 13, it is shown that embedded generation should not exceed 25% of the notified maximum demand where customers are supplied by shared low voltage feeders and where dedicated low voltage feeders exist the embedded generation should not exceed 75% of the notified maximum demand. Higher up in the supply chain it is suggested that embedded generation does not exceed 15% of the demand from a medium voltage feeder.

If the NRS097-3 rules are applied to the maximum load at substation level, over 24 MW_p[10] of PV can be installed in Drakenstein as seen in Table 3. This is equal

10 This is equal to 24 244 kW_p

to over 800 installations the size of IMPERIAL Cargo (30 kW_p) or over 5 700 installations the size of the homeowner (4.25 kW_p) as discussed in

Case Study 2: Residential Installation. To put this into perspective, this is more than twice as much as all the installations in the Western Cape to date (see Appendix 1 for a list of installations).

Table 3: **Drakenstein maximum PV installations**

Transmission Substation Name	Installed Transformer Capacity [kVA]	N-1 [kVA]	NMD [kVA]	Peak Load [kW]	15% of installed capacity - PV [kW]	15% of NMD [kVA]	15% of Peak Load – PV [kW_p]
Dalweiding	60 000	45 000	55 000	50 407	9 000	8 250	7 561
Dwarsrivier	30 000	15 000	20 000	10 422	4 500	3 000	1 536
Hugenote	60 000	45 000	60 000	65 699	9 000	9 000	9 855
Wellington	30 000	15 000	25 000	24 907	4 500	3 750	3 736
Slot	30 000	15 000	12 000	10 191	4 500	1 800	1 529
TOTAL	210 000	135 000	172 000		31 500	25 800	24 244

Four typical 250 W_p solar PV modules (giving 1 000 W_p or 1 kW_p) will cover an area of about 6.5 m^2. If allowance is made for spacing between panels, wiring, brackets etc., it can be conservatively estimated that the area needed to install 1 kW_p of PV is about 10 m^2. This means that the area needed to install 1 MW_p of PV is about 1 hectare (ha).

Impact of maximum PV generation on the load profile

PVsyst software was used to model final production estimates per hour for 2014 and 2015. These production estimates were then plotted against the load profiles per transmission substation where this was available to show the impact that solar PV can have. The Civic Centre in central Paarl was taken as the site and the mounting angle of the PV modules was optimised for annual energy production.

Impact of PV on energy demand

The energy demand on the individual substations is shown in Table 4, along with the energy that could have been supplied by solar PV if 31.5 MW_p of PV or 24.2 MW_p of PV was installed in the Drakenstein in 2014. As a comparison, 31.5 MW_p PV would have generated 53 213 MWh of energy, the equivalent to providing more than 9 700 houses with electricity for a full year[11].

11 This figure is calculated with the assumption that a household consumes 15 kWh per day.

Table 4: **Substation energy usage for 2014 and potential PV energy generation**[12,13]

Transmission Substation Name	Installed Transformer Capacity [kVA]	Energy used during 2014 [MWh][12]	15% of Transformer Capacity		15 % of Peak load	
			Potential PV installed [kW]	Potential PV Energy for 2014 [MWh][13]	Potential PV installed [kW_p]	Potential PV Energy for 2014 [MWh]
Dalweiding	60 000	263 774	9 000	15 204	7 561	12 773
Dwarsrivier	30 000	72 441	4 500	7 602	1 536	2 595
Hugenot	60 000	252 287	9 000	15 204	9 855	16 648
Wellington	30 000	121 864	4 500	7 602	3 736	6 311
Slot	30 000	29 300	4 500	7 602	1 529	2 583
TOTAL	210 000	739 665	31 500	53213	24 244	40 910

Impact of PV on the load profile for a summer week

The impact of Solar PV on the combined load profile of the Dalweiding, Hugenote and Dwarsrivier substations for a summer week is shown in Figure 14. The fall in the load seen on Monday, 9 February and Saturday, 14 February 2015, is the effect of load shedding on two of the substations[14]. The energy contributions are shown for the conservative case (yellow on figure) where 15% of the peak energy demand was used to calculate the PV contribution and the additional solar energy (orange on graph) is shown that could have been generated if 15% of the installed transformer capacity was used to estimate the PV production[15]. Outlined in black on the graph is the total energy demand profile of the three substations for 9 to 15 February 2015, while the grey area would be the resulting load Eskom would have had to supply if these potential solar PV installations were contributing to the network.

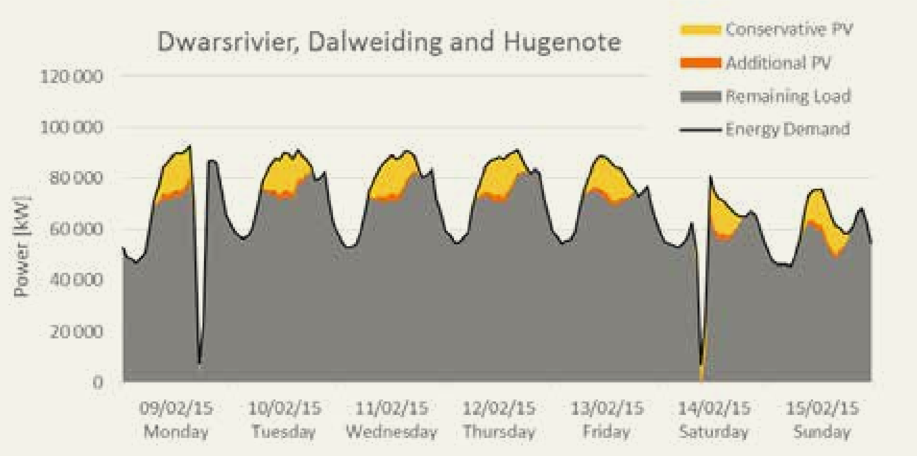
12 From the Eskom accounts

13 1 689 kWh/kWp/year, as calculated by PVSyst Software, North facing with optimal tilt using the Drakenstein Civic Centre in central Paarl as the reference site

14 The PV systems alone will not be able provide electricity during loadshedding. If electricity is needed during loadshedding, the PV systems will need to be supplemented with batteries and/or other generators.

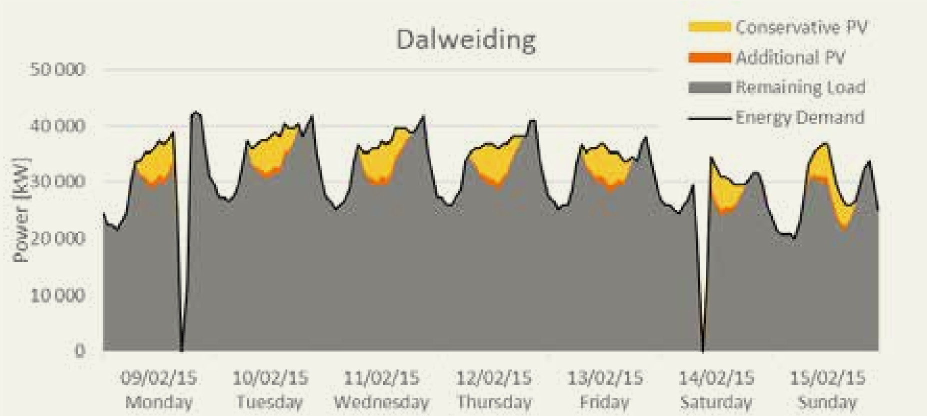
15 As the peak load according to the Eskom accounts for the Hugenote substation was more than the installed capacity, 15 % of installed capacity was taken as the conservative capacity and 15% of the peak load as additional possible capacity.

Figure 14: **Impact of PV generation on the load profile of three substations[16] in Drakenstein for a summer week[17]**



The impact of solar PV for a summer week on the three individual substations that hourly load data was available for, can be seen in Figure 15, Figure 16 and Figure 17.

Figure 15: **Impact of PV generation on the load profile Dalweiding substation for a summer week[18]**



16 Dwarsrivier, Dalweiding and Hugenote

17 Instantaneous power values for an hour is averaged over the hour, resulting in the kW value indicated on the y-axis

18 Instantaneous power values for an hour is averaged over the hour, resulting in the kW value indicated on the y-axis

Figure 16: **Impact of PV generation on the load profile Hugenote substation for a summer week**

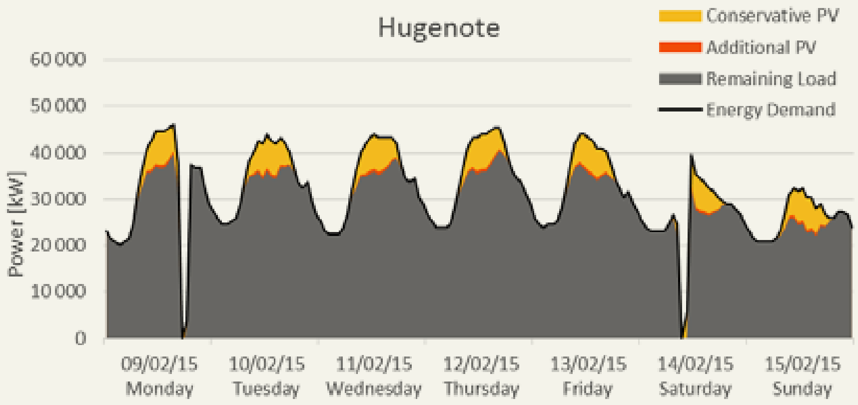
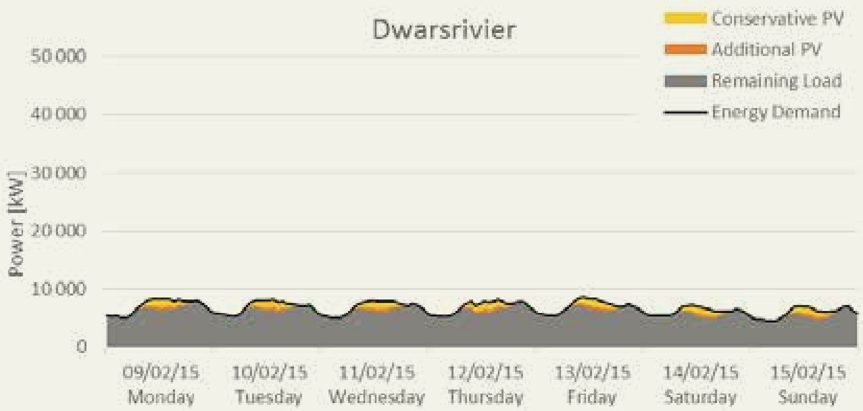


Figure 17: **Impact of PV generation on the load profile Dwarsrivier substation for a summer week**[19]

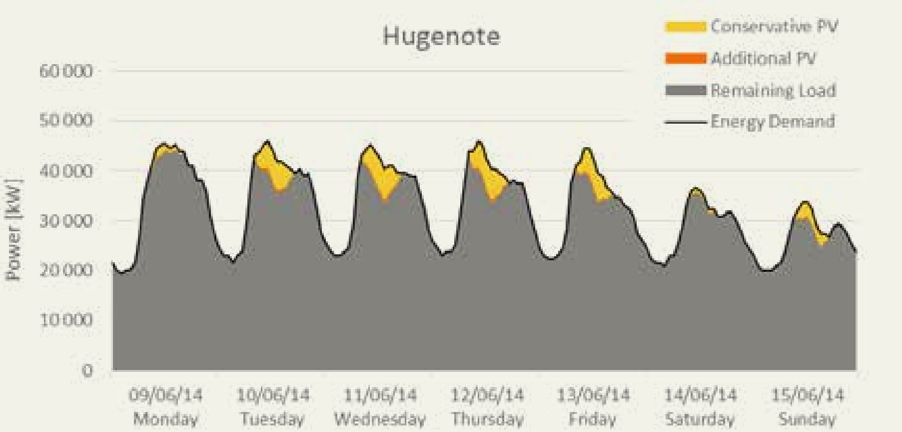


19 Instantaneous power values for an hour is averaged over the hour, resulting in the kW value indicated on the y-axis

Impact of PV on the load profile for a winter week

The only substation in Drakenstein where load data was available for a winter week is the Hugenote substation. This substation feeds electricity to the Paarl central business district, Denneburg and Boschenmeer. The impact of Solar PV on the load profile of the Hugenote substation for a winter week is shown in Figure 18.

Figure 18: **Impact of PV generation on the load profile Hugenote substation for a winter week**



As can be seen in Figure 18, the Monday, Saturday and Sunday from this specific week, were cloudy winter days and Tuesday to Friday were sunny winter days.

Impact of PV on the load profile of a summer day

The impact of Solar PV on the load profile of the three substations that load data was available for, as well as the combined load profile of Drakenstein is shown in the Figure 19, Figure 20, Figure 21 and Figure 22. The energy contribution is shown for the conservative case (yellow on figure) where only 15% of the peak energy demand was used to calculate the PV contribution and the additional solar energy (orange on graph) is shown that could have been generated if 15% of the installed transformer capacity was used to estimate the PV production[20]. Outlined in black on the graph is the total energy demand profile of Drakenstein, while the grey area would be the resulting load Eskom would have had to supply if these potential solar PV installations were contributing to the network.

20 As the peak load according to the Eskom accounts for the Hugenote substation was more than the installed capacity, 15 % of installed capacity was taken as the conservative capacity and 15% of the peak load as additional possible capacity.

Figure 19: **Impact of PV generation on the load profile three substations in Drakenstein for a summer day**[21]

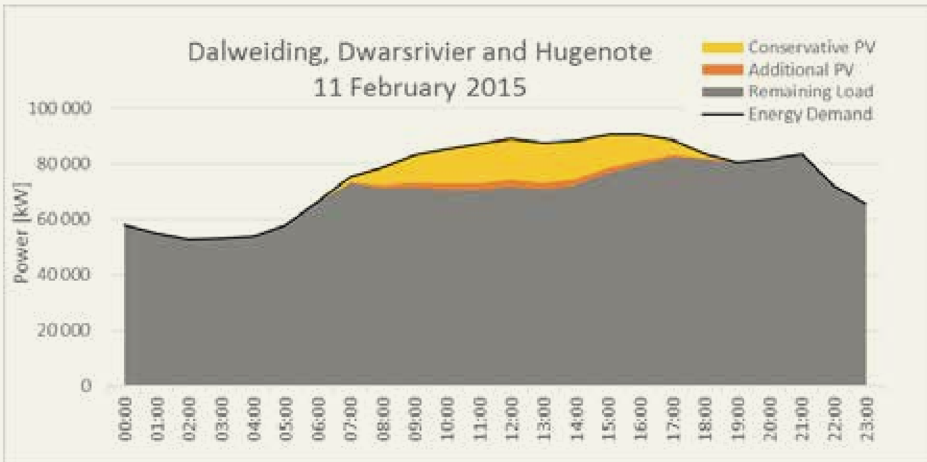
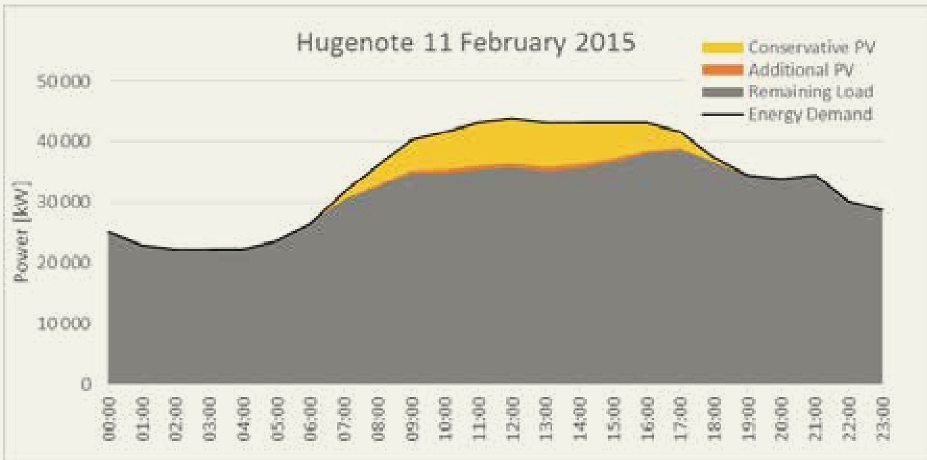


Figure 20: **Impact of PV generation on the load profile Hugenote substations for a summer day**[22]



21 Instantaneous power values for an hour is averaged over the hour, resulting in the kW value indicated on the y-axis

22 Instantaneous power values for an hour is averaged over the hour, resulting in the kW value indicated on the y-axis

Figure 21: **Impact of PV generation on the load profile Dalweiding substations for a summer day**

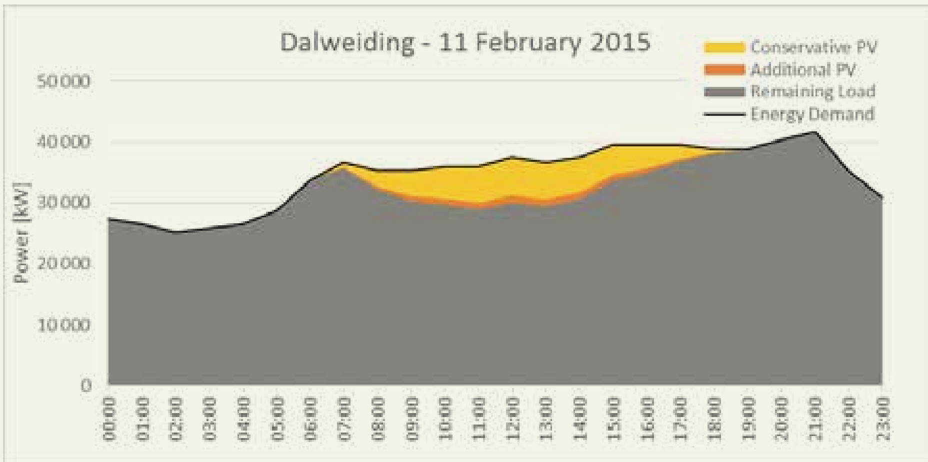
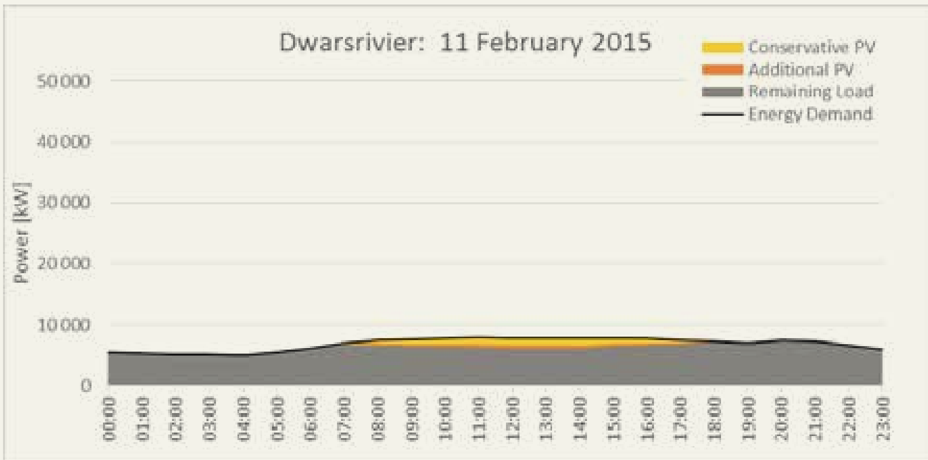


Figure 22: **Impact of PV generation on the load profile Dwarsrivier substations for a summer day**[23]



Impact of PV on the load profile of a winter day

The only winter load data that was available, is for Hugenote substation. The impact of Solar PV on the load profile on a sunny winter and a cloudy winter day is can only be shown for Hugenote substation. The total electricity generation for 24 244 kWp of solar PV installations for a cloudy day, 9 June 2014, was 9 638 kWh. The equivalent electricity generation for a sunny winter day (11 June 2014) was four times as much, at 40 014 kWh for the same capacity of installations[24]. See Figure 23 and Figure 24.

23 Instantaneous power values for an hour is averaged over the hour, resulting in the kW value indicated on the y-axis

24 The electricity generation for the same capacity of solar PV installations for Saturday, 15 June 2015 was even lower at 5 838 kWh.

Figure 23: **Impact of PV generation on the load profile of Hugenote substations for a cloudy winter day**[25]

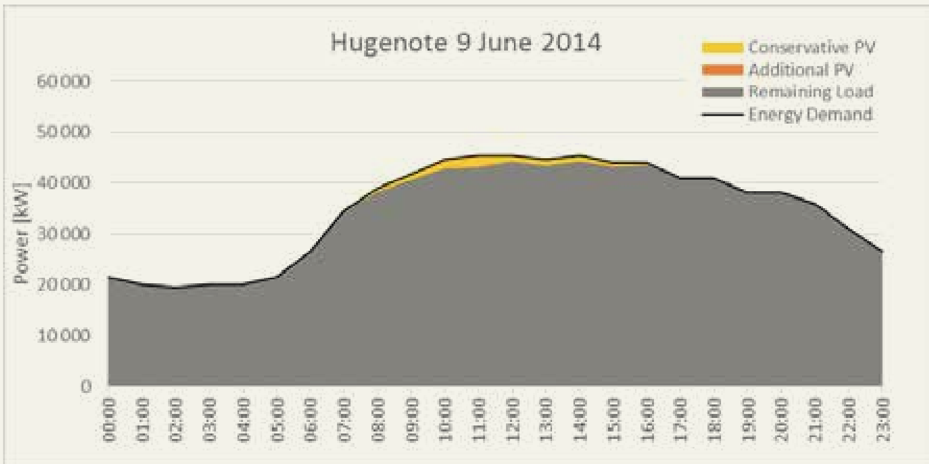
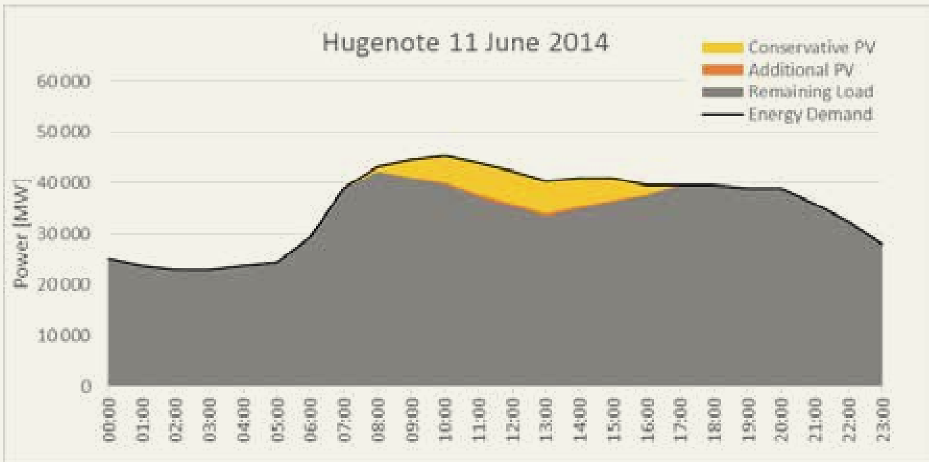


Figure 24: **Impact of PV generation on the load profile of Hugenote substations for a sunny winter day**[26]



Potential PV Systems by analysing electricity use

In the section above, the maximum PV system installations in Drakenstein was calculated, using the substation capacities. In this section, the electricity user profiles of Drakenstein municipality is analysed to see what the actual potential for PV system installations are from the electricity users' perspective.

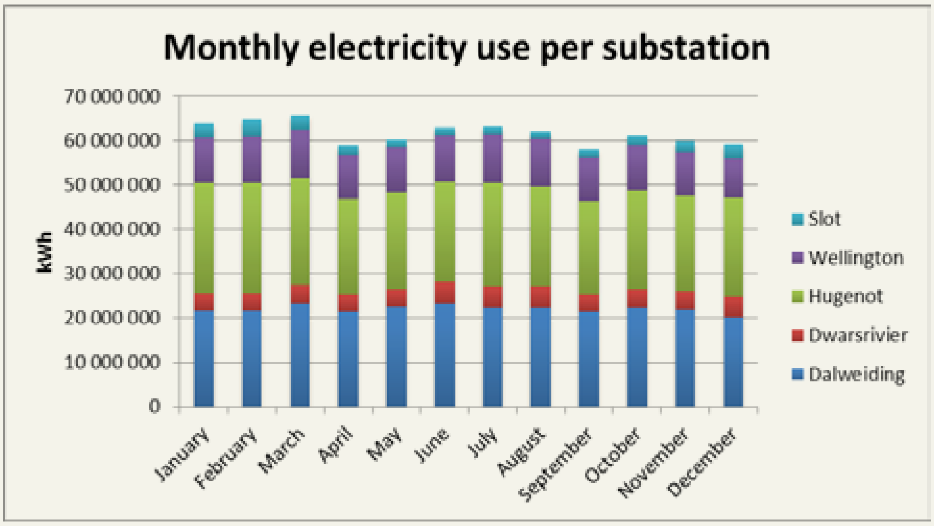
25 Instantaneous power values for an hour is averaged over the hour, resulting in the kW value indicated on the y-axis

26 Instantaneous power values for an hour is averaged over the hour, resulting in the kW value indicated on the y-axis

Potential PV installations on residential homes

Drakenstein municipality purchased a total of 739 665 MWh of electricity from Eskom in 2014[27]. The months with the highest electricity use, was February and March and the months with the lowest electricity use, were April and September. Electricity use is highest in the summer months, lower in the winter and at its lowest in spring and autumn.

Figure 25: **Monthly electricity use in Drakenstein per substation**[28]



There were about 32 000 residential users purchasing prepaid electricity in 2014. About half of these customers regularly purchase more than 200 kWh of electricity per month, and about 7 000 regularly purchase more than 500 kWh per month.

There were about 9 000 residential electricity users with credit meters in Drakenstein in 2014. Of the users, about 4 500 users regularly use more than 500 kWh per month.

In total there were about 11 500 residential electricity users in Drakenstein who regularly use more than 500 kWh of electricity per month. In Table 3 it was seen that the technical maximum solar PV that can be installed in Drakenstein before grid studies are needed, is 24 244 kW_p. This amounts to over 5 700 residential users installing solar PV systems of the size seen in 0 **[???????]**

Case Study 2: Residential Installation. If a more reasonable 3 kW_p is taken as the average residential installation, this equates to over 8 000 residential installations[29].

This equates means that between 50 and 70% of Drakenstein residences who regularly use more than 500 kWh of electricity per month can install rooftop PV before grid studies are needed.

27 As was shown in Table 4
28 Data from the Drakenstein municiplaity Eskom bills. Also see Appendix 3.
29 It is assumed here that residents who use less than 500 kWh of electricity per month are unlikely to install solar PV on their rooftops.

Should all the residential customers in Drakenstein who use more than 500 kWh per month install rooftop PV of 3 kW_p each, this would amount to 34 500 kW_p, about 40 % more than what would be allowed before requiring grid studies. This is, however a very unlikely scenario.

Potential PV installations on industrial buildings

There were about 600 business customers on prepaid for 2014. Most of these prepaid customers purchase less than 1 000 kWh of electricity per month and are unlikely to install large solar PV on their rooftops.

There were about 2 500 credit customers in Drakenstein for 2014 on industrial, rural and commercial tariffs. In Table 3 it was seen that the technical maximum solar PV that can be installed in Drakenstein before grid studies are needed, is 24 244 kW_p. This adds up to over 800 commercial users installing solar PV systems of the size seen in A.2.1: Case Study 1: Industrial installation. This amounts to about 30% of these customers. If larger, 100 kW_p installations are taken, this amounts to about 240 of these customers – or about 10%.

Should all of these customers install rooftop PV of 30 kW_p average, this would amount to 75 000 kW_p installations, 3 times more than the allowable PV installations before grid studies are needed. This is, however an unlikely scenario.

Conclusion

Part A quantifies the maximum amount of PV that can be installed in the Drakenstein municipal district before grid studies are needed. The electricity generated from this calculated installed PV capacity was then compared with the load profiles at the substations that load data was available for, to evaluate the impact.

A conservative approach based on the electricity load profiles at substation level, indicates that just over 24 MW_p of distributed solar PV could easily be installed in Drakenstein

Furthermore, if this PV potential is installed across the Drakenstein, the electricity generation from these installations will complement the load profiles well at substation level.

It is further confirmed, when analysing electricity use per customer, that it is highly unlikely that installations of PV systems in Drakenstein will exceed 24 MW_p in the short to medium term.

IMPACT OF PV INSTALLATIONS ON MUNICIPAL REVENUE IN DRAKENSTEIN

Introduction

Making use of the results in Part A, the impact that these installations will have on municipal revenue is examined. In Table 3, it was shown that the maximum PV installations in Drakenstein before grid studies will be needed is 24 244 kW_p. In this section the effect on the Drakenstein municipal revenue is calculated should this high amount of PV be installed.

The following information was received from Drakenstein Municipality to aid in the research;

- Monthly invoices from Eskom for the five substations in Drakenstein
- Load profiles for three of these substations;
- Monthly electricity purchases for all prepaid customers in Drakenstein for July 2012 to February 2015
- Monthly metered electricity statistics for all credit customers in Drakenstein for the period July 2013 to January 2015

The monthly electricity usage profiles for electricity users in Drakenstein is then analysed and the financial impact on the municipality is calculated.

Reduction of Eskom bill for Drakenstein

In Table 3, it was shown that the maximum PV installations in Drakenstein before grid studies will be needed is 24 244 kW_p. In this section the impact on the Drakenstein municipal revenue is calculated should this high amount of PV be installed.

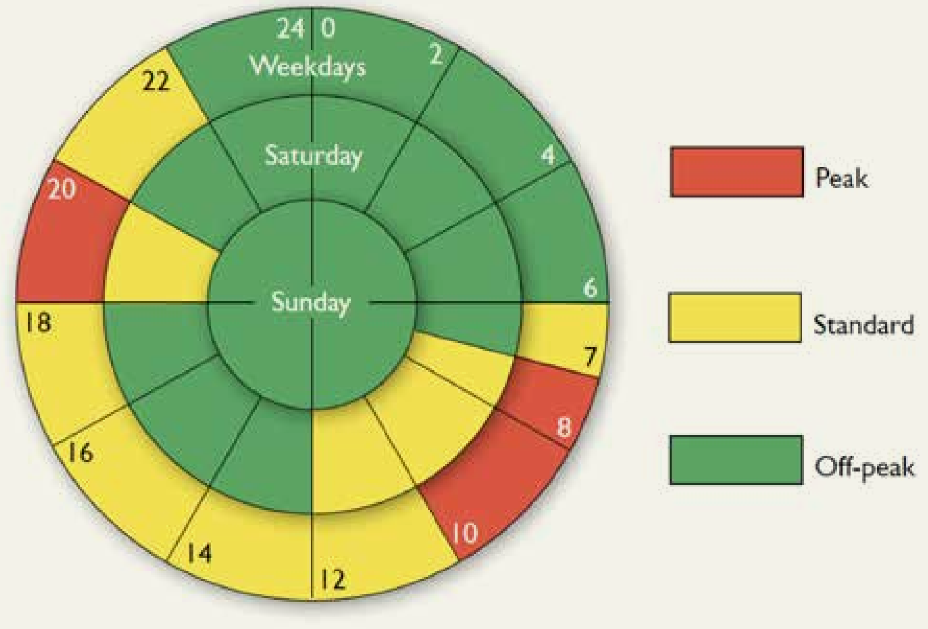
Most of the Drakenstein Eskom accounts are billed at Megaflex Diversity. The impact that the installation of 24 244 kW_p of PV installations will have on the Drakenstein Eskom account for a full year is calculated on the Megaflex Diversity tariff for 2014 / 2015. Only the active energy charges are considered[30].

Eskom defined time periods as can be seen in Figure 26[31] were used in the calculations.

30 kVA charges might be reduced too, but are not considered here.

31 New Year's Day, Good Friday, Family Day, Christmas Day and Day of Goodwill were treated as Sundays. All other public holidays were treated as Saturdays unless it fell on a Sunday in which case it was treated as a Sunday.

Figure 26: **Eskom defined time periods**



As can be seen in Table 5, the Eskom bill for Drakenstein would have been reduced by R 23 370 896 for the year, if 24 244 kW_p of PV was installed[32].

Table 5: **Reduction of Eskom bill when 24 244 kW_p PV is installed**

		PV generation per per 1 kW_p PV (kWh)	PV generation per 24 244 kW_p PV (kWh)	R/kWh (Megaflex diversity 2014 / 2015)	Total reduction of Eskom bill (VAT excl)
Low Season - September to May	Monday to Friday off peak	0	0	R0.3165	R0
	Monday to Friday Standard	755	18 294 771	R0.4989	R9 127 261
	Monday to Friday Peak	154	3 734 857	R0.7249	R2 707 397
	Saturday off peak	136	3 303 503	R0.3165	R1 045 558
	Saturday standard	97	2 361 178	R0.4989	R1 177 991
	Sunday off peak	227	5 503 490	R0.3165	R1 741 854

32 As calculated using the Eskom Megaflex Diversity Tariff for 2014 / 2015.

		PV generation per per 1 kW_p PV (kWh)	PV generation per 24 244 kW_p PV (kWh)	R/kWh (Megaflex diversity 2014 / 2015)	Total reduction of Eskom bill (VAT excl)
High Season - June to August	Monday to Friday off peak	0	0	R0.3656	R0
	Monday to Friday Standard	184	4 468 308	R0.6732	R3 008 064
	Monday to Friday Peak	23	547 768	R2.2224	R1 217 360
	Saturday off peak	29	694 618	R0.3656	R253 952
	Saturday standard	18	435 808	R0.6732	R293 385
	Sunday off peak	48	1 160 994	R0.3656	R424 459
	Reliability Charge	1 671	40 505 295	R0.0027	R109 364
	Electrification and rural subsidy	1 671	40 505 295	R0.0559	R2 264 245
	TOTAL				R23 370 896

Reduction of municipal income if all PV installations were done by residential users

In this section, the impact on income from electricity for Drakenstein municipality will be calculated, should all of the potential 24 244 kW_p of PV be installed by residential users only. In the first scenario, it is assumed that the households all stay on their current tariff and thereafter a switch to the SSEG tariff is proposed. It should be noted that the maximum amount of PV that can be installed in Drakenstein before grid studies are needed (24 244 kW_p) is a high penetration, as was noted in A.6.1: Potential PV installations on residential homes.

The new Drakenstein SSEG tariff increases the household's monthly fixed charge as can be seen in Table 6.

Table 6: **Fixed monthly charges for Drakenstein residential electricity customers**[33]

	SSEG monthly fixed charge	Current tariff monthly fixed charge	Difference	Total increase in monthly charge for 1 143 households on each tariff[33]
1 phase 40 Amp	R300	R209	R91	R1 260 688
1 phase 60 Amp	R440	R301	R139	R1 925 666
1 phase 80 Amp	R580	R393	R187	R2 590 644
3 phase 40 Amp	R685	R532	R153	R2 119 618
3 phase 60 Amp	R1 000	R778	R222	R3 075 524
3 phase 80 Amp	R1 315	R1 024	R291	R4 031 430
3 phase 100 Amp	R1 630	R1 270	R360	R4 987 337
				R19 990 909

The impact that the installation of 8 000 residential installations of 3 kW_p will have on the municipal income of Drakenstein can be seen in Table 7.

Table 7: **Reduction in electricity income for Drakenstein municipality from 8 000 x 3 kW_p residential PV installations**[34]

	Increase in income from change in fixed monthly charges	Reduction in income due to new kWh tariff[34]	Reduction in income due to PV generation	Net reduction in income for Drakenstein
Households stay on the same tariff			-R47 796 247	-R47 796 247
Household change to SSEG tariff	R19 990 909	-R6 912 000	-R47 796 247	-R34 717 338

From this it is clear that the municipal electricity revenue of Drakenstein municipality would have been reduced by a maximum of R24 425 350[35] if the maximum technically possible amount of solar rooftop PV is installed on residential roofs in the municipal area. This is about 5% of the Drakenstein Eskom accounts for 2014[36] and less than 3% of the yearly income from electricity for Drakenstein. Should all households change to the new SSEG tariff, the reduction in revenue would have been R11 346 441[37].

33 A total of 8 000 residential customers with a 3 kWp system each

34 Current tariff is R1.18 per kWh. The new SSEG tariff is R1.00 per kWh. A remaining monthly kWh per household of 400 kWh per month is assumed.

35 R47 796 247 (reduction in income to Drakenstein) – R24 425 351 (reduction of Eskom bill) = R 24 425 350

36 See Appendix 3 for the Drakenstein Eskom accounts for 2014

37 R34 717 338 (reduction in income to Drakenstein) – R24 425 351 (reduction of Eskom bill) = R 11 436 442

It should be pointed out again that this scenario is for the maximum technical possible amount of rooftop PV installations before grid studies are needed. It is highly unlikely that this amount of PV will be installed in the short to midterm in Drakenstein.

Reduction of municipal income if all PV installations were done by industrial and commercial users

In this section, the impact on income from electricity for Drakenstein municipality will be calculated, should all of the potential 24 244 kW_p of PV be installed by industrial and commercial users only. In the first scenario, it is assumed that the commercial users all stay on their current tariff and thereafter a switch to the SSEG tariff is proposed. It should be noted that the maximum amount of PV that can be installed in Drakenstein before grid studies are needed (24 244 kW_p) is a high penetration, as was noted in A.6.2: Potential PV installations on industrial buildings.

The new Drakenstein SSEG tariff increases the commercial customers' monthly fixed charge as can be seen in Table 8.

Table 8: **Fixed monthly charges for Drakenstein commercial electricity customers**[38]

	SSEG fixed charge	Current tariff fixed charge	Difference	Total increase in monthly charge for 800 commercial users[38]
1 phase 40 Amp	R300.00	R200.00	R100.00	R106 667
1 phase 60 Amp	R440.00	R300.00	R140.00	R149 333
1 phase 80 Amp	R580.00	R400.00	R180.00	R192 000
1 phase 100 Amp	R720.00	R450.00	R270.00	R288 000
3 phase 40 Amp	R815.00	R480.00	R335.00	R357 333
3 phase 60 Amp	R1 190.00	R720.00	R470.00	R501 333
3 phase 80 Amp	R1 560.00	R960.00	R600.00	R640 000
3 phase 100 Amp	R1 930.00	R1 200.00	R730.00	R778 667
3 phase 150 Amp	R2 200.00	R1 800.00	R400.00	R426 667
				R3 440 000

The impact that the installation of 800 PV installations of 30 kW_p on the rooftops of commercial electricity customers will have on the municipal income of Drakenstein can be seen in Table 9.

38 Evenly distributed between customer categories.

Table 9: **Reduction in electricity income for Drakenstein municipality from 800 x 30 kW_p commercial PV installations** [3940]

	Increase in income from change in fixed monthly charges[39]	Reduction in income due to new kWh tariff[40]	Reduction in income due to PV generation	Net reduction in income for Drakenstein municipality
Commercial customers stay on the same tariff			-R10 085 818	-R10 085 818
Commercial customers change to SSEG tariff	R3 440 000	-R23 904 000	-R10 085 818	-R30 549 818

From this it is clear that the municipal electricity revenue of Drakenstein municipality would have been increased by R13 285 079[41] if the maximum technically possible amount of solar rooftop PV is installed on the roofs of commercial customers in the municipal area and all of these customers stay on their current tariff structure. Should all of these commercial customers have switched to the new SSEG tariff there would have a loss of revenue to Drakenstein municipality of R7 178 921 for the year[42]. This is less than 1% of the Eskom bills for 2014[43].

It should be pointed out again that this scenario is for the maximum technical possible amount of rooftop PV installations before grid studies are needed. It is highly unlikely that this amount of PV will be installed in the short to midterm in Drakenstein.

Conclusion

The impact that the installation of 24 MW_p of rooftop PV installations will have on the revenue of Drakenstein municipality will depend on the type of customer installing the rooftop PV as well as the tariff structure that the customers were on before and are on after the installations.

The absolute worst case scenario, when all the customers installing PV are on a residential tariff and do not switch to the new SSEG tariff, is a net potential loss to the municipality of R24 million for the 2014/2015 financial year, should these systems have already been installed. This is less than 3% of electricity revenue to Drakenstein. It needs to be pointed out that this high penetration of rooftop PV is highly unlikely in the short and medium term.

39 This was calculated by taking 800 Installations of 30 kWp equally divided between the 9 commercial tariffs for Drakenstein municipality. The existing bulk Time of Use tariffs were not included in this calculation. The financial impact from a user point of view for the bulk Time of Use tariff can be seen in Part D.

40 An assumption is made of 800 commercial electricity users with a remaining 10 000 kWh per month bill remaining after the installation of PV and this remaining electricity is billed at R1.00 per kWh instead of R1.259 per kWh.

41 The net of a reduction in income of R10 085 818 and a reduction in the Eskom bill of R23 370 897. This gives a net gain in revenue of R13 285 079 for the year.

42 The net of a reduction in income of R30 549 818 and a reduction in the Eskom bill of R23 370 897

43 See Appendix 3 for the Drakenstein Eskom accounts for 2014

PV OPPORTUNITIES FOR THE DRAKENSTEIN MUNICIPAL OWNED BUILDINGS

Introduction

In the sections above, it was seen that an accelerated installation rate of PV systems in Drakenstein is technically possible and might have some effect on municipal income.

Shifting focus from the private to the municipal sector, Part C now examines the possibility for Drakenstein Municipal owned building to reduce their carbon footprint, off-set their energy usage and reduce their monthly electricity bill.

This section identifies opportunities for the municipality to install solar photovoltaic technologies on municipal owned buildings and/or municipal land, based on generic data. The overall solar resource in Paarl is examined and compared to other sites in South Africa, followed by closer inspection of three identified sites, where the impact of building orientation and roof incline is considered. The three municipal sites identified are (see Figure 27) the electricity building (1 Jan Van Riebeeck Drive), the Civic Centre (Bergriver Boulevard) and the Civil Engineering building (1 Market Street). One of these three sites is identified in consultation with Drakenstein municipality. Part D sees a full prefeasibility study on this site to determine the viability of installing solar PV on this specific building.

Figure 27: **The location of the 3 sites in relation to Paarl Mountain**

Paarl Electricity Building

Site

The Paarl Electricity Building is situated at 1 Jan Van Riebeeck Drive, in western-central Paarl. (See Figure 27). The site details are presented in Table 10. A general analysis of the site and its orientation and azimuth is carried out but no specific localised shading is considered in this analysis.

Table 10: **Electricity Building Site Information**

Site name	Paarl, Electricity building
Coordinates	33° 44' 26.54" S, 18° 58' 36.12" E
Elevation a.s.l.	115 m
Slope inclination	5°
Slope azimuth	277° west

Figure 28: **Top view of the Paarl electricity building, Google maps**

Figure 28 and Figure 29 show that the buildings have flat roofs that are at multiple levels. A significant draw back for this building is that the highest roof is located in the north. This tall building in the north will throw a shadow on the buildings behind it, limiting the space that can be used to install PV panels. However, even though the building is facing east, the flat roofs will enable that the panels be installed facing north at an optimised angle, which will maximise the electricity out of the PV array.

Figure 29: **Side view of the Paarl electricity building, Google Maps**

System

As this analysis is done for comparative purposes, only the specific yield of a system and not the total yield is of interest here. For this reason, a 1 kW system is proposed and analysed for the location. Table 11 outlines the system specifications.

Table 11: **PV system specifications**

Installed power	1.0 kWp
Type of modules	crystalline silicon (c-Si)
Mounting system	fixed mounting, free standing
Azimuth/inclination	0° north / 29°
Inverter Euro eff.	97.5%
DC / AC losses	5.5% / 1.5%
Availability	99.0%

Potential PV production

As stated previously, the PV production is directly proportional to the irradiation falling on the panels. Table 12 compares the irradiation falling on the panels' surface for different system configurations. The system configuration chosen for this building is a panel inclined at 29° (the optimum angle), north facing and mounted on the flat roofs. A 2-axis tracking system performs better, but for non-concentrated solar options the additional cost and maintenance far outweighs the additional electricity production.

Table 12: **Average yearly sum of global irradiation for different system configurations**

	Global tilt irradiation [kWh/m^2]	Relative to optimally inclined [%]
Optimally inclined (29°)	2105	100
Horizontal	1886	89.6
2-axis tracking	2818	133.9

The panel performance is also affected by the ambient air temperature. This correlation can be seen clearly in Figure 30 and Figure 31 where the performance ratio (PR) is higher in the colder months of the year. The performance ratio indicates the effective yield a module has actually produced in relation to the maximum theoretical yield possible for the module. The PR is fairly low in summer, dropping down to approximately 75% compared to the winter months where a PR of up to 81.5% is seen. This is predominately due to the high ambient temperature in summer. The higher solar irradiance in the summer months, however, more than makes up for the loss due to PR. Detailed system losses are shown in Table 13.

Figure 30: **Monthly sum of global irradiation and the daily air temperature**

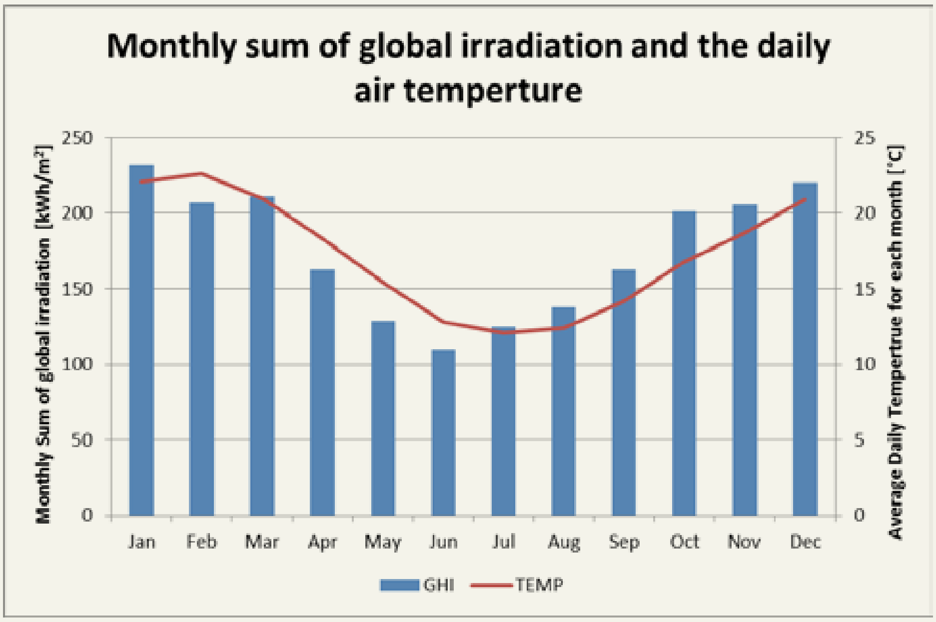


Figure 31: **Monthly sum of specific electricity produced and the performance ratio of the system**

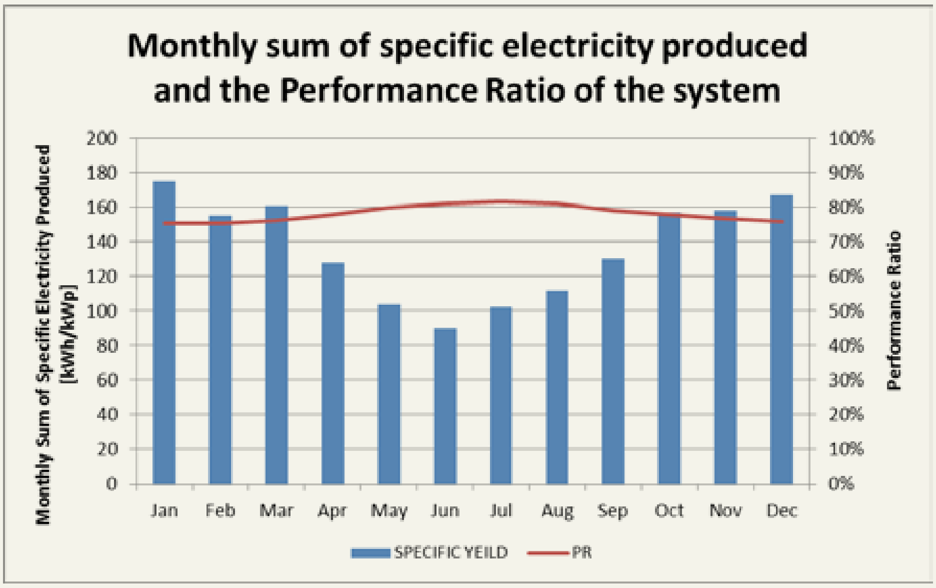


Table 13: **System losses and Performance ratio**

	Energy output [kWh/kWp]	Energy loss [kWh/kWp]	Energy loss [%]	Performance ratio [partial %]	[cumul. %]
1. Global in-plane irradiation (input)	2117			100.0	100.0
2. Global irradiation reduced by terrain shading	2104	-13.0	-0.6	99.4	99.4
3. Global irradiation reduced by reflectivity	2049	-55.0	-2.6	97.4	96.8
4. Conversion to DC in the modules	1830	-219.0	-10.7	89.3	86.4
5. Other DC losses	1729	-101.0	-5.5	94.5	81.7
6. Inverters (DC/AC conversion)	1686	-43.0	-2.5	97.5	79.6
7. Transformer and AC cabling losses	1661	-25.0	-1.5	98.5	78.5
8. Reduced availability	1644	-17.0	-1.0	99.0	77.7
Total system performance	1644	-473.0	-22.3		77.7

Civic Centre

Site

The Paarl Civic Centre is situated in Bergriver Boulevard, central Paarl (see Figure 27). The site details are presented in Table 14. A general analysis of the site and its orientation and azimuth is carried out but no specific localised shading is considered in this analysis.

Table 14: **Civic Centre Site Information**

Site name	Paarl, Civic Centre
Coordinates	33° 44' 13.6" S, 18° 58' 4.68" E
Elevation a.s.l.	110 m
Slope inclination	0°
Slope azimuth	286° west

Figure 32: **Top view of the Civic Centre, Google maps**

Figure 32, Figure 33 and Figure 34 show that the buildings have flat roofs that are at multiple levels. Owing to the orientation of the building, the shading effects on the lower roofs will not be significant. As with the electricity building, even though the building is facing north west, the flat roofs will enable the panels to be installed facing north at an optimised angle which will maximise the electricity output of the PV array.

Figure 33: **Side view of the Civic Conference Centre, Google Maps**

Figure 34: **Front view of the Civic Centre, Google Maps**

System

As this analysis is done for comparative purposes, only the specific yield of a system and not the total yield is of interest here. For this reason, a 1 kW system is proposed and analysed for the location. Table 15 outlines the system specifications.

Table 15: **PV system specifications**

Installed power	1.0 kWp
Type of modules	crystalline silicon (c-Si)
Mounting system	fixed mounting, free standing
Azimuth/inclination	0° north / 29°
Inverter Euro eff.	97.5%
DC / AC losses	5.5% / 1.5%
Availability	99.0%

Potential PV production

As stated previously the PV production is directly proportional to the irradiation falling on the panels. Table 16 compares the irradiation falling on the panels' surface for different system configurations. The system configuration chosen for this building is a panel inclined at 29° (the optimum angle), north facing and mounted on the flat roofs. A 2-axis tracking system does perform better but for non-concentrated solar options the additional cost and maintenance far outweighs the additional electricity production.

Table 16: **Average yearly sum of global irradiation for different system configurations**

	Global tilt irradiation [kWh/m^2]	Relative to optimally inclined [%]
Optimally inclined (29°)	2104	100
Horizontal	1882	89.4
2-axis tracking	2786	132.4

The panel performance is also affected by the ambient air temperature. This correlation is clearly seen in Figure 35 and Figure 36 where the performance ratio (PR) is higher in the colder months of the year. The performance ratio indicates the effective yield a module has actually produced in relation to the maximum theoretical yield possible for the module. The PR is fairly low in summer, dropping down to approximately 75% compared to the winter months where a PR of up to 80.5% is seen. This is predominately due to the high ambient temperature in summer. The higher solar irradiance in the summer months, however, more than makes up for the loss due to PR. Detailed system losses are shown in Table 17.

Figure 35: **Monthly sum of global irradiation and the daily air temperature**

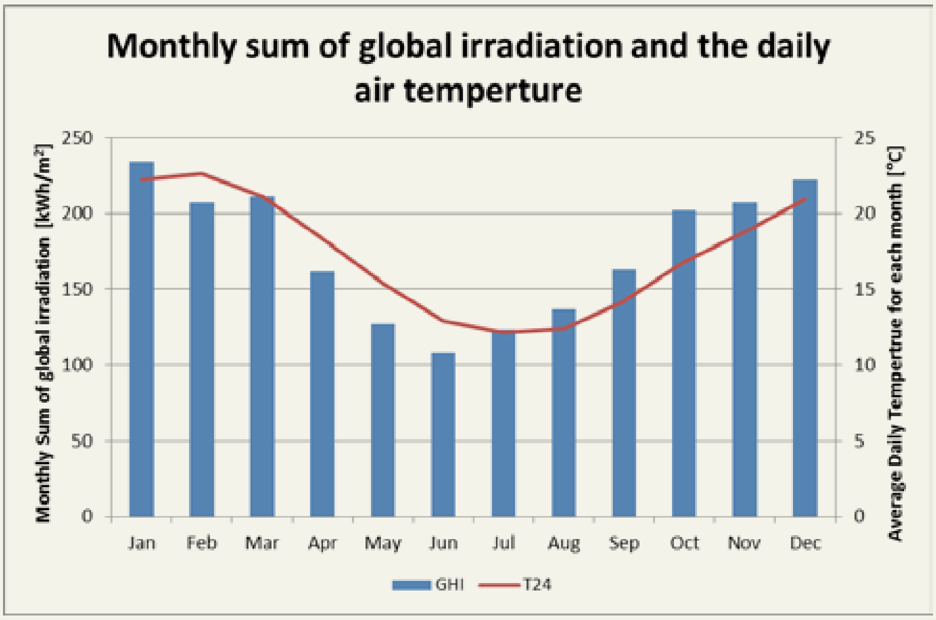


Figure 36: **Monthly sum of specific electricity produced and the performance ratio of the system**

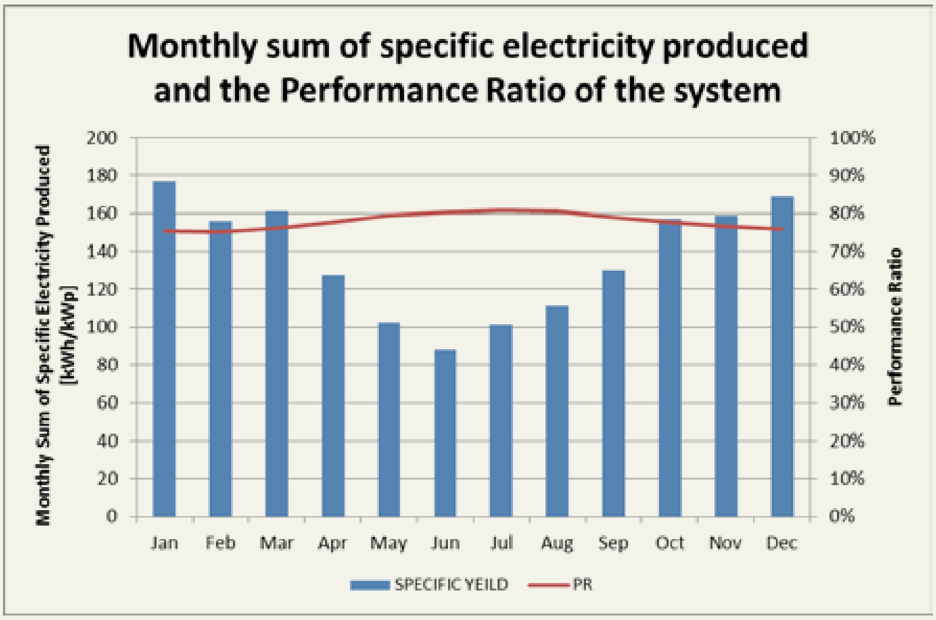


Table 17: **System losses and Performance ratio**

	Energy output [kWh/ kWp]	Energy loss [kWh/ kWp]	Energy loss [%]	Performance ratio [partial %]	[cumul. %]
1. Global in-plane irradiation (input)	2121			100.0	100.0
2. Global irradiation reduced by terrain shading	2104	-17.0	-0.8	99.2	99.2
3. Global irradiation reduced by reflectivity	2049	-55.0	-2.6	97.4	96.6
4. Conversion to DC in the modules	1829	-220.0	-10.7	89.3	86.2
5. Other DC losses	1729	-100.0	-5.5	94.5	81.5
6. Inverters (DC/AC conversion)	1685	-44.0	-2.5	97.5	79.4
7. Transformer and AC cabling losses	1660	-25.0	-1.5	98.5	78.3
8. Reduced availability	1643	-17.0	-1.0	99.0	77.5
Total system performance	1643	-478.0	-22.5		77.5

1 Market Street building

Site

The Civil Engineering Building is situated at 1 Market Street, in eastern-central Paarl (see Figure 27). The site details are presented in Table 18. A general analysis of the site and its orientation and azimuth is carried out but no specific localised shading is considered in this analysis.

Table 18: **1 Market Street Building Site Information**

Site name	Paarl, 1 Market Street
Coordinates	33° 44’ 20.03” S, 18° 57’ 47.11” E
Elevation a.s.l.	121 m
Slope inclination	3°
Slope azimuth	79° east

Figure 37: **Top view of the 1 Market Street Building, Google maps**

Figure 37 and Figure 38 show that the buildings consist of two adjacent flat roofs. The roofs are at the same level, however the ornamental gables on the facades of the building, causes some localised shadings. As these gables are located on the east and west sides of the building, the PV arrays on both roofs will be affected. The building is orientated north and the roofs are flat, allowing the panels to be installed facing north at an optimised angle, which will maximise the electricity out of the PV array.

Figure 38: **Side view of the Civic Centre, Google Maps**

System

As this analysis is done for comparative purposes, only the specific yield of a system and not the total yield is of interest here. For this reason, a 1 kW system is proposed and analysed for the location. Table 19 outlines the system specifications.

Table 19: **PV system specifications**

Installed power	1.0 kWp
Type of modules	crystalline silicon (c-Si)
Mounting system	fixed mounting, free standing
Azimuth/inclination	352° north / 29°
Inverter Euro eff.	97.5%
DC / AC losses	5.5% / 1.5%
Availability	99.0%

Potential PV production

As stated previously the PV production is directly proportional to the irradiation falling on the panels. Table 20 compares the irradiation falling on the panels' surface for different system configurations. The system configuration chosen for this building is a panel inclined at 29° (the optimum angle), north facing and mounted on the flat roofs. A 2-axis tracking system does perform better but for non-concentrated solar options the additional cost and maintenance far outweighs the additional electricity production.

Table 20: **Average yearly sum of global irradiation for different system configurations**

	Global tilt irradiation [kWh/m^2]	Relative to optimally inclined [%]
Optimally inclined (29°)	2080	100
Horizontal	1865	89.7
2-axis tracking	2717	130.7

The panel performance is also affected by the ambient air temperature. This correlation is clearly seen in Figure 39 and Figure 40 where the performance ratio (PR) is higher in the colder months of the year. The performance ratio indicates the effective yield a module has actually produced in relation to the maximum theoretical yield possible for the module. The PR is fairly low in summer, dropping down to approximately 75% compared to the winter months where a PR of up to 79.8% is seen. This is predominately due to the high ambient temperature in summer. The higher solar irradiance in the summer months, however, more than makes up for the loss due to PR. Detailed system losses are shown in Table 21.

Figure 39: **Monthly sum of global irradiation and the daily air temperature**

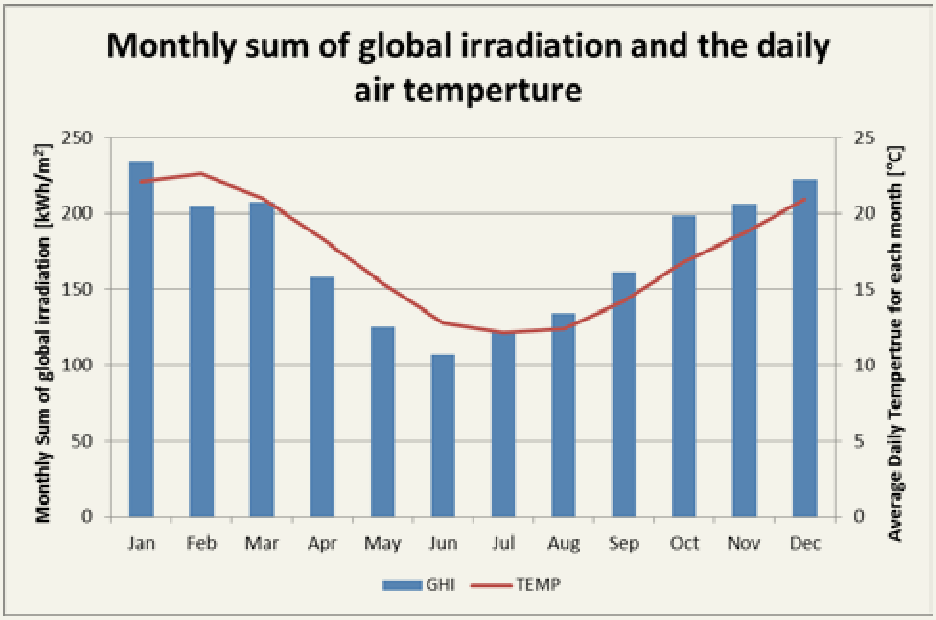


Figure 40: **Monthly sum of specific electricity produced and the performance ratio of the system**

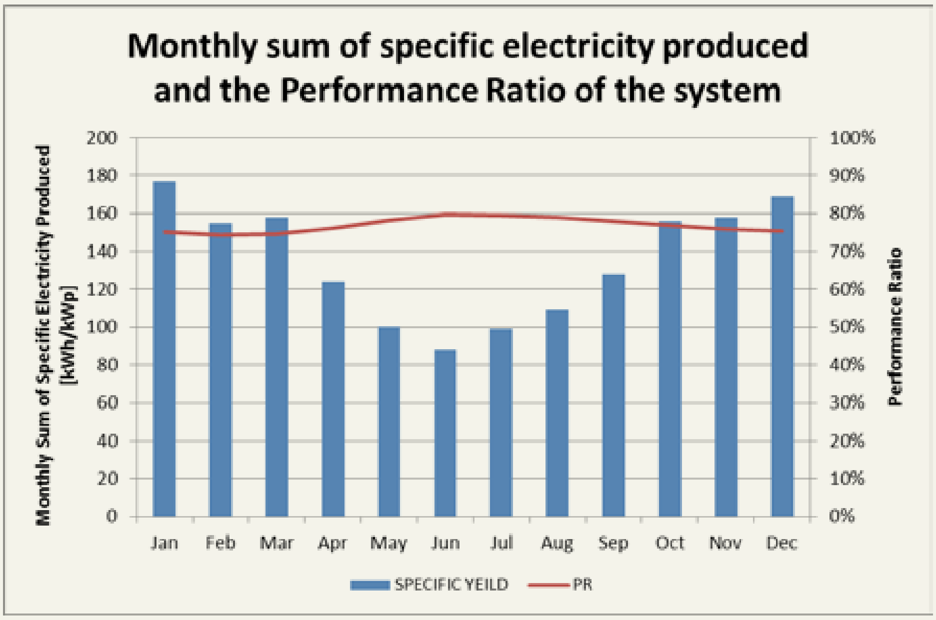


Table 21: **System losses and Performance ratio**

	Energy output [kWh/kWp]	Energy loss [kWh/kWp]	Energy loss [%]	Performance ratio [partial %]	[cumul. %]
1. Global in-plane irradiation (input)	2125			100.0	100.0
2. Global irradiation reduced by terrain shading	2080	-45.0	-2.1	97.9	97.9
3. Global irradiation reduced by reflectivity	2029	-51.0	-2.5	97.5	95.5
4. Conversion to DC in the modules	1808	-221.0	-10.9	89.1	85.1
5. Other DC losses	1709	-99.0	-5.5	94.5	80.4
6. Inverters (DC/AC conversion)	1666	-43.0	-2.5	97.5	78.4
7. Transformer and AC cabling losses	1641	-25.0	-1.5	98.5	77.2
8. Reduced availability	1625	-16.0	-1.0	99.0	76.5
Total system performance	1625	-500.0	-23.5		76.5

Discussion and comparison of sites

Table 22 summarises the performance of each site.

Table 22: **Site comparison**

	Electricity building	Civic Centre	1 Market Street
GHI [kWh/m^2]	2105	2104	2080
PR [%]	77.7	77.5	76.5
Specific Yield [kWh/kWp]	1644	1643	1625

The slight difference in performance at each site can be attributed to the distance of the site to Paarl Mountain, see Figure 27. This is clearly visualised through the shading diagrams for each location shown in Figure 41 to Figure 43.

Figure 41: **Shading diagram for the Electricity Building**

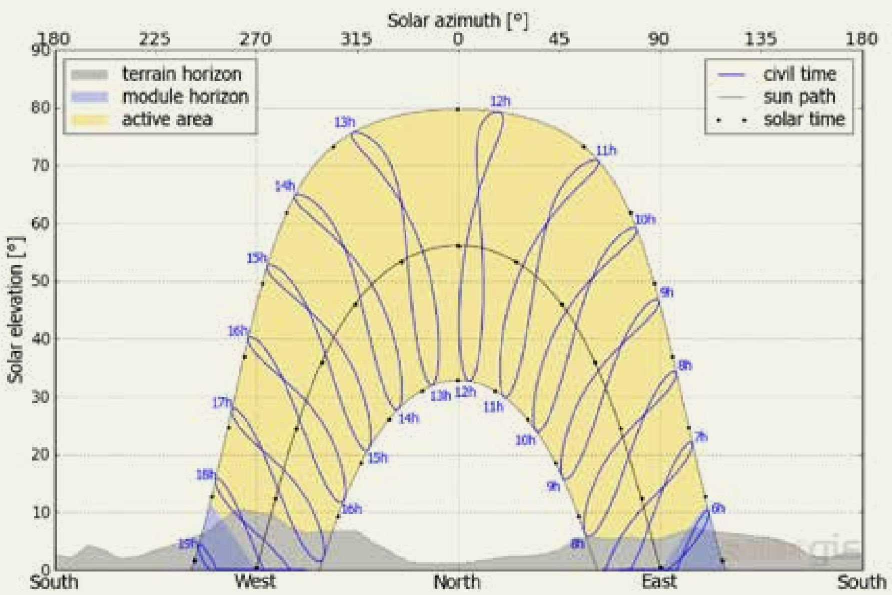


Figure 42: **Shading diagram for the Civic Centre**

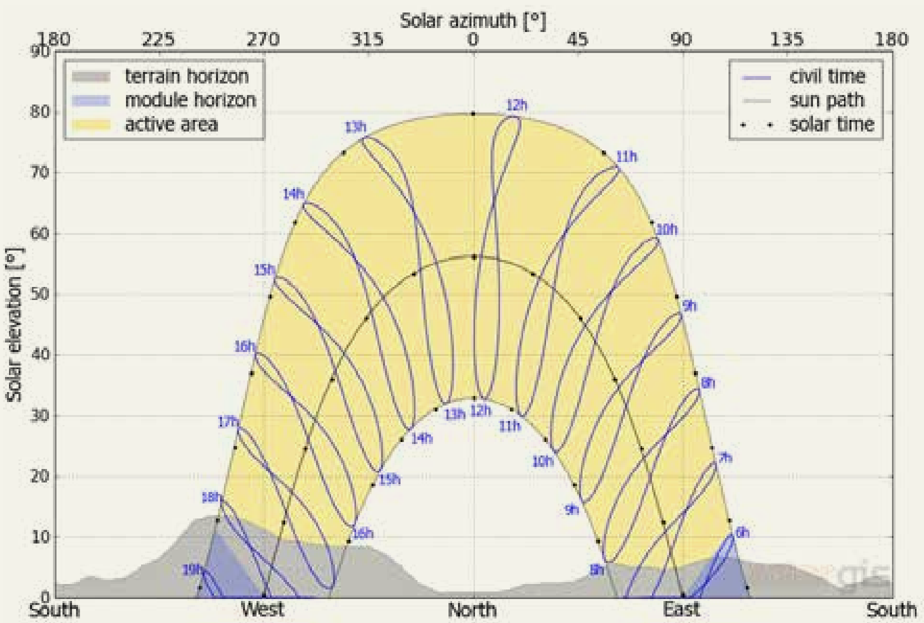


Figure 43: **Shading diagram for the 1 Market Street Building**

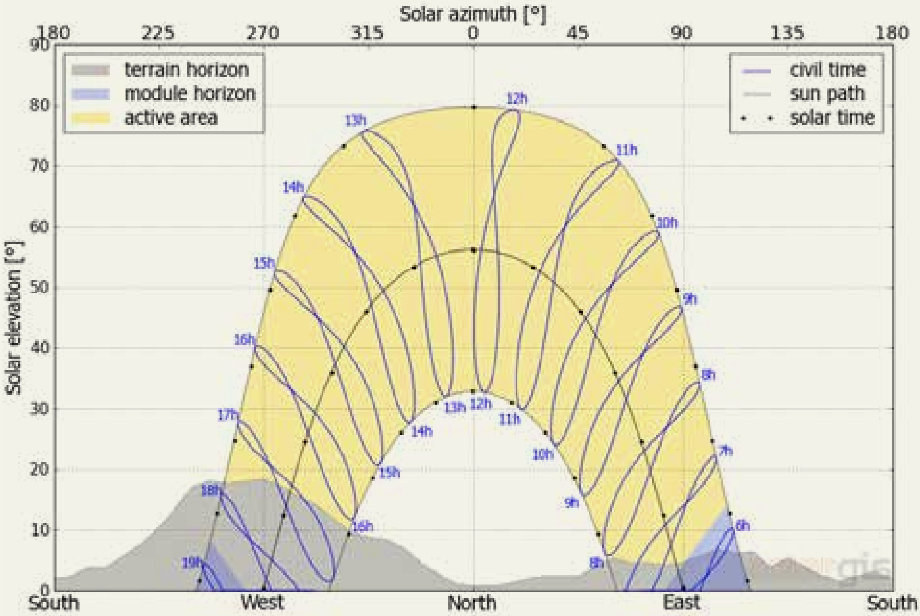


Figure 41 to Figure 43 show how the PV production day becomes shorter, the closer the site is to Paarl Mountain, with all generation stopping just before 18h in the summer for the 1 Market Street building, and at about 18:15 in the summer for both the Electricity Building and the Civic Centre. This correlates with the =/- 1% difference in electricity production between the buildings as discussed earlier.

The PV yield is only one factor to consider when choosing an optimal PV installation. Other factors are; matching the load to the electricity produced and the condition of the roof. All the analysed buildings are predominantly used for office activities, which match well with the diurnal solar cycle indicating that the generated electricity will be used by the building. However, weekends and public holidays, especially the shutdown period over the festive season, pose as a problem as the usage during these periods is significantly lower. The 1 Market Street building contains the Paarl library which is open on a Saturday, which will help alleviate part of this problem for this building.

The condition of the roofs for each of the buildings was assessed with the use of Google Earth, since no site visits have been carried out for this preliminary assessment. From this vantage point, the Electricity building appears to have very little useable roof space as large part of the visible roofing is corrugated iron which is unsuitable for PV installation while the case concrete part of the roof has many shading concerns as a result of the raised centre and parapets surrounding the roof (As seen in Figure 44). Owing to these concerns, the Electricity building this building will not be further considered for PV installation.

Figure 44: **Roof concerns of the Electricity building**

The roof of the Civic Centre appears to be structurally sound for a PV installation. Hhowever there are concerns around the possible localised shading due to the different heights of the various roofs of the building. This is illustrated in Figure 45. Most of the raised sections are to the north of most of the available roof space which will have a negative impact on the local shading of the PV panels.

Figure 45: **Shading concerns of the Civic Centre**

As seen from Table 22, the 1 Market Street building has the poorest performance (by 1%, thus minimal) of the 3 sites, but has a better capacity to off take the generated load as discussed with the presence of the library on the ground floor. This building also has a gravel covered concrete roof, which will be able to hold the weight of a PV installation with minimal shading concerns. For these reasons, and after consultation with Drakenstein municipal officials, a pre-feasibility study into the economic viability of installing PV panels on the roof of this building will be done for this building.

Conclusion

The analysis shows that a typical site within the Drakenstein Municipality has a good solar resource and PV yield. If a PV array is installed in within the municipal area, orientated to the north and inclined at an optimised angle of 29° a performance ratio of approximately 77% is achieved. The high temperature in the summer months reduces the efficiency of the PV panels and the presence of Paarl Mountain limits the late afternoon generation capacity. However, in comparison to other sites in South Africa, a typical site in the area of focus has a good solar yield. Since the specific yield for all three analysed sites is greater than 1600 kWh/kW_p economically viable projects are expected.

PREFEASABILITY STUDY FOR THE INSTALLATION OF PV ON 1 MARKET STREET PAARL

Introduction

As determined in Part C, the solar resource within the Drakenstein municipal area is good and should result in economically viable PV projects. Through this study a prefeasibility analysis is carried out to determine the economic viability of a Photovoltaic (PV) installation on the roof of 1 Market Street, Paarl. The location of this building is seen in Figure 46. The available solar resources are evaluated, the potential electricity generated and the financial projections for the site are modelled.

Figure 46: **The location of the three analysed buildings in the PV Opportunities Report**

Site Information

The town of Paarl is located at the coordinates of -33.724° S, 18.956° E, and 1 Market Street, at -33.7389° S, 18.9631° E (site information is given in Table 18). The town is located in a valley with Paarl Mountain to the west and Haweqwa mountain range to the east. Owing to this location there are foreseeable drawbacks with regards to the electricity production from a PV installation on a macro scale (discussed in detail in Part C). The town sits at the foot of the Paarl Mountain, which obscures the late afternoon sun, reducing the period of time that the PV array will produce electricity.

The town is located further from the Haweqwa range and thus this range should not have such a great impact on the early morning electricity production.

Table 23: **1 Market Street, Paarl: Building Site Information**

Site name	1 Market Street, Paarl
Coordinates	33° 44' 20.03" S, 18° 57' 47.11" E
Elevation a.s.l.	121 m
Slope inclination	3°
Slope azimuth	79° east

Figure 47: **Top view of 1 Market Street, Paarl, Google maps**

The building has two adjacent flat roofs, as can be seen in Figure 47. The roofs are at the same elevation, however the presence of the large middle dome separating the two roofs may prove problematic in respect to localised shadings. Together with the raised centre dome, the ornamental gables on the facades of the building will also cause localised shadings, Figure 48. The red areas in Figure 47 show the spaces where PV panels can possibly be installed. As the gables are located on the east and west sides of the building, the PV arrays on both roofs will be affected. The building is orientated 5° west of north and the roofs are flat, allowing the panels to be installed at an optimised angle, maximising the electricity output of the PV array. The general solar resource in the Paarl area and possible PV production for this building has been analysed in the PV Opportunities Report with a detailed analysis following in this report.

Figure 48: **Side view of the Civic Centre, Google Maps**

Assessment Method

For the successful implementation of a PV system, it is imperative to match the electricity produced by the PV array to the electricity demand of the building. Thus, the load profiles of the building must be analysed together with the behaviour of the PV array. The available usage data consists of monthly bills over a two-year period and half-hourly temporal data over a 10-month period. The half-hourly data is of great interest, as through an analysis, the daily, weekly and monthly load trends of the building are illuminated.

PVPlanner and PVsyst software are among the tools used to derive the most suitable locations for PV panel installations. The solar data is sourced from two different sources, SoDa and SolarGIS, depending on the purpose. The layout of the panels and area covered is determined by the selected equipment and spacing thereof.

The identified roof areas are modelled in PVsyst to obtain the final production estimates. PVsyst software allows for detailed modelling, taking into account the effects of local shading, equipment losses, and panel- and string layouts, among other features. The same annual data as used for the macro scale study (the PV Opportunities Report) will not provide the necessary accuracy for the detailed modelling. Solar irradiation data, HelioClim, which combines measurements from ground stations and satellite data, is sourced from SoDa to provide hourly GHI data that is used in the PVsyst software for detailed modeling. There are standard industry practices used in the report, which will not be described in detail, however concerns specific to this installation location will be discussed.

In order to model the potential production of a PV array, a specific PV panel and inverter needs to be selected. The choice of reference equipment is based on global statistics on the manufacturers' production volumes, age of the company and the manufacturer having an established presence in South Africa.

The reference PV panel that is used for modelling purposes is the polycrystalline panel available from Yingli Solar, YL240P-29b. Yingli Solar is one of the top global producers of PV panels that has been manufacturing for more than 15 years and fall in the Gigawatt production category. The reference inverter used is a SMA Sunny Tripower 25 kW inverter. SMA is currently the largest inverter manufacturer globally, with more than 25 years of experience and an established local market. Both of the reference equipment manufacturers are very large globally and in South Africa with proven reliability.

The study and its results are impacted by data inconsistencies, loss assumptions and equipment selection. Owing to the unpredictable nature of the climate and the variety of installation setups, the actual production of the installation can differ from the predicted values. The results of the study is therefore for decision making purposes and should not be used as an accurate prediction of the PV production of the installed system.

Assessment Results

Electricity energy consumption and characterisation

In order to match the PV production to the required building load the temporal load data is analysed. Half-hourly data is available the 15th April 2014 to the 10th of February 2015. The raw data for the real power and apparent power is plotted in Figure 49.

Figure 49 shows that the power demand rarely drops below 20 kW. Time periods when the usage drops to zero, a power cut or load shedding is assumed. From this plot, in order to avoid any feed back into the grid the PV system should be no greater than 20 kW_p. To fully utilise a PV system it should be matched to the lowest demand on an annual basis, thus the usage trends are evaluated. Such an analysis will indicate which period of the day saving can be achieved and the associated cost savings per kWh of PV generated electricity. An hourly analysis will determine how well matched the proposed PV system and the usage profiles will be.

Figure 49: **Raw data plot 30 min intervals**

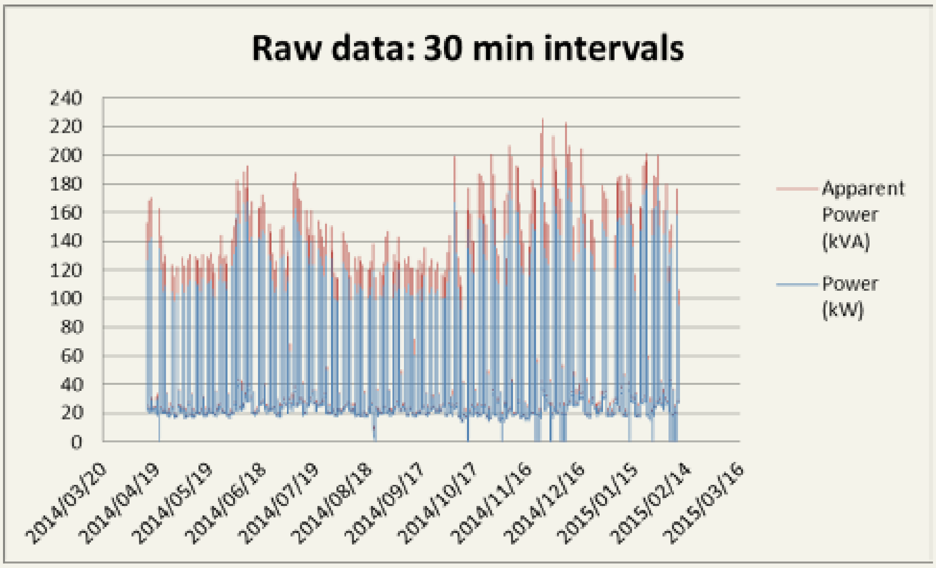


Figure 50: **Electricity Usage: Hourly averaged plots for each month of the year**

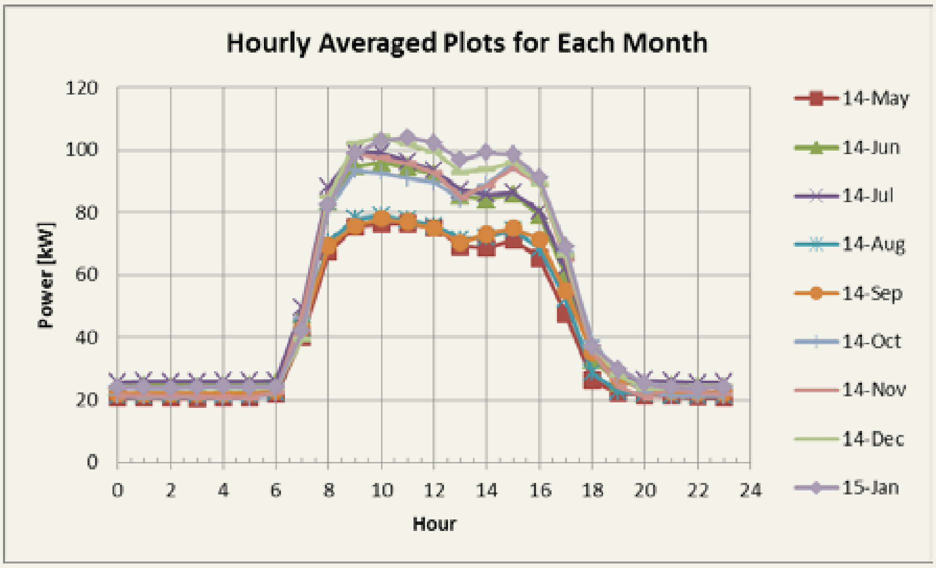


Figure 50 shows the hourly power usage averaged for each month and Figure 51 shows the hourly power usage averaged for each month for weekdays only. Figure 51 shows that the peak, daily weekday demand takes place between 9:00 to 16:00. This usage profile makes the application of a PV system desirable as it coincides with the diurnal solar cycle. It is typically during these hours that electricity is produced by the PV array and will thus off set the required electricity from the municipality feed in point. This will result in not only active energy savings but also demand charge savings as the consumption peak occurs during daylight hours. These plots also show that the electricity usage is at a peak in the mornings when all the air-conditioners are running at full. A further trend that is observed shows that the highest usage occurs in the summer months and this electricity usage trend matches well with the electricity production of a PV system which will be the highest during this period.

Figure 51: **Electricity Usage: Hourly averaged plots for each month of the year, weekdays only**

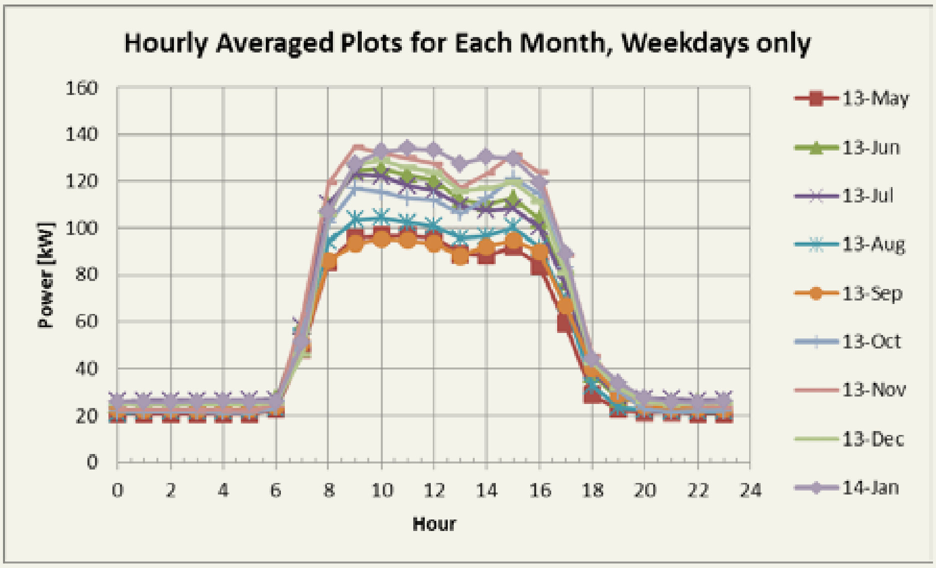


Figure 52 shows the average power demand for each day of the week for each month of the year. It is seen that Saturday and Sunday require less electricity than the rest of the week, thus the minimum load needs to be matched to these demand profiles. Figure 53 shows that the daylight minimum is 20 kW and thus the PV system must be matched to this minimum demand if all the electricity produced is to be used for self-consumption. However, since Drakenstein municipality has recently established a co-generation tariff, a larger system will be allowed. The size of this system will be constrained by the available roof space. If there is available roof space it is suggested that this system be no bigger than 120 kW_p which is the weekday maximum demand.

Figure 52: **Power Usage: Average power usage for each day of the week for each month of the year**

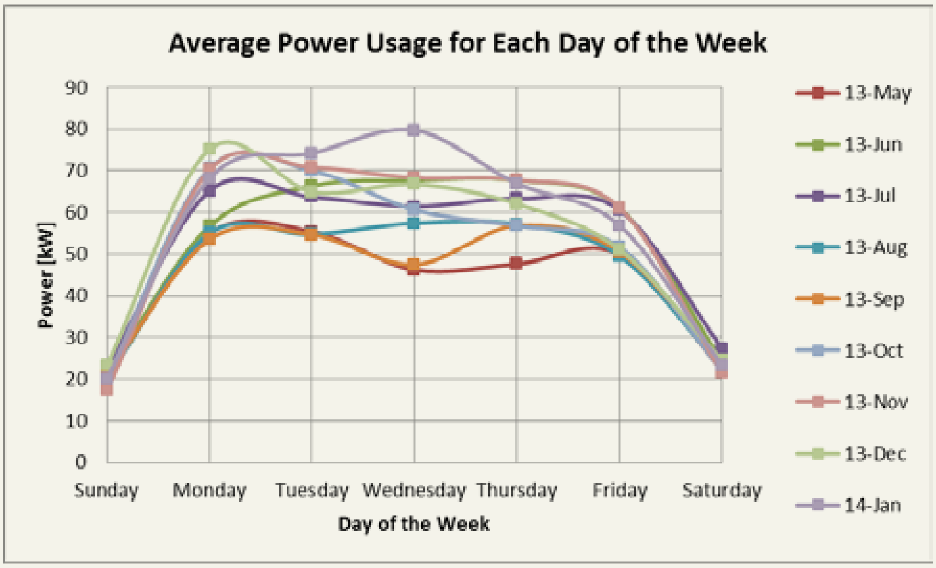
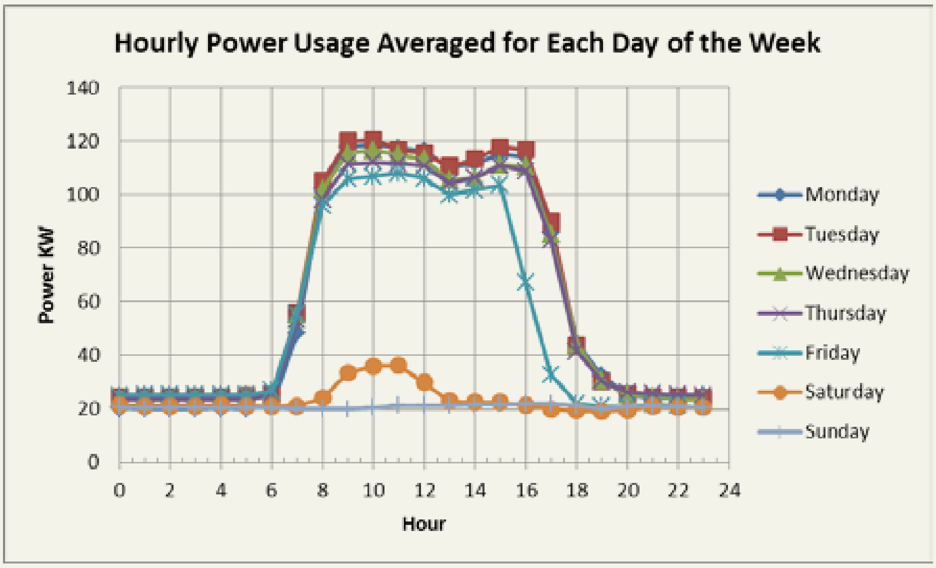


Figure 53: **Power Usage: Hourly power usage averaged for each day of the week**



Achievable Energy Savings through PV installation

From the macro solar analysis carried out in the PV Opportunities Report, a specific yield of 1 624 kWh/kW$_p$ with a performance ratio (PR) of 76.5% was found. Such a macro scale analysis does not take the local shading effects of the building into account, thus a detailed analysis is carried out through the use of PVsyst software with HelioClim hourly solar irradiation data. One of the main concerns of installing

PV panels in the Paarl area is the high daily temperatures that will affect the performance of the PV panels reducing the PV panel efficiency.

The detailed shading analysis is based on measured irradiation for the year 2014. The roof areas are modelled as per the architectural layout drawings provided and various photographs. Areas with significant shading impact are identified and the PV panel layout adjusted to reduce the impact where possible.

25 kWp System

In order to achieve a nominal power out of approximately 20 kW_p with the preliminary indicated PR of 76.5%, a 25 kW_p system is proposed. The PR value is an averaged value and due to daily variation the proposed 25 kW_p system can possibly exceed the 20 kW_p threshold. This concern will be addressed when the hourly output from the numerical PV simulation is analysed. During the modelling process significant shading effects are seen due to the gables situated on the east and west sides of the building (Figure 38) and the centre dome. Owing to this shading, the layout shown in Figure 54 is proposed with the PV panels located in the centre of each roof. The building is orientated 5° towards the west, and the panels follow this orientation.

Figure 54: **Proposed panel layout for the 25 kW_p system**

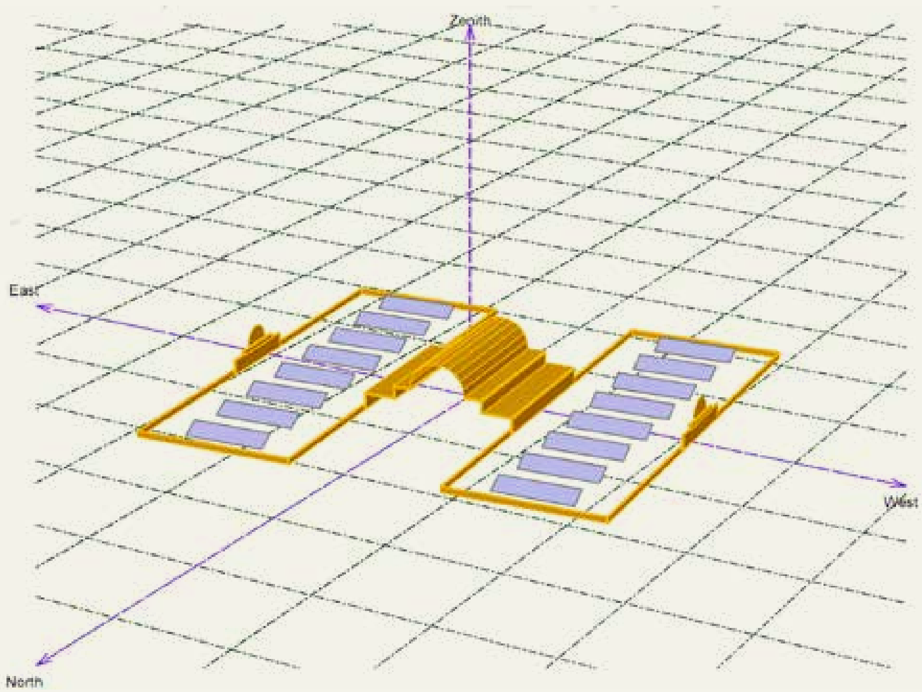


Figure 55 shows the sun's movement and shading effect on the PV system during different times of the day and different seasons, throughout the year.

Owing to the height of the gables and centre dome roof significant amount of shading is shed on the PV panels, with the worst effects seen in winter, when the sun is at a low angle. In order to minimize these shading effects, the panels are placed in the centre of each roof. The seen shading profile may be problematic with respect to reducing the morning peak (highest peak of the day), but the system will lower the electricity usage between 9:00 and 16:30 in summer and 10:00 and 15:30 in winter on clear days.

Figure 55: **Sun path diagram, indicating the shading losses for the proposed 25 kW_p system**

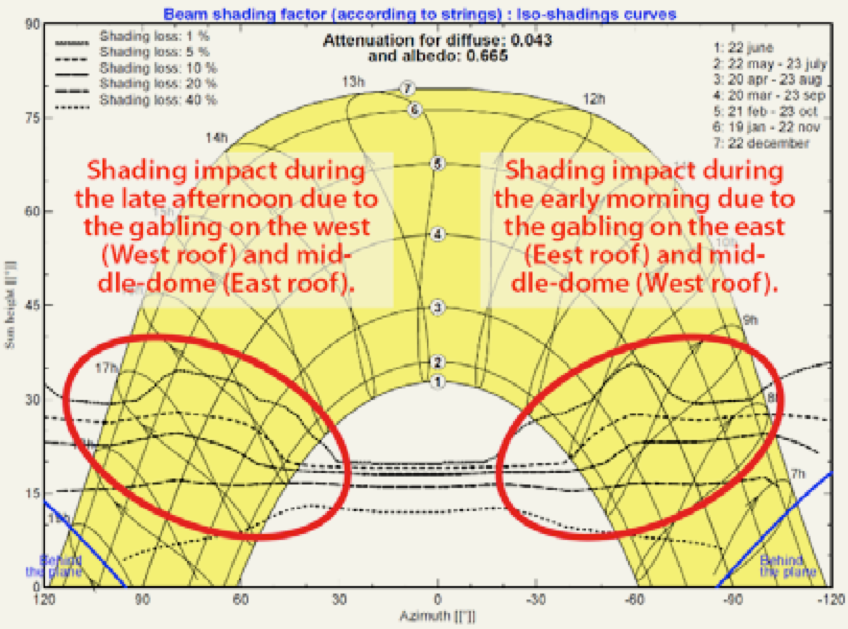


Table 24 outlines the system's production output and production losses. Figure 56 shows the monthly PV electricity supply. Figure 57 and Figure 58 show the load profile with the installation of the PV array of a typical summer and winter day respectively in order to visually see the energy savings that can be realised through the installation of a PV array. Figure 59 shows the comparison between the hourly PV production and the hourly power usage of the building.

Table 24: **25 kW_p system production output and production losses**

Parameter	Value
Production Output	
Performance Ratio	77.4%
Specific Yield	1 643 kWh/kW_p/year
Produced Electricity	41.41 MWh/year
Production Losses (System layout specific)	
Far shading losses	1.9%
Near shading losses	1.7%
Shading: electrical loss due to strings	0.2%
Temperature Losses	10.2 %

Table 24 shows a reasonable specific yield and performance ratio that should result in an economically feasible system. Table 24 highlights that the major loss of PV production is due to high ambient temperatures that is an order larger than the shading losses. Figure 57 and Figure 58 show that the morning and afternoon peaks are still significant and thus the maximum demand will not be reduced as significantly as the active energy. To overcome this problem, a staggering of the usage load (putting air-conditioners on a timer to combat the morning start up peak), is suggested to even out the peaks and in turn increasing savings.

Figure 56: **Monthly electricity production by the 25 kW_p PV system**

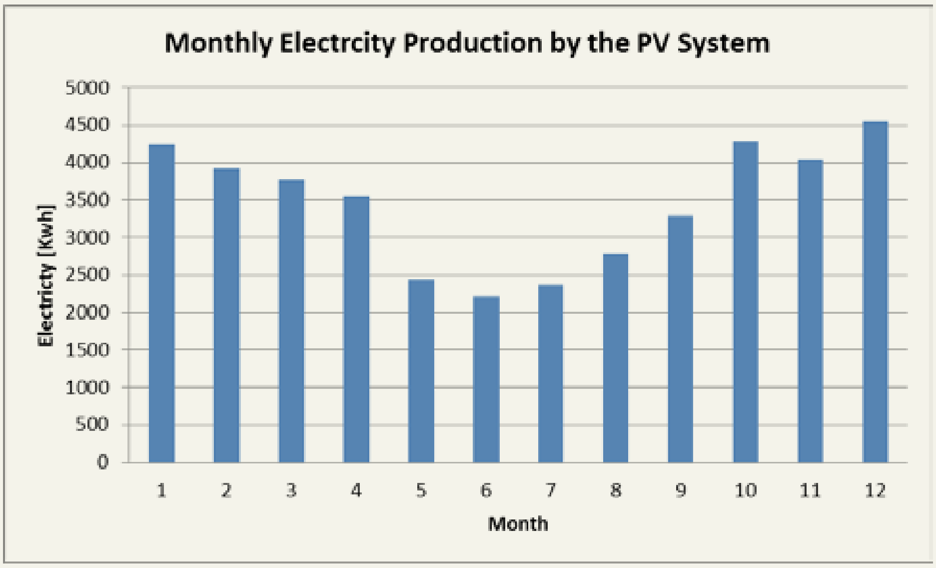


Figure 57: **Hind cast load profile after PV array is installed for a typical day in December**

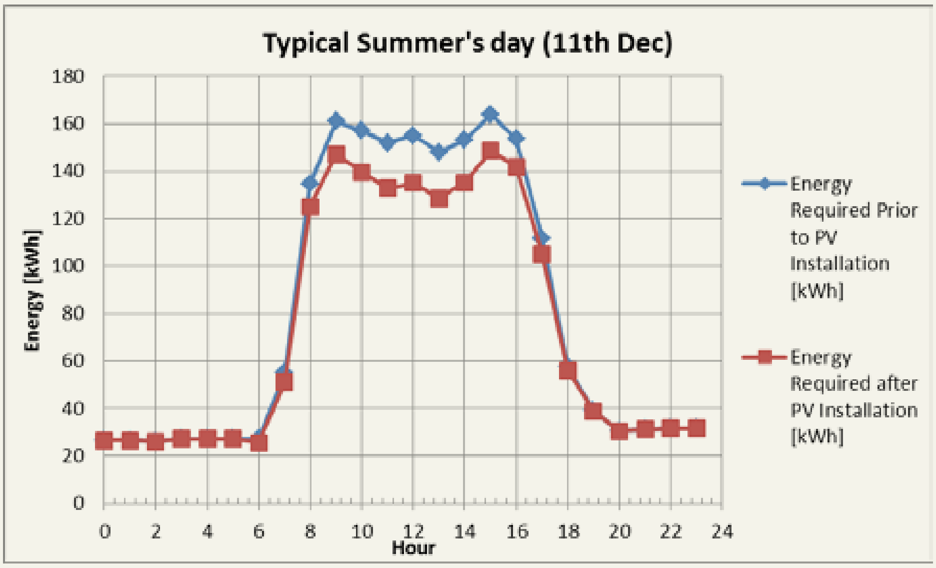
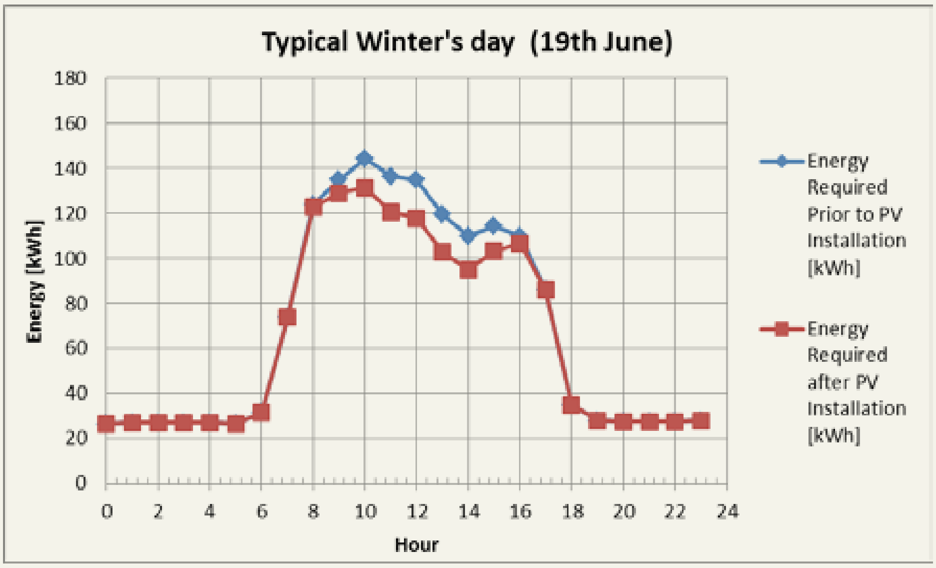


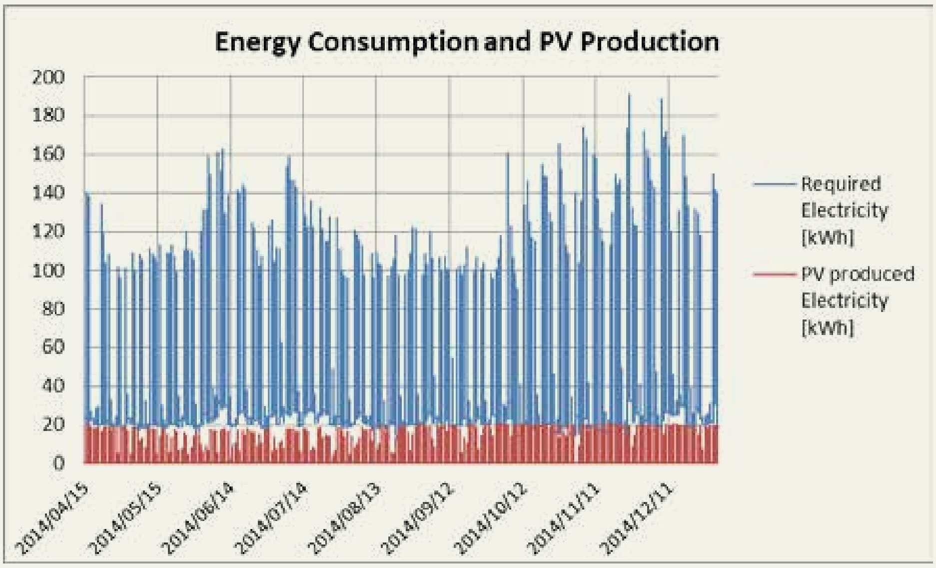
Figure 58: **Hind cast load profile after PV array is installed for a typical day in June**



The hind cast model results are presented in Figure 59. Figure 59 shows that during December there may be times when not all the electricity produced by the PV system is used. When the 10 months of available electricity usage data is compared with the hind cast PV model, the total excess electricity amounts to 74.8 kWh, which is seen as negligible when compared to the total 27 763 kWh produced over this same period of time. This assumption can hold for the entire year as the period over which the comparison is carried out encompasses the majority of South Africa's public holidays (times of little electricity usage) and the summer months (period of highest

PV production). The economic validity of this system will be carried out in the next chapter of this report.

Figure 59: **Comparison between electricity consumed and electricity produced by the proposed 25 kW_p PV plant**



50 kW_p System

The largest system that can be accommodated on the roof of 1 Market Street, is a 50 kW_p system. The panels will cover the entire roof space and the shading effects of the gables and centre dome cannot be avoided. The layout of this system is shown in Figure 60. The building is orientated 5° towards the west and the panels follow this orientation.

Figure 61 shows the sun's movement and shading effect on the PV system during different times of the day and different seasons, throughout the year. The height of the gables and centre dome roof, shed significant amount of shading on the PV panels, with the worst effects seen in winter when the sun is at a low angle. At the extreme case of winter equinox, production will only take place between 12:00 and 14:00 on 1% of the panels, and between 10:30 and 15:15 on 10% of the panels. Ideally all shading is to be avoided, however due to the limited roof space, the shading cannot be avoided, and the string layout of the panels must be carefully considered to minimize the shading impact.

Figure 60: **Proposed panel layout for the 50 kW$_p$ system**

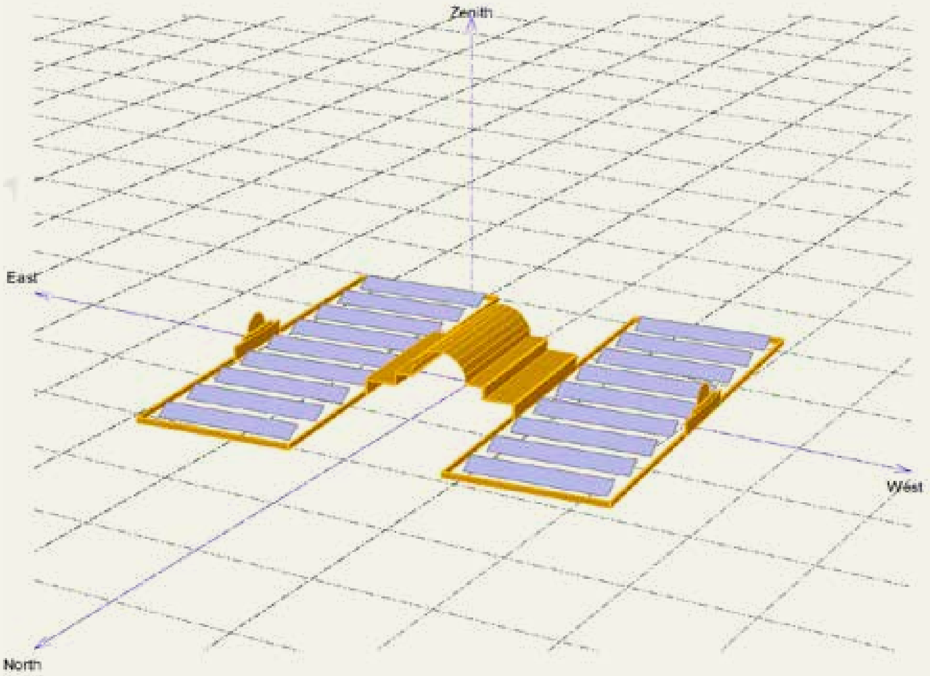


Figure 61: **Corresponding shading diagram for the 50 kW$_p$ system**

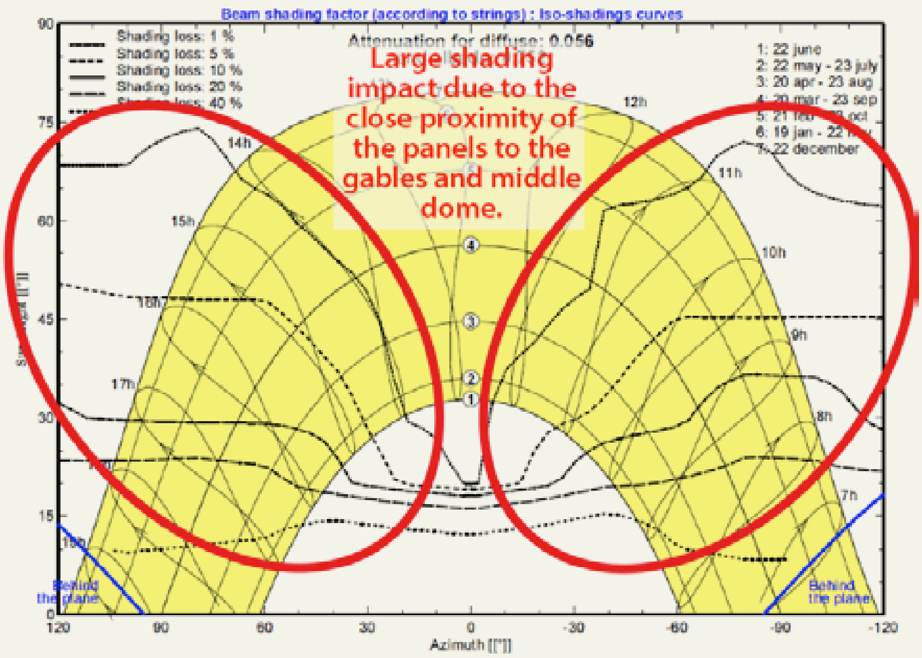


Table 25 outlines the 50 kW$_p$ system's production output and production losses. Figure 62 shows the monthly PV electricity supply. Figure 63 and Figure 64 show the load profile with the installation of the PV array of a typical summer and winter day respectively in order to visually see the electricity savings that can be realised through the installation of a PV array. Figure 65 shows the comparison between the hourly PV production and the hourly power usage of the building.

Table 25: **50 kW_p system production output and production losses**

Parameter	Value
Production Output	
Performance Ratio	76.2%
Specific Yield	1 619 kWh/kW_p/year
Produced Electricity	81.57 MWh/year
Production Losses (System layout specific)	
Far shading losses	1.9%
Near shading losses	2.6%
Shading: electrical loss due to strings	0.7%
Temperature Losses	10.1 %

Table 25 shows that even with the large localized shadings a reasonable specific yield is realised, only 1.2% lower than the 25 kW_p system. Figure 62 and Figure 63 show that the morning and afternoon peaks are still significant, but for the summer day the morning and afternoon peaks are reduced by approximately 30 kW. The PV system will not be producing at rated power at 9:00 and 15:00 (times when peaks are seen) due to the incidence angle of the incoming solar radiation. In winter only one daily peak is seen at 10:00 and the PV installation reduces this peak by 20 kW, shifting the peak consumption to 9:00.

When the 10 months of available electricity usage data is compared with the hind cast PV model, Figure 65, the total excess electricity amounts to 4 100 kWh, which is 7.5% of the total electricity produced over this period. It is important to take note of when this excess electricity (wastage if not billed on a net metering tariff) occurs as this building is billed on a time of use tariff and this excess electricity can result in a small monetary value due to time of occurrence with the larger system promoting demand reduction. The economic validity of this system will be carried out in the next chapter of this report.

Figure 62: **Monthly electricity production by the 50 kW_p PV system**

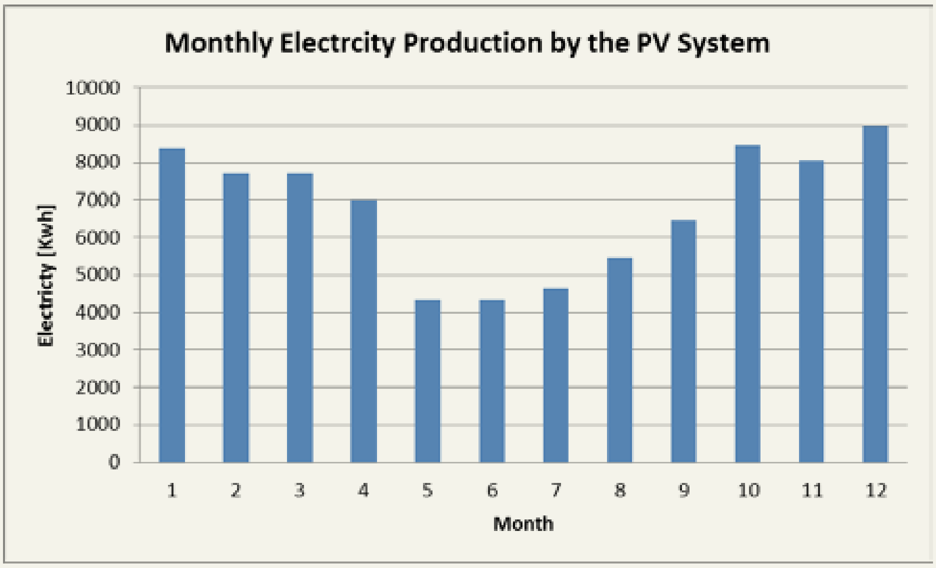


Figure 63: **Load profile after PV array is installed for a typical day in December**

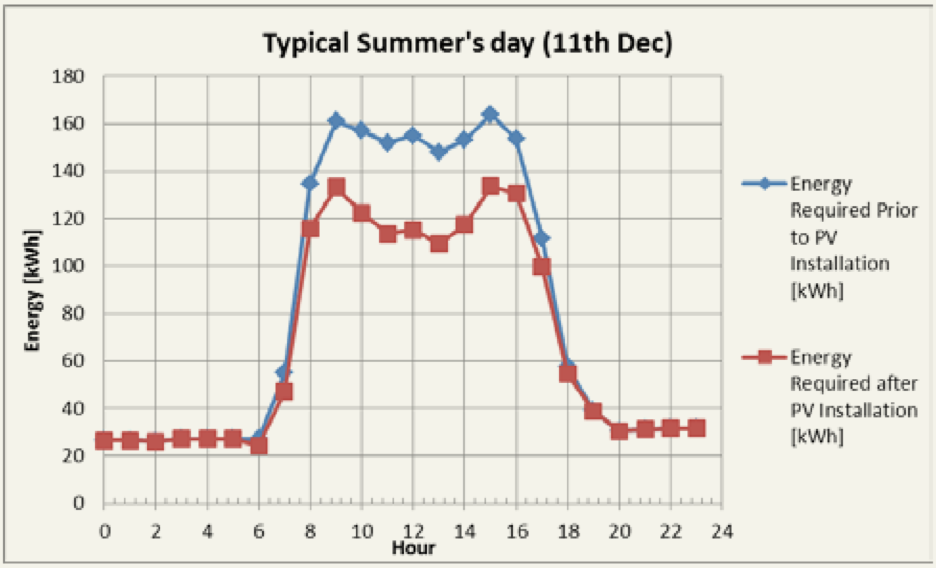


Figure 64: **Load profile after PV array is installed for a typical day in June**

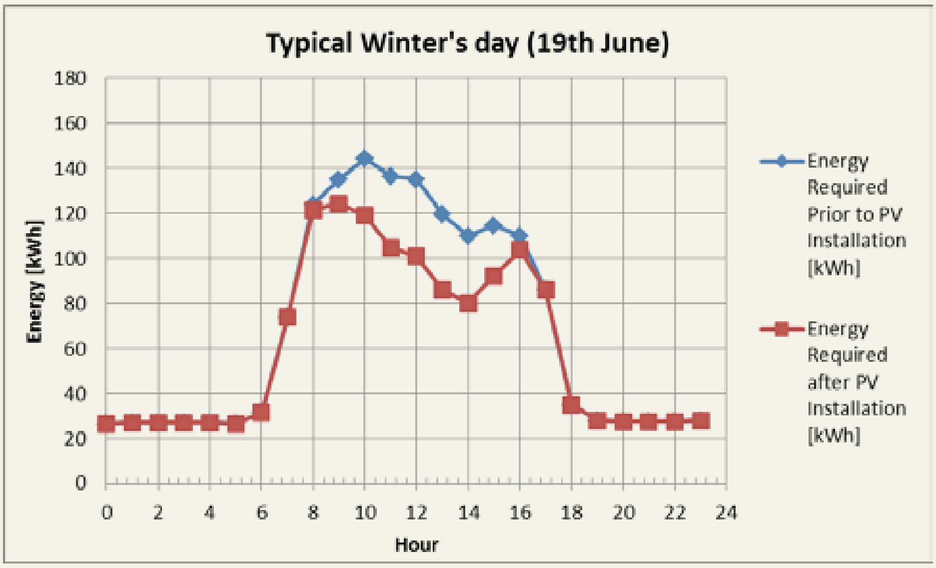
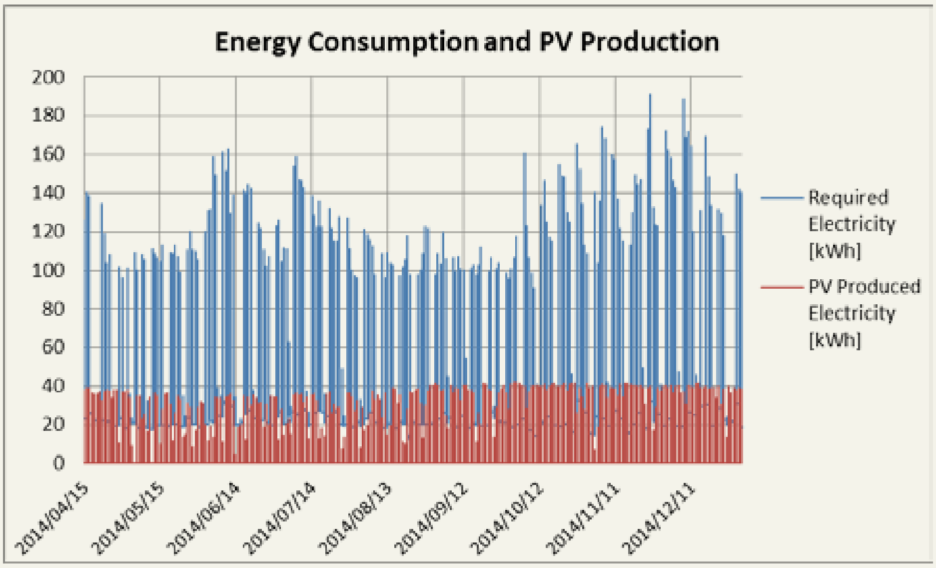


Figure 65: **Comparison between electricity consumed and electricity produced by the proposed 50 kW$_p$ PV plant**



Financial Feasibility

Input parameters

In order for the implementation of the proposed PV array to be successful the financial feasibility of the project needs to be determined. The feasibility of the 25 kW_p and the 50 kW_p system will be investigated so that the best solution can be found for this building. Since the building is municipal owned, three scenarios are modelled;

- Building is seen as a private entity buying electricity from Drakenstein Municipality only for self-consumption on the Bulk Time-of-Use Medium Voltage tariff.
- Building is seen as a Drakenstein Municipality entity reducing the active energy and demand required from Eskom and savings are calculated from the Eskom Megaflex tariff.
- Building is seen as a private entity buying electricity from Drakenstein Municipality on Large Power Users Small Scale Embedded Generation Medium Voltage tariff (only the 50 kW_p system).

For each of these scenarios, a comparison between a fully grant funded project, a 50% grant funded project and a 100% debt funded project is examined. The grant funding will be treated as upfront available capital for the project. National government will possibility award grant funding for this project and thus the grant funded cases presented can be used as the business case to present this project to National government. For the debt-funded cases, it is assumed the loan will be repaid over a 20 year period at a rate of 10% with a fixed repayment schedule.

For each of these funding cases, a range of capital costs are evaluated, as cost per watt peak of PV is the greatest variable in determining the cost of the project. Prior involvement of CRSES in a tender process for roof mounted PV system of a 20 kW_p size estimated values at R 16/W_p – R 20/W_p for turnkey solutions. It should be mentioned however that the cost per watt for PV in the tenders included warranties and guarantees and in some cases also maintenance cost.

For all cases evaluated the following assumptions are used:

- The model generated assumes cash flows to originate from the savings (active energy and demand charge) incurred by the PV system.
- The financial model assumes a lifetime of 20 years however in general, projects can generate electricity beyond this life span.

Table 26 shows the assumptions used as inputs to the financial model.

Table 26: **Financial model assumptions**

Funding scenarios	Fully grant funded, 50% grant funded and 100% loan funded
Capital Costs scenarios investigated	R 16/W_p, R 18/W_p and R 20/W_p
Annual electricity increase over 20 years	12.2% year on year for the first 2 years, 8% for the next 10 and then 6% for the remaining 8 years

Inflation rate	5.5%
PV production degradation	Linear to 80% of original production in year 20
Project lifetime	20 years
Inverter replacement cost	R 3.20 /W_p
O&M	0.35% of initial project cost annually
Depreciation	Depreciated over project life time
Discount rate	5.5%
Lending Rate	10%

Business tax is excluded as municipalities do not pay tax, and thus the tax incentives available in South Africa for renewable energy projects are not considered in this report.

Further, as seen in Table 26 the associated risks with the Drakenstein Municipality electricity costs are only accounted for by an assumed price increase of 12.2% every year for the first 2 years, 8% over the next 10 years and 6% for the remaining 8 years. This assumption disregards any new build programmes in future that might require additional price increases to consumers. Keep in mind that by 2045, most of the current coal fire stations will be decommissioned. This proposed electricity price increase is thus very conservative.

Demand charge savings are taken into consideration as a hind cast solar and electricity usage model is set up, and thus these savings can be predicted. The manner in which the demand charge is billed is: the charge payable per unit of the maximum demand supplied during any 30 consecutive minutes of the billing period (e.g. a month) measured in kilovolt-ampere (kVA). Owing to this manner of billing there are risks involved in predicting the demand charge savings. In order to predict these savings as accurately as possible, a hind cast model is set up for the past year whereby the half-hourly energy usage is compared to the output generated by the numerical PV model. The numerical PV model uses hind cast climatic data over the same period of time as input so that the theoretical maximum demand can be found had the PV installation been active. In this manner the demand savings for each month of the past year can be found. Since actual climatic data is used as the input to the PV model, times when there is cloud cover are accounted for and this, coupled with the actual energy usage data allows some of the uncertainties to be minimized. Other uncertainties such as plant down time (3 random days a year) and soiling factors (1.5%) are built into the numerical PV model.

As mentioned, there are risks associated in predicting the demand savings as one spike in energy usage that does not coincide with PV production can cause the savings for the month to the nullified. Similarly if the PV plant is down during the peak usage period of the day for one day of the month the savings again will not be realised. The unavailability of the PV plant is taken into consideration in the numerical model, but unforeseen incidents can occur. CRSES wants the client to be aware of these risks when considering the financial outcome when demand savings are considered.

The found savings from the active energy charge and the demand charge are used as the input into the financial model at year 1. Since only one year of hind cast data is available only one year's savings can be found and it is known that not every year will see these same savings. However since these savings are extrapolated over a 20 year period, the years experiencing peaks and dips in savings will be levelised over this period and thus this input is seen as realistic.

The following financial feasibility indictors are presented for each scenario and range of capital costs:

- Total cost over project lifetime
- Initial capital cost
- Cost for Business-as-usual
- Profit/Savings Incurred
- Project IRR
- Net present value (NPV) of project
- Payback period [years]
- LCOE of PV energy over duration of project
- LCOE of Utility energy over duration of project

The future costs of the project are not discounted in the total project cost figure. Similarly, neither LCOE value makes use of discounted future values, however the NPV and IRR of the project use discounted future values.

25 kW$_p$ System

Scenario 1

In this scenario, the building is seen as a private entity, buying electricity from Drakenstein Municipality only for self-consumption on the Bulk Time-of-Use Medium Voltage tariff

a. Achievable Savings

Together with the use of the listed input parameters that define the financial model, the tariff structure on which each building is billed must be considered, as this will determine the magnitude of the achievable savings. The tariff structure determines the associated cost of electricity, the avoided costs with the use of the PV system and thus determines the savings, payback period and internal rate of return (IRR) of the project. The tariff structure for this scenario is listed in Table 27.

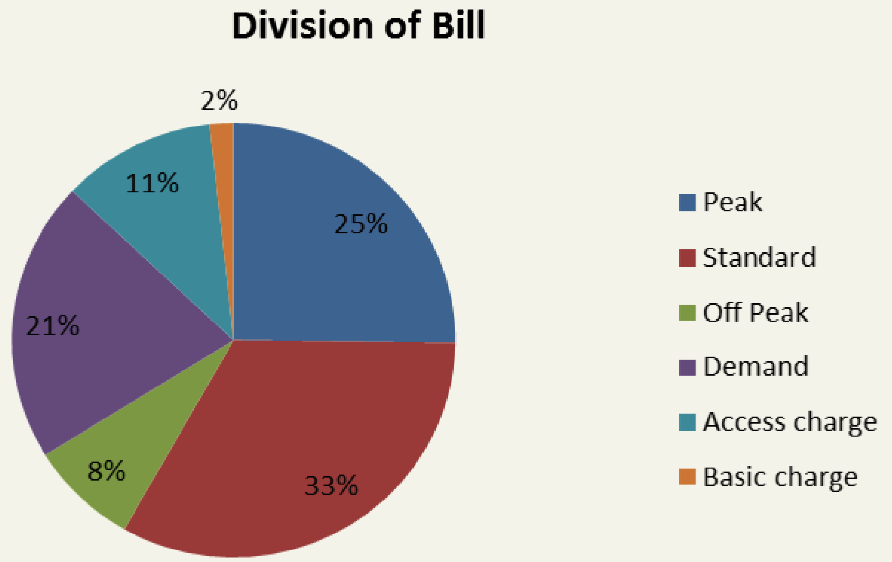
Table 27: **Bulk Time of Use Medium Voltage Tariff 2014/2015**

Fixed Charge	R 1 296.00	
Demand Charge per kVA	R 44.00	
Access Charge per kVA (12 months)	R 37.00	
Active Energy Charge	High demand season [Jun-Aug]	Low demand season [Sept-May]
Peak [R/kWh]	R 1.853	R 1.1369
Standard [R/kWh]	R 0.7778	R 0.6358

Off peak [R/kWh]	R 0.4463	R 0.3947
Reactive Energy per kVArh	R 0.0200	

The Bulk Time of Use Medium Voltage tariff structure consists of a fixed service charge, an access charge, a demand charge, and an active energy charge. It is assumed that savings will only be realised from the reduction of active energy [kWh] and demand [kVA]. Figure 66 shows the division of the bill with this tariff structure. The bill consists of 66% active energy charge and 21% demand charge indicating that the majority of the savings will be realised from the reduction of required active energy.

Figure 66: **Current division of the bill on Bulk Time of Use Medium Voltage Tariff**



The achievable savings for 1 year is based on the 2014/2015 rates which are applicable from 1st July 2014 for the proposed 25 kW_p PV system. These found savings are used as the input into the financial model.

Table 28: **Potential savings for year 1**

	Saved [ZAR]	% of total savings
Energy Charge	R 27 282.65	86.5%
Demand Charge	R 4 272.63	13.5%

b. Results

The information and assumptions in Table 26 and Table 28 are used as input into the financial model. The summary of results is presented in Table 29, Table 30 and Table 31.

Table 29: **Financial results for scenario 1 @ R 16/W_p, 25 kW_p system**

	@ R 16/W_p		
	100% Grant funded	50% Grant funded	100% Debt funded
Total cost over project lifetime	R 528 815.65	R 798 654.14	R 1 068 492.64
Initial capital cost	R 400 000.00	R 200 000.00	R 0.00
Cost for Business-as-usual	R 1 315 725.62	R 1 315 725.62	R 1 315 725.62
Profit/Savings Incurred	R 786 909.98	R 517 071.48	R 247 232.98
Project IRR	10.44%	10.74%	12.30%
NPV	R 221 191.14	R 144 662.71	R 68 134.29
Payback period [years]	10	11	14
LCOE of PV energy over duration of project	R 0.71	R 1.33	R 1.96
LCOE of Utility energy over duration of project	R 1.76	R 1.76	R 1.76

Table 30: **Financial results for scenario 1 @ R 18/W_p, 25 kW_p system**

	@ R 18/W_p		
	100% Grant funded	50% Grant funded	100% Debt funded
Total cost over project lifetime	R 584 917.60	R 888 485.91	R 1 192 054.22
Initial capital cost	R 450 000.00	R 225 000.00	R 0.00
Cost for Business-as-usual	R 1 315 725.62	R 1 315 725.62	R 1 315 725.62
Profit/Savings Incurred	R 730 808.02	R 427 239.71	R 123 671.40
Project IRR	9.02%	8.35%	5.37%
NPV	R 170 653.19	R 84 558.71	-R 1 535.77

	@ R 18/W_p		
	100% Grant funded	50% Grant funded	100% Debt funded
Payback period [years]	11	13	17
LCOE of PV energy over duration of project	R 0.78	R 1.49	R 2.19
LCOE of Utility energy over duration of project	R 1.76	R 1.76	R 1.76

Table 31: **Financial results for scenario 1 @ R 20/W_p, 25 kW_p system**

	@ R 20/W_p		
	100% Grant funded	50% Grant funded	100% Debt funded
Total cost over project lifetime	R 641 019.56	R 978 317.68	R 1 315 615.80
Initial capital cost	R 500 000.00	R 250 000.00	R 0.00
Cost for Business-as-usual	R 1 315 725.62	R 1 315 725.62	R 1 315 725.62
Profit/Savings Incurred	R 674 706.07	R 337 407.94	R 109.82
Project IRR	7.80%	6.28%	0.00%
NPV	R 120 115.24	R 24 454.71	-R 71 205.82
Payback period [years]	12	14	19
LCOE of PV energy over duration of project	R 0.86	R 1.64	R 2.42
LCOE of Utility energy over duration of project	R 1.76	R 1.76	R 1.76

The LCOE values found for the 100% grant funded and 50% grant funded cases for the turnkey installed solution of all R16/W_p, R18/W_p and R20/W_p show that savings can be realised through the installation of the PV project. For all the capital costs investigated, the 100% debt funded scenario returns LCOE values larger than the utility LCOE values with extended payback periods seen.

Considering the case where the installed turnkey solution is R 18/W the annual cash flow, accumulative net cash flow and accumulative cost is investigated. The avoided costs constitute the cash flow for the project. Here the total savings are subtracted from the associated expenses as seen in Figure 67, Figure 68 and Figure 69 for the 3 differently funded cases. Figure 70 to Figure 75 shows the cumulative costs associated with the PV project and compare these costs with the situation where no intervention is made and the management of 1 Market Street, continues paying Drakenstein Municipality to deliver electricity. Figure 70, Figure 71 and Figure 72 show the payback period and Figure 73, Figure 74 and Figure 75 shows the accumulative cost associated with both the PV installation and the cost of electricity bought from Drakenstein Municipality.

Figure 67: **Scenario 1, 25 kW$_p$ system: Annual Cash flow: 100% grant funded case at R18/W$_p$**

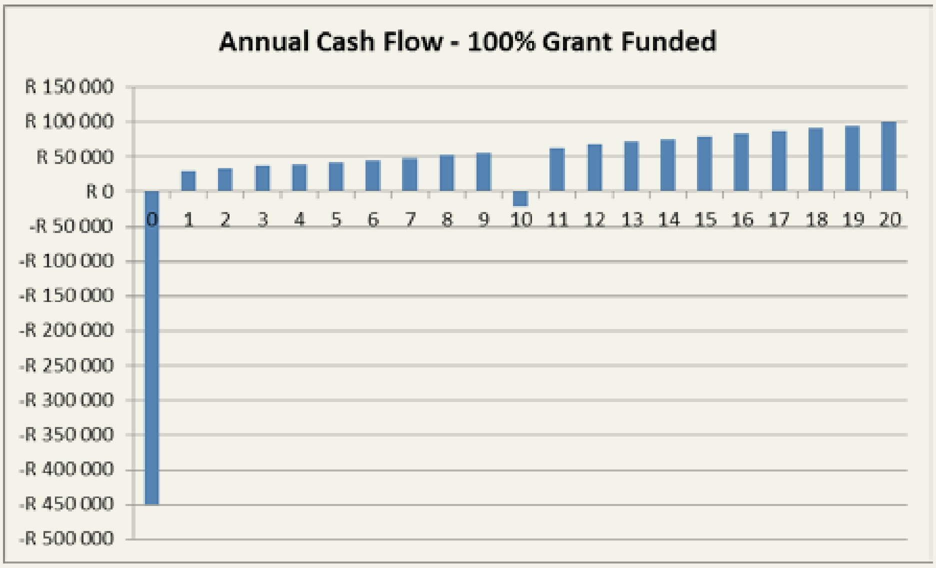
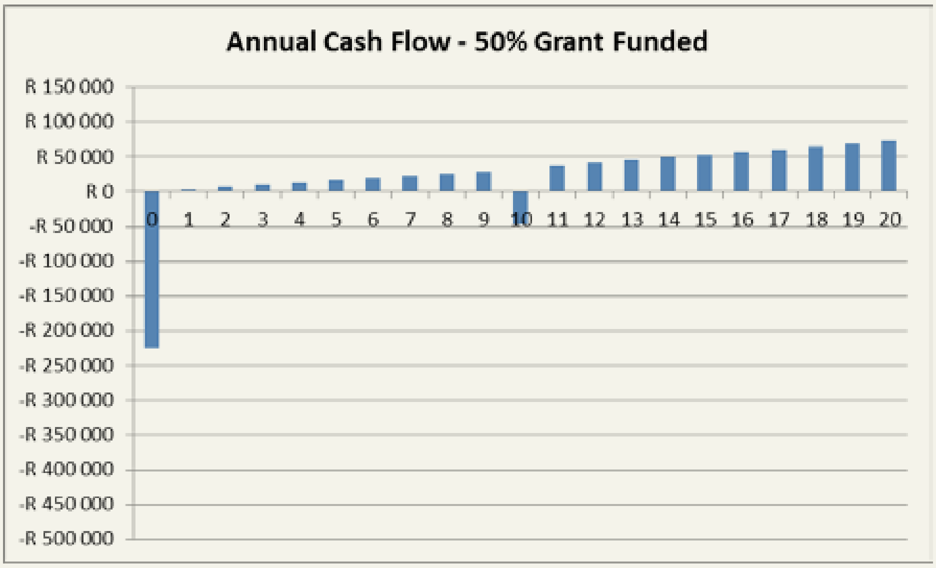


Figure 68: **Scenario 1, 25 kW$_p$ system: Annual Cash flow: 50% grant funded case at R18/W$_p$**



As seen from Figure 68, 50% of the initial project capital is invested in the project. Important to note is that the savings incurred covers the debt repayment annually from year 1. Year 10 sees a negative cash flow and is related to the replacement of the inverter, this can however be financed out of the initial loan but was left out in this instance.

Figure 69: **Scenario 1, 25 kW_p system: Annual Cash flow: 100% debt funded case at R18/W_p**

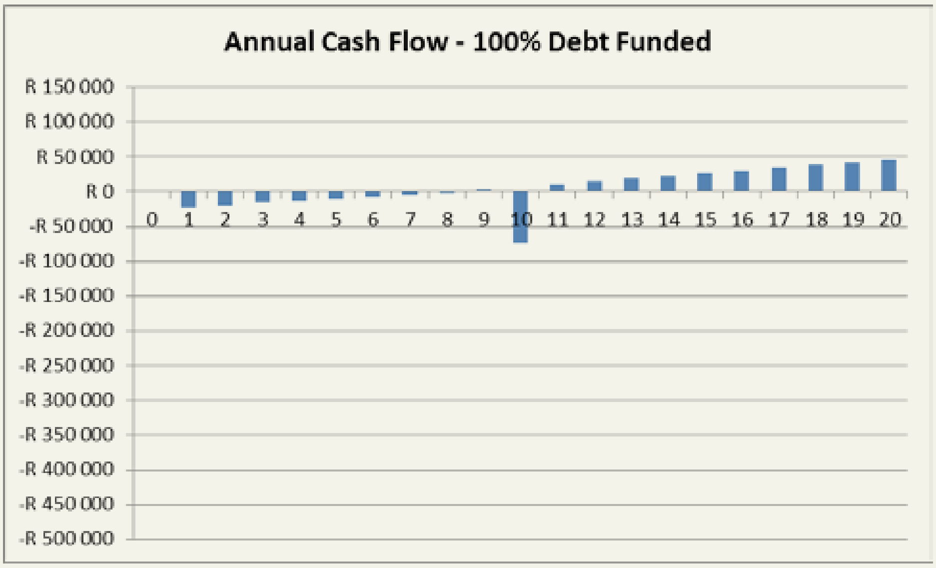


Figure 70: **Scenario 1, 25 kW_p system: Cumulative net cash flow with 100% grant funded case at R18/W_p**

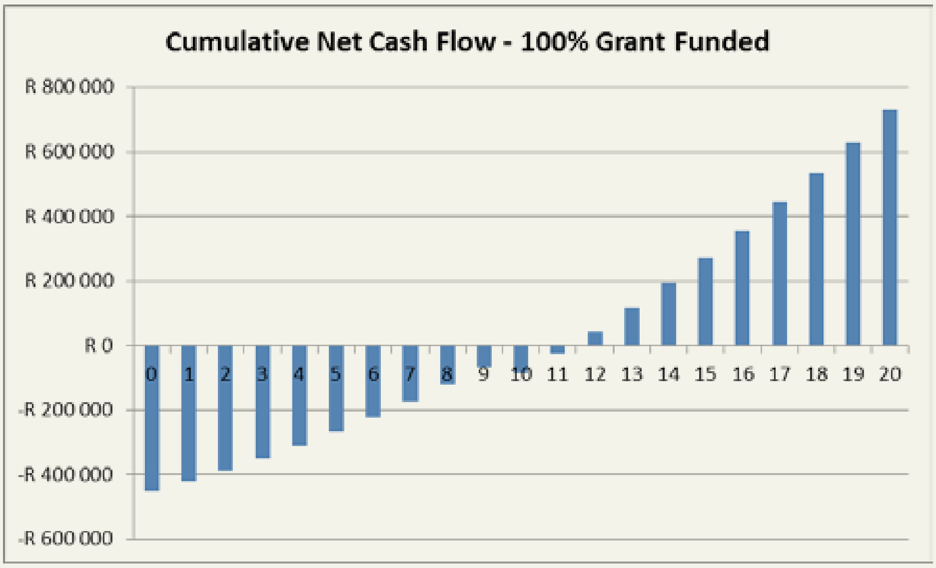


Figure 71: **Scenario 1, 25 kW$_p$ system: Cumulative net cash flow with 50% grant funded case at R18/W$_p$**

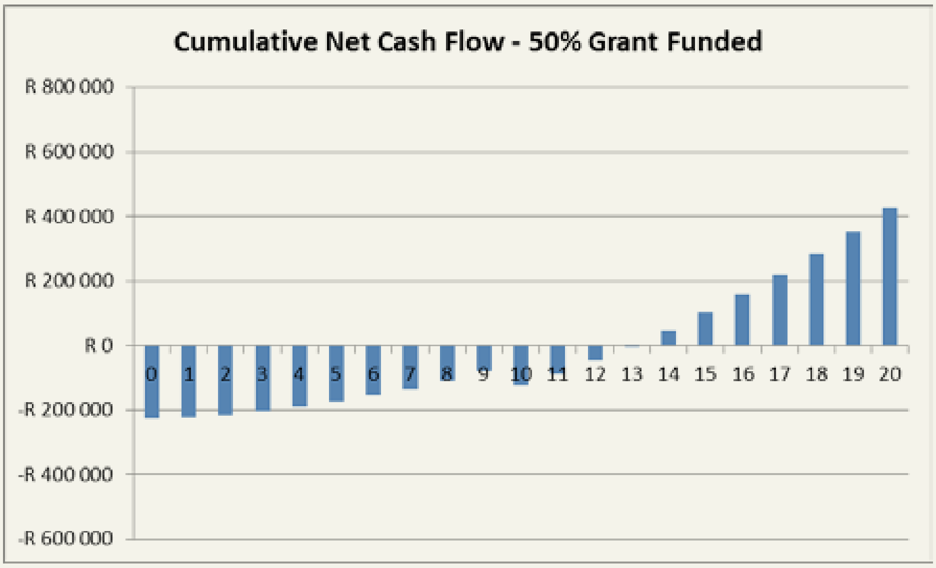


Figure 72: **Scenario 1, 25 kW$_p$ system: Cumulative net cash flow for the 100 % debt funded case at R18/W$_p$**

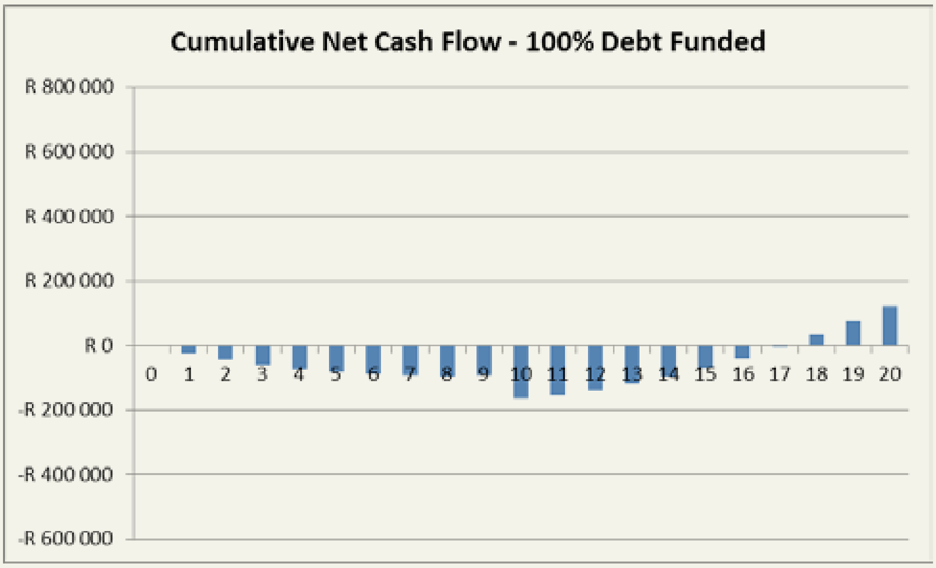


Figure 73: **Scenario 1, 25 kW$_p$ system: Cumulative cost for the 100% grant funded case at R18/W$_p$**

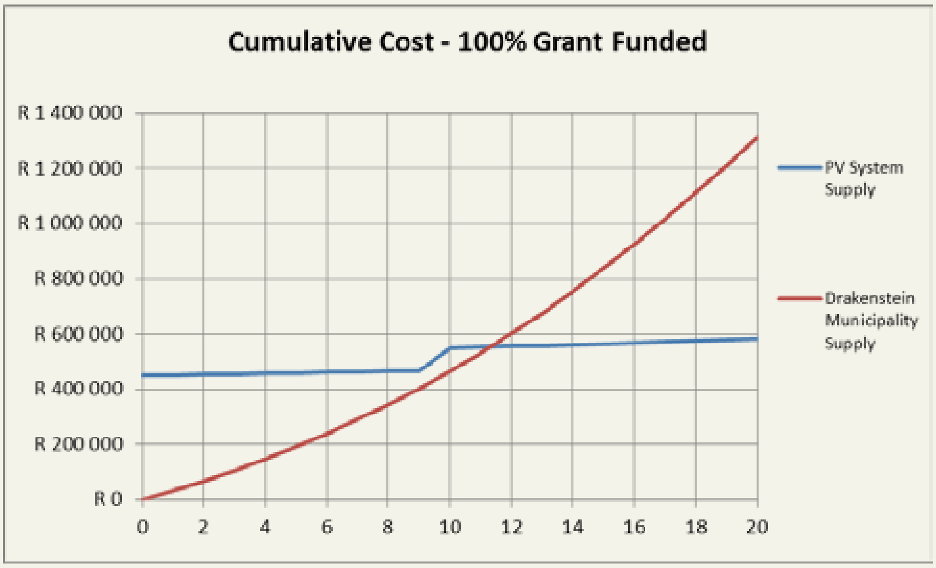


Figure 74: **Scenario 1, 25 kW$_p$ system: Cumulative cost for the 50% grant funded case at R18/W$_p$**

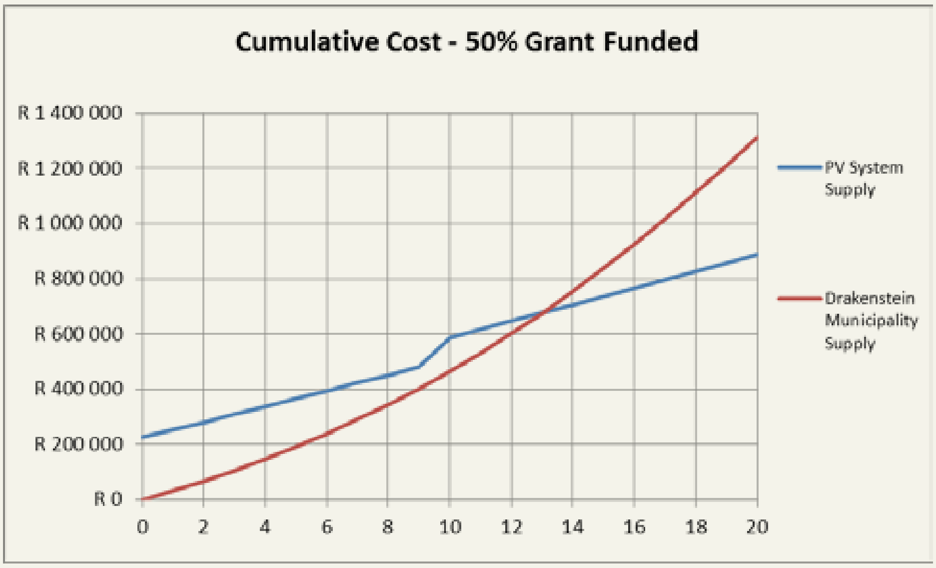
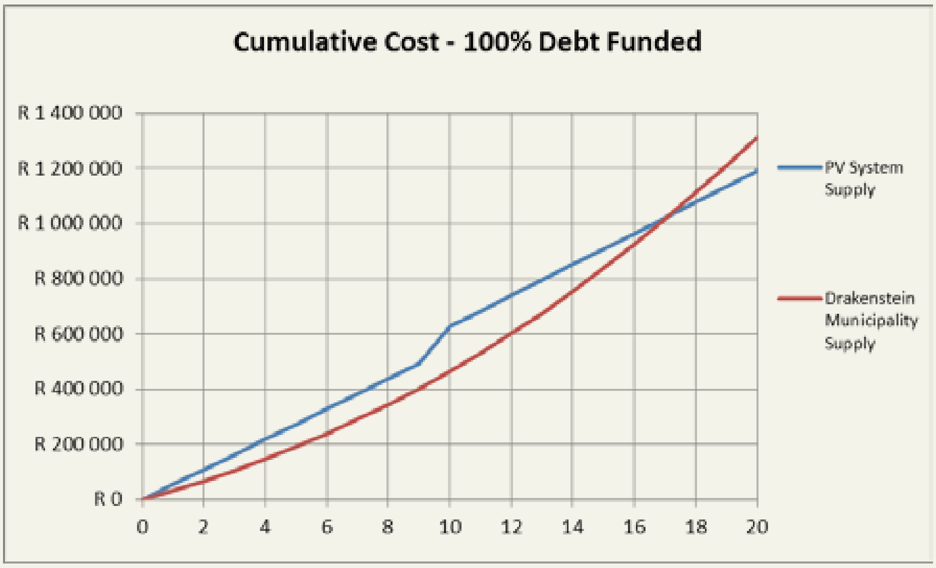


Figure 75: **Scenario 1, 25 kW_p system: Cumulative cost for the 100% debt funded case at R18/W_p**



A payback period of 11, 13 and 17 years is achieved for the 100% grant funded, 50% grant funded and 100% debt funded cases respectively. From the accumulative cost graphs it is seen that savings will be achieved from installing a PV system versus the situation where 1 Market Street management continues buying electricity from the Drakenstein municipality with a positive business case made for a grant funded project.

Scenario 2

In this scenario, the building is seen as a Drakenstein Municipality entity reducing the active energy and demand required from Eskom and savings are calculated from the Eskom Megaflex tariff

a. Achievable Savings

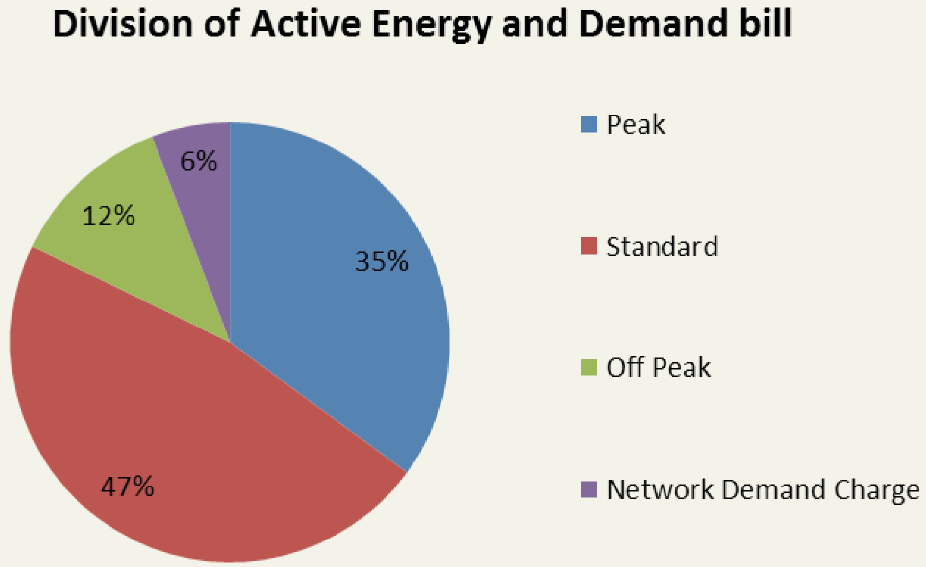
The tariff structure determines the associated cost of electricity, the avoided costs with the use of the PV system and thus determines the savings, payback period and internal rate of return (IRR) of the project. Drakenstein Municipality buys electricity in bulk from Eskom on a 66 kV line in the >900 km transmission zone. The tariff structure for this scenario is listed in Table 32.

Table 32: **Eskom Megaflex – Local authority rates 2014/2015**

Service charge R/Account/day	R 2 813.83	
Administration charge R/POD/day	R 89.86	
Transmission network charge per kVA	R 5.73	
Network access charge per kVA	R 4.12	
Network demand charge per kVA	R 7.62	
Urban low voltage subsidy charge per kVA	R 10.09	
Reliability service charge per kWh	R 0.0027	
Electrification and rural network subsidy charge per kWh	R 0.0559	
Active Energy Charge	**High demand season [Jun-Aug]**	**Low demand season [Sept-May]**
Peak [R/kWh]	R 2.2224	R 0.7249
Standard [R/kWh]	R 0.6732	R 0.4989
Off peak [R/kWh]	R 0.3656	R 0.3165
Reactive Energy per kVArh	R 0.1010	R 0.00

The Megaflex tariff structure consists of a service charge, an administration charge, transmission network charge, network access charge, network demand charge, urban low voltage subsidy charge, reliability service charge, electrification and rural network subsidy charge and an active energy charge. It is assumed that savings will only be realised from the reduction of active energy [kWh] and demand [kVA]. Figure 76 shows the division of the bill (as seen on the Megaflex tariff) with respect to the kWh and kVA charges, where the urban low voltage subsidy charge, reliability service charge, electrification and rural network subsidy charge are added to the active energy charges. The bill consists of 94% active energy charge and 6% demand charge indicating that the majority of the savings will be realised from the reduction of required active energy.

Figure 76: **Current division of the bill on the Eskom Megaflex local authority tariff**



The achievable savings for 1 year is based on the 2014/2015 rates, which are applicable from 1st July 2014 for the proposed 25 kW_p PV system. These found savings are used as the input into the financial model. When Table 33 is compared to Table 28 the achievable savings are less when the building is billed on the Megaflex tariff. Although the Eskom Megaflex tariff has a higher peak active energy charge than the Drakenstein Bulk Time of Use medium voltage tariff, the majority of the savings occur at the standard energy charge, which in the Eskom Megaflex tariff is lower than the Drakenstein Bulk Time of Use tariff.

Table 33: **Potential savings for year 1 on the Eskom Megaflex tariff**

	Saved [ZAR]	% of total savings
Energy Charge	R 23 974.52	97.00%
Demand Charge	R 739.94	3.00%

b. Results

The information and assumptions in Table 26 and Table 33 are used as input into the financial model. The summary of results is presented in Table 34, Table 35 and Table 36.

Table 34: **Financial results for scenario 1 @ R 16/W_p, 25kW_p system**

	@ R 16/W_p		
	100% Grant funded	**50% Grant funded**	**100% Debt funded**
Total cost over project lifetime	R 528 815.65	R 798 654.14	R 1 068 492.64
Initial capital cost	R 400 000.00	R 200 000.00	R 0.00
Cost for Business-as-usual	R 1 030 491.44	R 1 030 491.44	R 1 030 491.44
Profit/Savings Incurred	R 501 675.79	R 231 837.29	-R 38 001.21
Project IRR	7.34%	5.48%	-1.90%
NPV	R 75 967.22	-R 561.21	-R 77 089.63
Payback period [years]	12	15	20+
LCOE of PV energy over duration of project	R 0.71	R 1.33	R 1.96
LCOE of Utility energy over duration of project	R 1.37	R 1.37	R 1.37

Table 35: **Financial results for scenario 1 @ R 18/W_p,25 kW_p system**

	@ R 18/W_p		
	100% Grant funded	**50% Grant funded**	**100% Debt funded**
Total cost over project lifetime	R 584 917.60	R 888 485.91	R 1 192 054.22
Initial capital cost	R 450 000.00	R 225 000.00	R 0.00
Cost for Business-as-usual	R 1 030 491.44	R 1 030 491.44	R 1 030 491.44
Profit/Savings Incurred	R 445 573.83	R 142 005.52	-R 161 562.79
Project IRR	6.07%	3.19%	-7.85%
NPV	R 25 429.27	-R 60 665.21	-R 146 759.69
Payback period [years]	13	17	20+
LCOE of PV energy over duration of project	R 0.78	R 1.49	R 2.19
LCOE of Utility energy over duration of project	R 1.37	R 1.37	R 1.37

Table 36: **Financial results for scenario 1 @ R 20/W_p, 25kW_p system**

	@ R 20/W_p		
	100% Grant funded	50% Grant funded	100% Debt funded
Total cost over project lifetime	R 641 019.56	R 978 317.68	R 1 315 615.80
Initial capital cost	R 500 000.00	R 250 000.00	R 0.00
Cost for Business-as-usual	R 1 030 491.44	R 1 030 491.44	R 1 030 491.44
Profit/Savings Incurred	R 389 471.88	R 52 173.76	-R 285 124.37
Project IRR	4.98%	1.13%	-14.18%
NPV	-R 25 108.68	-R 120 769.21	-R 216 429.74
Payback period [years]	14	18	20+
LCOE of PV energy over duration of project	R 0.86	R 1.64	R 2.42
LCOE of Utility energy over duration of project	R 1.37	R 1.37	R 1.37

The 100% grant funded case for the capital costs of R 16/W_p and R 18/W_p are the only positive business cases realised.

Considering the case where the installed turnkey solution is R 18/W the annual cash flow, accumulative net cash flow and accumulative cost is investigated. The avoided costs constitute the cash flow for the project. Here the total savings are subtracted from the associated expenses as seen in Figure 77, Figure 78 and Figure 79 for the 3 differently funded cases. Figure 80 to Figure 85 shows the cumulative costs associated with the PV project and compare these costs with the situation where no intervention is made and the management of 1 Market Street continues paying Eskom to deliver electricity. Figure 80, Figure 81 and Figure 82 show the payback period and Figure 83, Figure 84 and Figure 85 shows the accumulative cost associated with both the PV installation and the cost of electricity bought from Drakenstein Municipality.

Figure 77: **Scenario 2, 25 kW$_p$ system: Annual Cash flow: 100% grant funded case at R18/W$_p$**

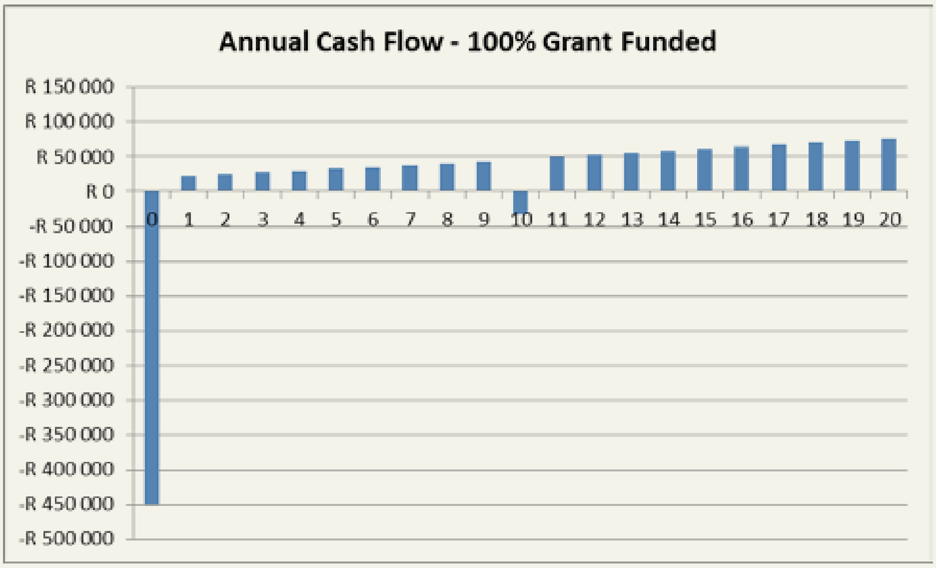
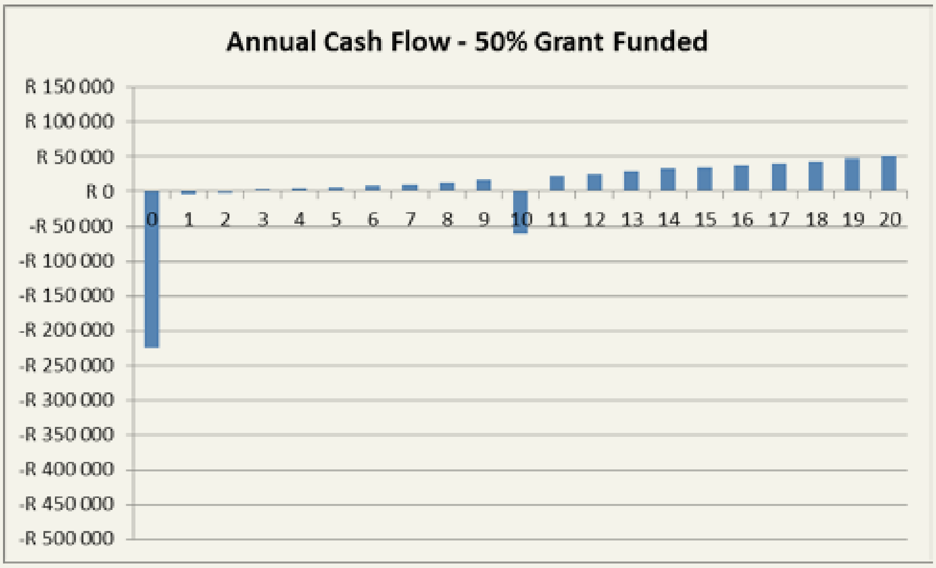


Figure 78: **Scenario 2, 25 kW$_p$ system: Annual Cash flow: 50% grant funded case at R18/W$_p$**



As seen from Figure 78, 50% of the initial project capital is invested in the project. Important to note is that the savings incurred covers the debt repayment annually from year 3, unlike scenario 1 where the savings cover the debt repayment from year 1. Year 10 sees a negative cash flow and is related to the replacement of the inverter, this can however be financed out of the initial loan but was left out in this instance.

Figure 79: **Scenario 2, 25 kW$_p$ system: Annual Cash flow: 100% debt funded case at R18/W$_p$**

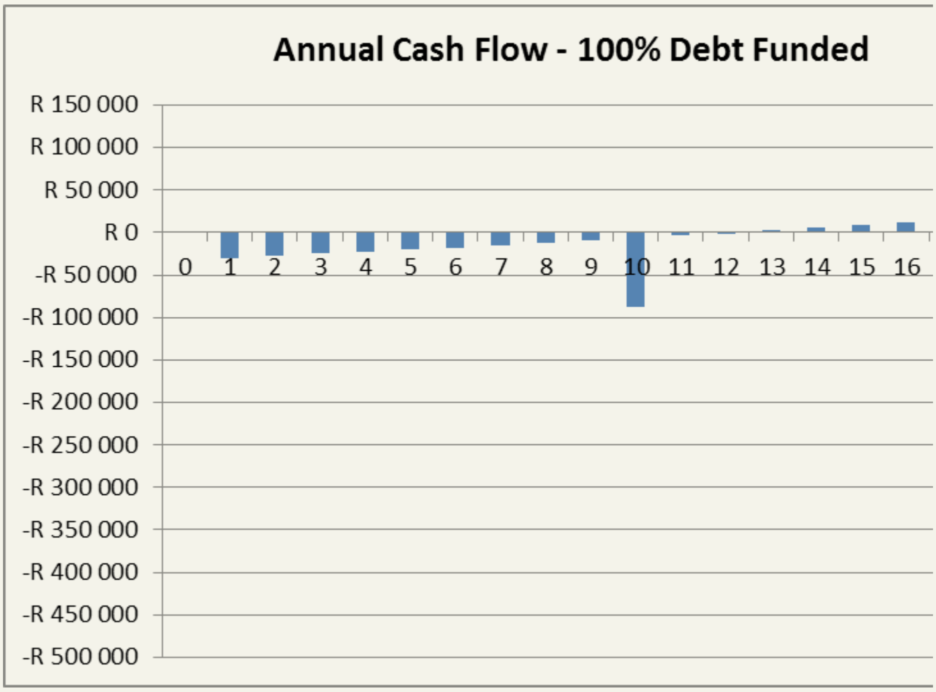


Figure 80: **Scenario 2, 25 kW$_p$ system: Cumulative net cash flow with 100% grant funded case at R18/W$_p$**

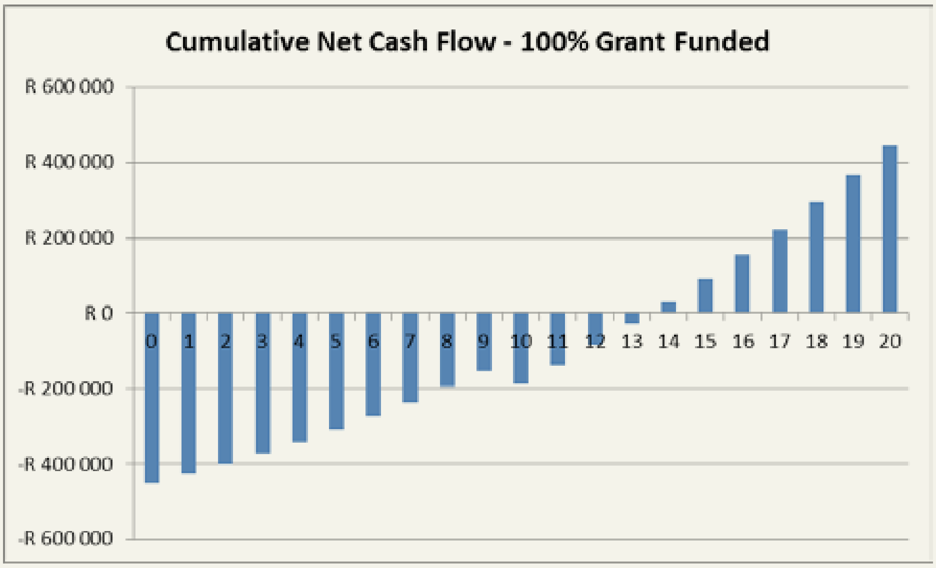


Figure 81: **Scenario 2, 25 kW$_p$ system: Cumulative net cash flow with 50% grant funded case at R18/W$_p$**

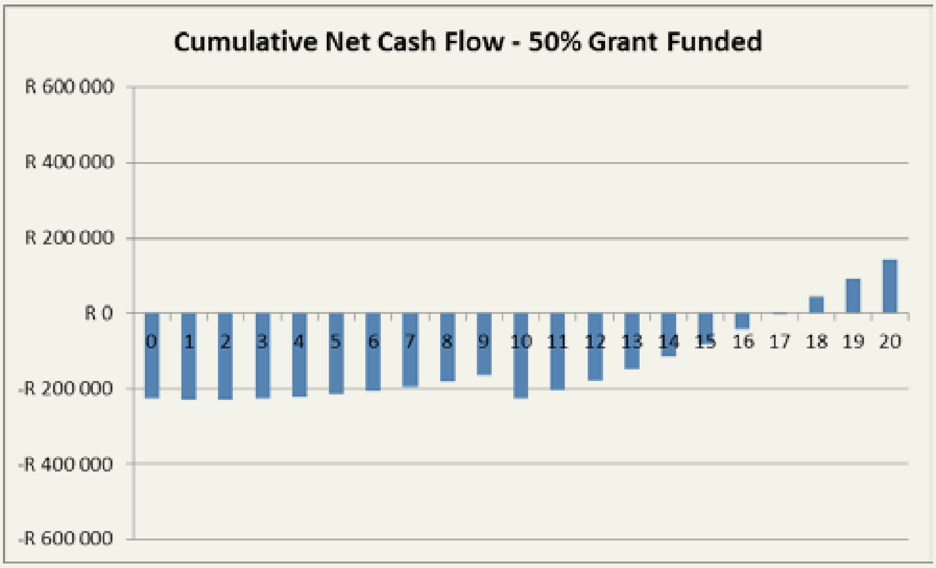


Figure 82: **Scenario 2, 25 kW$_p$ system: Cumulative net cash flow for the 100 % debt funded case at R18/W$_p$**

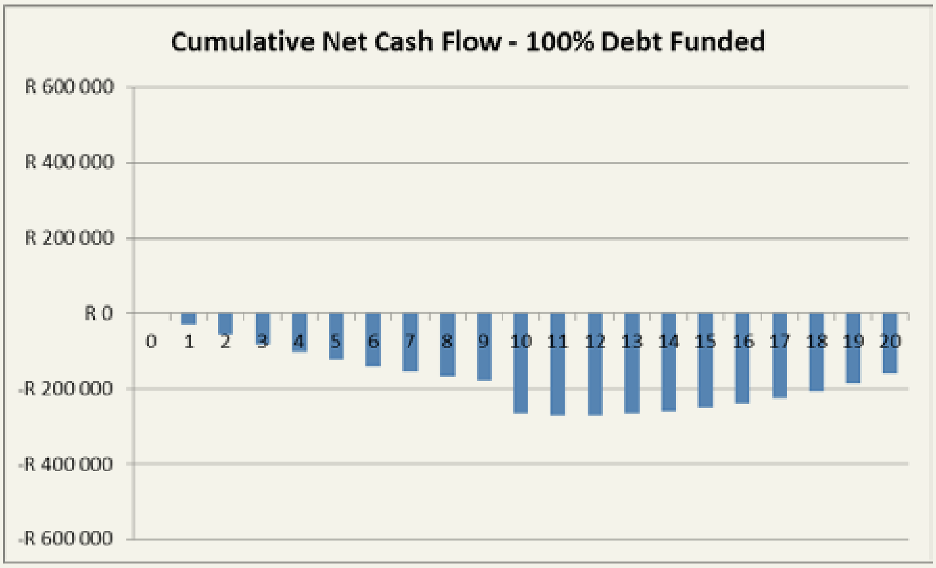


Figure 83: **Scenario 2, 25 kW_p system: Cumulative cost for the 100% grant funded case at R18/W_p**

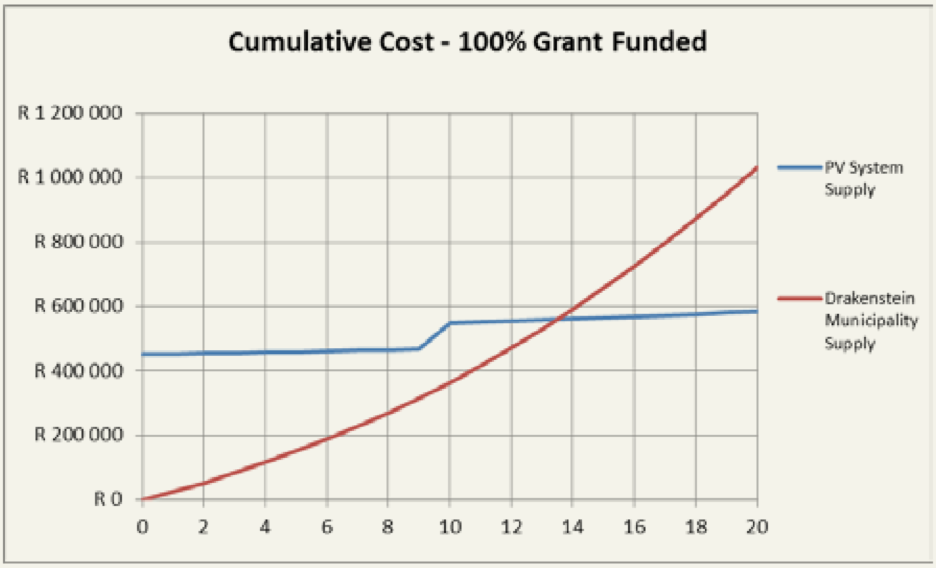


Figure 84: **Scenario 2, 25 kW_p system: Cumulative cost for the 50% grant funded case at R18/W_p**

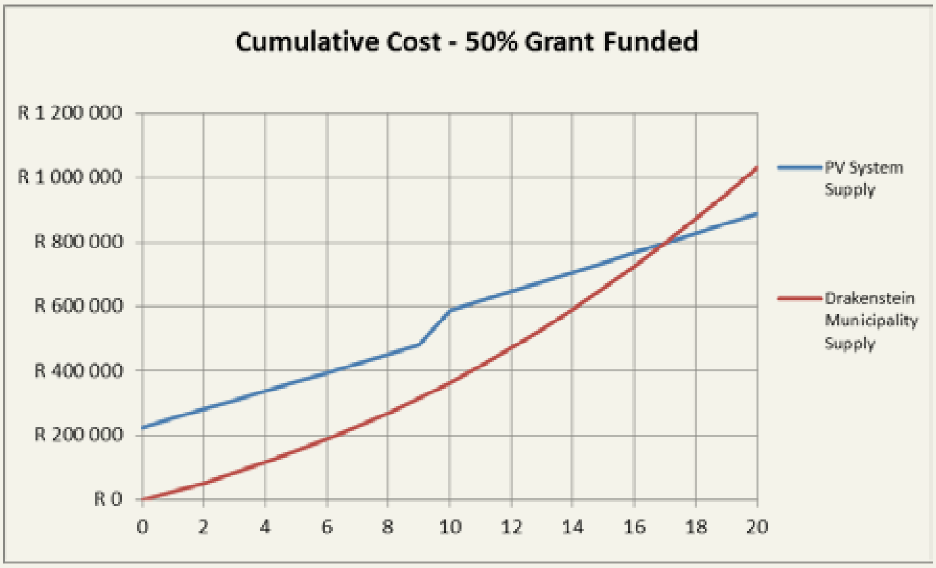
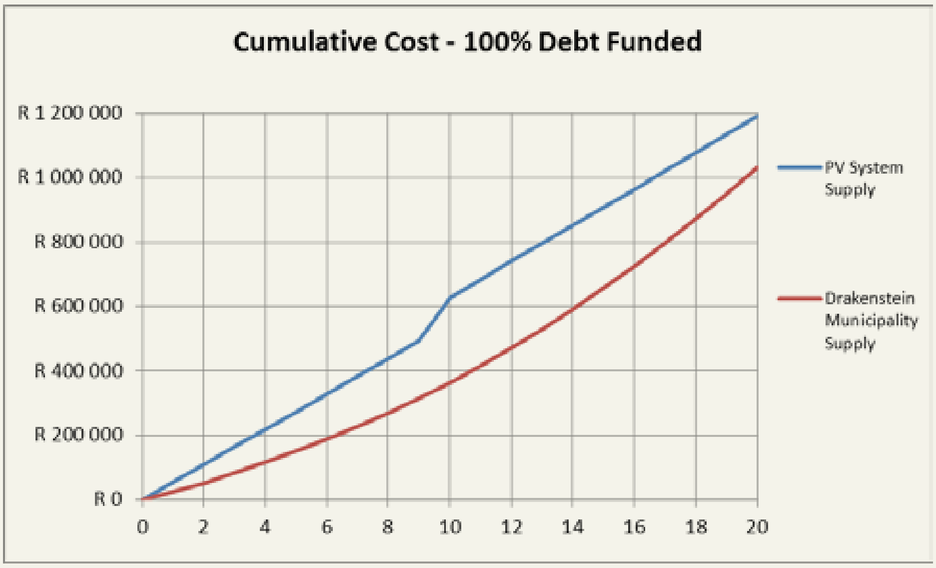


Figure 85: **Scenario 2, 25 kW$_p$ system: Cumulative cost for the 100% debt funded case at R18/W$_p$**



A payback period of 13, 17 and 20+ years is achieved for the 100% grant funded, 50% grant funded and 100% debt funded cases respectively. This compares poorly to scenario 1 where payback periods of 11, 13 and 17 years are realised for the 100% grant funded, 50% grant funded and 100% debt funded cases respectively. From the accumulative cost graphs it is seen that savings will be achieved from installing a PV system if the capital cost of R18/W$_p$ or less is realised versus the situation where 1 Market Street management continues buying electricity from Eskom.

50 kW$_p$ System

Scenario 1

In this scenario the building is seen as a private entity buying electricity from Drakenstein Municipality only for self-consumption on the Bulk Time-of-Use Medium Voltage tariff.

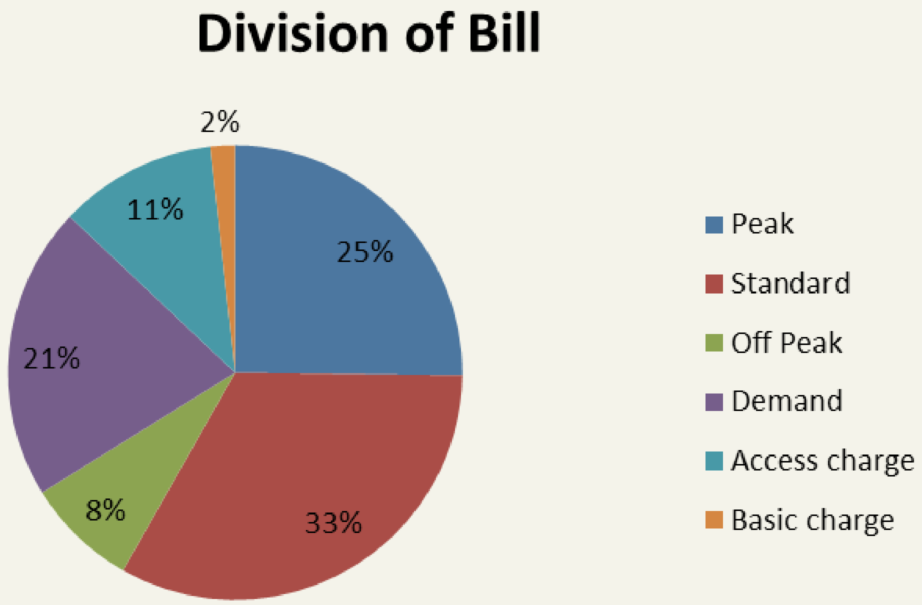
a. Achievable Savings

Together with the use of the listed input parameters that define the financial model, the tariff structure on which the building is billed must be considered. The tariff structure determines the associated cost of electricity, the avoided costs with the use of the PV system and thus determines the savings, payback period and internal rate of return (IRR) of the project. The tariff structure for this scenario is listed in Table 29, repeated here for convenience in Table 37. The division of the bill on this tariff structure is also repeated in Figure 86.

Table 37: **Bulk Time of Use Medium Voltage Tariff 2014/2015**

Fixed Charge	R 1 296.00	
Demand Charge per kVA	R 44.00	
Access Charge per kVA (12 months)	R 37.00	
Active Energy Charge	**High demand season [Jun-Aug]**	**Low demand season [Sept-May]**
Peak [R/kWh]	R 1.853	R 1.1369
Standard [R/kWh]	R 0.7778	R 0.6358
Off peak [R/kWh]	R 0.4463	R 0.3947
Reactive Energy per kVArh	R 0.0200	

Figure 86: **Current division of the bill**



The achievable savings for 1 year is based on the 2014/2015 rates, which are applicable from 1st July 2014 for the proposed 50 kW_p PV system. These found savings are used as the input into the financial model. The excess energy monetary value amounts to R 1 833.34 which insignificant in comparison to the total savings.

Table 38: **Potential savings for year 1 for scenario 1: 50 kW_p system**

	Saved [ZAR]	% of total savings
Energy Charge	R 51 682.19	87.43%
Demand Charge	R 7 430.92	12.57%

b. Results

The information and assumptions in Table 26 and Table 38 are used as input into the financial model. The summary of results is presented in Table 39, Table 40 and Table 41.

Table 39: **Financial results for scenario 1 @ R 16/W_p, 50 kW_p system**

	@ R 16/Wp		
	100% Grant funded	50% Grant funded	100% Debt funded
Total cost over project lifetime	R 1 057 631.29	R 1 597 308.29	R 2 136 985.29
Initial capital cost	R 800 000.00	R 400 000.00	R 0.00
Cost for Business-as-usual	R 2 464 773.31	R 2 464 773.31	R 2 464 773.31
Profit/Savings Incurred	R 1 407 142.02	R 867 465.02	R 327 788.02
Project IRR	9.58%	9.30%	7.98%
NPV	R 357 520.00	R 204 463.15	R 51 406.30
Payback period [years]	11	12	15
LCOE of PV energy over duration of project	R 0.75	R 1.42	R 2.09
LCOE of Utility energy over duration of project	R 1.76	R 1.76	R 1.76

Table 40: **Financial results for scenario 1 @ R 18/W_p, 50 kW_p system**

	@ R 18/W_p		
	100% Grant funded	50% Grant funded	100% Debt funded
Total cost over project lifetime	R 1 169 835.20	R 1 776 971.82	R 2 384 108.45
Initial capital cost	R 900 000.00	R 450 000.00	R 0.00
Cost for Business-as-usual	R 2 464 773.31	R 2 464 773.31	R 2 464 773.31
Profit/Savings Incurred	R 1 294 938.11	R 687 801.49	R 80 664.86
Project IRR	8.20%	6.96%	1.77%
NPV	R 256 444.10	R 84 255.14	-R 87 933.81

	@ R 18/W_p		
	100% Grant funded	50% Grant funded	100% Debt funded
Payback period [years]	11	13	19
LCOE of PV energy over duration of project	R 0.83	R 1.59	R 2.34
LCOE of Utility energy over duration of project	R 1.76	R 1.76	R 1.76

Table 41: **Financial results for scenario 1 @ R 20/W_p, 50 kW_p system**

	@ R 20/W_p		
	100% Grant funded	50% Grant funded	100% Debt funded
Total cost over project lifetime	R 1 282 039.11	R 1 956 635.36	R 2 631 231.61
Initial capital cost	R 1 000 000.00	R 500 000.00	R 0.00
Cost for Business-as-usual	R 2 464 773.31	R 2 464 773.31	R 2 464 773.31
Profit/Savings Incurred	R 1 182 734.20	R 508 137.95	-R 166 458.30
Project IRR	7.02%	4.91%	-3.47%
NPV	R 155 368.20	-R 35 952.86	-R 227 273.92
Payback period [years]	12	15	20+
LCOE of PV energy over duration of project	R 0.91	R 1.75	R 2.59
LCOE of Utility energy over duration of project	R 1.76	R 1.76	R 1.76

Similar to the 25 kW_p system, the LCOE values found all the different funded cases for the turnkey installed solution of R 16/W_p or R 18/W_p show that savings can be realised through the installation of the PV project. If the installed cost is R 20/W_p then the business case becomes questionable for the debt funded cases if the decision is based purely on financial returns.

Considering the case where the installed turnkey solution is R 18/W the annual cash flow, accumulative net cash flow and accumulative cost is investigated. The avoided costs constitute the cash flow for the project. Here the total savings are subtracted from the associated expenses as seen in Figure 87, Figure 88 and Figure 89 for the 3 differently funded cases. Figure 90 to Figure 95 shows the cumulative costs associated with the PV project and compare these costs with the situation where no intervention is made and the management of 1 Market Street continues paying Drakenstein Municipality to deliver electricity. Figure 90, Figure 91 and Figure 92 show the payback period and Figure 93, Figure 94 and Figure 95 shows the accumulative cost associated with of both the PV installation and the cost of electricity bought from Drakenstein Municipality.

Figure 87: **Scenario 1, 50 kW$_p$ system: Annual Cash flow: 100% grant funded case at R18/W$_p$**

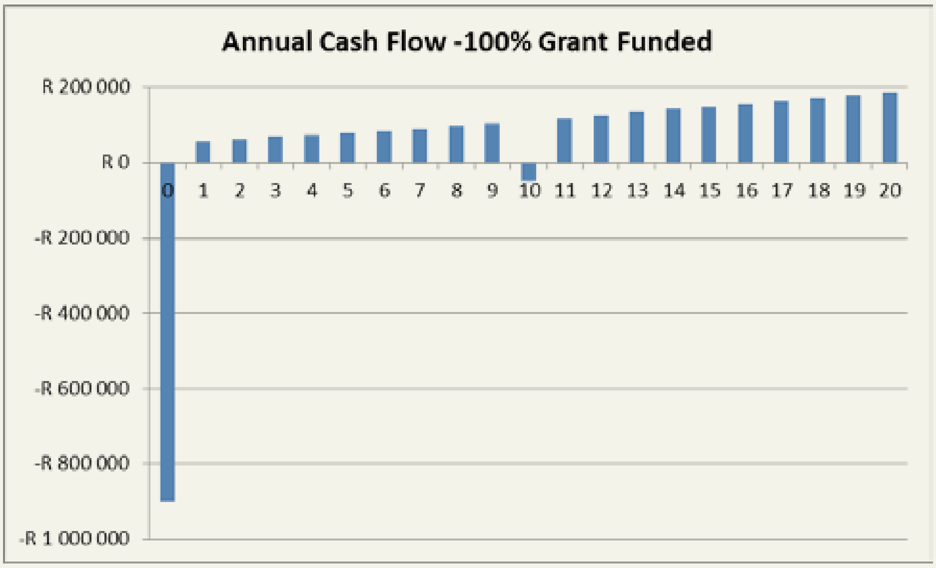
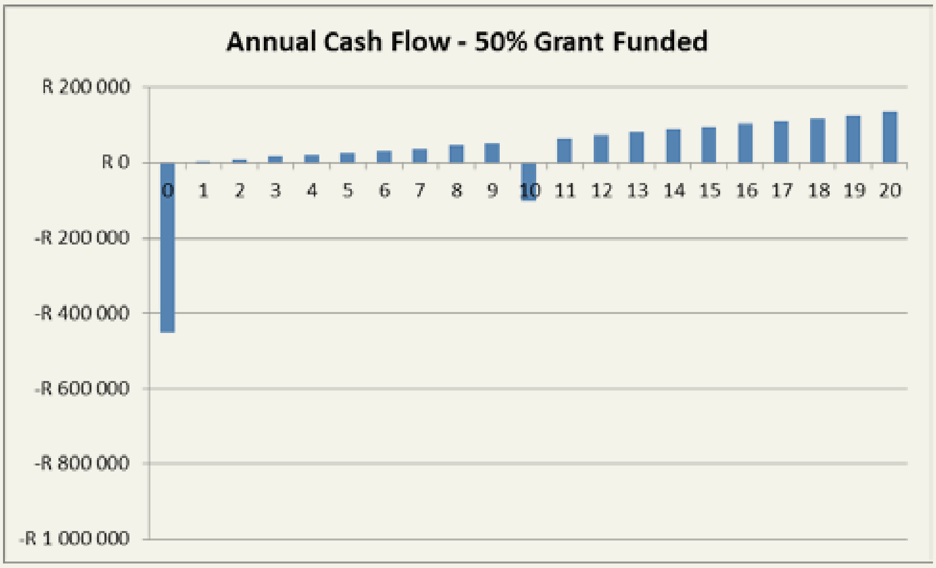


Figure 88: **Scenario 1, 50 kW$_p$ system: Annual Cash flow: 50% grant funded case at R18/W$_p$**



As seen from Figure 88, 50% of the initial project capital is invested in the project. Important to note is that the savings incurred covers the debt repayment annually from year 1. Year 10 sees a negative cash flow and is related to the replacement of the inverter, this can however be financed out of the initial loan but was left out in this instance.

Figure 89: **Scenario 1, 50 kW_p system: Annual Cash flow: 100% debt funded case at R18/W_p**

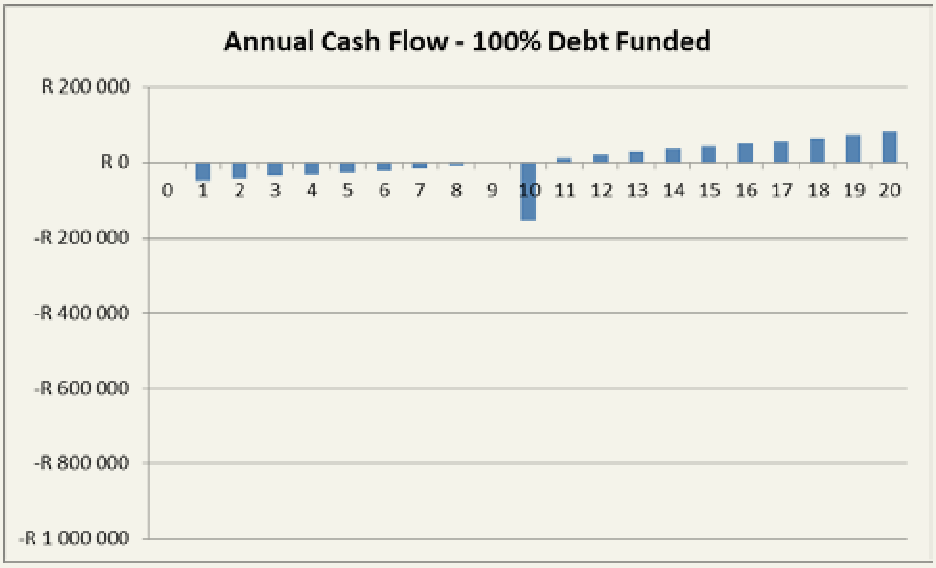


Figure 90: **Scenario 1, 50 kW_p system: Cumulative net cash flow with 100% grant funded case at R18/W_p**

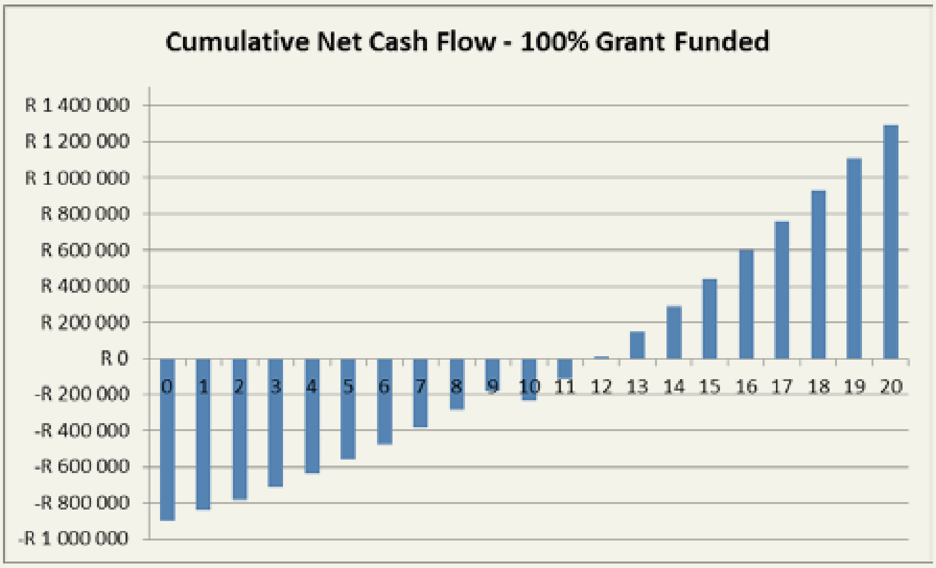


Figure 91: **Scenario 1, 50 kW$_p$ system: Cumulative net cash flow with 50% grant funded case at R18/W$_p$**

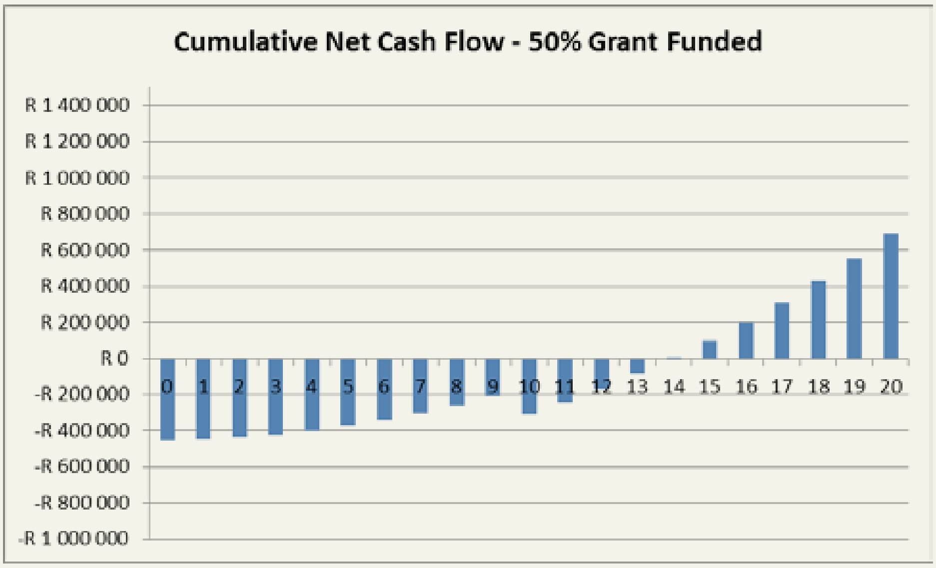


Figure 92: **Scenario 1, 50 kW$_p$ system: Cumulative net cash flow for the 100% debt funded case at R18/W$_p$**

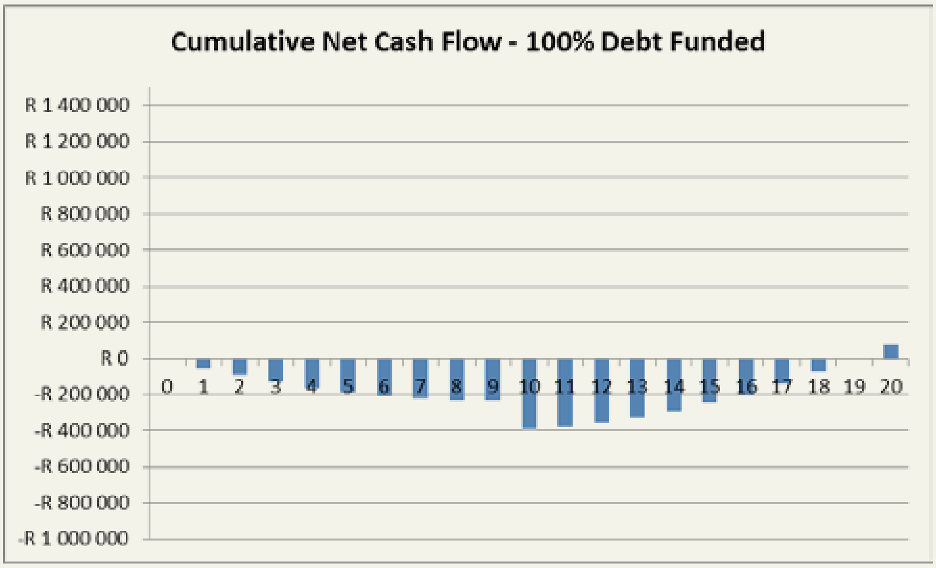


Figure 93: **Scenario 1, 50 kW$_p$ system: Cumulative cost for the 100% grant funded case at R18/W$_p$**

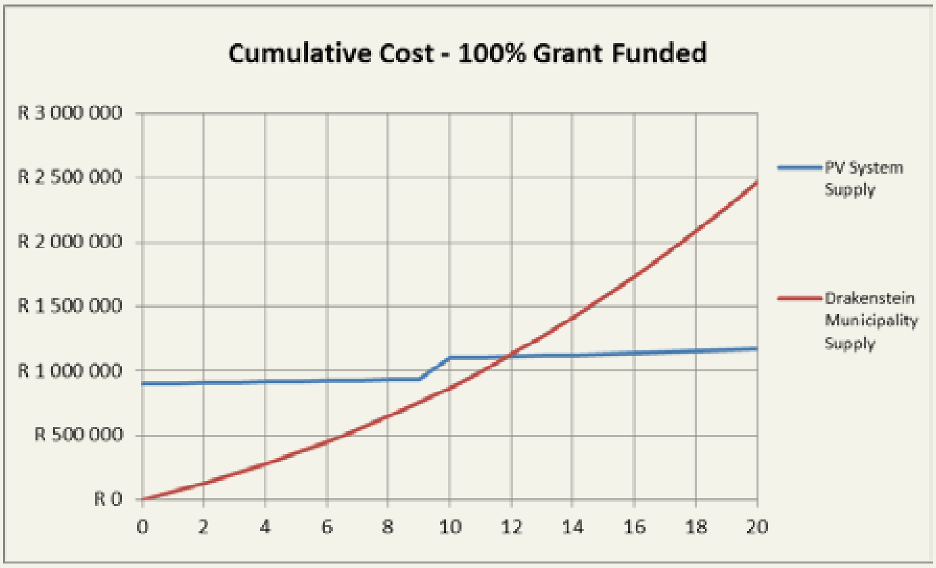


Figure 94: **Scenario 1, 50 kW$_p$ system: Cumulative cost for the 50% grant funded case at R18/W$_p$**

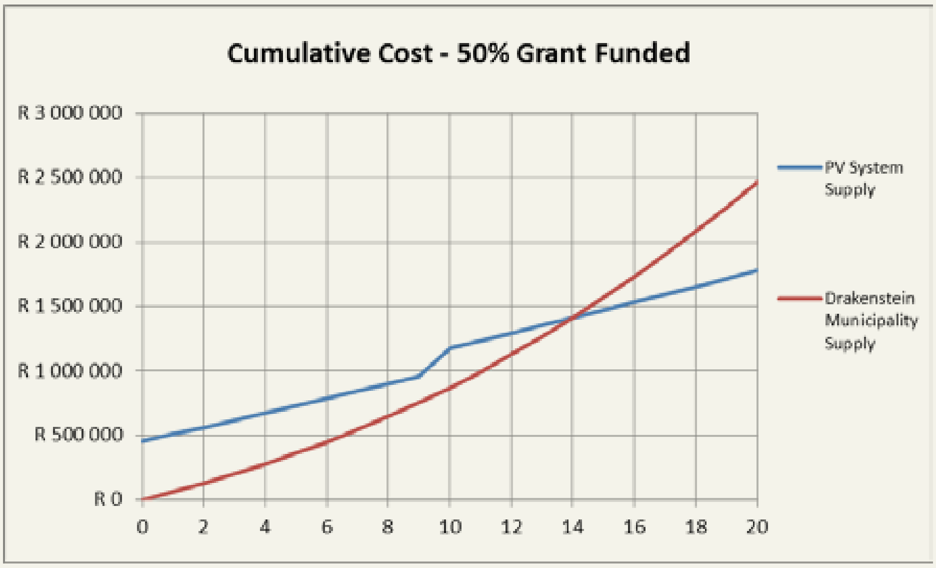
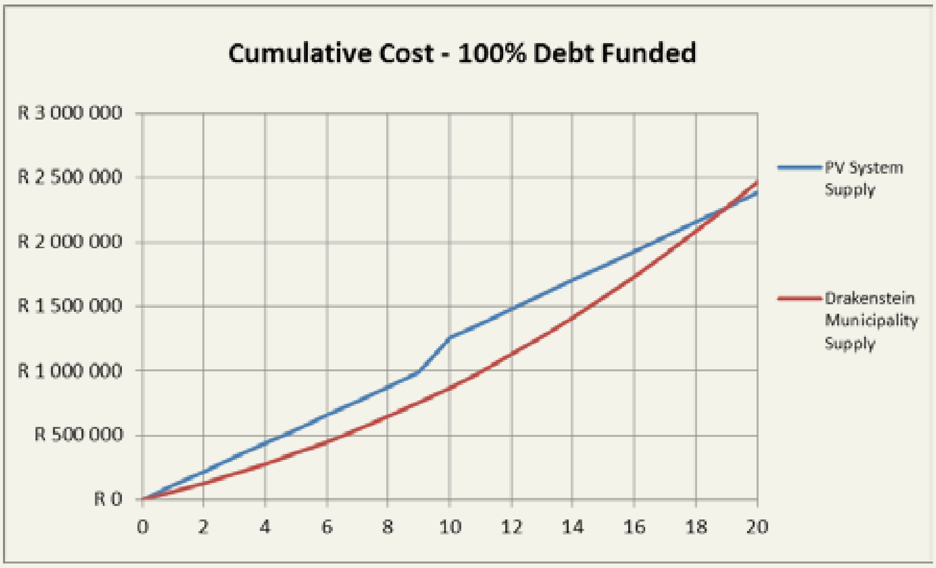


Figure 95: **Scenario 1, 50 kW_p system: Cumulative cost for the 100% debt funded case at R18/W_p**



A payback period at R 18/W_p of 11 years is achieved for the 100% grant funded, 13 years for the 50% grant funded and 19 years for the 100% debt funded case. The payback period is comparable to the 25 kW_p system bar the 100% debt funded case. Although the payback periods compare well, the IRR of the 25 kW_p system shows a more positive business case. The IRR of the 50 kW_p system at R 18/W_p is 8.20% is achieved for the 100% grant funded, 6.96% for the 50% grant funded and 1.77% for the 100% debt funded case. The IRR of the 25 kW_p system at R 18/W_p is 9.02% is achieved for the 100% grant funded, 8.35% for the 50% grant funded and 5.37% for the 100% debt funded case, indicating that the 25 kW_p system will be a better investment. From the accumulative cost graphs it is seen that savings will be achieved from installing the 50 kW_p PV system versus the situation where 1 Market Street management continues buying electricity from the Drakenstein municipality.

Scenario 2

In this scenario the building is seen as a Drakenstein Municipality entity reducing the active energy and demand required from Eskom and savings are calculated from the Eskom Megaflex tariff.

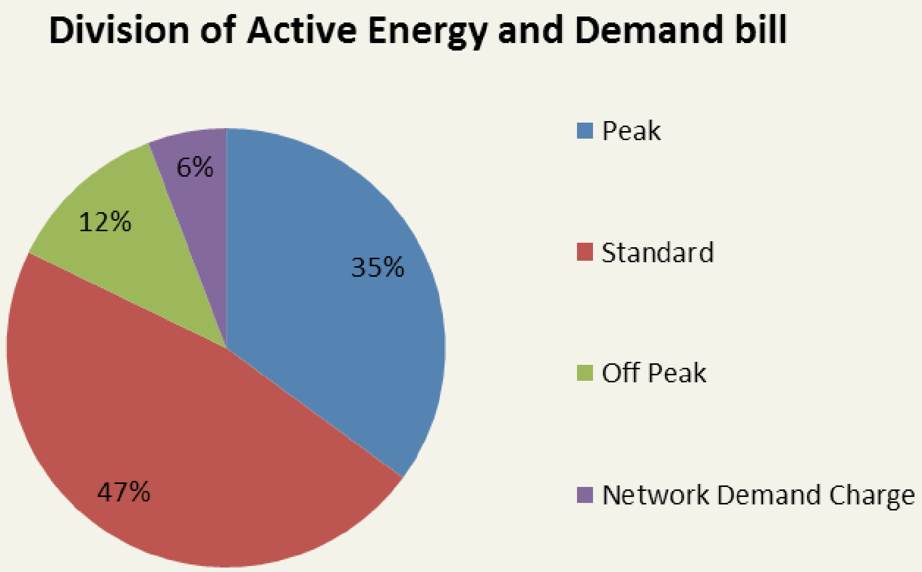
a. Achievable Savings

The tariff structure for this scenario is listed in Table 32, repeated here in Table 42 for convenience. Similarly the division of the bill is repeated in Figure 96.

Table 42: **Megaflex – Local authority rates 2014/2015**

Service charge R/Account/day	R 2 813.83	
Administration charge R/POD/day	R 89.86	
Transmission network charge per kVA	R 5.73	
Network access charge per kVA	R 4.12	
Network demand charge per kVA	R 7.62	
Urban low voltage subsidy charge per kVA	R 10.09	
Reliability service charge per kWh	R 0.0027	
Electrification and rural network subsidy charge per kWh	R 0.0559	
Active Energy Charge	High demand season [Jun-Aug]	Low demand season [Sept-May]
Peak [R/kWh]	R 2.2224	R 0.7249
Standard [R/kWh]	R 0.6732	R 0.4989
Off peak [R/kWh]	R 0.3656	R 0.3165
Reactive Energy per kVArh	R 0.1010	R 0.00

Figure 96: **Current division of the bill on the Eskom Megaflex local authority tariff**



The achievable savings for 1 year is based on the 2014/2015 rates which are applicable from 1st July 2014 for the proposed 50 kW_p PV system. These found savings are used as the input into the financial model. When Table 43 and Table 38 are compared the achievable savings are less when the building usage is billed on the Megaflex tariff. Although the Megaflex tariff has a higher peak active energy charge, the majority of the savings will occur at the standard energy charge, which in the Megaflex tariff is lower than the Drakenstein bulk time of use tariff. The excess energy monetary value for this scenario amounts to R 1 708.70 which insignificant in comparison to the total savings.

Table 43: **Potential savings for year 1 on the Eskom Megaflex tariff**

	Saved [ZAR]	% of total savings
Energy Charge	R 45 346.77	97.24%
Demand Charge	R 1 286.90	2.76%

b. Results

The information and assumptions in Table 26 and Table 43 are used as input into the financial model. The summary of results is presented in Table 44, Table 45 and Table 46.

Table 44: **Financial results for scenario 2 @ R 16/W_p,50 kW_p system**

	@ R 16/W_p		
	100% Grant funded	50% Grant funded	100% Debt funded
Total cost over project lifetime	R 1 057 631.29	R 1 597 308.29	R 2 136 985.29
Initial capital cost	R 800 000.00	R 400 000.00	R 0.00
Cost for Business-as-usual	R 1 944 432.00	R 1 944 432.00	R 1 944 432.00
Profit/Savings Incurred	R 886 800.71	R 347 123.72	-R 192 553.28
Project IRR	6.65%	4.24%	-4.98%
NPV	R 92 593.81	-R 60 463.04	-R 213 519.89
Payback period [years]	13	16	20+
LCOE of PV energy over duration of project	R 0.72	R 1.35	R 1.99
LCOE of Utility energy over duration of project	R 1.32	R 1.32	R 1.32

Table 45: **Financial results for scenario 2 @ R 18/W_p,50 kW_p system**

	@ R 18/W_p		
	100% Grant funded	50% Grant funded	100% Debt funded
Total cost over project lifetime	R 1 169 835.20	R 1 776 971.82	R 2 384 108.45
Initial capital cost	R 900 000.00	R 450 000.00	R 0.00
Cost for Business-as-usual	R 1 944 432.00	R 1 944 432.00	R 1 944 432.00
Profit/Savings Incurred	R 774 596.80	R 167 460.18	-R 439 676.44
Project IRR	5.40%	1.95%	-11.33%
NPV	-R 8 482.09	-R 180 671.04	-R 352 860.00
Payback period [years]	14	18	20+
LCOE of PV energy over duration of project	R 0.79	R 1.51	R 2.22
LCOE of Utility energy over duration of project	R 1.32	R 1.32	R 1.32

Table 46: **Financial results for scenario 2 @ R 20/W_p, 50 kW_p system**

	@ R 20/W_p		
	100% Grant funded	50% Grant funded	100% Debt funded
Total cost over project lifetime	R 1 282 039.11	R 1 956 635.36	R 2 631 231.61
Initial capital cost	R 1 000 000.00	R 500 000.00	R 0.00
Cost for Business-as-usual	R 1 944 432.00	R 1 944 432.00	R 1 944 432.00
Profit/Savings Incurred	R 662 392.89	-R 12 203.36	-R 686 799.60
Project IRR	4.33%	-0.14%	Negative
NPV	-R 109 557.98	-R 300 879.05	-R 492 200.11
Payback period [years]	14	20	20+
LCOE of PV energy over duration of project	R 0.87	R 1.66	R 2.46
LCOE of Utility energy over duration of project	R 1.32	R 1.32	R 1.32

The 100% grant funded, capital cost of R 16/W_p is the only positive business case. However the LCOE values found for the range of capital cost for the 100% grant funded case show that savings can be realised through the installation of the PV project if this funding case can be realised.

Considering the case where the installed turnkey solution is R 18/W the annual cash flow, accumulative net cash flow and accumulative cost is investigated. The avoided costs constitute the cash flow for the project. Here the total savings are subtracted from the associated expenses as seen in Figure 97, Figure 98 and Figure 99 for the 3 differently funded cases. Figure 100 to Figure 105 shows the cumulative costs associated with the PV project and compare these costs with the situation where no intervention is made and the management of 1 Market Street continues paying Drakenstein Municipality to deliver electricity. Figure 100, Figure 101 and Figure 102 show the payback period and Figure 103, Figure 104 and Figure 105 shows the accumulative cost associated with of both the PV installation and the cost of electricity bought from Drakenstein Municipality.

Figure 97: **Scenario 2, 50 kW$_p$ system: Annual Cash flow: 100% grant funded case at R18/W$_p$**

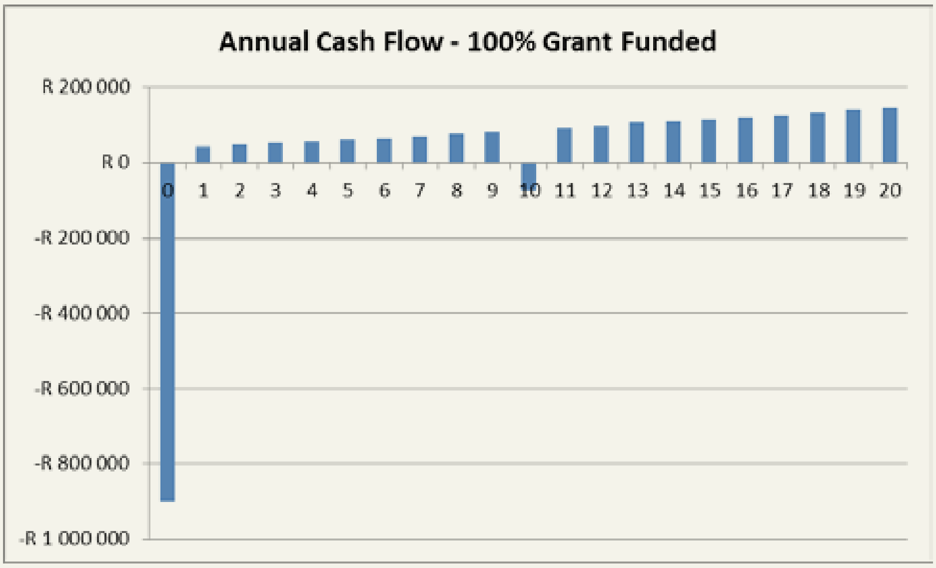
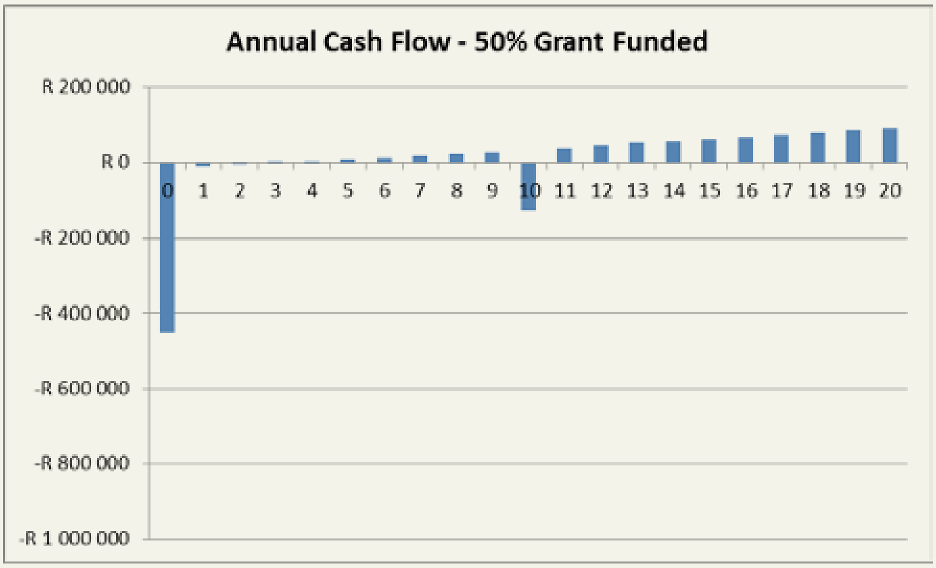


Figure 98: **Scenario 2, 50 kW$_p$ system: Annual Cash flow: 50% grant funded case at R18/W$_p$**



As seen from Figure 68, 50% of the initial project capital is invested in the project. Important to note is that the savings incurred covers the debt repayment annually from year 3, unlike scenario 1 where the savings cover the debt repayment from year 1. Year 10 sees a negative cash flow and is related to the replacement of the inverter, this can however be financed out of the initial loan but was left out in this instance.

Figure 99: **Scenario 2, 50 kW$_p$ system: Annual Cash flow: 100% debt funded case at R18/W$_p$**

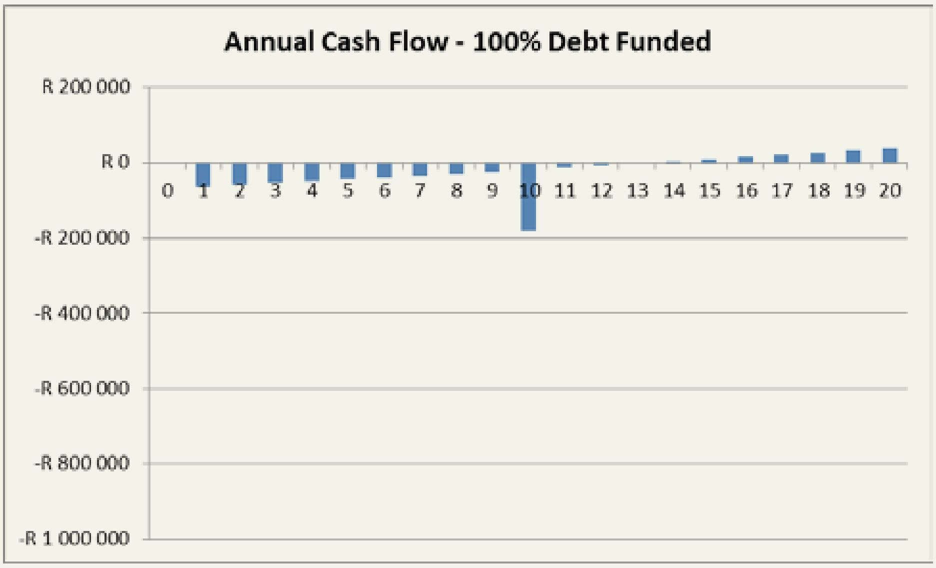


Figure 100: **Scenario 2, 50 kW$_p$ system: Cumulative net cash flow with 100% grant funded case at R18/W$_p$**

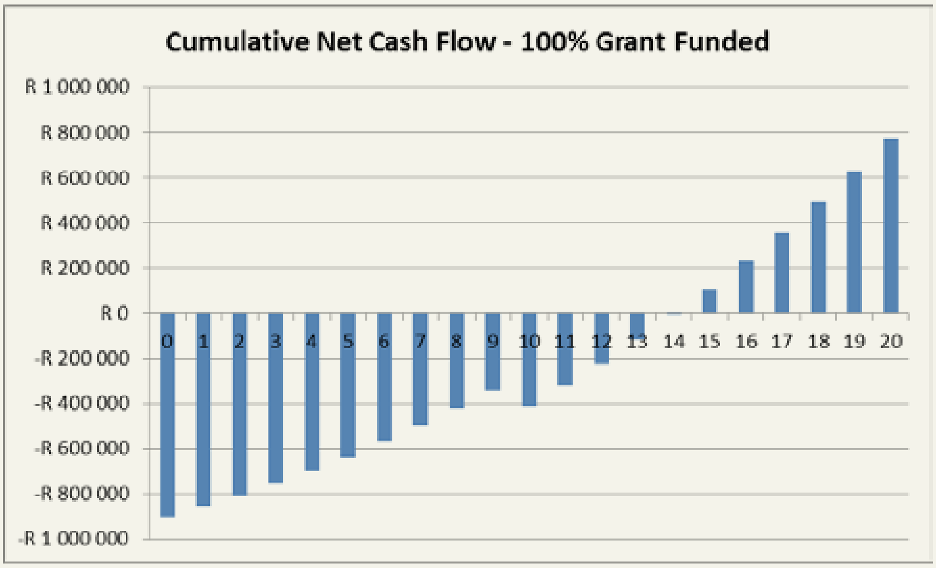


Figure 101: **Scenario 2, 50 kW$_p$ system: Cumulative net cash flow with 50% grant funded case at R18/W$_p$**

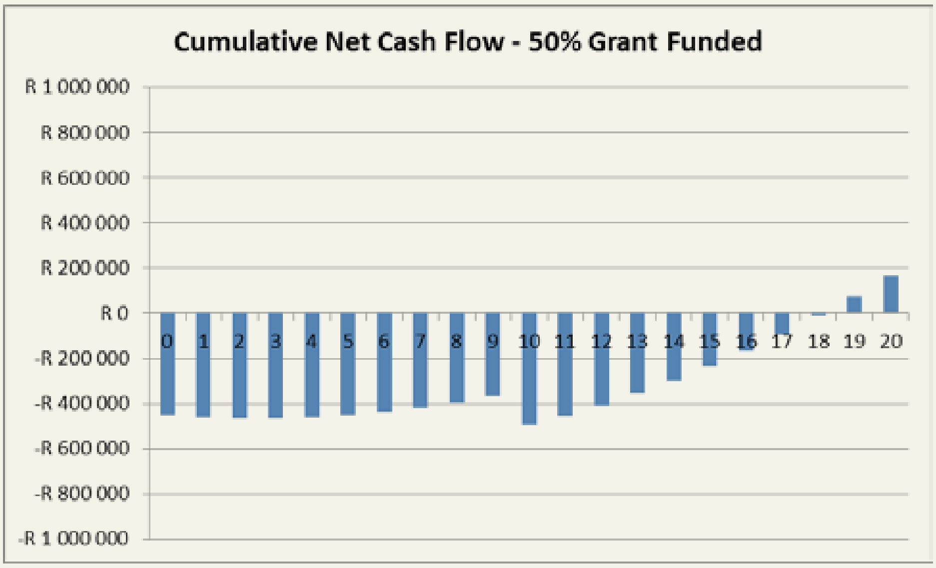


Figure 102: **Scenario 2, 50 kW$_p$ system: Cumulative net cash flow for the 100 % debt funded case at R18/W$_p$**

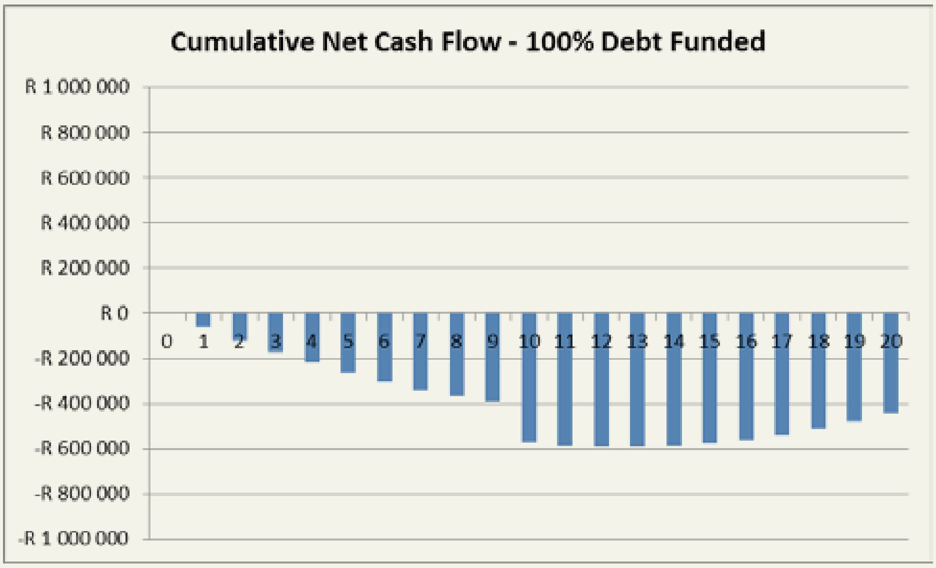


Figure 103: **Scenario 2, 50 kW$_p$ system: Cumulative cost for the 100% grant funded case at R18/W$_p$**

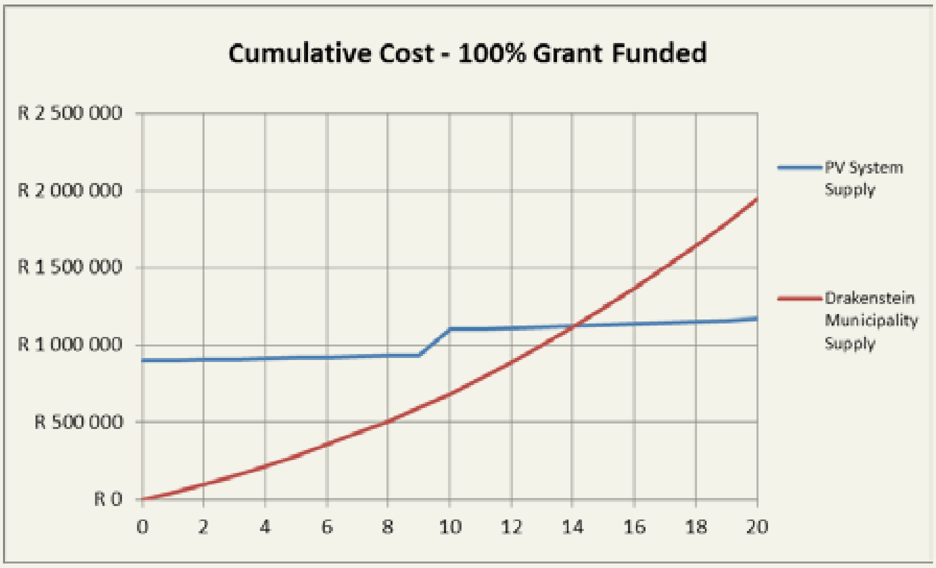


Figure 104: **Scenario 2, 50 kW_p system: Cumulative cost for the 50% grant funded case at R18/W_p**

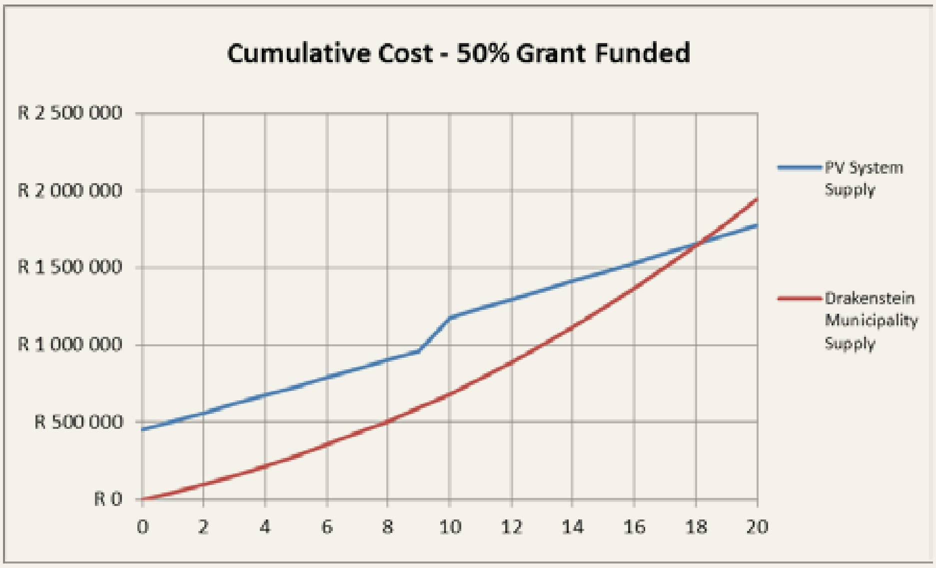
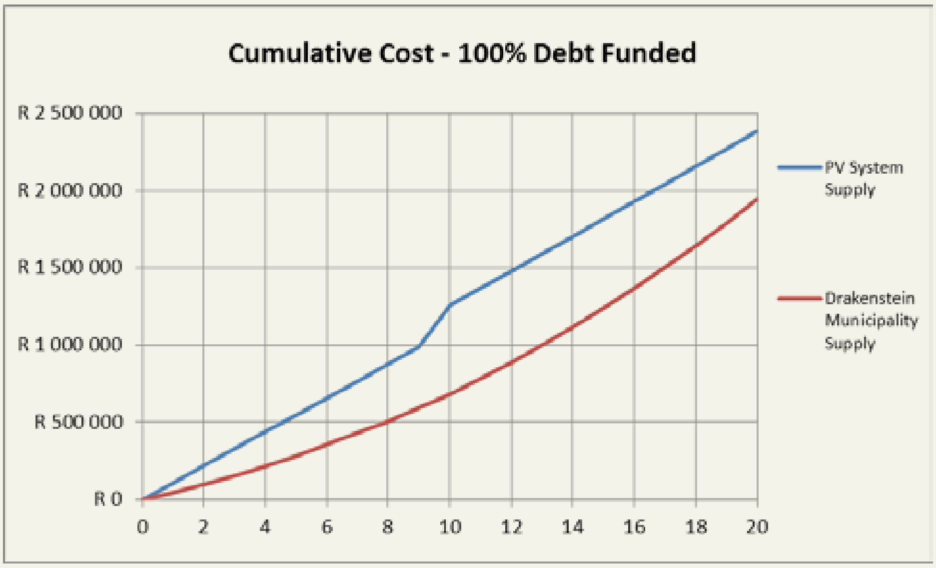


Figure 105: **Scenario 2, 50 kW_p system: Cumulative cost for the 100% debt funded case at R18/W_p**



A payback period of 14 year is achieved for the 100% grant funded case, 18 years for the 50% grant funded case and 20+ years for the 100% debt funded cases respectively for a capital cost of R 18/W_p. The validity if the business case must be carefully considered with these extended payback periods.

Scenario 3

In the scenario the building is seen as a private entity buying electricity from Drakenstein Municipality on Large Power Users Small Scale Embedded Generation Medium Voltage tariff.

a. Achievable Savings

Together with the use of the listed input parameters that define the financial model, the tariff structure on which the building is billed must be considered. The tariff structure determines the associated cost of electricity, the avoided costs with the use of the PV system and thus determines the savings, payback period, and internal rate of return (IRR) of the project. The tariff structure for this scenario is listed in Table 47.

Table 47: **Large Power Users Small Scale Embedded Generation Medium Voltage 2014/2015**[44]

Fixed Charge	R 1 495.00	
Demand Charge per kVA	R 52.00	
Access Charge per kVA (12 months)	R 44.00	
Active Energy Charge	High demand season [Jun-Aug]	Low demand season [Sept-May]
Peak [R/kWh]	R 1.5924	R 0.9771
Standard [R/kWh]	R 0.6684	R 0.5464
Off peak [R/kWh]	R 0.3836	R 0.3392
Reactive Energy per kVArh	R 0.0200	

When the Large Power Users Small Scale Embedded Generation Medium Voltage tariff is compared to the bulk consumers time of use medium voltage tariff it is noted that service, demand and access charge is higher but the active energy charges are lower. This will result in larger demand charge savings if the energy usage peaks are reduced significantly. For this tariff all the generated electricity is used thus the kWh's saved will increase. However an additional expense is the smart meter required when billed on this tariff structure. An estimated cost of R 3300 for the smart meter is incorporated into the system costs.

The achievable savings for 1 year is based on the 2014/2015 rates, which are applicable from 1st July 2014 for the proposed 50 kW_p PV system. These found savings are used as the input into the financial model.

44 Note that the building requires a smart meter to be installed if this tariff structure is to be implemented

Table 48: **Potential savings for year 1 on the Large Power Users Small Scale Embedded Generation Medium Voltage tariff**

	Saved [ZAR]	% of total savings
Energy Charge (used when produced)	R 44 415.34	83.97%
Energy Charge (accounted for through net-metering)	R 1 575.59	
Demand Charge	R 8 781.99	16.03%

Table 48 shows the energy charge savings due to net metering (excess energy) is small in comparison to the savings due to instantaneous reduction of required electricity. The excess savings amounts to 3.6%. This increase in savings is less than the decrease in active energy charge (14%) and together with the increase in access and basic service charge positive returns are not expected.

b. Results

The information and assumptions in Table 26 and Table 48 are used as input into the financial model. The summary of results is presented in Table 49, Table 50 and Table 51.

Table 49: **Financial results for scenario 3 @ R 16/W_p, 50 kW_p system**

	@ R 16/W_p		
	100% Grant funded	50% Grant funded	100% Debt funded
Total cost over project lifetime	R 1 060 931.29	R 1 602 834.46	R 2 144 737.62
Initial capital cost	R 803 300.00	R 401 650.00	R 0.00
Cost for Business-as-usual	R 2 283 805.81	R 2 283 805.81	R 2 283 805.81
Profit/Savings Incurred	R 1 222 874.52	R 680 971.35	R 139 068.19
Project IRR	8.56%	7.58%	3.37%
NPV	R 262 254.38	R 108 566.17	-R 45 122.04
Payback period [years]	11	13	18
LCOE of PV energy over duration of project	R 0.72	R 1.36	R 2.00
LCOE of Utility energy over duration of project	R 1.55	R 1.55	R 1.55

Table 50: **Financial results for scenario 3 @ R 18/W$_p$, 50 kW$_p$ system**

	@ R 18/W$_p$		
	100% Grant funded	50% Grant funded	100% Debt funded
Total cost over project lifetime	R 1 173 135.20	R 1 782 497.99	R 2 391 860.78
Initial capital cost	R 903 300.00	R 451 650.00	R 0.00
Cost for Business-as-usual	R 2 283 805.81	R 2 283 805.81	R 2 283 805.81
Profit/Savings Incurred	R 1 110 670.61	R 501 307.82	-R 108 054.97
Project IRR	7.24%	5.29%	-2.44%
NPV	R 161 178.48	-R 11 641.84	-R 184 462.15
Payback period [years]	12	15	20+
LCOE of PV energy over duration of project	R 0.79	R 1.51	R 2.23
LCOE of Utility energy over duration of project	R 1.55	R 1.55	R 1.55

Table 51: **Financial results for scenario 3 @ R 20/W$_p$, 50 kW$_p$ system**

	@ R 20/W$_p$		
	100% Grant funded	50% Grant funded	100% Debt funded
Total cost over project lifetime	R 1 285 339.11	R 1 962 161.53	R 2 638 983.94
Initial capital cost	R 1 003 300.00	R 501 650.00	R 0.00
Cost for Business-as-usual	R 2 283 805.81	R 2 283 805.81	R 2 283 805.81
Profit/Savings Incurred	R 998 466.70	R 321 644.28	-R 355 178.13
Project IRR	6.10%	3.25%	-7.84%
NPV	R 60 102.58	-R 131 849.84	-R 323 802.26
Payback period [years]	13	16	20+
LCOE of PV energy over duration of project	R 0.87	R 1.67	R 2.47
LCOE of Utility energy over duration of project	R 1.55	R 1.55	R 1.55

The LCOE values found for the 100% grant funded and 50% grant funded case for the turnkey installed solution of R 18/W$_p$ or less show that savings can be realised through the installation of the PV project. If the installed cost is R 20/W$_p$ then the business case becomes questionable.

Considering the case where the installed turnkey solution is R 18/W_p the annual cash flow, accumulative net cash flow and accumulative cost is investigated. The avoided costs constitute the cash flow for the project. Here the total savings are subtracted from the associated expenses as seen in Figure 106, Figure 107 and Figure 108 for the 3 differently funded cases. Figure 109 to Figure 114 shows the cumulative costs associated with the PV project and compare these costs with the situation where no intervention is made and the management of 1 Market Street continues paying Drakenstein Municipality to deliver electricity. Figure 109, Figure 110 and Figure 111 show the payback period and Figure 112, Figure 113 and Figure 114 shows the accumulative cost associated with of both the PV installation and the cost of electricity bought from Drakenstein Municipality.

Figure 106: **Scenario 3, 50 kW_p system: Annual Cash flow: 100% grant funded case at R18/W_p**

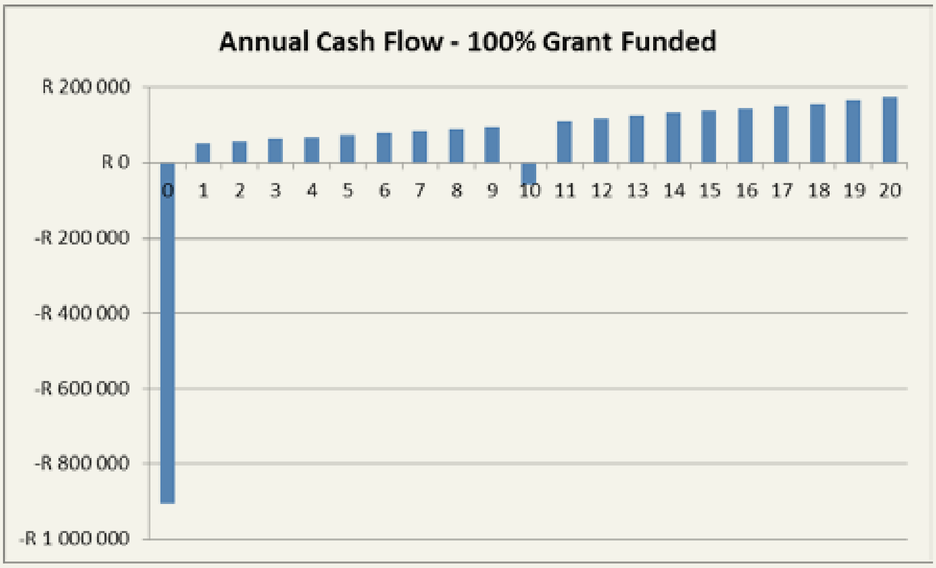
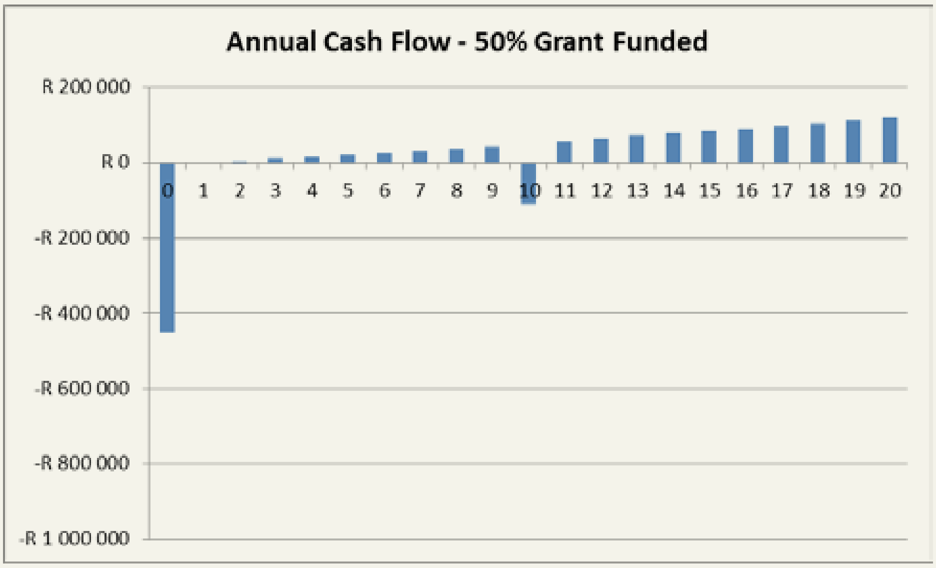


Figure 107: **Scenario 3, 50 kW_p system: Annual Cash flow: 50% grant funded case at R18/W_p**



As seen from Figure 107, 50% of the initial project capital is invested in the project. Important to note is that the savings incurred covers the debt repayment annually from year 1. Year 10 sees a negative cash flow and is related to the replacement of the inverter, this can however be financed out of the initial loan but was left out in this instance.

Figure 108: **Scenario 3, 50 kW_p system: Annual Cash flow: 100% debt funded case at R18/W_p**

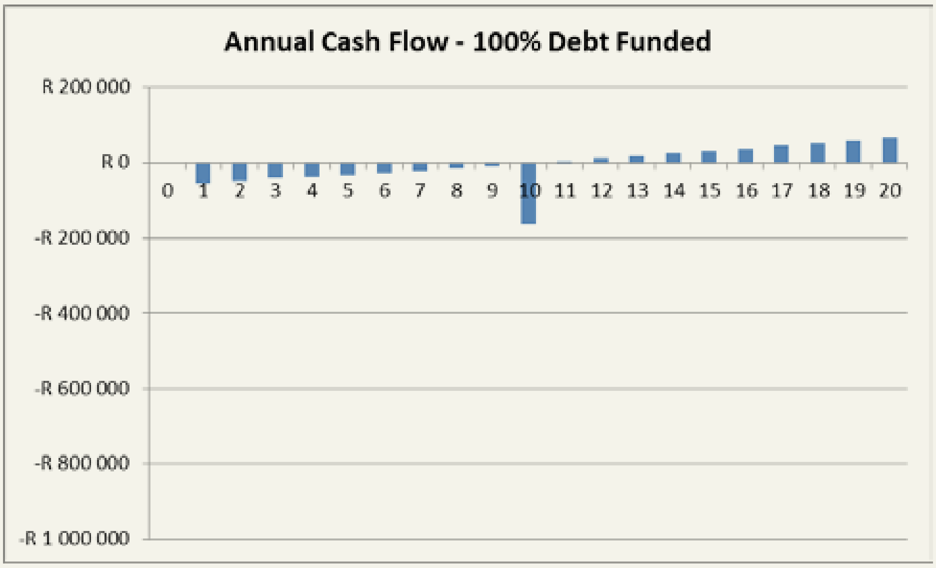


Figure 109: **Scenario 3, 50 kW$_p$ system: Cumulative net cash flow with 100% grant funded case at R18/W$_p$**

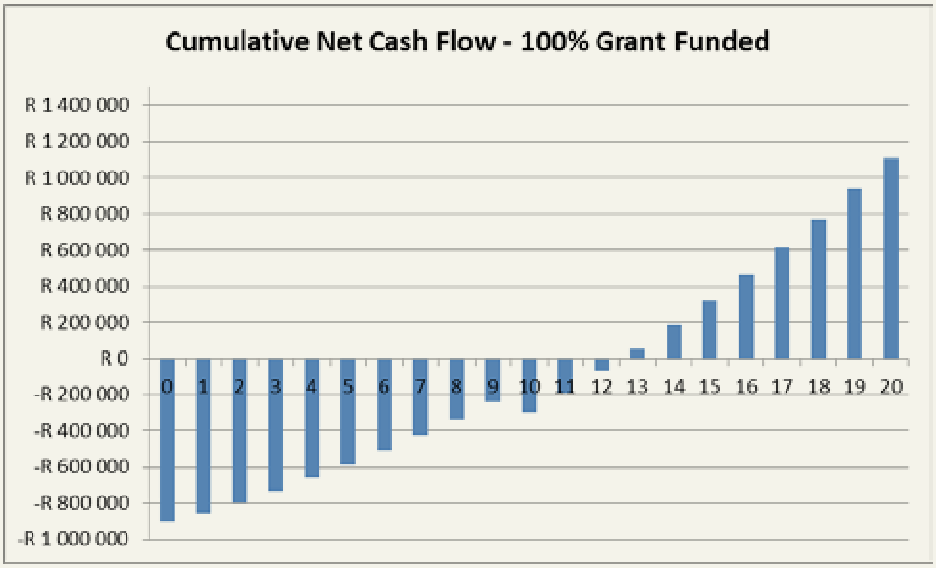


Figure 110: **Scenario 3, 50 kW$_p$ system: Cumulative net cash flow with 50% grant funded case at R18/W$_p$**

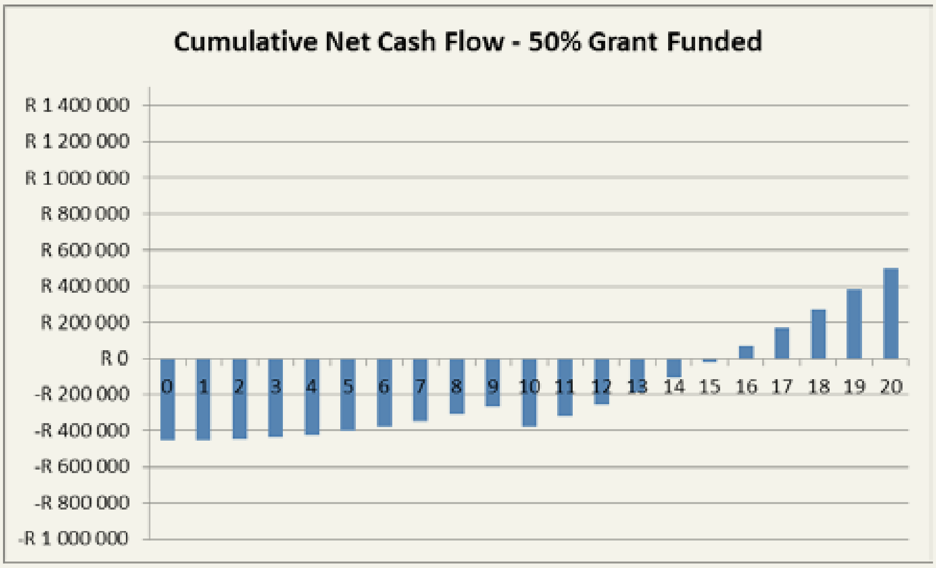


Figure 111: **Scenario 3, 50 kW_p system: Cumulative net cash flow for the 100% debt funded case at R18/W_p**

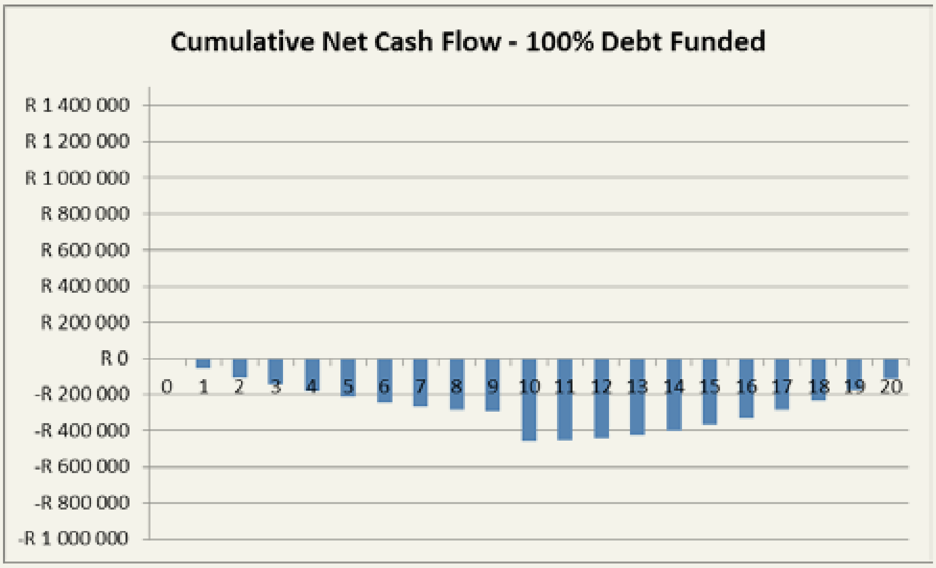


Figure 112: **Scenario 3, 50 kW_p system: Cumulative cost for the 100% grant funded case at R18/W_p**

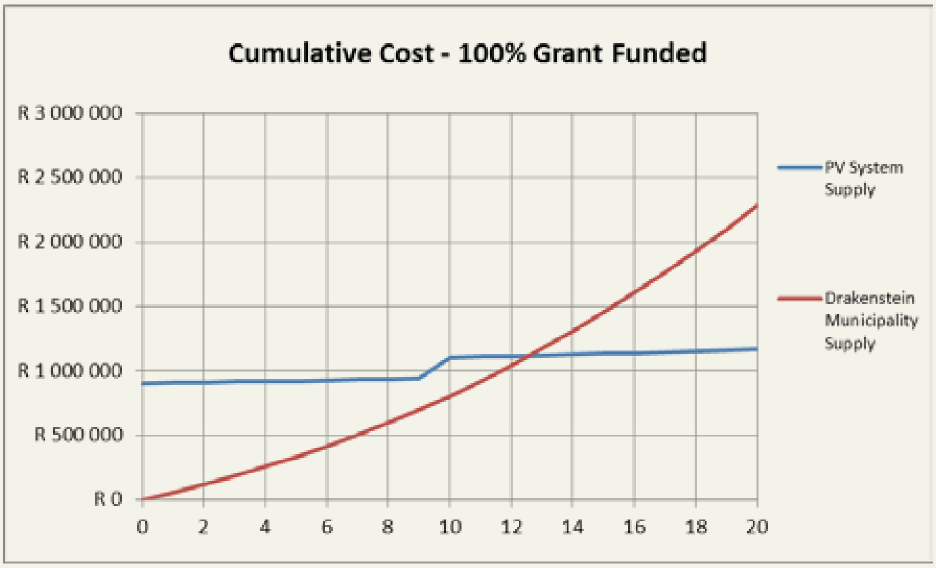


Figure 113: **Scenario 3, 50 kW_p system: Cumulative cost for the 50% grant funded case at R18/W_p**

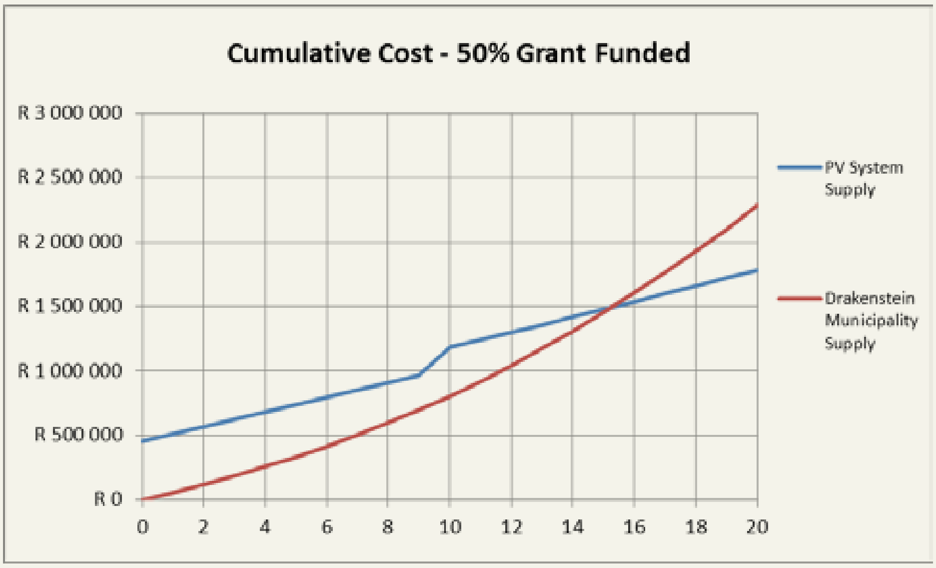
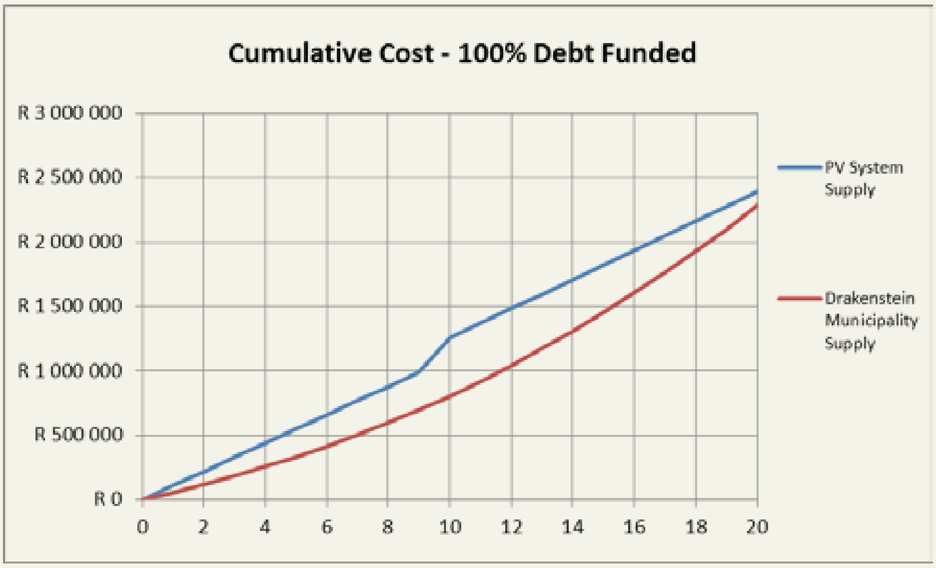


Figure 114: **Scenario 3, 50 kW_p system: Cumulative cost for the 100% debt funded case at R18/W_p**



A payback period of 12 years is achieved for the 100% grant funded case, 15 years for 50% grant funded case and 20+ years for the 100% debt funded cases respectively. The payback period for the 50 kW_p system on the Bulk Time of Use tariff shows a better business case even with the lesser energy savings due to the higher cost of electricity in this tariff. From the accumulative cost graphs it is seen that savings will be achieved from installing a PV system versus the situation where 1 Market Street management continues buying electricity from the Drakenstein municipality.

Summary

Table 52 and Table 53 present a summary for each system at R 18/W_p. When all the scenarios are compared, the most feasible business case is achieved from the 25 kW_p system if 1 Market Street, remains on the Bulk Time of Use Medium Voltage tariff. The 100% grant funded case sees an IRR of 9.02% and a payback period of 11 years. For the 50% grant funded case, an IRR of 8.35% is seen and a payback period of 13 years. The 50 kW_p does not perform as well as the 25 kW_p system due to the increased shading losses and lower specific yield of the system. For this reason the 50 kW_p system on the Large Power Users Small Scale Embedded Generation Medium Voltage tariff does not produce the savings expected.

Further, if the building is to switch over to the Large Power Users Small Scale Embedded Generation Medium Voltage tariff the PV system needs to be larger so that the excess produced electricity, over and above that electricity used to reduce the instantaneous electricity demand can significantly reduce the overall energy usage through the use of net metering. The high ambient temperatures are of concern in the examined area and careful consideration must be given to the type of panels installed in this area.

Table 52: **Summary of the financial feasibility of the 25 kW_p system at R18/W_p**

	25 kW_p System					
	Scenario 1@ R 18/W_p (Building billed on Bulk Time of Use Medium Voltage Tariff)			Scenario 2@ R 18/W_p (Building billed on Bulk Time of Eskom Megaflex Tariff)		
	100% Grant funded	50% Grant funded	100% Debt funded	100% Grant funded	50% Grant funded	100% Debt funded
Total cost over project lifetime	R 584 917.60	R 888 485.91	R 1 192 054.22	R 584 917.60	R 888 485.91	R 1 192 054.22
Initial capital cost	R 450 000.00	R 225 000.00	R 0.00	R 450 000.00	R 225 000.00	R 0.00
Cost for Business-as-usual	R 1 315 725.62	R 1 315 725.62	R 1 315 725.62	R 1 030 491.44	R 1 030 491.44	R 1 030 491.44
Profit/Savings Incurred	R 730 808.02	R 427 239.71	R 123 671.40	R 445 573.83	R 142 005.52	-R 161 562.79
Project IRR	9.02%	8.35%	5.37%	6.07%	3.19%	-7.85%
NPV	R 170 653.19	R 84 558.71	-R 1 535.77	R 25 429.27	-R 60 665.21	-R 146 759.69
Payback period [years]	11	13	17	13	17	20+
LCOE of PV energy over duration of project	R 0.78	R 1.49	R 2.19	R 0.78	R 1.49	R 2.19
LCOE of Utility energy over duration of project	R 1.76	R 1.76	R 1.76	R 1.37	R 1.37	R 1.37

Table 53: **Summary of the financial feasibility of the 50 kW_p system at R18/W_p**

	50 kW_p System								
	Scenario 1@ R18/W_p (Building billed on Bulk Time of Use Medium Voltage Tariff)			Scenario 2@ R18/W_p (Building billed on Bulk Time of Eskom Megaflex Tariff)			Scenario 3@ R18/W_p (Building billed on Bulk Time of Large Power Users Small Scale Embedded Generation Medium Voltage tariff)		
	100% Grant funded	50% Grant funded	100% Grant funded	50% Grant funded	100% Debt funded	100% Debt funded	50% Grant funded	100% Debt funded	100% Debt funded
Total cost over project lifetime	R 1 169 835.20	R 1 776 971.82	R 2 384 108.45	R 1 169 835.20	R 1 776 971.82	R 2 384 108.45	R 1 173 135.20	R 1 782 497.99	R 2 391 860.78
Initial capital cost	R 900 000.00	R 450 000.00	R 0.00	R 900 000.00	R 450 000.00	R 0.00	R 903 300.00	R 451 650.00	R 0.00
Cost for Business-as-usual	R 2 464 773.31	R 2 464 773.31	R 2 464 773.31	R 1 944 432.00	R 1 944 432.00	R 1 944 432.00	R 2 283 805.81	R 2 283 805.81	R 2 283 805.81
Profit/Savings Incurred	R 1 294 938.11	R 687 801.49	R 80 664.86	R 774 596.80	R 167 460.18	-R 439 676.44	R 1 110 670.61	R 501 307.82	-R 108 054.97
Project IRR	8.20%	6.96%	1.77%	5.40%	1.95%	-11.33%	7.24%	5.29%	-2.44%
NPV	R 256 444.10	R 84 255.14	-R 87 933.81	-R 8 482.09	-R 180 671.04	-R 352 860.00	R 161 178.48	-R 11 641.84	-R 184 462.15
Payback period [years]	11	13	19	14	18	20+	12	15	20+
LCOE of PV energy over duration of project	R 0.83	R 1.59	R 2.34	R 0.79	R 1.51	R 2.22	R 0.79	R 1.51	R 2.23
LCOE of Utility energy over duration of project	R 1.76	R 1.76	R 1.76	R 1.32	R 1.32	R 1.32	R 1.55	R 1.55	R 1.55

Conclusion

This prefeasibility study made use of half-hourly metered data that was available over a 10 month period to determine the electricity usage profile of the building. Detailed roof layout drawings were obtained and used to model two potential PV systems on the roof of 1 Market Street, Paarl. Hourly solar data was used as input into the numerical PV model in order to create a hind cast model where historical usage data is compared to hind cast PV production data.

A 25 kW_p and a 50 kW_p system are proposed and through financial assessments carried out. The most feasible case found is the 25 kW_p system, where the building remains on the Bulk Time of Use Medium Voltage tariff. For the 100% grant funded case an IRR of 9.02%, a payback period of 11 years and LCOE of R 0.78 is achieved. For the 50% grant funded case an IRR of 8.35% is seen, a payback period of 13 years and LCOE of R 1.49. It is hypothesised that these savings can be increased if the usage profiles are altered to decrease the morning and afternoon peaks. It is suggested that air-conditioners be placed on timers so that the start-up is staggered from early morning, reducing the 9:00 peak.

CRSES is aware that an energy efficiency programme is currently being rolled out for this building and recommends that prior to installing the PV array, the reduction in usage load is evaluated to ensure that the 25 kW_p system is still well matched to the required usage load.

Owing to the site concerns surrounding the high ambient temperature in the Paarl area, CRSES suggests that should Drakenstein Municipality decide to install PV panels on the roof of 1 Market Street, the service providers investigate the use of thin film panels that are less affected by temperature. The drawback to these panels are however, that such an array cannot achieve the same power density as with the poly crystalline panels, and roof space is already a constraint in this project.

CRSES concludes that if grant funding is awarded for this project, the installation of a 25 kW_p PV array will be successful. For this building, with the shading concerns and restricted roof space CRSES suggest that the PV system that is implemented does not feed back into the grid and all produced energy is for self-consumption. It does not make business sense for this building to move over to the Large Power Users Small Scale Embedded Generation tariff with the implementation of this size PV system, however this tariff may be applicable to larger PV installations.

CRSES trusts that the implementation of the described promising PV system will not only reduce the energy required from an already over constrained grid, it will also promote the green mandate of the Drakenstein Municipality.

CONCLUSION

This research proves that there is a PV system installation potential in Drakenstein municipal area of 24 MW_p before grid studies are needed. When this PV installation potential is compared to the electricity user profiles in Drakenstein, it is shown that it is unlikely that this technical maximum will be exceeded in the short to medium term. This research further demonstrated that the installation of these potential PV systems might have a negative impact on the municipal electricity revenue of 3%.

This research also indicates that there is a good potential for Drakenstein municipality to install PV systems on the roofs of their own buildings, with a feasible financial outcome.

APPENDIX 1

List of installed PV in the WC (excluding off grid and REIPPPP)[45]

Description / Location	Application	Size (kWp)
Somerset College	Commercial	2
Zootee Studios		2
Hi Temp Johan	Residential	3
Clan William		3.2
Hout bay		3.3
Constantia		3.3
Constantia		3.7
Llandudno		4.5
Constantia		4.5
Hout bay		4.5
Tokai		4.5
Durbanville		4.5
Durbanville		4.5
Two Oceans Aquarium		5
Claremont		5
Hout bay		5.5
Durbanville		5.8
Christian brothers centre	Commercial	7
Somerset west	Residential	7
Cape Town		8
Wolwedans	Commercial	9
Hout bay		10
Wellington		10
Stellekaya Wine Farm	Agricultural	10
House Whitaker	Commercial	12
Cavendish Square	Commercial	15
Khayalitsha Environmental Health Offices		17
Cybersmart	Commercial	20
Vineyard Hotel spa		20

45 From: http://pqrs.co.za/s-a-solar-pv-list-2/solar-pv-list/

Description / Location	Application	Size (kWp)
Chaloner	Commercial	21
Solar irrigation system Montague	Agricultural	24
Khayalitsha Distric Hospital	Commercial	25
Koppie Alleen	Commercial	25
Kleinood	Agricultural	28
Impahla Clothing	Industrial/ Manufacturing	30
Store-age Pinehurst	Commercial	30
Imperial Logistics	Commercial	30
Hessequa Municipality	Commercial	33
Beaufort West Municipality	Commercial	33
Rectron Cape Town	Commercial	34
Lelienfontein	Agricultural	35
Oldenburg Vineyards	Agricultural	45
Boland bottling plant	Commercial	48
Bosman Family vineyards	Agricultural	53
Cavalli Wine and Stud Farm	Agricultural	58
La Motte Winery	Agricultural	60
Klein Constantia	Agricultural	60
Eric Miles	Commercial	62
Cape Town Mitchells plain hospital	Commercial / Industrial	62
BP Offices	Commercial	67
Glenelly Wine Estate	commercial	70
Cornerstone	Commercial	81
Historic wine	Commercial	84
J.C.Bosman & Groenfontein	Agricultural	88
Bloemhof	Commercial	100
Quoin Rock Winery	Agricultural	102
HQ Foods Cape Town	Commercial	103
Woolworths		108
Blue jay fruit	Agricultural	127
Villiera Wine Estate	Agricultural	132
Glaxo Smith Kline	Industrial	143
Bo-Radyn Farm	Agricultural	162
De Grendel Winery	Agricultural	210
Cape Quarter		212

Description / Location	Application	Size (kWp)
Vrede & Lust		218
Bowler Plastics Phillipi		280
Apple warehouse	Agricultural	288
Pick n Pay Distribution	Commercial	300
Stellenpak Fruit packers		420
Arbeidsvreugd	Agricultural	450
Villiersdorp Cold storage	Commercial	450
Lourensford	Agricultural	500
Bayside Mall	Commercial	500
Vodacom Century City		542
Wembley square		576
Silver stream business Park		691
Ceres Coldrooms	Commercial	1015
Black River Park	Industrial	1200
TOTAL		10 229

APPENDIX 2

Maximum demand in kVA per substation for 2013-2014[46]

	Municipality Paarl (Dalweiding)	Dwarsrivier	Hugenot	Wellington	Slot
Jan-13			59522	22755	
Feb-13	39635	10422	60800	21839	9886
Mar-13			61879	23160	
Apr-13			51732	21758	3465
May-13	47181	7621			
Jun-13	49669	8977	40556	23368	3567
Jul-13	49063	8602	38881	23264	3406
Aug-13	42005	9413	47423	20796	3438
Sep-13	46245	8490	37991	22240	3164
Oct-13	37263	7421	43680	18105	5177
Nov-13	37029	8191	50584	18166	5343
Dec-13	38638	7487	55384	20780	6839
Jan-14	43727	8666	61386	22737	9063
Feb-14	42201	8970	65699	24907	10191
Mar-14	44868	8086	59646	23204	9338
Apr-14	42166	7228	53710	21694	6016
May-14	45414	7485	39976	21329	3208
Jun-14	50407	9719	43217	21389	3892
Jul-14	41186	9676	45764	20822	3634
Aug-14			46647	20568	
Sep-14			44953	20304	
Oct-14	38678	7516	48720	19435	5925
Nov-14	40802	8750	53672	21089	6723
Dec-14	41998	8896	55348	21006	7301

46 Data from Eskom accounts to Drakenstein municiplaity. Empty cells are where the Eskom account was not available to the researchers

APPENDIX 3

Drakenstein Eskom accounts for 2014

	Total Eskom account (excl. VAT)
January 2014	R35 512 600
February 2014	R36 078 374
March 2014	R35 970 208
April 2014	R32 578 097
May 2014	R33 605 639
June 2014	R55 536 920
July 2014	R62 451 027
August 2014	R59 249 816
September 2014	R35 330 105
October 2014	R37 147 505
November 2014	R35 935 136
December 2014	R35 215 781
	R494 611 209

(Footnotes)

1 From the Eskom accounts

2 1 689 kWh/kWp/year, as calculated by PVSyst Software, North facing with optimal tilt using the Drakenstein Civic Centre in central Paarl as the reference site

3 A total of 8 000 residential customers with a 3 kWp system each

4 Current tariff is R1.18 per kWh. The new SSEG tariff is R1.00 per kWh. A remaining monthly kWh per household of 400 kWh per month is assumed.

5 Evenly distributed between customer categories

6 This was calculated by taking 800 Installations of 30 kWp equally divided between the 9 commercial tariffs for Drakenstein municipality. The existing bulk Time of Use tariffs were not included in this calculation. The financial impact from a user point of view for the bulk Time of Use tariff can be seen in Part D.

7 An assumption is made of 800 commercial electricity users with a remaining 10 000 kWh per month bill remaining after the installation of PV and this remaining electricity is billed at R1.00 per kWh instead of R1.259 per kWh

UNIVERSITEIT
STELLENBOSCH
UNIVERSITY

CENTRE FOR RENEWABLE & SUSTAINABLE ENERGY STUDIES

CRSES

The Centre for Renewable and Sustainable Energy Studies at Stellenbosch University was established in 2007 as the national hub for postgraduate programmes in renewable and sustainable energy (RE) through a grant form the Department of Science and Technology. The Centre has a duel purpose: the training of scientists and engineers with the required technical expertise to unlock the country's RE resources, and the implementation of appropriate technologies for the sustainable use of RE.

The Centre acts as a central point of entry into Stellenbosch University for the general field of RE. The work of the Centre focuses on contract research, postgraduate modules in RE and the coordination of other training courses in RE. Some contract research projects are completed within the Centre while others are channelled to the relevant academic departments or research groups of the University.

http://www.crses.sun.ac.za

WWF

WWF is one of the world's largest and most experienced independent conservation organisations, with over 5 million supporters and a global network active in more than 100 countries. WWF's mission is stop the degradation of the planet's natural environment and to build a future in which humans live in harmony with nature, by conserving the world's biological diversity, ensuring that the use of renewable natural resources is sustainable, and promoting the reduction of pollution and wasteful consumption.

The Global Climate & Energy Initiative (GCEI) is WWF's global programme addressing climate change and a move to 100% renewable energy through engagement with business, promoting renewable and sustainable energy, scaling green finance and working nationally and internationally on low carbon frameworks. The team is based over three hubs – Mexico, South Africa and Belgium.

www.panda.org/climateandenergy

Publication Details
Published in August 2015 by WWF International (World Wide Fund for Nature (formerly World Wildlife Fund), Gland, Switzerland. Any reproduction in full or in part of this publication must mention the title and credit the above-mentioned publisher as the copyright owner.

Recommended citation:
WWF, 2015, Potential for integration of distributed solar photovoltaic systems in Drakenstein municipality .
WWF-SA, South Africa.

Contributors

Author/s:
K. Kritzinger
I. Meyer
Prof. J.L. Van Niekerk
L. Scholtz

Special contributors:
The author would like to thank everyone involved for their collaboration and contributions which helped to improve the final report.

For WWF-South AfricaL Living Planet Unit:
Louise Scholtz
lscholtz@wwf.org.za

WWF South Africa: Living Planet Unit
Bridge House 1st Floo
Boundary Terraces
Mariendahl Lane
Newlands

P O Box 23273
Claremont 7735
South Africa

www.panda.org/climateandenergy

Design:
Farm Design, www.farmdesign.co.za
Cover Photograph:
Daleen Loest, Shutterstock.com

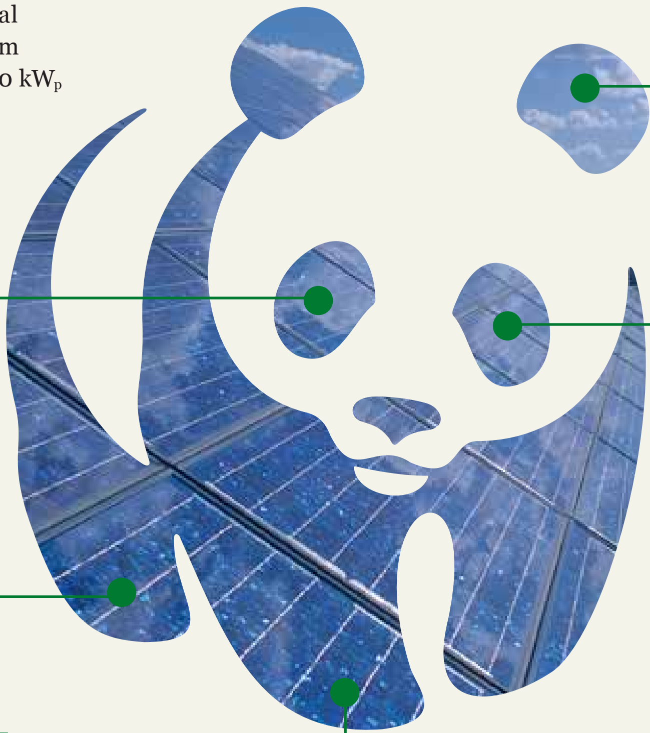
Potential for integration of distributed solar photovoltaic systems in Drakenstein municipality

3% POTENTIAL IMPACT

on Drakenstein municipal revenue might result from the installation of 24 000 kW_p PV systems

INSTALLATION OF 24 000 KW_p

is technically possible for the whole of Drakenstein, following a conservative approach based on the electricity load profiles at substation level



INSTALLATION OF 25KW_p

is proposed for the 1 Market Street building, owned by Drakenstein municipality

PV POTENTIAL

is highly place specific, determined by the solar resource, existing electricity use and access to public and/or private finance

NEW MODELS

in municipal electricity generation and distribution (financial and technical) is required from municipalities

Why we are here

To stop the degradation of the planet's natural environment and to build a future in which humans live in harmony with nature.

wwf.panda.org/climateandenergy

PHOTO: SHUTTERSTOCK.COM