

Article

Validation of a Simulation-Based Pre-Assessment Process for Solar Photovoltaic Technology Implemented on Rooftops of South African Shopping Centres

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Abstract: The existing processes that determines the yield of a photovoltaic (PV) system before construction commences are fairly unstructured. Research that defines a structured process for simulation purposes is limited. This article builds on prior research where a proposed structured pre-assessment process, which may be applied before construction commences, was generated so that electricity yield from a PV system can be predicted with a higher degree of accuracy, and then subsequently optimized. By implementing the proposed pre-assessment process, calculating the future return on investment (ROI) by private investors is simplified, given that the existing process is restrictive. The research used the results from a South African case study over 24 months to ascertain the validity of the proposed pre-assessment process. The validation process includes analyzing the load demand of the shopping centre before and after the PV system was constructed, comparing the electricity yield from the PV system to the simulation results obtained in the preceding research, and amending the proposed pre-assessment process accordingly for improved electricity estimation. The case study shopping centre operates in Johannesburg, Gauteng, and consumes approximately 5000 kVA under maximum load.

Keywords: photovoltaic; angle of tilt; module degradation; array-to-inverter ratio; yield simulation; tender process

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1. Introduction

Deployment of renewable energy technologies is undertaken to improve energy security, reduce dependency on current infrastructure, encourage economic development in rural and manufacturing sectors and reduce the environmental mitigating effects caused by fossil fuel-based technologies [1]. In recent history, the South African utility has experienced difficulties in providing reliable electricity to the grid, resulting in the implementation of a controlled blackout mechanism (known as load shedding) to protect the power system from total failure [2]. This has further exaggerated the need for electricity, as approximately 40% of Southern Africa's inhabitants currently do not have ready access to electricity while the remainder is dependent on the current utility [3].

Electricity supply relates directly to economic growth. Research conducted by Andersen and Dalgaard [4] suggests that gross domestic product (GDP) growth rates in sub-Saharan Africa are held back by 2 percentile points because of weak electrical infrastructure, with the current GDP of South Africa being 17% [5]. The threat of future load shedding and the accompanying lack of economic growth led to the South African government to announce the Integrated Resource Plan (IRP) in 2010 [6]. The IRP is a defined plan that directs the expansion of the existing electricity network over a given period [7]. By imple-

menting the IRP, diversification of the various energy sources within South Africa is possible [6]. This is especially important since approximately 77% of South Africa's energy supply is reliant on coal-based technologies [8].

The IRP recognizes the potential of solar photovoltaic (PV) technologies within the country. Regarding the IRP iteration of 2019, the expected grid penetration of solar PV by the end of 2030 will be approximately 8.29 GW [9]. Investment into PV technologies was expected to stagnate for 2019, but then increase to an average of 900 MW/annum between 2021 and 2023. Thereafter, investment is expected to decrease between 2024 and 2027 to an average of 250 MW/annum, and will then increase to 1000 MW/annum between 2028 and 2030. By the end of 2030, PV grid penetration is estimated to increase to 10% of the total grid size [9].

By utilizing a PV system, sunlight is converted into thermal or electrical power and then fed into the existing grid of the consumer, known as a microgrid. Provided that such a system is managed correctly and that periodic maintenance is performed, as per the prescribed service intervals, clean, discreet and inexhaustible electricity can be generated over 20 to 25 years [10,11]. South Africa's annual solar PV potential ranges from 1500 kWh/m² along the eastern coastline to 2300 kWh/m² in the Northern Cape. Gauteng has an annual solar PV potential of approximately 2100 kWh/m² [12].

A portion of the aggregate solar PV systems to be implemented will be funded and utilized by private investors on their property. On-site PV systems utilize grid-tie inverters, among other components, where the energy from the sun is converted and fed into the existing electrical network of the consumer. In addition, the PV modules are mounted to an existing sub-structure such as a roof of a building, or are isolated and installed as a carport structure [13]. The main advantage of affixing the PV modules to an existing structure is that installation and acquisition costs are reduced while building cooling loads are reduced as conduction heat theory applies [14]. However, since the majority of the lattice structures (accommodating the roof) were designed without considering the addition of PV modules, it is common for structural reinforcements to be implemented—resulting in increased investment costs [15]. Grid-tie PV systems are connected without the ability to store energy, as storage technologies are not currently financially feasible [16]. This implies that all electricity from the PV system is consumed by the consumer, given that the electrical load surpasses the electricity generation ability of the PV system [17].

The estimated financial savings of a PV system have stimulated an increase in deployment rates. The financial feasibility is calculated based on the estimated electricity savings incurred if it is assumed that the electricity is acquired from the existing utility over the lifespan of the system. There are, however, restrictions imposed by the South African government where the Electricity Regulation Act of 2006 states that PV systems can be constructed and feed electricity of up to 1 MVA into the micro-grid (not including the electrical grid of the utility) of the consumer without obtaining a generation license [18]. Systems that have the potential to generate more electricity must obtain a generation license. Due to the associated waiting period and costs, investors in South Africa have restricted their systems to 1 MVA. This limitation has necessitated the optimization of the performance of the PV system before construction commences since changing the operational characteristics of the system after construction is completed can prove difficult and expensive.

Since the implementation of PV systems within South Africa is a relatively new concept, a clear and concise process that estimates the electricity yield of a PV system before construction commences is lacking. The rationale of this research is to develop and validate a structured pre-assessment process that can be utilized by investors to accurately estimate the electricity yield from a PV system before construction commences.

If the process is applied correctly, the decision-making procedure of the investor will be supported, while enabling engineering, procurement and construction (EPC) companies to modify their design proposals accordingly when submitting a tender proposal, thus minimizing their risk. Furthermore, the research aims to provide a mechanism that

enables the private investor to estimate the return on investment (ROI) of the PV system with a higher degree of accuracy, since current methodologies are restrictive. This estimation will be calculated using the data obtained by the EPC company or by their independent consulting engineer. This research is novel in that limited research exists which encompass all of the behavioural characteristics of a rooftop PV system and then subsequently provide a mechanism to utilize for investing purposes.

This article follows a previous article [19], in which the proposed simulation-based theoretical pre-assessment process was developed, where this article aims to validate and adjust the aforementioned process accordingly.

The following is a summary of the layout of this article: the literature review is presented in Section 2, the methodological approach applied in obtaining the results is discussed in Section 3, the results and discussion are presented in Section 4 and Section 5 presents the conclusion and future recommendations.

2. Literature Review

In line with the Sustainable Development Goals (SDGs) [20] and the Integrated Resource Plan (IRP) of 2010 [21], which aims to reduce dependence on coal-intensive resources while simultaneously increasing the deployment of sustainable, clean and affordable energies, this research facilitates compliance with the aforementioned. In order to promote the use of PV technologies (considered as a clean source of energy), mechanisms must be put in place to promote its deployment in developing countries. The literature review addresses the evolution of a PV system throughout its life cycle, followed by a summary of the results from the preceding research [19].

2.1. Existing Process in Constructing a PV System

Wahlström et al. [22] identify three main scenarios where a PV system can be constructed, namely, in a new large individual utility or building; new housing areas; and the renovation of an existing building. New large individual utility or domestic buildings involve the construction of new buildings. New housing areas involve the construction of a residential area, and renovation involves the process of improving or repairing an existing building. Concerning a commercial-sized PV system (greater than 50 kW), a combination of the first and third scenarios is utilized as existing shopping centres expand and upgrade their current premises simultaneously. When a PV system is affixed to an existing structure, it is common to implement upgrades to the existing truss system or the lattice support structure (if applicable) [15], the main reason being that older structures were designed without provision for the extra mass of the PV modules.

When considering the operational nature of a grid-tie PV system, its integration with a shopping centre can be beneficial. Shopping centres consist of parking space for vehicles, enabling the erection of stand-alone carport structures, or have newly built structures due to the constant expansion to accommodate new shops/tenants. Furthermore, the overall trajectory of the baseload of shopping centres coincides with the electricity production curve of a PV system [16].

Gevorkian [23] states that when a PV system is implemented, it undergoes several phases through which it evolves, including the following:

1. preliminary project assessment;
2. project site survey;
3. feasibility study or preliminary design, and report;
4. advertisement in a tender process and proposal generation;
5. contract award negotiations;
6. final design;
7. project integration into existing infrastructure;
8. system commissioning, test and verification;
9. final test and acceptance or performance verification; and

10. system maintenance.

2.1.1. Preliminary Project Assessment and Project Site Survey

The initial two phases include conducting a preliminary project assessment and a site survey at the prospective location. The main purpose is to determine the viability of a PV system. If required, an environmental impact assessment (EIA) determines the impact of the PV system on the local environment [24]. Once the preliminary assessment and site survey have been completed, a feasibility study will be initiated.

2.1.2. Feasibility Study or Preliminary Design

The feasibility study determines the required operating parameters of the proposed PV system and is generally conducted by external parties such as consulting engineers [19]. The purpose of the feasibility study is to provide an in-depth assessment of the energy potential of the solar project. In addition, architects play an integral role in the implementation of the feasibility study since they investigate various solutions and create an optimum building design that corresponds to the client's needs and, in some cases, the local and national requirements [22,25]. In the case of a newly built domestic building, the results of the feasibility study will influence design parameters, including the architecture of the building [26].

Wahlström et al. [22] state that the first requirement is to conduct a technical evaluation of the new or existing building and its electrical network. Examples of what must be considered, related to the technical evaluation of the new or existing building, include:

- The existing load demand of the consumer must be investigated. If the possibility arises that the PV system may surpass the maximum load demand, then control systems must be implemented to avoid feedback into the grid. In South Africa, feedback is only permitted under certain conditions [27].
- The existing electrical network of the consumer must be investigated and, if required, amended. In the case of renovations, electrical networks are not commonly addressed, resulting in that tie-in points do not accommodate the electricity supply. Therefore, contingencies must be made in the case of a system update [28].
- In line with current legislation pertaining to consumers who produce their electricity, PV systems are restricted to 1MVA without obtaining a generation license in South Africa [18].
- In the case of power disruptions due to load shedding (a controlled mechanism implemented by the South African utility because of inadequate electricity supply [2,29,30]) or system malfunction, shopping centres utilize multiple backup generators. When a PV system is designed for the relevant shopping centre, integration with the backup generators must be considered. Diesel generators must operate at 60–75% of their rated power to prevent bore glazing of the piston sleeves [31]. When bore glazing occurs, the honing marks of the bore are smoothed over, resulting in a reduced seal between the piston rings and the cylinder bore, the result being that combustion gases mix with the oil deposits [32].

Once the technical evaluation has been completed, three additional evaluations of the project must be conducted: economic, organisational and environmental. The process involves a comparison of three possible design alternatives (including alternatives to PV power systems) through a comparative matrix system. Thereafter, the results for each scenario must be summarized [22]. Once all of the various scenarios have been compared with each other, a decision will be made to invest in the appropriate PV system.

2.1.3. Advertisement in a Tender Process and Proposal Generation

Phase 4 of a PV system involves advertising the PV system in a tender process and generating proposals. A tender process is a formal and structured invitation to suppliers

to submit a bid to provide a product or a service based on various specifications, contractual periods and any other relevant conditions [33]. The tender process will be either by invitation only or open to all prospective contractors, with the aim to generate an EPC agreement between the respective parties [16]. The tenderer will submit various solutions at their specified price [19].

Tender processes are particularly preferred in private industry. This is because two economic enablers are met, namely to establish a guaranteed demand and to ensure that revenues are recovered [1,34]. Regarding renewable energy, these processes have been successfully implemented in South Africa in recent history [35].

The presentation of proposals provides the client with a multitude of choices, starting with the optimum solution based on the aesthetic, functional, technical and financial features of the building project [22]. As part of the proposal phase, the tenderer will provide proposals of PV systems with alternative characteristics. This will include varying the rated system size and, in some cases, providing alternatives for the PV system [22]. Alternative PV concepts will be considered and evaluated in terms of technical, economic or organizational and environmental aspects using simulation software [22].

When proposals are submitted, an investigation of the existing electricity demand of the consumer is conducted. The existing load demand must be estimated or analysed to design a solution that coincides accordingly; the information from the existing load demand is obtained through the feasibility study.

System performance throughout the life cycle of a PV system is critical and must be considered during the proposal phase [22,36]. Failure to deliver a product that complies with the requirements may result in legal disputes [37].

2.1.4. Contract Award Negotiations

After the various proposals from tenderers have been received by the investor, a contract award process is entered to award the project to the selected EPC company. Factors such as system costs, yield guarantees, quality guarantees and time limits are considered in granting the tender award [23]. Once the project has been awarded to the EPC company, negotiations occur between the relevant parties to minimize the installation time, reduce the PV system costs and resolve any relevant issues [23]. Furthermore, the legally binding agreement between the two parties ensures that the EPC company is held liable for any defects, while yield warranties are agreed upon. Yield warranties are determined based on the results obtained from simulation software such as PVSyst [38].

In addition, a service level agreement (SLA) may be required. An SLA is a contractual agreement between the service provider and the investor that is initiated once the PV system has been commissioned. The agreement requires the EPC company to provide post-construction services for a predetermined period after the operation of the PV system has commenced. The conditions of the SLA are determined during the negotiation phase when contracts are agreed upon [39].

2.1.5. Final Design

This phase involves finalizing the design of the PV system. This is generated based on the agreement between the EPC company and the relevant engineers. Additional changes to the design will be allowed only under strict conditions [23].

2.1.6. Project Integration into Existing Infrastructure

Project integration into the existing infrastructure involves integrating the PV system into the infrastructure of the investor. This relates to the construction of the PV system on the premises of the investor and connecting the PV system to the existing electrical network (if a grid-tie system is implemented). The period of construction is defined during contract negotiations, and system integration into the existing network occurs before commissioning [22].

2.1.7. System Commissioning, Test and Verification

After the system has been connected to the electrical network, the various inverters can be commissioned. As part of commissioning, additional testing and verification are conducted, including investigating the installation method for the various components to ensure that they comply with the requirements of the manufacturer [22].

2.1.8. Final Test and Acceptance or Performance Verification

After commissioning, the PV system will enter the hand-over phase, where the investor takes ownership. Once hand-over has taken place, certain responsibilities from the EPC company are relaxed (depending on the contractual conditions) [22].

2.1.9. System Maintenance

System maintenance involves the costs that may be incurred during the operation of the PV system. As previously stated, an SLA may be entered into by the relevant parties, or the investors may choose to maintain the system themselves.

After the system has been in operation for a specified period, the investor and EPC company will liaise to investigate the electrical yield from the PV system (as was determined during the contract negotiation phase). If the system does not yield the predetermined electricity, legal disputes may arise. Currently, no defined process exists that can be used to accurately estimate the yield from a PV system while simultaneously improving its efficiency. The previous research [19] proposed a process that may be applied and can be summarized as follows.

2.2. Results from Preceding Research Article

When the feasibility study is performed or the EPC company submits a proposal, yield simulations are conducted to estimate the electricity yield of a PV system [40]. By estimating the electricity yield from the PV system before construction commences, an investor can determine the financial viability of the investment or the EPC company can determine warranty conditions accordingly [37].

The previous research [19], on which this article is based, identified the need to accurately estimate the electricity yield from a PV system before construction commences [19,40]. The following is a brief literature review of various simulation techniques applied in estimating the electricity yield from a PV system.

2.2.1. Literature Relating to Simulations of PV Systems

The basic programming approach relating to modelling and simulating has been applied as early as 1955 [41]. Due to technological improvements, computing power evolved to integrate additional factors such as the given energy demand during a specific time of day, improving the demand-supply interactions and aiding the system planning process. One example of this includes simulating and estimating the specific supply from a system to determine instability and intermittency associated with renewable energy. The main advantages of simulating electricity yield from a system are twofold; firstly, implementation of modelling techniques that simulate the synergy between existing infrastructures and a new source reduces costs; and secondly, it enables planners to design a system that consists of contingencies in the case of certain occurrences [42–44].

Recent history has seen simulation restrictions occur when applied to developing countries. Since there are some uncertainties in applying simulation to a system, unique characteristics are not always captured. One example includes how climatic conditions affect the system behaviour when renewable energies are deployed, resulting in high instability as these conditions vary greatly within South Africa. This is important since it is expected that deployment rates of PV and wind technologies, of which both are associated with unstable electricity supply, will increase in the future [42]. According to Chiodi et al.

[45], developing methodologies that incorporate high variability in power systems is important. If it is not considered, then existing and outdated systems may have to be adapted accordingly.

A variety of modelling tools exist that are distinguished by varying user interface simplicity, cost and accuracy (reliant on the computing power) [41,46]. Recent history has seen a higher utilization of simulating software such as PVSyst and HelioScope. Research conducted by Siyabi et al. [47] investigated the effect of soiling on solar PV performance operating within desert climatic conditions. They state that factors such as soiling, module loss (instigated by temperature variation, shading, and variant conversion efficiency), inverter loss and cable loss (before and after inverting the electricity from DC to AC) must be considered. Their research concluded that there is a production variation of between 0.23% to 7.8% when simulated data from HelioScope are compared to actual yield [47]. This is especially important when considering that electricity production can vary by as much as 38.1% due to soiling alone [47]. Another example of the utilization of simulation software includes the research conducted by Corba et al. [48] in which PVSyst was used to 1) optimize the electricity yield from a PV system and 2) compare the results over a period spanning from 2012 to 2019. Their results yielded an average Performance Ratio (PR) of 0.816, compared to a simulated value of 0.782, a deviation of approximately 4.35%.

In some cases, the disparity between simulation results and actual yield can greatly increase. Research conducted by Dobрева et al. [49] modelled the yield of a PV system in Namibia. Their results suggest that a variation of up to 11.4% can be obtained, whereby it was concluded that long-term predictions for electricity yield depend on various uncertainties in solar radiation and de-rate factors [49].

Various other literature [50–52] exists that compares the results from electricity yield simulations to actual performance. By implementing the appropriate simulation techniques, “the planned PV system will provide the operational benefits to the installer or the owner” [53].

Based on the research that was conducted, it was determined that simulations are important to mitigate risk before a system is constructed. However, a structured and sequential process that accurately estimates the electricity yield from a PV system was lacking. Therefore, a need existed to derive such a process. The following is a summary of the process that was derived in the previous research.

2.2.2. Pre-Assessment Process Derived from the Preceding Research Article

A structured and sequential process was developed that must be implemented before construction commences. The process excluded the formalities that are analysed during the preliminary project assessment and project site survey and focused on the simulation permutations that must be investigated during simulations. The various steps of the process are as follows [19]:

Step 1: Analyse the existing load demand of the premises for the intended PV system

The existing load demand of the shopping centre or consumer determines the rated generation capacity of the PV system. The information is obtained during the feasibility study and is presented in the tender documents when the project is being advertised. However, due to generation limitations by NERSA, PV systems are limited to 1 MVA [18]; this will generally not exceed the existing load demand of the consumer.

Understanding of the load profile ensures that optimal integration between the PV system and the back-up generator occurs when the existing electricity supply from the utility is unavailable. If the two systems do not integrate efficiently, bore glazing of the piston sleeves may occur, resulting in engine malfunction [31]. Effective integration can be assisted by implementing a control system.

The results from the research also identified a relationship between the load demand, ambient temperatures and radiation levels. Although cloud cover increased in the summer season due to precipitation [54], ambient temperatures simultaneously increased due to an increase in radiation levels. As a result, the load demand from the case study increased due to increased cooling loads. Research conducted by Seneviratne [55] estimates that cooling accounts for 5 to 24% of a shopping centre's total electrical load.

Step 2: Investigate the effect of tilt and azimuth angle variation on the production of the PV system

By analysing the effect of tilt and orientation during the feasibility study, architecture can be implemented to improve the electrical yield from the PV system. This is especially beneficial if the mounting structure has not been constructed. In the case where a carport structure is to be provided as part of the solution, then EPC companies can optimize the solution when they submit their tender proposal.

The literature [56,57] and results from the research indicate that there is a relationship between the electricity yield and the angle of tilt (β) and orientation on the azimuth (Ψ). Peak average daily specific yield of 4.7 kWh/kWAC/day is obtained when the PV modules are mounted such that $\Psi = 6^\circ$ and $\Psi = 7^\circ$ in a north north-easterly direction and $\beta_{opt} = 28^\circ$. The lowest average daily specific yield of 3.1 kWh/kWAC/day is observed when the PV modules are mounted such that $\Psi = -180^\circ = 180^\circ$. It was found that there is an average reduction of 0.926%/1° when the angle of tilt is reduced from 30° to 0° in the northerly direction. However, due to practical and shading restrictions, PV modules are installed such that $-10^\circ \leq \beta \leq 10^\circ$ when commercial-sized PV systems are affixed to roofs of buildings. It was also concluded that the geographical location of the PV system affects the electricity yield.

Due to South Africa's electricity tariff structure, it was concluded that PV systems be designed so that winter electrical yield is favoured. That is because tariffs are approximately 2.5 times higher in the winter season compared to the summer season [58].

Step 3: Investigate the effect of module degradation on the yield of the PV system over its life cycle

Module degradation is a term used to describe the output performance degradation of PV modules over their lifespan due to factors such as lengthy outdoor operation, lack of maintenance, enclosure problems, thermal cycling and ineffective grounding [59,60]. The module supplier warrants that PV modules will not exceed a degradation rate of 0.7%/annum after the first year: this equates to a guaranteed production value of 80% of the initial installed power rating of the PV modules after 25 years [61]. However, various authors [62–64] suggest that degradation rates are lower than the warrant values of the PV module supplier and that they are inherently conservative.

It is imperative to consider degradation when financial feasibility studies are conducted or when the EPC company provides a solution during the tender process since yield conditions are calculated over a predefined period.

Step 4: Investigate the effect on production due to increased ATIR

Due to limitations imposed with regard to the generation abilities of a PV system, the electrical yield must be optimized. The results from the simulations indicate that by increasing the array-to-inverter ratio (ATIR), where the rated DC power from the PV array is increased while the rated AC power from the inverters remains the same, electrical yield from a PV system will increase [65]. Given that increased ATIR operates within the warranty conditions of the inverter supplier, it was found that production will increase linearly up to an ATIR of 1.2; thereafter, losses will be encountered to attain a maximum of 5% at an ATIR of 1.5 due to clipping. However, the losses incurred were seasonally dependent where the highest losses occurred during the summer month of December when radiation levels are the highest. This was attributed to the fact that the power generation ability of the inverter becomes the limiting factor instead of the power from the PV array.

In South Africa, tariffs are structured according to the season and time of day and therefore increase in the winter months. It was concluded that the losses incurred during the summer months will be negated by the financial gains in the winter season, whereas the annual losses will become less evident in the future due to PV module degradation.

When steps 1 to 4 are performed, the theoretical yield from a PV system can be increased. This will allow investors to accurately estimate the return on investment while the risk of EPC companies can be mitigated. However, it was important to validate this process in subsequent research. The following sections involve a case study where the above process was validated and updated accordingly.

3. Experimental Methodology

During the contract award negotiation phase, tendering EPC companies agree with the investor on a specified guaranteed electricity yield that the PV system will produce over its lifespan. If the system cannot provide the agreed-upon electricity yield, legal disputes may arise [35]. The contractual requirements expected from the PV system are obtained through simulations conducted during the feasibility study (in the case where the consumer determines the viability of the PV system before advertising it in the tender scheme) or when the EPC company provides a solution in their bid. The previous research, on which this article builds [19], proposed variables that must be investigated when simulations are conducted as part of a structured pre-assessment process. The purpose of this article is to validate the results from the pre-assessment process to a case study. For structuring purposes, Figure 1 summarizes the procedure followed in validating the proposed process:

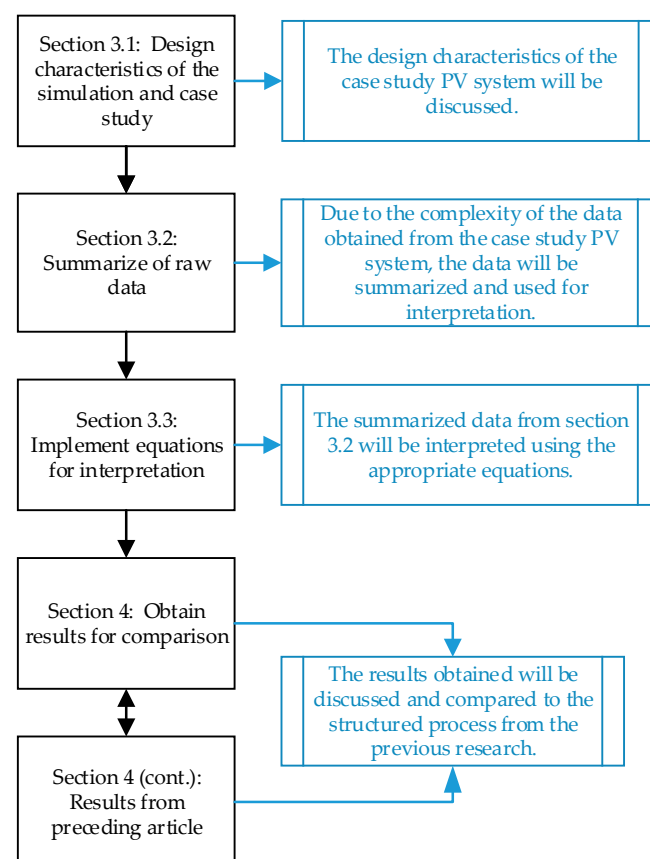


Figure 1. Illustration of the flow for Section 3 and how it will be used in Section 4.

Due to time constraints experienced during tender processes, simulation techniques are restrictive. Simulation is commonly applied to the location of the proposed PV system

where its operating conditions are disclosed when the project is advertised in the tender process. To replicate the conditions used in industry, PVSyst was used to simulate the electricity yield from the case study PV system [66]. The following is a summary of the design characteristics of the case study PV system.

3.1. Design Characteristics of the Simulation and Case Study

The basic layout of the components of the case study PV system is presented in Figure 2, followed by a summary of the content in the figure.

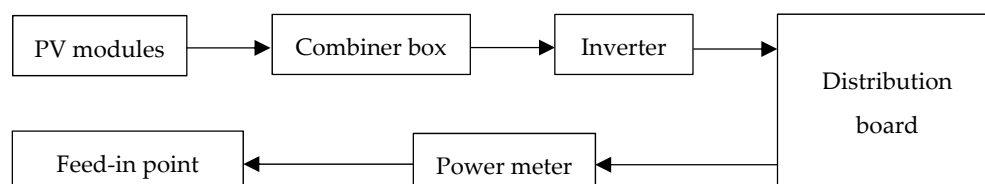


Figure 2. Layout of the PV plant based on the modelling approach [19].

- The PV modules are connected in various series and parallel combinations to form an array, each set of series PV modules being described as a string. The system was rated to 924.48 kWp and encompasses 2889×320 Wp modules. Each string consisted of 17 or 18 modules whereby it was ensured that parallel strings consist of the same number of modules in series. The PV modules were connected such that each string's modules were at the same inclination in each parallel combination.
- To combine the various strings, a combiner box is used so that a single cable (pre MPPT) can be used to feed the electricity into the inverter. It also enables the integration of DC surge arrestors to protect the system from lightning.
- 18×49.9 kVA grid-tie inverters were installed in the system.
- Once the AC source had been created by the inverters, each cable from the inverters was fed into the distribution board.
- The distribution board allows for the combination of the inverters as well as encompassing the circuit breakers and surge arrestors.
- The feed from the distribution boards is then directed to the feed-in point where the power meter is located. In the case of legal disputes, the basis for the dispute is reliant on the data from the power meter.
- Thereafter, the electricity was fed into the microgrid of the shopping centre for consumption, noting that the maximum generation ability of the solar system will not surpass the maximum load demand of the shopping centre.

The variables that were investigated during simulations entailed the PV modules and included the effect of tilt and orientation on the yield of the PV system; the effect of module degradation over the lifespan of the PV system; and the effect of variant ATIR. However, the results from the case study only reflected the effect of varying the tilt of the PV modules and the effect of module degradation over 24 months.

To investigate the effect of tilt, the PV modules were affixed to a curved roof such that $-9^\circ \leq \beta \leq 10^\circ$. A graphical illustration of the PV modules and its curved nature can be seen in Figure 3.

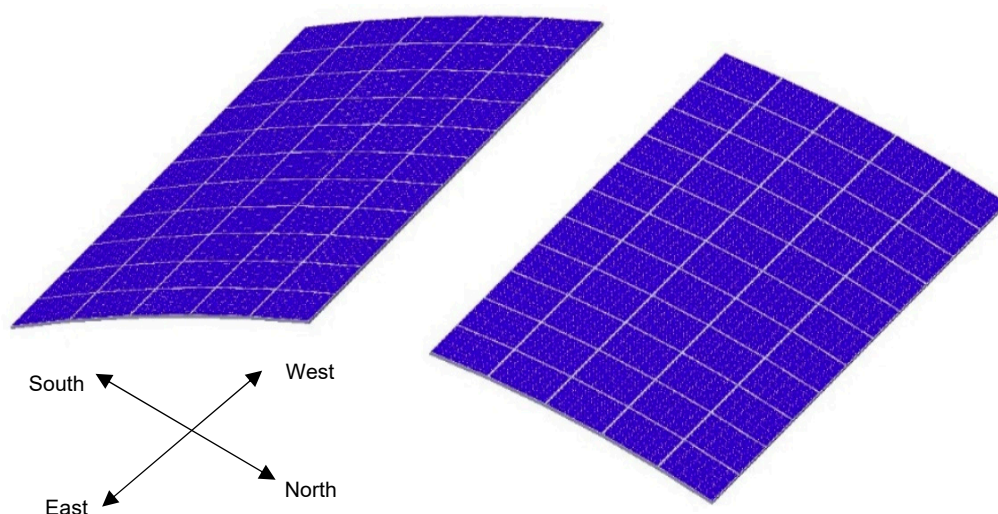


Figure 3. The curvature of the PV modules.

The relative angle of the PV modules for each maximum power point tracker (MPPT) was measured using an inclinometer placed on the frame of the module, certified to an accuracy of $\pm 0.2^\circ$. The average of six readings was used as the angle for the PV modules and each angle was then connected to an MPPT.

To maintain anonymity, the exact location of the case study is not disclosed. The location is, however, within a 40 km radius of OR Tambo International Airport. The operating conditions of the PV system are summarized in Table 1.

Table 1. Summary of operating conditions of the case study.

Parameter: System Design Characteristics		
Component Description	Name and Model/Quantity	Unit
Inverter	Kaco new energy Powador 60.0 TL3	
Number of inverters	18	
Rated inverter power	49.9	kVA
PV module	Canadian Solar Inc. CS6X-320P	
Number of PV modules	2 889	W
Rated PV module power (1 module)	320	W
Latitude (within a 40 km radius of the case study)	26°8'12.02" S	
Longitude (within a 40 km radius of the case study)	28°14'28.13" E	
Plane tilt	$-9 \leq \beta \leq 10$	°
Azimuth	0	°
PV module fixation method	Rooftop, approximately 200 mm from the surface of the roof	
DC cable length	50–200 (6 mm ² DC cable)	m
Approximate DC voltage loss at max load	0.36 – 0.84	%
AC cable length	75–200 (4 × 95 mm ² × 4 core SWA ECC armoured cables)	m
Approximate AC voltage loss at max load	3.54	%
System logging component	Solar-log 2000	
Parameter: System operating conditions		
Installation date of system components	1 August–30 November 2016	
System commission date	1 December 2016	
Duration of system analysis	24 months	
Start date of analysis	December 2016 (Month 1)	
Stop date of analysis	November 2018 (Month 24)	

For reference purposes, the simulation parameters of the case study from the previous research article [19] can be summarized in Table 2. The simulations were conducted

on PVsyst under the assumption that only 1 x 50 kWac inverter was generating electricity. The total electricity yield from the PV system would be calculated using the required multiplication factor.

Table 2. Summary of assumptions in PVsyst for simulation.

Component Description	Name and Model/Quantity	Unit
Parameter: System		
Inverter	Kaco new energy Powador 60.0 TL3	
Number of inverters	1	
Rated inverter power	49.9	kVA
PV module	Canadian Solar Inc. CS6X-320P	
Rated PV module power	320	W
Number of PV modules in array	Varies as a variable	
Rated PV array power	Varies as a variable	W
Parameter: PV module fixation properties		
Latitude (within a 40 km radius of the case study)	26°8'12.02" S	
Longitude (within a 40 km radius of the case study)	28°14'28.13" E	
Plane tilt	Varies as a variable	°
Azimuth	Varies as a variable	°
Data source in simulation	Meteonorm 7.2, Sat = 67%	
Parameter: Detailed losses		
Constant loss factor	15	W/m ² k
Wind loss factor	0	W/m ² k/m/s
Global wiring resistance (calculated)	226.5	mOhm
Voltage drop across series diode	0.7	V
Voltage drop between inverter and injection	1.7	V
Module efficiency loss	−0.4	%
Light-induced degradation	2	%
Module mismatch losses	2.5	%
String mismatch losses	0.5	%
Yearly loss factor through soiling	3	%
Incidence angle modifier losses	Definition as per PV module supplier	
Auxiliary power consumption	5	W
Duration of PV module degradation	Varies as a variable	
Average degradation factor	0.4	%/year
Imp RMS dispersion	0.4	%/year
Vmp RMS dispersion	0.4	%/year
System unavailability duration	7.3	days/year
Number of unavailability periods	3	periods/year

When simulations were conducted, it was assumed that the length of the DC cables was 200 m. The length was acquired using Google Earth as this method is commonly applied when an EPC company submits a proposal. However, due to the operational nature of a PV system, as-built DC cable lengths vary. As such, it was very difficult to accurately measure the exact length of the cables installed in the case study. It is important to note that cable length influences the voltage drop over the entire length of all of the cables—resulting in a reduction in electricity yield. Figure 4 illustrates the percentage voltage drop when the PV modules operate at the optimum current of 8.69A. The voltage drop was calculated based on the technical specification sheet obtained from the cable supplier [67,68].

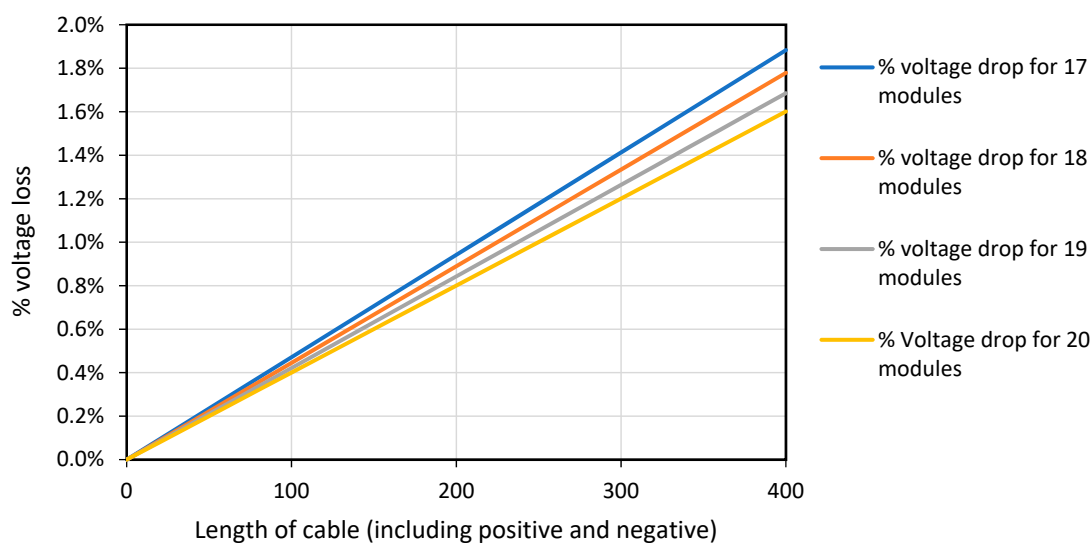


Figure 4. The percentile voltage drop over cables.

Regarding Figure 4, it can be seen that the effective voltage drop at 200 m was approximately 0.94% for 17 modules connected in series and reduced to approximately 0.25% when the DC cables were 50 m long. For 18 modules connected in series, the effective voltage drop over 200 m was approximately 0.89% and 0.23% for a cable length of 50 m. This implies that there was a maximum efficiency variation of approximately 0.69% for 17 modules connected in series and a maximum efficiency variation of approximately 0.66% for 18 modules connected in series. The data obtained from the inverters integrates the various losses from the PV modules into the inverter. Therefore, it is worth noting that a variation in transfer efficiency may be experienced but cannot be compensated for when interpreting the data.

Finally, it can be seen that as the number of modules connected in series increased, the voltage drop over the cable reduced. This is because the voltage increases as the number of PV modules in series increases, whereas the voltage loss over the cable is current-dependent: the current remains the same, irrespective of the number of PV modules connected in series.

It must also be noted that the PV module supplier estimates an efficiency loss of 0.41%/°C above 20 °C as the ambient temperature increases [61]. However, it was assumed that this loss remained the same for all of the PV modules since each PV module operated under the same climatic conditions. No corrections were made when the data was interpreted. It was also assumed that this loss was integrated within the algorithm of PVSyst and incorporated in the results obtained from the simulations.

3.2. Summarizing of Raw Data

The following is a summary of the method used to determine the net electricity yield from each MPPT within an inverter.

In order to simplify the interpretation method, the average production curve for each MPPT for each month was calculated. The average power production was obtained using a trendline acquired through Microsoft Excel. The average power from a single MPPT was used since the angle of inclination for the various PV modules connected to the MPPTs on each inverter was not the same. Figure 5 is an illustration depicting the average DC power production from an MPPT and how the trendline was generated.

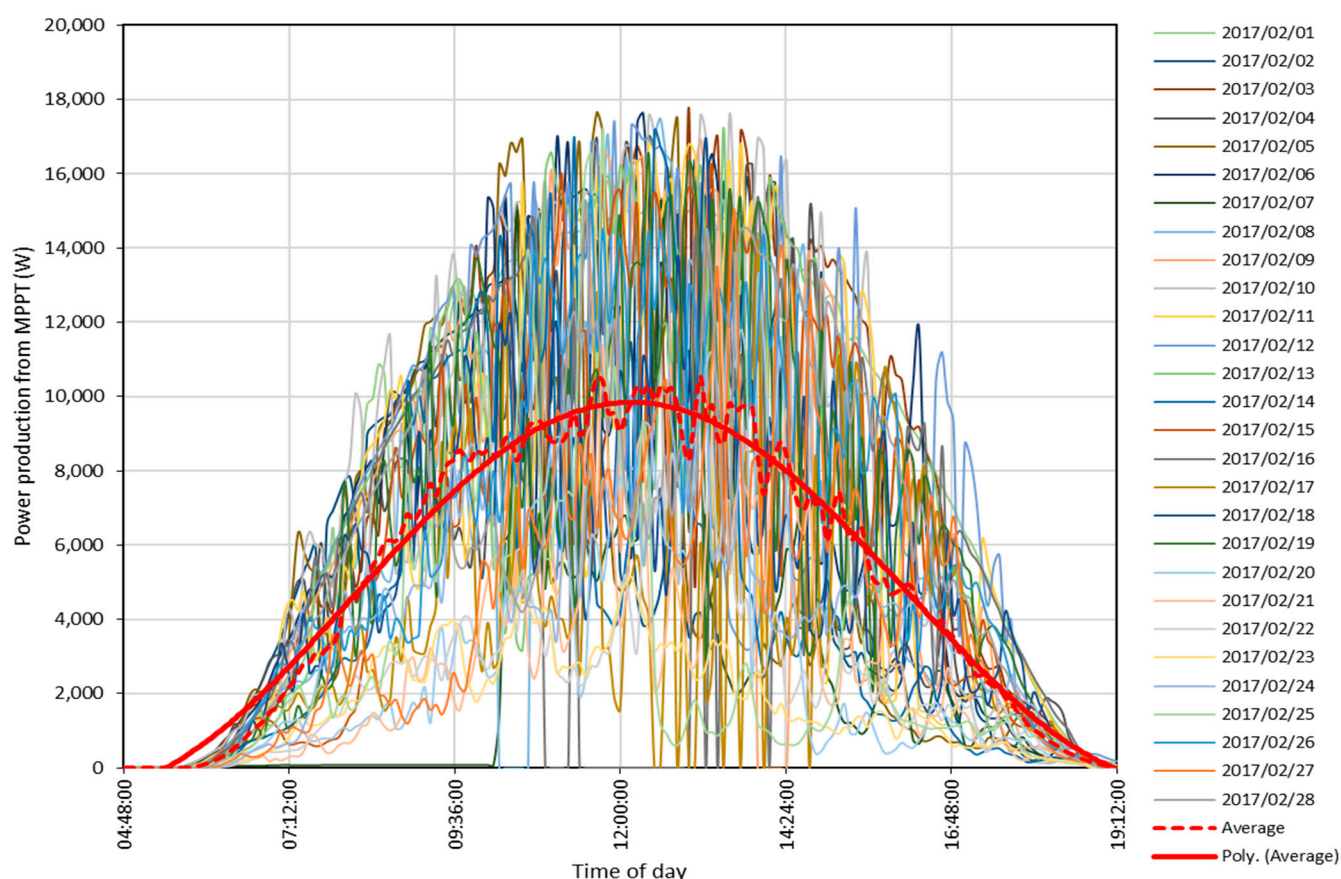


Figure 5. Illustration of the average power production from an MPPT of an inverter.

From Figure 5, it can be observed that production reduced as radiation levels reduced. This is commonly experienced in the early mornings during sunrise and late afternoons during sunset. Furthermore, a high standard deviation can be seen when comparing the average yield of the PV system to the yield of the individual days of each month. This was observed for each month, but the effects became less evident during the winter season when cloud cover reduced. In comparing the polynomial trendline of the average yield, peak production occurred at approximately 12:20 when 9700 W of the rated 17,280 W was produced—resulting in a specific yield of approximately 0.56 $\text{kW}_{\text{DC}}/\text{kW}_{\text{DC-Peak}}/\text{day}$. This implies that only approximately 56.13% of the rated power was produced, indicating high levels of unstable supply for a PV system. This is part of the reason as to why simulating a PV system is important. As mentioned earlier, electrical networks must be able to compensate for the high degree of instability, regardless of whether the source is from the electric utility or the backup generators [42–44].

Once the average production from each MPPT had been calculated, the information captured from the inverter was interpreted to generate the summary of results as in Figure 6. Each inverter provides the production from each array into the corresponding MPPT, the aggregate DC power (denoted as P_{dc}) from the three MPPTs and the aggregate AC power (denoted as P_{ac}) produced.

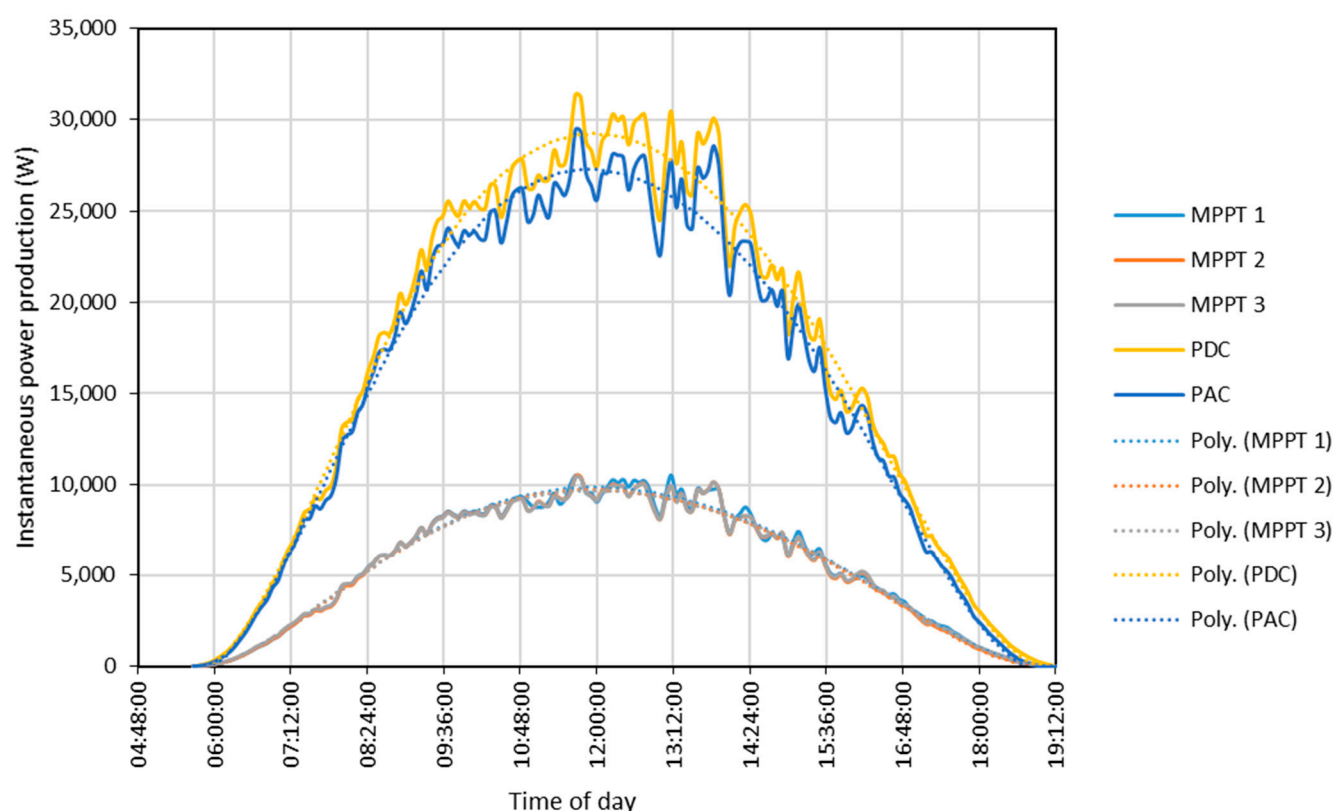


Figure 6. Summary of information captured from an inverter for each month.

The AC power fed into the grid in respect of each MPPT is not provided but was mathematically calculated for the subsequent analyses. Concerning Figure 6, the average power from the DC source was higher compared to the average AC power generated from the inverter. Further analyses of the data revealed that the conversion efficiency of the inverters varied between 92 and 98%, based on the time of day and the season. This implies that ambient temperatures, which vary as radiation levels vary, affect the conversion efficiency of the inverters. Furthermore, it can also be concluded that no inverter is the same as some efficiency variations occurred simultaneously. Research conducted by Corba et al. [48] indicates that an average daily efficiency of 90% can be expected. It was noted that efficiency varied according to factors such as to time of day and shading.

By considering this and the effect of AC cabling losses, the conversion efficiency of 94% $((98 + 92)/2 - 1\% = 94\%)$ was assumed for the subsequent calculations.

3.3. Equations for Interpretation

The following equations were applied in interpreting the summarized data from the PV system. This section is divided into two subsections according to the load demand factor (used for the load demand of the shopping centre) and the PV module factor (used for the PV system).

3.3.1. Load Demand Factor

The load demand of the case study was measured using an electricity meter connected on the incomer cable from the utility. To depict the effect of the PV system on the electricity load of the case study, the load demand was measured for two years before and for two years after the PV system was constructed. The average energy consumption is calculated as follows [19]:

$$\text{Average daily energy demand} = \frac{\sum \text{Energy demand}}{n_{\text{days}}}, \quad (1)$$

where:

$$\begin{aligned} \sum \text{Energy demand} &= \text{Energy demand (W)} \\ n_{\text{days}} &= \text{Number of days in the respective month} \end{aligned}$$

3.3.2. PV Module Factor

The following equation was applied in presenting the specific yield from the PV modules based on a specific time for each string [69]:

$$\text{Specific production}_{DC} = \frac{\text{Instantaneous daily yield}_{DC}}{\text{Maximum DC rating}} \times \frac{1}{n}, \quad (2)$$

where:

$$\begin{aligned} \text{Instantaneous daily yield}_{DC} &= \text{Yield from the string (kW)} \\ \text{Maximum DC rating} &= \text{Maximum power from the string (kWp)} \\ n &= \text{Number of days for corresponding month} \end{aligned}$$

The maximum power production from a string can be calculated using Equation (3):

$$\begin{aligned} \text{Maximum DC rating} = \\ P_{PV \text{ panel rated power}} \times N_{PV \text{ panels in series}} \times N_{strings \text{ in parallel}} \end{aligned} \quad (3)$$

where:

$$\begin{aligned} P_{PV \text{ panel rated power}} &= \text{Rated power of PV modules (320 W)} \\ N_{PV \text{ panels in series}} &= \text{Number of PV modules connected in series (17 or 18)} \\ N_{strings \text{ in parallel}} &= \text{Number of strings connected in parallel} \end{aligned}$$

Therefore, the average daily specific electricity yield can be calculated using the following equation:

$$\begin{aligned} \text{Average daily specific electricity yield} = \\ \frac{\text{Average power from MPPT} \times T_{\text{Duration of operation per day}}}{\text{Maximum DC rating} \times n}, \end{aligned} \quad (4)$$

where:

$$\begin{aligned} \text{Average daily specific electricity yield} &= \text{Average energy from MPPT (kWh)} \\ T_{\text{Duration of operation per day}} &= \text{Duration of operation (hour)} \end{aligned}$$

4. Results and Discussion

The results from the case study are compared to the proposed pre-assessment process in Section 4. Section 4.1 includes the evaluation of the load demand of the existing building due to the addition of the PV system; Section 4.2 includes the PV module load factor, whereby 4.2.1 deals with the effect of module tilt, Section 4.2.2 covers the effect of module degradation and 4.2.3. discusses the possible effects of increased ATIR. Finally, Section 4.3 summarizes the results and updates the pre-construction process accordingly.

4.1. Load Demand Factor of Case Study

Step 1 of the process involved analysing the existing load demand for the case study. As stated earlier, by analysing the existing load demand before construction commences, the integration between the PV system and the existing infrastructure can be optimized. Since a grid-tie system was used, energy could not be stored. This means that the consumer consumed the electricity as it was being generated by the PV system. Figure 7 depicts the effect of electricity production from the PV system on the load demand of the case study. The data were obtained by calculating the average load demand for the case study for two years before and two years after the PV system was commissioned.

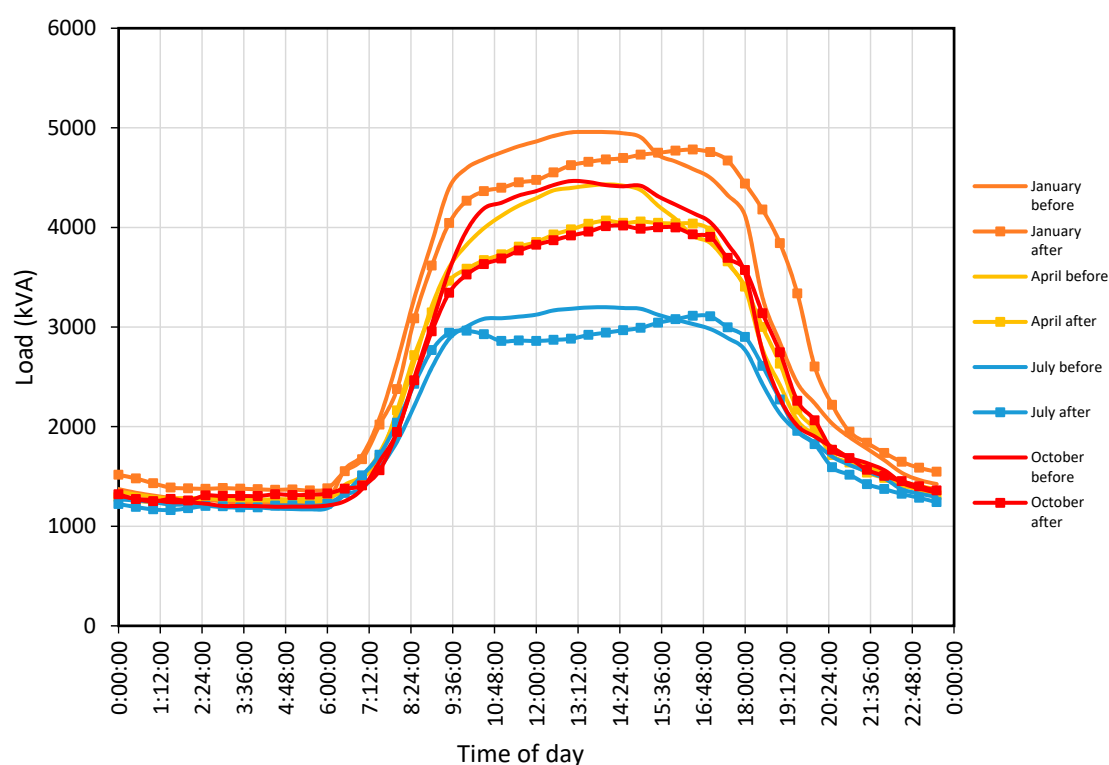


Figure 7. Average load demand variation of the case study for before and after construction.

Concerning Figure 7, it can be seen that the effect of the PV system became evident at approximately 09:30. This effect then progressively increased to attain a maximum at approximately 12:00 to 13:00, after which it decreased to completely subside at approximately 18:00–19:30 (depending on the season). The maximum effect of the PV system was at approximately 12:00 due to an increase in radiation levels. However, the PV system is rated to produce 898.20 KVA under ideal operating conditions. This equates to a penetration of approximately 15–20% of the maximum baseload at 12:00 in the summer season. Due to variability in supply from the PV array, the net average penetration of the PV system reduced to approximately 8–12% in the summer season. When considering the aggregate average daily load demand of the case study, the net penetration of the PV system reduces to approximately 2–5% of the baseload, depending on the season.

From the previous research [19], it was concluded that radiation levels affect the ambient temperatures of buildings, increasing building electricity consumption to reduce building temperatures [54,70]. When building temperatures are increased, air-conditioning and refrigeration systems increase their load, accordingly.

It can be seen that the load demand and the effect of the PV system increased in the summer and decreased in the winter. The discrepancy in load demand is attributed to a reduction in ambient temperatures, resulting in a reduction in cooling loads. This can be seen in Figure 7 where, on average, the maximum load demand in the winter season was approximately 60% of the maximum load demand during the summer season. Similarly, the effect of the PV system also reduced. The reason for this is that the radiation levels decreased.

4.2. PV Module Factor

This section includes a discussion of the electricity production variation based on the tilt of the PV modules, the effect of module degradation on the yield of the PV system over a period and a discussion of increased ATIR.

4.2.1. Electricity Production Variation Based on the Tilt

Literature [56,57] indicates that electrical yield from a PV system is influenced by varying the angle of tilt (β) and the relative orientation to the azimuth (Ψ). Step 2 of the proposed pre-assessment involves analysing its effect on the electricity yield. The case study consisted of a curved roof such that $-9^\circ \leq \beta \leq 10^\circ$ and the relative orientation to the azimuth remained consistent at 0° .

Figures 8 and 9 illustrate the average daily specific power production for a summer month and winter month, respectively, as a function of angle of tilt.

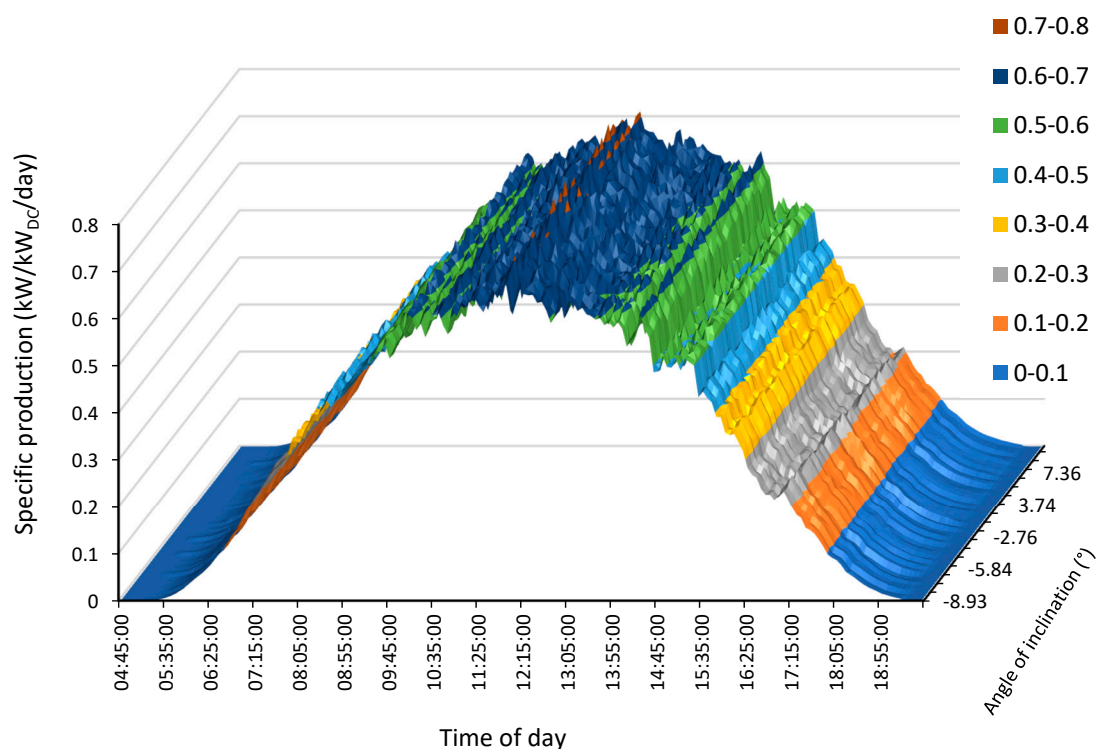


Figure 8. Average daily specific power production for January (summer season).

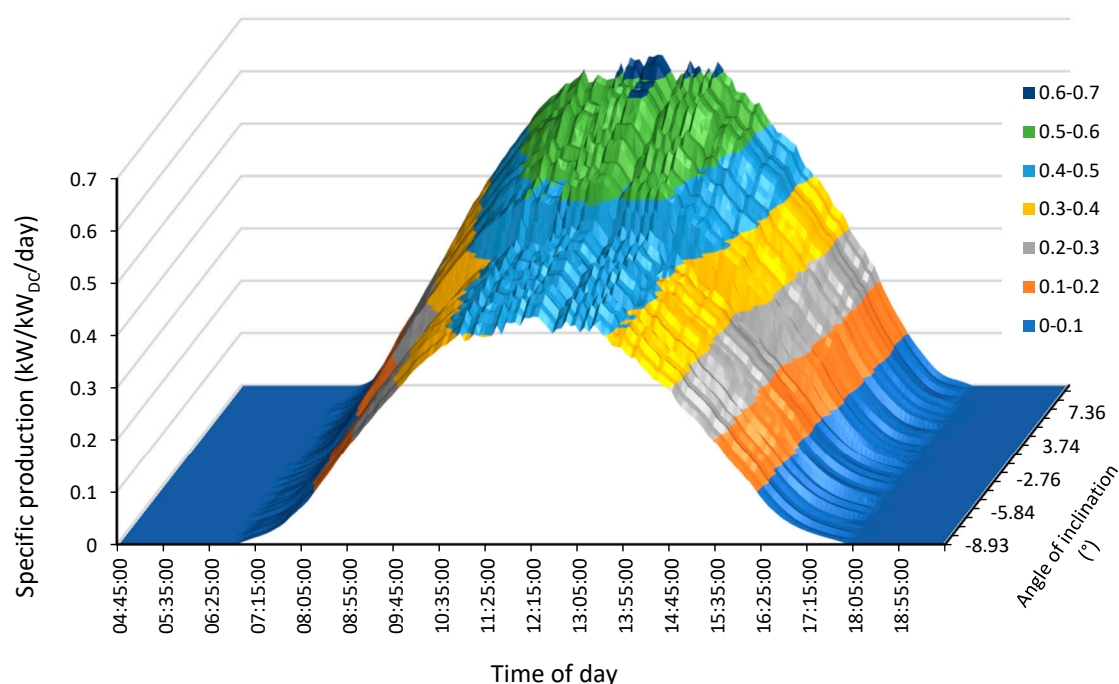


Figure 9. Average daily specific power production for July (winter season).

When comparing Figures 8 and 9, the effect of the angle of tilt became evident in the winter season but remained the same in the summer season. Peak production of 0.71 kW/kW_{DC}/day was attained when the PV modules were orientated at a 0° angle of tilt in the summer season near 12:20. It was also noted that the effect of a changed angle of inclination has little effect on the peak production, whereby it remained constant.

In the winter season, average peak production occurred when the PV modules were orientated in the northerly direction at 10° to attain a maximum of approximately 0.63 kW/kW_{DC}/day and 0.55 kW/kW_{DC}/day at 0°. This means that a reduction of approximately 23% occurs when the peak production in winter is compared to the summer season at 0°. However, a reduction of approximately 25–30% in peak radiation levels can be expected from the summer to winter season. The reason for the disparity could be twofold; firstly, the location of the case study experiences a precipitation in the summer season and since the data is obtained from calculating the average values, the results may be affected accordingly; and secondly, winter season sees a reduction in ambient temperatures which will increase the efficiency of the PV modules.

The reduction in radiation levels can be attributed to the relative position of the sun to that of the PV modules. Figure 10 is a non-scaled side view illustration of the sun relative to PV modules in the summer and winter seasons. In the summer season, the sun is positioned so that it tends towards a perpendicular direction to the horizon at approximately 12:00. However, in the winter season, the position of the sun is orientated in the northerly direction, meaning that modules orientated in the northerly direction produce more electricity.

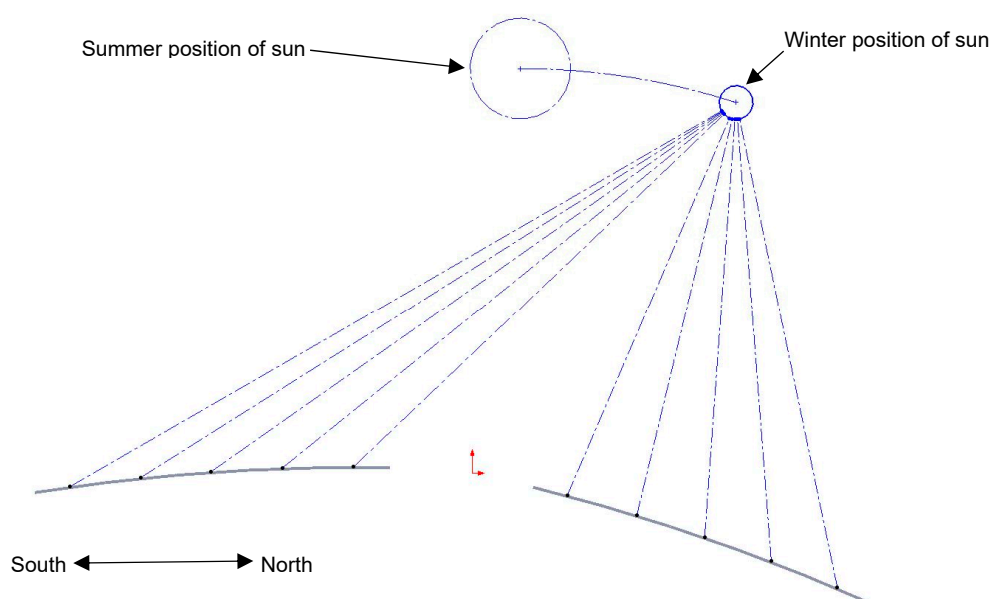


Figure 10. Non-scaled side view of PV modules in respect of the sun.

By comparing the production in Figures 8 and 9, it is noted that the effect of seasonal change influenced the time when daily production started. In the summer season, average daily production commenced at approximately 05:05 and subsided at approximately 19:45. In the winter season, average daily production started at approximately 06:35 and subsided at approximately 18:15. Furthermore, the effect of tilt resulted in PV modules orientated in the northerly direction producing electricity over a longer span by approximately 10 min in the winter season, while tilt had little effect in the summer season. This means that, since tariffs are increased during the high demand period (winter season) in the early mornings, savings are higher when the PV modules are orientated in the northerly direction.

The purpose of this article is to compare the results from the case study to those obtained through simulations in the pre-assessment process. Figures 11 and 12 illustrate the average daily electricity production from the pre-assessment process and case study, respectively. Figure 12 was generated based on linearly interpreting the data obtained from the average measurements of the case study over 24 months.

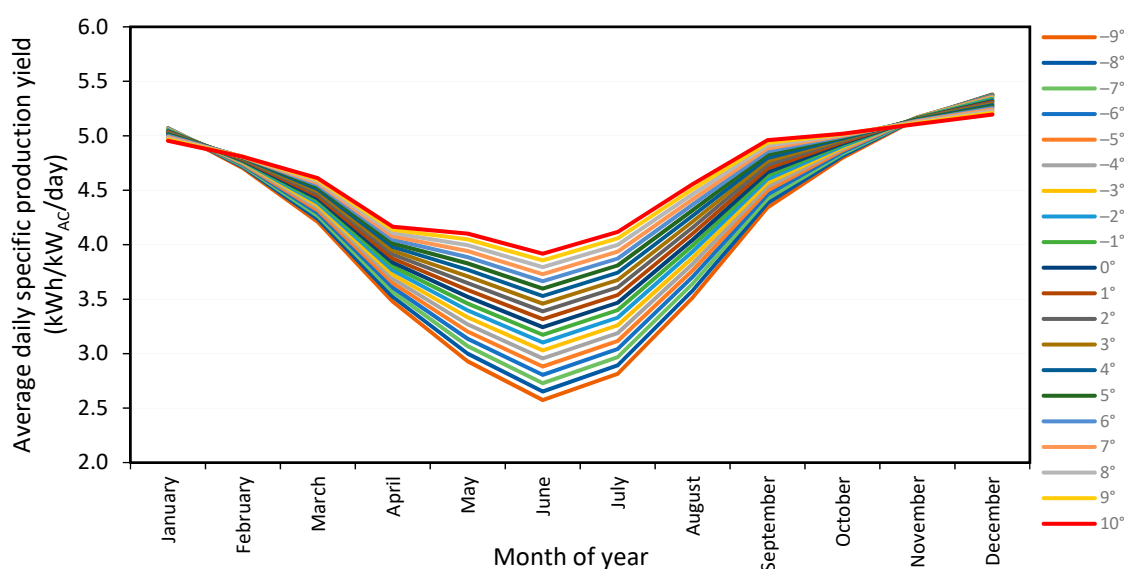


Figure 11. Average daily electricity production estimated in the pre-assessment process [19].

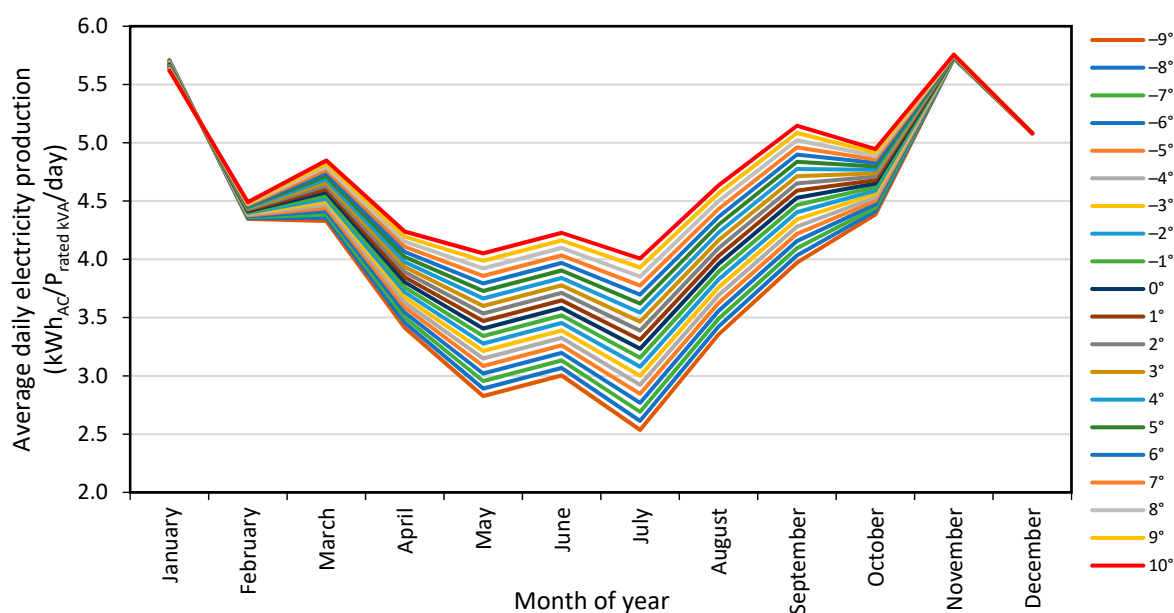


Figure 12. Average daily electricity production from case study PV system.

Based on Figure 12, peak production from the case study occurred during the summer months of November, December and January and then progressively decreased in the winter months. Peak specific production was 5.7 kWh/P_{rated} kVA/day in November (irrespective of the angle of inclination) and minimum production occurred during July, ranging from 2.53 to 4.00 kWh/P_{rated} kVA/day as the angle of tilt decreased from -9° to 10° . When comparing Figures 11 and 12, it can be noted that the results from the simulations are similar to those from the case study. However, the effect of varying the angle of inclination spanned over a higher range, resulting in a variation of 0.077 kWh/P_{rated} kVA/day/ 1° against the simulated variation of 0.066 kWh/P_{rated} kVA/day/ 1° in the winter season. The variation indicates that modules orientated in either a northerly or southerly direction operate at increased efficiency in the winter season compared to the results from the simulations. This is especially evident when comparing the results from Figures 8 and 9.

From Figure 11 it is estimated that production must attain a maximum in December. The results from the case study in Figure 12 indicate that peak production occurred during November to attain a maximum of 5.75 kWh/P_{rated} kVA/day. This deviation is attributed to the system being out of operation (the EPC company attempted to optimize the integration process between the PV system and the back-up generation units, resulting in downtime). From this, it can be concluded that the effect of downtime is higher in the summer season compared to the winter season. However, with structured tariffs applicable, the effect of down-time will be higher in the winter season when considering the return on investment. Since summer tariffs apply to autumn and spring, it is advised that intentional down-time be scheduled for spring and summer.

Finally, the PV system generated, on average, approximately 0.68% more electricity for each month compared to the simulation results. The simulation results estimate that the average daily energy yield over the year is approximately 4.37 kWh/kW_{rated} kVA/day, whereas the results from the case study yielded an average daily energy production of 4.40 kWh/kW_{rated} kVA/day. Considering that the PV system was not in operation for approximately 20 days (5 days due to system integration and 15 days due to system failure) against the estimated 14 days (7 days per year) from simulations, it can be concluded that a PV system will produce more electricity compared to what is simulated. From this, it can be concluded that the results from simulations are inherently conservative.

4.2.2. Electricity Production loss due to PV Module Degradation

The case study investigated module degradation over 24 months. The results of the analysis are illustrated in Figure 13. Figure 13 was generated based on linear regression where a trendline was generated for the yield for each month and the corresponding angle of inclination. The months (December, September and October) where the system was not in operation for any period were not considered, as this would have influenced the results. It must be noted that due to the construction process, the PV modules were affixed to the roof approximately 3 months before the PV system was commissioned. Therefore, it is assumed that the PV modules lost approximately 3% of their rated power generation ability before the PV system was commissioned, as per the module supplier. As such, it can be assumed that the years following commissioning will only see an annual decrease of approximately 0.7%/annum [61].

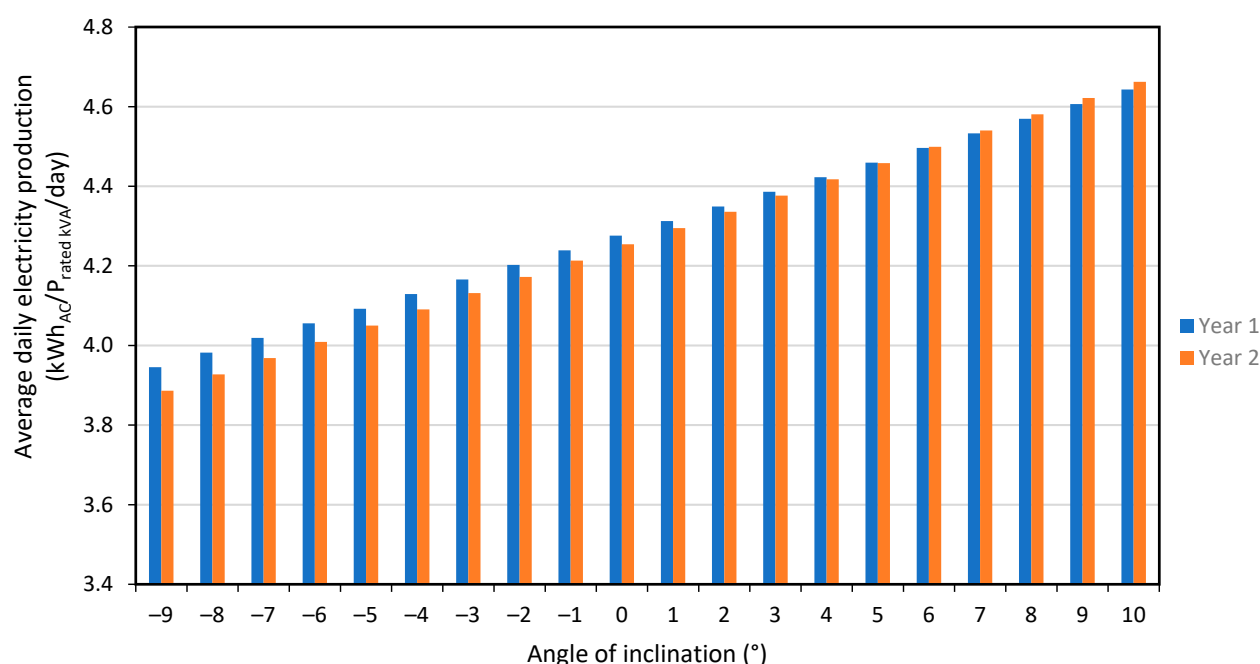


Figure 13. Effect of module degradation on case study PV system.

The effect of module degradation, specifically for south-orientated PV modules, can be seen in Figure 13. For south-orientated PV modules, module degradation between years 1 and 2 resulted in approximately 1.49% of the rated power generation ability being lost at 9°. The percentile degradation then progressively decreased as the angle of inclination was increased in the northerly direction, until the power generated in year 2 at 6° in a northerly direction surpassed the electricity generated at the same angle for year 1. The electricity generated for north-orientated PV modules tended to increase in year 2 as the angle of inclination was increased to eventually reach a maximum deviation of 0.42% at 10°. The literature suggests that, although degradation varies according to operating and climatic conditions, the effect of degradation will be evident. The increase in yield for north-orientated PV modules is attributed to the elimination of three months during the summer and spring seasons from the analysis, implying that the data was susceptible to the interpretation method used. Since the data were mostly from the winter season, the effect of varying climatic conditions (clouding) in the summer season affected the net yield disproportionately for PV modules orientated in the southerly direction.

By considering the average yield for the relative angle of inclination, it was found that degradation between years 1 and 2 resulted in an electricity reduction of 0.46%/annum. The module supplier warrants a degradation factor of approximately 0.7%/annum [61]. This indicates that there is a variation of approximately 0.24% between the measured

data and the module supplier warranty. This result is lower in comparison with research conducted by Jordan and Kurtz [63], who investigated the degradation of PV modules. They concluded that a reduction of approximately 0.64%/year can be expected. However, research conducted by Silvestre et al. [62] over 3 years on silicon-based PV modules found that degradation of 0.74%/year can be expected. From this, it can be concluded that module suppliers are generally conservative in estimating their degradation factor while climatic conditions affect the PV modules differently. It is, however, advised that additional testing be conducted over a longer period to increase the accuracy of these findings and to consider the effects of the summer season in greater detail.

4.2.3. Array-to-Inverter Ratio (ATIR) Variation

The effect of varying ATIR was also investigated in the pre-construction process. However, due to the design characteristics of the case study PV system, it was not analysed in this research article. Based on the results from the two preceding analyses, it can be concluded that an increasing ATIR will behave similarly to the results obtained in the previous article [19].

4.3. Validation of Pre-Assessment Process

To validate the pre-assessment process, Table 3 compares the results from the pre-assessment process to those from the case study PV system. In addition, a recommendation is made to assist the consumer in mitigating their risk or to aid the EPC company in generating warranty conditions. The process is to be applied during the feasibility study or when the EPC company submits their proposal for the tender process.

Table 3. Summary of effect of the post-construction process on proposed pre-construction process.

Steps in Process	Variations/Effect from the Case Study	Recommendations
Step 1: Analyse the existing load demand of the premises for the intended PV system	After analysis, it was found that the PV system affected the load demand of the case study. Due to the PV system, load demand decreased at 09:30 to approximately 16:30, after which the effect of the PV systems became limited. Furthermore, the presence of a PV system can reduce the existing load demand since cooling loads are decreased – however, this must be verified.	Design the size of the PV system according to load demand from the consumer, considering limiting factors such as generator integration between the PV system and the back-up generators and system registration requirements.
Step 2: Investigate the effect of tilt and orientation	Results from the case study indicate that the effect of tilt and orientation remained the same. There was a 0.68% variation between simulation and actual yield.	EPC company can warrant an electricity yield of 95% and higher from the results obtained through simulation.
Step 3: Investigate the effect of module degradation on electricity yield	PV module suppliers warrant an annual degradation of 0.7% per annum. Results from the case study reveal that module degradation was only 0.46% per annum.	EPC company can warrant module degradation of between 0.46% and 0.7% per annum. However, further analysis is recommended.
Step 4: Investigate the effect of varying the ATIR	This was not investigated in the research. However, based on the accuracy of the above results, the results from the simulations are valid.	PV systems can be designed so that ATIR is increased to approximately 1.5. Energy will be lost beyond an ATIR of 1.2 to reach a maximum of approximately 5% at an ATIR of 1.5. However, this will be offset due to module degradation after approximately 10.8 years.

5. Conclusions

This research validated a proposed pre-assessment process that was generated in a previous article. Research that defines a structured pre-assessment process to be implemented by investors to estimate the electricity yield from a PV system within South Africa, is limited. This research aimed to provide such a process whereby the risk exposure of the investor can be reduced.

In developing the pre-assessment process, a case study was used to investigate the behavioural characteristics of a PV system – resulting in the development of the process. All of the relevant characteristics that must be considered, before construction commences, is included in the research.

The literature review provided a background of the various phases of a PV system; literature relating to existing simulation techniques; and a summary of the preceding article on which this research was built. The experimental methodology discussed the design parameters of the case study, the assumptions made simulating the electricity yield from the case study and the equations used in interpreting the data. The results from the research were interpreted to derive the structured pre-construction process that must be applied:

- Step 1: Analyse the existing load demand of the premises for the intended PV system. In doing so, design restrictions relating to the integration of the system into existing infrastructure is investigated. This research analysed the effect the PV system had on the case study load demand after construction was completed.
- Step 2: Analyse the effect of tilt and orientation. If it is analysed, then investors can design building architecture to optimize the electricity yield from the PV system. This is especially important when new buildings are being constructed.
- Step 3: Analyse the effect of module degradation on electricity yield. This is important if future electricity yield must be estimated. Module degradation has a detrimental effect on the yield of a PV system over a period. This will be especially useful when investors have to decide between investing immediately or waiting for improved technologies.
- Step 4: Analyse the effect of varying the ATIR. Increased ATIR is important when considering the gains of electricity potential in the winter season. Return on investment losses incurred in the summer season, due to clipping, will be recuperated by the gains in the winter season since the tariffs are structured to be more expensive in winter.

The results from the research indicate that by implementing the proposed process, accuracy of yield estimations can be increased while electricity yield from a PV system will be increased. This will promote the deployment of PV technologies, resulting in a more sustainable future.

Future recommendations to optimize the simulation process includes performing a financial analysis to a case study where structured tariffs are applied and using a case study where increased ATIR is implemented.

Author Contributions: Conceptualization, D.J.v.V.; methodology, all authors; software, D.J.v.V.; validation, all authors; formal analysis, D.J.v.V.; data curation, D.J.v.V.; writing—original draft preparation, D.J.v.V.; writing—review and editing, A.L.M. and J.H.C.P.; visualization, D.J.v.V.; supervision, A.L.M. and J.H.C.P. All authors have read and agreed to the published version of the manuscript.

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Informed Consent Statement: “Informed consent” was obtained from case study organisation to utilise data in analysis.

Data Availability Statement: Not applicable.

Conflicts of Interest: The authors declare no conflict of interest.

Nomenclature

β : angle of tilt; Ψ , azimuth angle.

Abbreviations

ATIR: array-to-inverter ratio; EPC, engineering, procurement and construction; IRP, Integrated Resource Plan; GDP, gross domestic product; MPPT, maximum power point tracker; NERSA, National Energy Regulator of South Africa; PR, performance ratio; PV,

photovoltaic; ROI, return on investment; SDGs, sustainable development goals; SLA, service level agreement; Wp, Watt-peak.

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